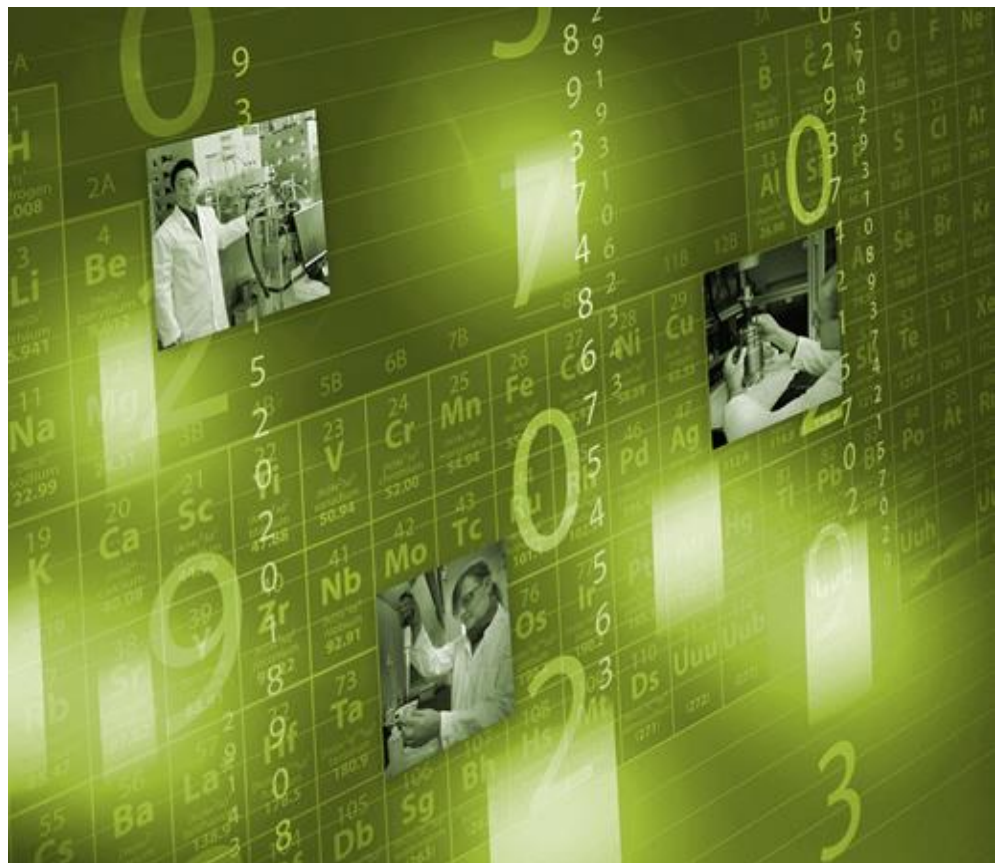


CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

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ACRONYMS AND ABBREVIATIONS

°C	Degrees Celsius	DSI	Dry sorbent injection
°F	Degrees Fahrenheit	EAF	Equivalent Availability Factor
AACE	AACE International (formerly American Association of Cost Engineering)	EFOR	Equivalent Forced Outage Rate
abs	Absolute	EGU	Electricity-generating unit
ABS	Ammonium bisulfate	ELG	Effluent Limitations Guidelines
ACC	Air-cooled condenser	EMF	Emission modification factors
acfm	Actual cubic foot per minute	Eng'g CM	
ACI	Activated carbon injection	H.O.& Fee	Engineering, construction, management, home office, and fees
ANSI	American National Standards Institute	EPA	Environmental Protection Agency
AP	Auxiliary power	EPC	Engineering, procurement, and construction
AQCS	Air quality control system	EPCC	Engineering, procurement, and construction cost
Ar	Argon	EPRI	Electric Power Research Institute
ASME	American Society of Mechanical Engineers	ESP	Electrostatic precipitator
Aspen	Aspen Plus®	FAC	Flow-assisted corrosion
atm	Atmosphere	FD	Forced draft
B&W	Black and white	FFA	Film-forming amine
BACT	Best available control technology	FFP	Film-forming product
BEC	Bare erected cost	FG	Flue gas
BFB	Bubbling fluidized bed	FGD	Flue gas desulfurization
BFD	Block flow diagram	FGR	Flue gas recirculation
BFW	Boiler feedwater	FRP	Fiberglass-reinforced plastic
BLHR	Burner-level heat release	ft	Foot
BMCR	Boiler maximum continuous rating	ft ³	Cubic foot
BOP	Balance of plant	gal	Gallon
Btu	British thermal unit	GJ	Gigajoule
CaCO ₃	Calcium carbonate	gpm	Gallons per minute
CaSO ₄	Calcium sulfate	H	Height
CDS	Circulating dry scrubber	H ₂ O	Water
CF	Capacity factor	HCl	Hydrogen chloride
CFB	Circulating fluidized bed	HCO ₃	Bicarbonate
CH ₄ S	Methanethiol	HEP	High-energy piping
cm	Centimeter	Hg	Mercury
CO	Carbon monoxide	HHV	Higher heating value
CO ₂	Carbon dioxide	HMI	Human machine interface
CT	Combustion turbine	hp	Horsepower
db	Dry basis	HP	High pressure
DCS	Distributed control system	hr	Hour
DOE	Department of Energy		

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HVAC	Heating, ventilation, and air conditioning	N/A	Not available/applicable
Hz	Hertz	N ₂	Nitrogen
I/O	Input/output	NERC-GADS	North American Electric Reliability Corporation – Generating Availability Data System
ID	Induced draft	NETL	National Energy Technology Laboratory
in. H ₂ O	Inches of water (pressure)	NFPA	National Fire Protection Association
IP	Intermediate pressure	NGCC	Natural gas combined cycle
ISO	International Organization for Standardization	NH ₃	Ammonia
kg	Kilogram	NOAK	N th -of-a-kind
kJ	Kilojoule	NO _x	Nitrogen oxides
kPa	Kilopascal	NPHR	Net plant heat rate
kV	kilovolt	NPO	Net plant output
kW	Kilowatt	NSPS	New Source Performance Standards
kWh	Kilowatt-hour	NTO	Net turbine output
kWt	Kilowatt thermal	NTU	Nephelometric turbidity unit
L	Length	O&M	Operation and maintenance
lb	Pound	O-H	Overhead
lbm	Pound-mass	O ₂	Oxygen
LHV	Lower heating value	OEM	Original equipment manufacturer
LNB	Low-NO _x burner	OFA	Overfire air
LP	Low pressure	OP/VWO	Over pressure/valves wide open
lpm	Liter per minute	ORP	Oxidation-reduction potential
LTSA	Long-term service agreement	PA	Primary air
m	Meter	PAC	Powdered activated carbon
m ³	Cubic meter	PC	Pulverized coal
MATS	Mercury and Air Toxics Standards	pH	Acidity
MCC	Motor control center	PJFF	Pulse-jet fabric filter
mg/Nm ³	Milligrams per cubic meter	PLC	Programmable logic controller
min	Minute	PM	Particulate matter
MJ	Megajoule	POTW	Publicly owned treatment works
mm	Millimeter	ppb	Parts per billion
MM	Million	ppm	Parts per million
MMacf	Million actual cubic feet	ppmv	Parts per million, volume
mol%	Mole percent	ppmw	Parts per million, weight
MPa	Megapascal	ppmwd	Parts per million, weight, dry
MST	Main steam temperature	ppt	Parts per trillion
MVA	Megavolt amps	psi	Pounds per square inch
MW	Megawatt		
MWe	Megawatt-electric		
MWgross	Megawatt-gross		
MWh	Megawatt-hour		
MWhgross	Megawatt-hour-gross		
MWhnet	Megawatt-hour-net		
MWnet	Megawatt-net		

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

psia	Pounds per square inch, atmospheric (pressure)	SO ₂	Sulfur dioxide
psig	Pounds per square inch, gauge	SO ₃	Sulfur trioxide
PTC	Power Test Code	ST	Steam turbine
QGEES	Quality Guidelines for Energy System Studies	STG	Steam turbine generator
R&D	Research and development	SubC	Subcritical
RAM	Reliability, availability, and maintainability	TBtu	Trillion Btu
RGFF	Reverse gas fabric filter	TOC	Total overnight cost
RHT	Reheat	tonne	Metric ton
RO	Reverse osmosis	TPC	Total plant cost
SA	Secondary air	tph	Tons per hour
SC	Supercritical	U.S.	United States
SCC	Stress corrosion cracking	UCC	United Conveyor Corporation
scf	Standard cubic foot	V	Volt
scfm	Standard cubic foot per minute	V-L	Vapor-liquid
scm	Standard cubic meter	VFD	Variable-frequency drive
SCR	Selective catalytic reduction	W	Width
SDA	Spray dryer absorber	WFGD	Wet flue gas desulfurization
SNCR	Selective non-catalytic reduction	wt%	Weight percent
		yr	Year
		ZLD	Zero liquid discharge
		μS/cm	Microsiemens per centimeter

EXECUTIVE SUMMARY

Decarbonization is a pressing matter being addressed through international agreements and national initiatives. Prominent sources of carbon-free electrical power – wind and solar – are variable in output, requiring either energy storage or reliance on under-utilized dispatchable generating capacity to accommodate periods (daily and seasonally) when carbon-free generation does not meet demand.

The United States has plentiful, low-cost natural gas resources - studies of aggressive decarbonization scenarios of the US energy sector suggest that the variability of carbon-free power can be economically addressed using dispatchable natural gas-fueled generation. [1] [2] [3] Globally, natural gas resources are not as plentiful or low cost; consequently, some regions of the world are anticipated to continue to rely upon coal generation, even as they pursue decarbonization efforts. Global coal consumption in 2022 has returned to historic highs due to a combination of geopolitical and economic factors and is expected to climb despite global decarbonization efforts. [4] [5] Increased demand for affordable, reliable electricity in developing nations is a major driver behind this trend. For perspective, in 2022 China and India announced plans to increase domestic coal production by 700 million tons per year. [6] This increase alone would be greater than the total U.S. coal production of 600 million tons per year. Total coal production of these two nations would then be approximately nine times the amount of total U.S. coal production.

Traditionally, coal-fueled power generating plants have been designed and optimized for steady-state full-load (i.e., baseload) operations; however, to support the increased utilization of variable renewable generation in these coal-dependent regions, plant designs must target low-capacity factor coal plants with increased emphasis on flexibility attributes such as start-up times, ramp rates, minimum load, and part-load heat rates.

While much work has been performed on the improvement of the flexibility for existing coal plants originally designed for baseload service, little public literature exists on clean sheet design for flexible operation. This conceptual design study aims to define the features, performance characteristics, and costs for greenfield coal plants intended for flexible operation. Quantifying these characteristics provides critical information required by utility owners, grid planners, energy market modelers, and energy policy decision makers in coal-dependent regions of the world to better understand how coal-fired power plants can support a transition to low carbon generation. The conceptual design was carried out by relying upon the performance and cost of state-of-the-art commercial process technologies and equipment. The plant cases in this study are not equipped with carbon capture; however, the integration of post-combustion capture systems is recommended as follow-on analysis.

CASE SELECTION AND ANALYSIS METHODOLOGY

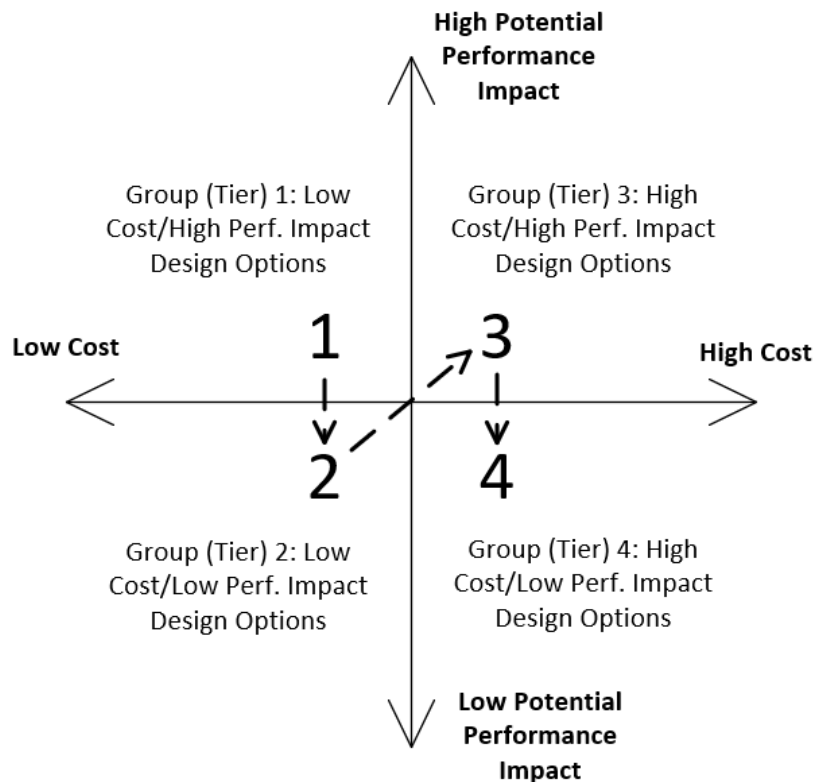
As part of this study, 87 flexibility options (provided in Section 2.8) were identified from literature sources (supplemented with Black & Veatch industry experience). Of these, three were excluded due to constraints imposed by the selected coal type and the desire to minimize the use of auxiliary fuel and remain regionally agnostic (excluded options are identified in

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 2-4). Six additional flexibility options were excluded due to being mutually exclusive with other flexibility options that were determined to be more beneficial or more applicable to this study (detailed in Exhibit 4-12).

To efficiently evaluate the remaining 78 flexibility options, their potential relative cost and performance impact were qualitatively evaluated on a “low” to “high” basis and grouped into four tiers based on the Kano model. A graphical depiction of the Kano methodology is provided in Exhibit ES-1.

Exhibit ES-1. Kano model for establishing plant flexibility option hierarchy and analysis cases



These designations were applied relatively (within each flexibility metric’s list of potential options) and assigned based on information collected during the literature review, as well as Black & Veatch experience based on analysis of these options in the past for other EGUs looking into retrofit opportunities for improving flexibility.

Each flexible plant case that is developed in this study assumes that an entire tier of flexibility options was installed on the plant. Furthermore, the tiers of flexibility options were assumed to be installed cumulatively, so each case contains new flexibility options in addition to the flexibility options that were installed on the previously developed case(s).

Ten power plant configurations were analyzed in this report, five subcritical and five supercritical configurations. A summary of the configurations is shown in Exhibit ES-2:

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Two baseload pulverized coal (PC) power plant configurations: the baseload plants are intended to serve as reference plants that are similar to the flexible plants in configurations and capacities.
- Eight flexible PC power plant configurations: the flexible plant cases utilized certain “flexibility options” in their design. These flexibility options are design strategies or operation & maintenance (O&M) procedures that are intended to improve flexibility (e.g., minimum load, ramp rate, part-load efficiency) of the plant.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit ES-2. Case configuration summary

Case Name	B11A-F0	B11A-F1	B11A-F2	B11A-F3	B11A-F4	B12A-F0	B12A-F1	B12A-F2	B12A-F3	B12A-F4
Unit Cycle	PC									
Steam Cycle, psig/°F/°F	1,800/1,000/1,000					3,500/1,100/1,100				
Intended Operational Profile	Baseload	Flexible				Baseload	Flexible			
Flexibility Option Tiers in Plant Design	Baseload Options Only	Tier 1	Tiers 1 and 2	Tiers 1, 2, and 3	Tiers 1, 2, 3, and 4	Baseload Options Only	Tier 1	Tiers 1 and 2	Tiers 1, 2, and 3	Tiers 1, 2, 3, and 4
Number of New Flexibility Options	N/A	38	9	21	2	N/A	37 ^B	9	19 ^C	2
Total Number of Flexibility Options ^A	N/A	38	47	68	70	N/A	37	46	66	68
Oxidant	Air									
Sulfur Removal	FGD System/Gypsum									
PM Control	Baghouse									
NO _x Control	LNB w/OFA and SCR									
Process Water Treatment	Spray dryer evaporator									

^A Due to the cumulative method of applying the flexibility options, the total number of flexibility options is the sum of the current case and all prior cases

^B As all supercritical cases are sliding pressure, Flexibility option 59 “Steam turbine sliding-pressure operation” introduced in Tier 1 for subcritical cases is not applicable to supercritical cases

^C As all supercritical cases use a Benson boiler, Flexibility option 2 “decrease drum holding time to reduce drum diameter and drum wall thickness” introduced in Tier 3 for subcritical cases is not applicable to supercritical cases. Additionally, supercritical plants typically include a condensate polishing system. Therefore, Flexibility option 12 “Use of condensate polishing system to maintain cycle chemistry parameters during shutdown and layup periods and reduce startup times” introduced in Tier 3 for subcritical cases is not applicable to supercritical cases

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

All plant configurations were evaluated based on installation at a greenfield site. Capacity factors (CFs) were not defined for any of the plants evaluated in this report, since the CF is heavily dependent on the operational profile of the plant, which will depend upon the details of the particular market in which the plant is deployed.

The nominal gross plant output for all baseload plants in this study is 150 megawatt (MW) and 300 MW for the subcritical and supercritical configurations, respectively. The plant sizes were selected to align with the average size of similar units being installed in global markets, and it aligns well with the proven size range for subcritical and supercritical PC units. Additionally, the unit sizes are considered small enough to be applicable to a variety of global regions while being large enough to leverage economies of scale. The coal feed rate was varied between cases to maintain constant gross steam turbine output, accounting for changes in the required extraction steam.

Air emission controls for all technologies are based on meeting the limits of the February 2013 update to the New Source Performance Standards (NSPS) for sulfur dioxide (SO₂), nitrogen oxide (NO_x), and particulate matter (PM), and the March 2013 update of the Utility Mercury and Air Toxics Standards (MATS) for mercury (Hg) and hydrochloric acid (HCl). Based on the assumptions presented in this study, all plants comply with the December 2015 update to the Effluent Limitation Guidelines (ELG).

For all cases, Hg and HCl are controlled with activated carbon injection (ACI) and dry sorbent injection (DSI), SO₂ is controlled with wet flue gas desulfurization (FGD), NO_x is controlled with low-NO_x burners (LNBs) with overfire air (OFA) and selective catalytic reduction (SCR), and PM is controlled with a baghouse. A spray dryer evaporator is included to treat FGD blowdown.

This report reflects varying degrees of technology vendor input for PC plant updates to the pollution control equipment and process water treatment systems^a; however, the final assessment of performance and cost was determined independently and is not endorsed by the individual vendors.

The consistent basis for technology comparison originates from NETL's Quality Guidelines for Energy System Studies (QGESS) documents, which provide guidance on topics ranging from how to perform a techno-economic analysis to recommended feedstock specifications and pricing, [7] as well as recommendations for performance modeling assumptions, [8] and guidance for cost estimation methodology. [9]

The methodology for developing the performance results presented in this report included performing steady-state simulations of the power plant configurations using the Aspen Plus® (Aspen) process modeling software. Performance curves were estimated for each case by modeling the steady-state performance at discrete part load operating points and using a best-fit approximation. As such, results at each discrete load point may not exactly match vendor data, and interpolation between data points may not be accurate.

^a One of the design objectives of this study was to present PC plants that are compliant with the Effluent Limitations Guidelines (ELG). Under the assumptions of this study, blowdown from both the steam cycle and cooling tower are exempt, provided that no process wastewater is utilized as makeup to either of these systems.

The methodology in which water discharged to local waterways is eliminated is referred to as zero liquid discharge (ZLD).

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

The major plant equipment performance and process limits (including the data used to develop performance curves) were based on published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment. [8] Mass and energy balance data from the Aspen models were used to size major pieces of equipment, which formed the basis for developing the cost estimates.

The methodology for assessing plant flexibility (e.g., ramp rate, minimum load) included utilizing results of modeled unit performance following design improvements, utilizing industry references that outlined flexibility that was empirically achieved by coal-fired EGUs, and/or utilizing Black & Veatch in-house data.

The capital and operating costs for the major equipment and plant sub-systems were estimated by Black & Veatch based on the simulation results using an in-house database, legacy plant estimates, and conceptual estimating models. The cost results were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects. The costs results are reported in 2018 United States dollars (USD).

The baseline fuel cost for this analysis is specified in the QGESS document “Fuel Prices for Selected Feedstocks in NETL Studies.” [10] The levelized, delivered price for Illinois No. 6 coal delivered to the Midwest is \$2.11/GJ (\$2.23/MMBtu), on a higher heating value (HHV) basis and in 2018 USD. The levelized, delivered price for natural gas delivered to the Midwest is \$4.19/GJ (\$4.42/MMBtu), on an HHV basis and in 2018 USD.

The cost of electricity is not reported, since it is not an adequate metric for characterizing the value of the operational flexibility that the plant designs in this study pursue.

There are several load profiles (e.g., two-shifting, peaking, baseload) a plant can operate in and numerous potential market pressures that plants operating today experience, such as:

- Regional variations in operating schemes between the various independent system organizations (e.g., choosing to shutdown overnight rather than staying online)
- Regional renewables penetration
- Regional regulations that affect load profile
- Revenue generation opportunities in the “spot market” that could make a unit’s operating profile seem atypical compared to its peers

The results shown for the cases considered in this study are not intended to reflect a specific load profile or all the potential market pressures experienced by plants operating today, or the price consumers can expect to pay. Rather, the primary focus is a repeatable and justifiable methodology to develop those results, built with industry and vendor input, which ultimately leads to an independent benchmark for the cases considered. This outcome is of significant value to both internal and external stakeholders.

RESULTS ANALYSIS

Exhibit ES-3 and Exhibit ES-4 shows the performance and environmental profile summary for subcritical and supercritical PC cases, respectively, at full and minimum sustainable load.^b

As shown, the normalized raw water consumption (gpm/MW-gross) at full load is 2.5 percent lower in the subcritical PC flexible plants (Cases B11A-F1 through B11A-F4) than in the baseload subcritical plant (Case B11A-F0). At the minimum loads, the normalized raw water consumption is 16.7 percent lower in the flexible plants (Cases B11A-F1 through B11A-F4) than in the baseload plant (Case B11A-F0).^c

For the supercritical PC flexible plants (Cases B12A-F1 through B12A-F4), the normalized raw water consumption (gpm/MW-gross) at full load is 3.9 percent lower than in the baseload supercritical PC plant (Case B12A-F0). At the minimum loads, the normalized raw water consumption is 1.4 percent lower in the flexible plants (Cases B12A-F1 through B12A-F4) than in the baseload plant (Case B12A-F0).^c

^b As discussed in Section 4.8.1, sustainable load is an operating point that is tenable for an indefinite period of time between outages; whereas, achievable load is an operating point that is tenable for a shorter period of time (<12 hours) in order to withstand atypical operating conditions (e.g., overnight operation, equipment malfunction, and weather events affecting grid dispatch).

^c The minimum load for Cases B11A-F0 and B12A-F0 is 40 percent; whereas, the minimum load for Cases B11A-F1 through B11A-F4 and B12A-F1 through B12A-F4 is 20 percent.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit ES-3. Performance summary and environmental profile for subcritical cases

Case Name	Baseload		Flexible							
	Case B11A-F0		Case B11A-F1		Case B11A-F2		Case B11A-F3		Case B11A-F4	
Load	Full Load (100%)	Min. Stable Load ^A (40%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)
PERFORMANCE										
Nameplate Capacity	150	150	150	150	150	150	150	150	150	150
Gross Power Output (MWe)	150	60	150	30	150	30	150	30	150	30
Auxiliary Power Requirement (MWe)	10	6	12	4	12	4	12	4	12	4
Total Auxiliaries (% of Gross Power)	6.6%	10.7%	8.3%	14.1%	8.3%	13.7%	8.2%	11.7%	8.2%	11.7%
Net Power Output (MWe)	140	54	138	26	138	26	138	26	138	26
Coal Flow Rate (lb/hr)	118,337	59,729	115,339	26,140	115,339	26,140	115,340	26,173	115,340	26,173
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	404,592	204,210	394,341	89,373	394,341	89,373	394,342	89,483	394,342	89,483
Net Plant HHV Efficiency (%)	34.6%	26.2%	34.9%	28.8%	34.9%	29.0%	34.9%	29.6%	34.9%	29.6%
Net Plant HHV Heat Rate (Btu/kWh)	9,851	13,002	9,784	11,833	9,784	11,778	9,775	11,526	9,775	11,526
Raw Water Withdrawal (gpm)	152	76	148	32	148	32	148	32	148	32
Process Water Discharge (gpm)	4	2	4	1	4	1	4	1	4	1
Raw Water Consumption (gpm)	148	75	144	31	144	31	144	31	144	31
CO ₂ Emissions (lb/MMBtu)	201	201	201	202	201	202	201	202	201	202
CO ₂ Emissions (lb/MWh-gross)	1,846	2,338	1,799	2,052	1,799	2,052	1,799	2,055	1,799	2,055
CO ₂ Emissions (lb/MWh-net)	1,975	2,618	1,962	2,389	1,962	2,378	1,960	2,327	1,960	2,327
SO ₂ Emissions (lb/MMBtu)	0.081	0.081	0.081	0.082	0.081	0.082	0.081	0.082	0.081	0.082
SO ₂ Emissions (lb/MWh-gross)	0.742	0.945	0.724	0.831	0.724	0.831	0.724	0.832	0.724	0.832
NO _x Emissions (lb/MMBtu)	0.076	0.060	0.078	0.069	0.078	0.069	0.078	0.069	0.078	0.069
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.010	0.008	0.010	0.009	0.010	0.009	0.010	0.009	0.010	0.009
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.326	0.258	0.334	0.295	0.334	0.295	0.334	0.295	0.334	0.295
Hg Emissions (lb/MWh-gross) ^B	3.00E-06	3.00E-6	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06

^A Minimum stable load is the operating point that is tenable for an indefinite period between outages

^B As discussed in Section 4.4.1, the mercury capture units were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit ES-4. Performance summary and environmental profile for supercritical cases

Case Name	Baseload		Flexible							
	Case B12A-F0		Case B12A-F1		Case B12A-2		Case B12A-3		Case B12A-F4	
Load	Full Load (100%)	Min. Stable Load ^A (40%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)
PERFORMANCE										
Nameplate Capacity	300	300	300	300	300	300	300	300	300	300
Gross Power Output (MWe)	300	120	300	60	300	60	300	60	300	60
Auxiliary Power Requirement (MWe)	17	9	27	7	27	7	27	5	27	5
Total Auxiliaries (% of Gross Power)	5.5%	7.7%	9.1%	11.5%	9.1%	11.2%	8.9%	8.6%	8.9%	8.6%
Net Power Output (MWe)	283	111	273	53	273	53	273	55	273	55
Coal Flow Rate (lb/hr)	214,007	89,486	205,762	46,390	205,762	46,390	205,763	46,451	205,763	46,451
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	731,682	305,949	703,493	158,607	703,493	158,607	703,496	158,815	703,496	158,815
Net Plant HHV Efficiency (%)	38.7%	36.2%	38.8%	33.5%	38.8%	33.6%	38.9%	34.5%	38.9%	34.5%
Net Plant HHV Heat Rate (Btu/kWh)	8,810	9,425	8,802	10,195	8,802	10,155	8,781	9,882	8,781	9,882
Raw Water Withdrawal (gpm)	276	115	265	57	265	57	265	57	265	57
Process Water Discharge (gpm)	8	3	8	1	8	1	8	1	8	1
Raw Water Consumption (gpm)	268	112	257	55	257	55	257	55	257	55
CO ₂ Emissions (lb/MMBtu)	201	201	201	202	201	202	201	202	201	202
CO ₂ Emissions (lb/MWh-gross)	1,669	1,751	1,605	1,821	1,605	1,821	1,605	1,823	1,605	1,823
CO ₂ Emissions (lb/MWh-net)	1,767	1,897	1,766	2,058	1,766	2,050	1,761	1,995	1,761	1,995
SO ₂ Emissions (lb/MMBtu)	0.081	0.081	0.081	0.082	0.081	0.082	0.081	0.082	0.081	0.082
SO ₂ Emissions (lb/MWh-gross)	0.671	0.708	0.645	0.738	0.645	0.738	0.645	0.739	0.645	0.739
NO _x Emissions (lb/MMBtu)	0.084	0.080	0.087	0.078	0.087	0.078	0.087	0.078	0.087	0.078
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.011	0.010	0.011	0.010	0.011	0.010	0.011	0.010	0.011	0.010
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.360	0.345	0.375	0.333	0.375	0.333	0.375	0.332	0.375	0.332
Hg Emissions (lb/MWh-gross) ^B	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06

^A Minimum stable load is the operating point that is tenable for an indefinite period between outages

^B As discussed in Section 4.4.1, the mercury capture units were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

The Environmental Protection Agency (EPA) promulgated New Source Performance Standards (NSPS) on October 23, 2015, for emissions of CO₂ for new fossil fuel-fired electric utility generating units; the limit for new steam generating units was set as 1,400 lb-CO₂/MWh-gross. [11] A December 2018 proposed update to 111(b) set the limit for new steam generating units based on size. For small-scale ($\leq 2,000$ MMBtu/hr heat input) PC plants, the limit is 2,000 lb-CO₂/MWh-gross, while that of larger ($> 2,000$ MMBtu/hr heat input) PC plants is 1,900 lb-CO₂/MWh-gross. [12]

All subcritical cases within this study are classified as small-scale electricity-generating units (EGUs), while all supercritical cases are subject to the larger-scale CO₂ emissions limit. All CO₂ limits are on a 12-operating-month average (including startup and shutdown periods). No CO₂ capture systems are included.

The CO₂ emissions for all supercritical cases and all full-load subcritical cases are below the established limit; however, in subcritical cases the CO₂ emissions increase above the limit at low loads. Exhibit ES-3 shows that the CO₂ emissions exceed the established limit at their minimum load, with Case B11A-F0 exceeding by 16.9 percent, cases B11A-F1 and B11A-F2 exceeding by 2.6 percent, and cases B11A-F3 and B11A-F4 exceeding by 2.8 percent.^c While no CO₂ capture systems are included in this study, if the plants were expected to regularly operate at or near their minimum loads, a capture system would need to be included to ensure compliance with applicable regulations. Alternatively, natural gas co-firing could be utilized at low load to reduce CO₂ emissions.

Accordingly, for each case/load point that exceeded the CO₂ emission limit of 2,000 lb/MWh gross, the amount of natural gas cofiring that was required to meet this emission limit exactly was determined. Case B11A-F0 exceeded this emission limit at 50 and 40 percent load, and cases B11A-F1–F4 only exceeded this emission limit at 20 percent load. Exhibit ES-5 presents the natural gas cofiring rate that is required to meet the emission limit exactly.

Exhibit ES-5. Natural gas cofire required to meet CO₂ emission limit of December 2018 update to 111(b)

Case	Percent Load	Original CO ₂ Emissions (lb/MWhgross)	NG Cofire Required to Meet 111(b) Emission Limit (Percent of HHV Thermal Input) ^A	CO ₂ Emissions with NG Cofire (lb/MWhgross)
B11A-F0	50%	2,180	22%	2,000
B11A-F0	40%	2,338	39%	2,000
B11A-F1	20%	2,052	7%	2,000
B11A-F2	20%	2,052	7%	2,000
B11A-F3	20%	2,055	7%	2,000
B11A-F4	20%	2,055	7%	2,000

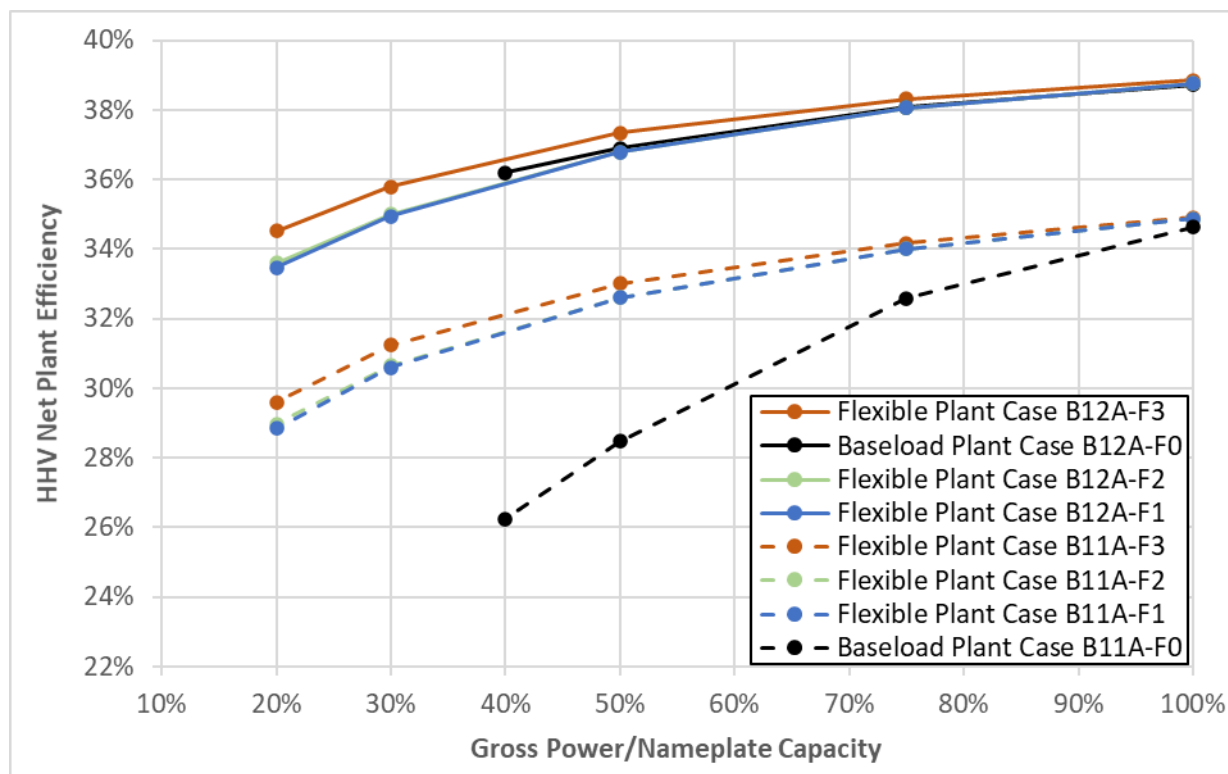
^A Cofire rates were determined with no modifications to plant performance or equipment design

All other emissions remain at or below the current applicable regulatory limits across all loads.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

A graph of the net plant efficiency, higher heating value (HHV) basis, across the load range for each case is provided in Exhibit ES-6. Note that the performance of Cases B11A-F0 and B12A-F0 is reported at 100, 75, 50, and 40 percent load, while the performance of Cases B11A-F1–F4 and B12A-F1–F4 is reported at 100, 75, 50, 30, and 20 percent load — the discrete load points used for modeling were modified for the flexible plant cases to reflect its reduced minimum load.

Exhibit ES-6. HHV Net plant efficiency for all cases



Note: The HHV net plant efficiency curves for cases B11A-F3/B11A-F4 and B12A-F3/B12A-F4 are overlapping

As shown in Exhibit ES-6, the installation of flexibility options at a subcritical plant has increasing impact on plant performance as the load of the plant is reduced. However, because sliding pressure operation is implemented into the supercritical baseload plant (Case B12A-F0), the net plant efficiency penalty across the load range was not as substantial as that of the subcritical baseload plant (Case B11A-F0). Consequently, the installation of Tier 1 (Case B12A-F1) and Tier 2 (Case B12A-F2) flexibility options at a supercritical plant results in lower plant performance at loads below 75 percent, relative to the supercritical baseload plant (Case B12A-F0).

The flexibility options introduced in:

- B11A-F1 (Tier 1) result in the greatest improvement to net plant efficiency for the subcritical plants, followed by those introduced in B11A-F3 (Tier 3)
- B12A-F2 (Tier 2) result in an increase in net plant efficiency below 30 percent load, relative to Case B12A-F1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- B12A-F3 (Tier 3) result in the greatest improvement to net plant efficiency for the supercritical plants

The following flexibility options were the primary contributor to the net plant efficiency change in each case:

- Case B11A-F1: Sliding pressure operation
- Case B12A-F1: Steam turbine driven pumps replaced with electric motor drives
- Cases B11A-F2 and B12A-F2: Auxiliary load optimization
- Cases B11A-F3 and B12A-F3: Outfitting large electric motors with variable-frequency drive (VFD) units

To allow for meaningful assessment of plant flexibility, several flexibility metrics were identified using published literature; the values achieved for each case are presented in Exhibit ES-7, and the relative impact is illustrated for each case in Exhibit ES-8 and Exhibit ES-9.

While not quantified in this study, there are competing influences of the implemented flexibility options for each of the flexibility metrics. For example, the addition of variable frequency drives, an electrode boiler, a condensate polishing system, a steam turbine bypass, and a fuel additive system in Case B11A-F3 improves several flexibility metrics; however, the addition of equipment accumulates single-points of failure within the plant design, which begins to effectively reduce availability. Additional examples of trade-offs associated with several flexibility options are provided in Section. 4.7.2.

Exhibit ES-7. Quantitative breakpoints for flexibility metrics for all cases

Flexibility Metric Quantitative Breakpoint Estimates	Baseload Plant	Tier 1	Tiers 1–2	Tiers 1–3	Tiers 1–4
Startup Time to Full Load					
Cold Start ^A to Full Load, Hours	7–15	5–6	5–6	4–5	4–5
Warm Start ^B to Full Load, Hours	3–6	1–2	1–2	1–2	1–2
Hot Start ^C to Full Load, Hours	1–3	0.5–1.0	0.5–1.0	0.5–1.0	0.5–1.0
Ramp Rate, % Load ^D per Minute	3–5	5–7	7–8	8–9	8–9
Minimum Stable Load (Emissions-Compliant, No Supplemental Firing), % Load	40	20	20	20	20
Minimum Achievable Load (Emissions-Compliant, No Supplemental Firing), % Load	30	15	15	12.5	12.5
Design Life, Years	30	30+	30+	30+	30+
Availability/Reliability (New Construction)					
Equivalent Availability Factor, %	88–90	90–92	92–94	92–94	92–94
Equivalent Forced Outage Rate, %	5–8	4–6	4–5	4–5	4–5

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Flexibility Metric Quantitative Breakpoint Estimates	Baseload Plant	Tier 1	Tiers 1–2	Tiers 1–3	Tiers 1–4
Planned Outages					
Plant Maintenance Outage (Spring/Fall)					
Frequency, Outage/Year	1–2	2–4	2–4	2–4	2–4
Duration, Days	1–7	1–4	1–4	1–4	1–4
Plant/Boiler Outage(s)					
Frequency, Years/Outage	1–2	2	2	2	2
Duration, Weeks	2–4	2	2	2	2
Steam Turbine Generator Outage(s)					
Frequency, Years/Outage	6–9	9–11	9–11	9–11	9–11
Duration, Weeks	6	4–6	4–6	4–6	4–6
Number of Starts, Per Year	10–20	30–60	30–60	30–60	30–60

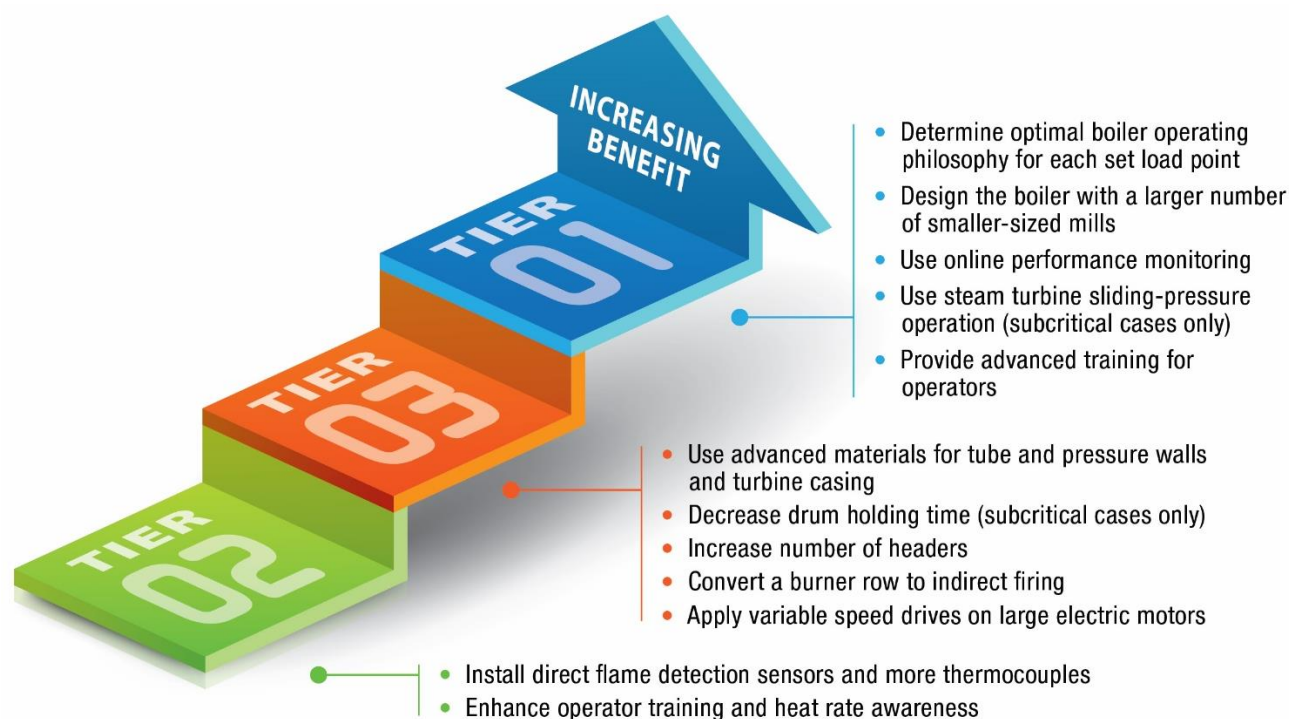
^A Cold Start – Offline greater than 48 hours

^B Warm Start – Offline between 8 and 48 hours

^C Hot Start – Offline less than eight hours

^D Ramp rate is often communicated as the ability to change load in percent full-load per minute

Exhibit ES-8. The relative impact of flexibility options on flexibility metrics

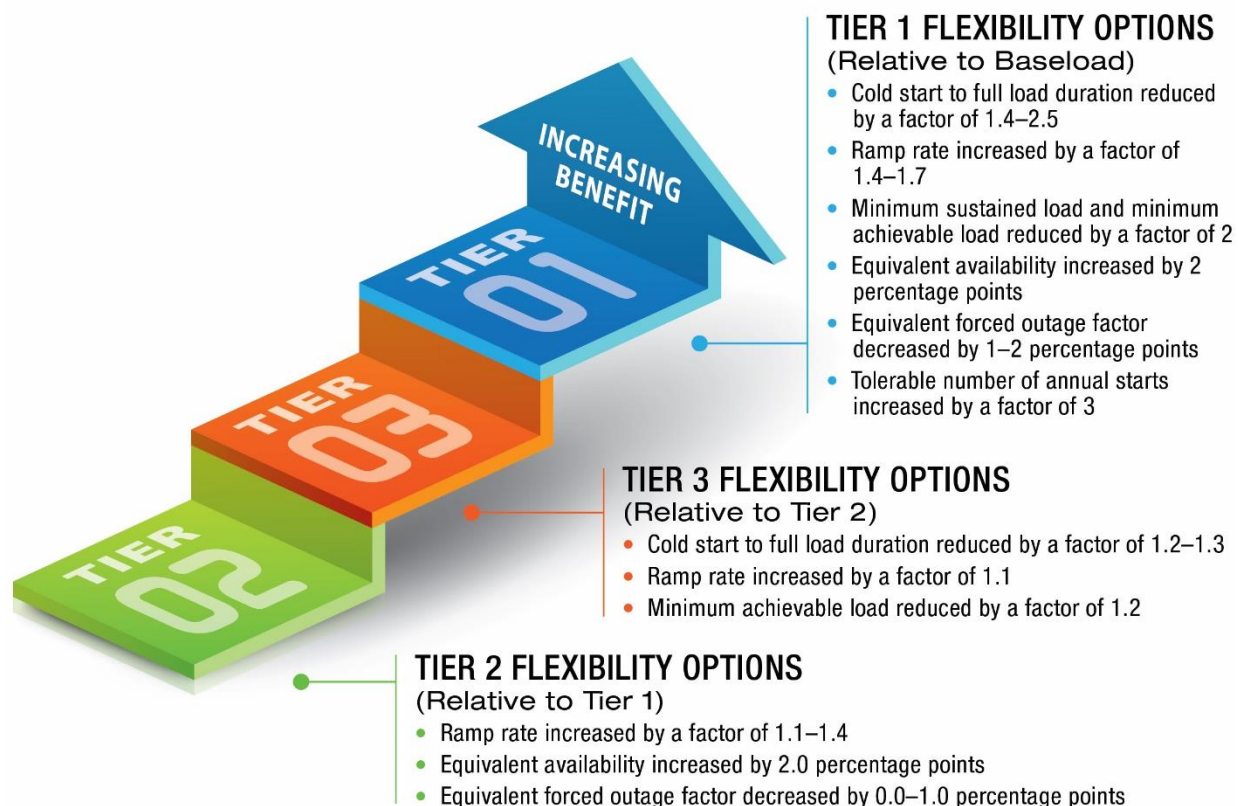


Note: Cases B11A-F4 and B12A-F4 (Tier 4) did not result in a noticeable impact on flexibility metrics

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

As illustrated in Exhibit ES-9, the flexibility options introduced in Cases B11A-F1 and B12A-F1 (Tier 1) are perceived to provide the greatest value-added improvement to the flexibility metrics, followed by those introduced in Cases B11A-F3 and B12A-F3 (Tier 3), and Cases B11A-F2 and B12A-F2 (Tier 2). The flexibility options introduced in Cases B11A-F4 and B12A-F4 (Tier 4) did not result in a noticeable improvement in flexibility metrics.

Exhibit ES-9. Primary observations on impact of flexibility options on flexibility metrics



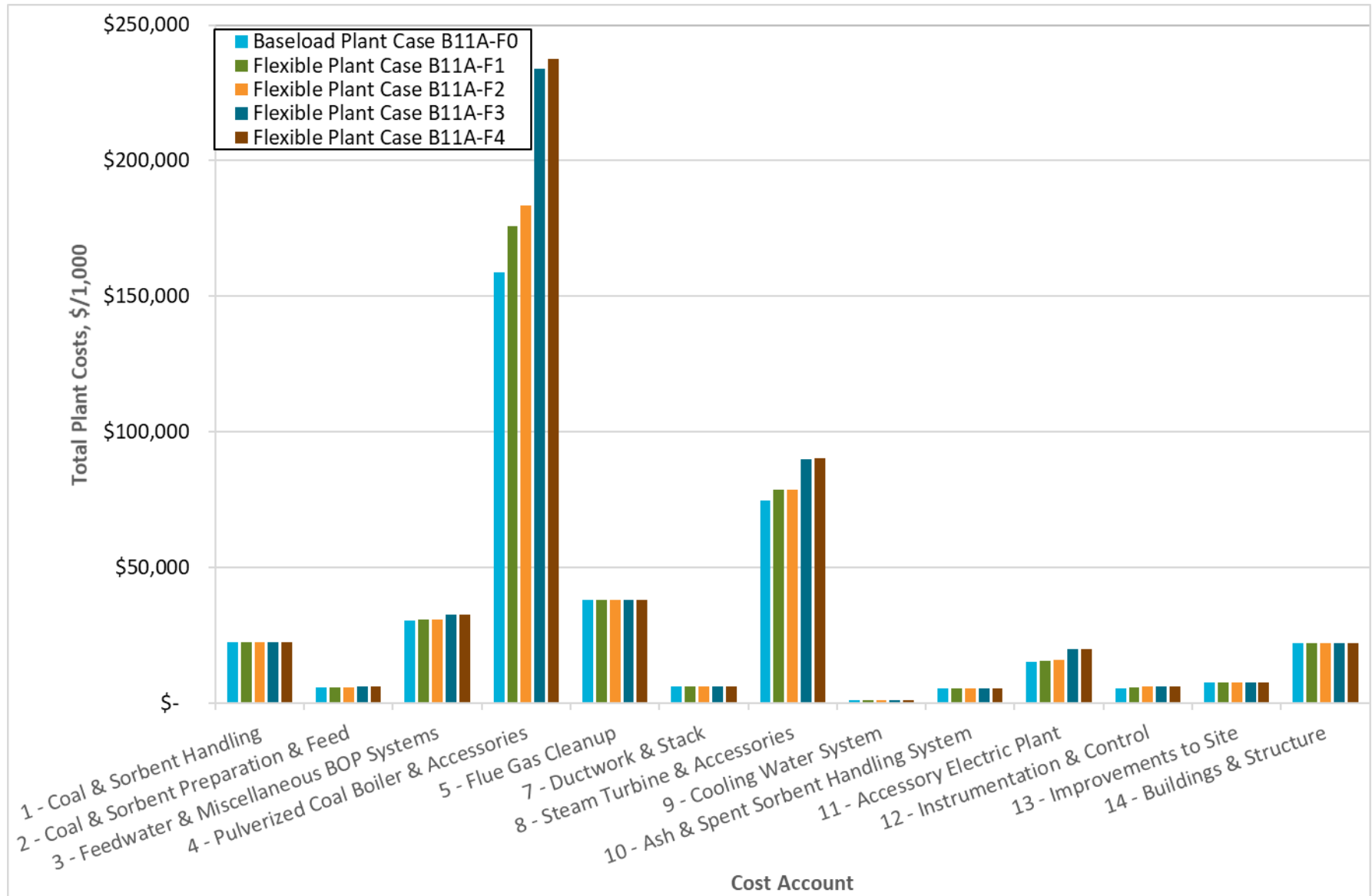
Note: Cases B11A-F4 and B12A-F4 (Tier 4) did not result in a noticeable impact on flexibility metrics

Exhibit ES-10 and Exhibit ES-11 present the capital cost summary by cost account for each subcritical and supercritical PC case, respectively. The following observations can be made:

- None of the flexibility options implemented in this study impact the capital costs of the coal and sorbent handling system (Account 1), flue gas cleanup systems (Account 5), cooling water system (Account 9), ash and spent sorbent handling system (Account 10), improvements to site (Account 13), or buildings and structures (Account 14).
- The boiler (Account 4) and steam turbine (Account 8) accounts represent the greatest portions of the total plant cost (TPC) and the two accounts together make up at least 90 percent of the cost increases that result from implementation of the flexibility options in all cases. As these accounts are frequently cited as the primary limiters for flexible operation, it is reasonable that the majority of the costs for improving plant flexibility are associated with these accounts.

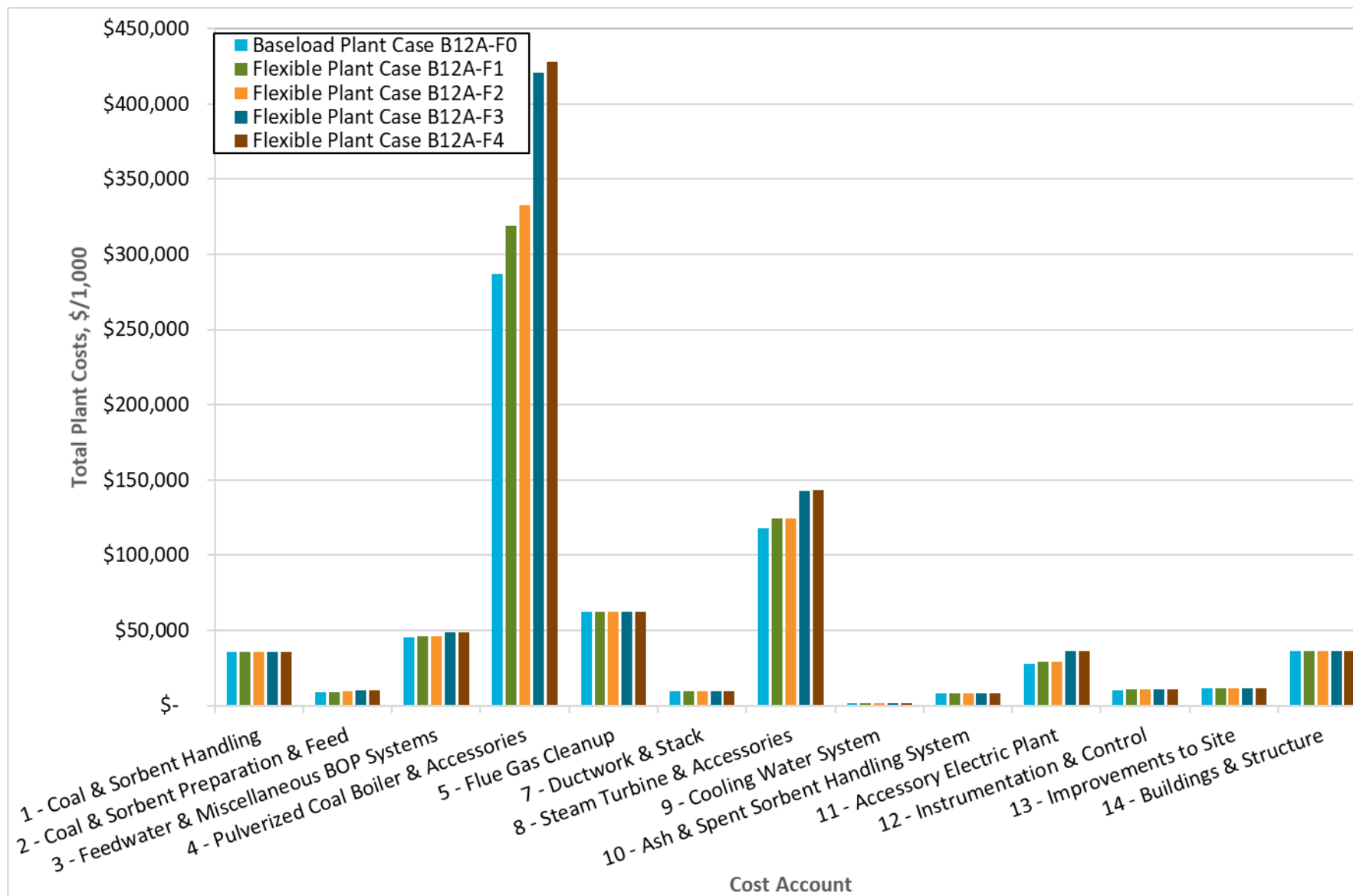
CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit ES-10. Total plant cost summary by cost account for subcritical cases



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit ES-11. Total plant cost summary by cost account for supercritical cases



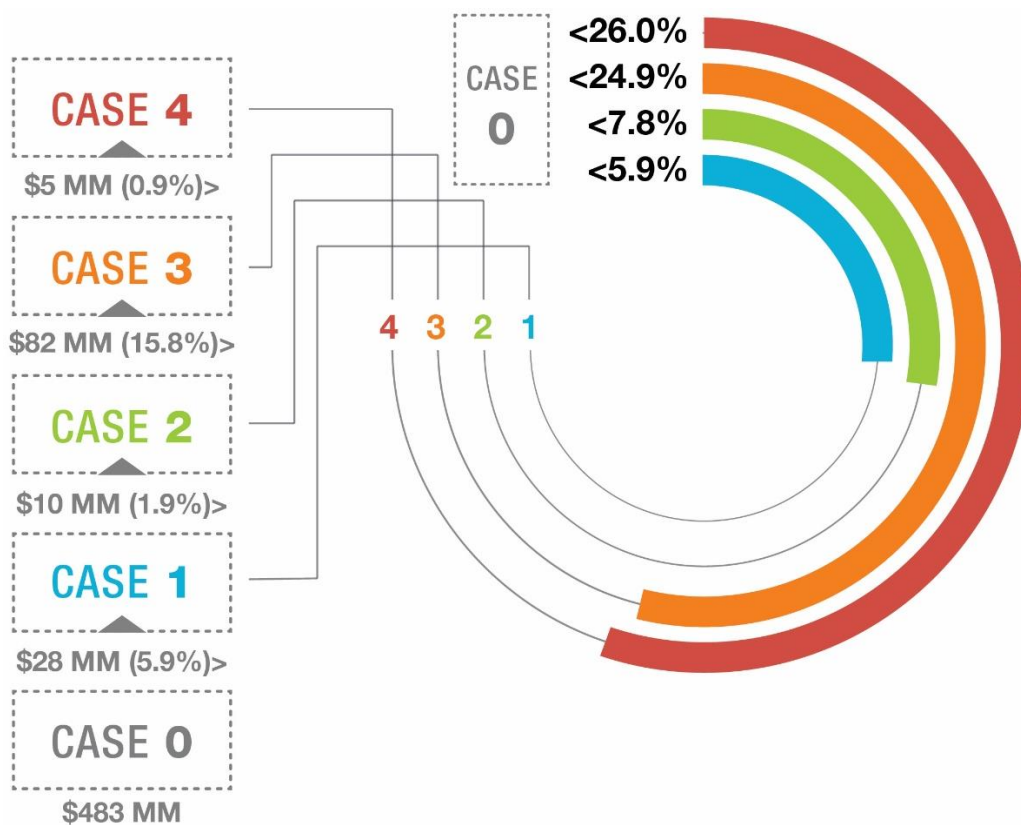
CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

The relative impact of each subcritical and supercritical case on total overnight cost (TOC) is illustrated in Exhibit ES-12 and Exhibit ES-13, respectively.

As shown, each subsequent addition of a tier of design options for improving the flexibility of a plant results in a corresponding increase in costs. While the flexibility options included in Cases B11A-F1 and B12A-F1 (Tier 1) are individually considered to be “low-cost” options, the large number of flexibility options included in this tier resulted in a TOC increase of \$28 million (5.9 percent) in Cases B11A-F1 and \$50 million (6.2 percent) in B12A-F1, relative to Cases B11A-F0 and B12A-F0, respectively. This relative increase in TPC is only exceeded by the flexibility options introduced in Cases B11A-F3 and B12A-F3 (Tier 3), which resulted in a TOC increase of \$82 million (15.8 percent) in Case B11A-F3 and \$142 million (16.1 percent) in Case B12A-F3, relative to Cases B11A-F2 and B12A-F2, respectively.

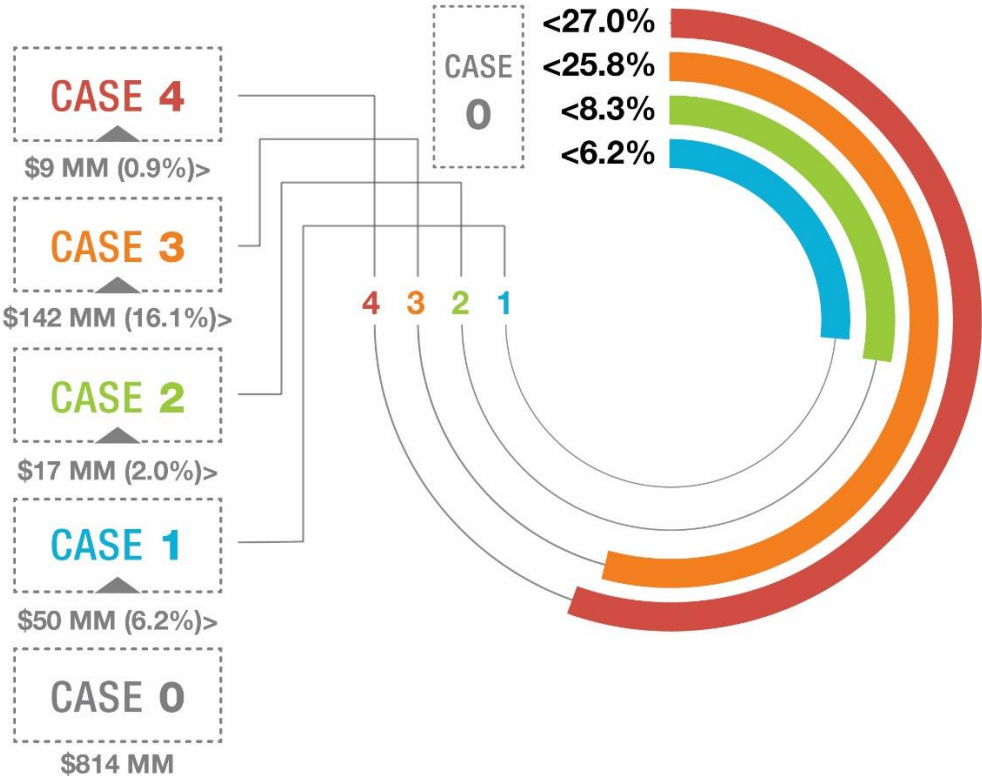
Further study is needed to determine the cost of individual options and which options would offer the greatest improvement to flexibility and plant performance.

Exhibit ES-12. Relative total overnight cost impact for subcritical cases



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
FLEXIBLE OPERATION

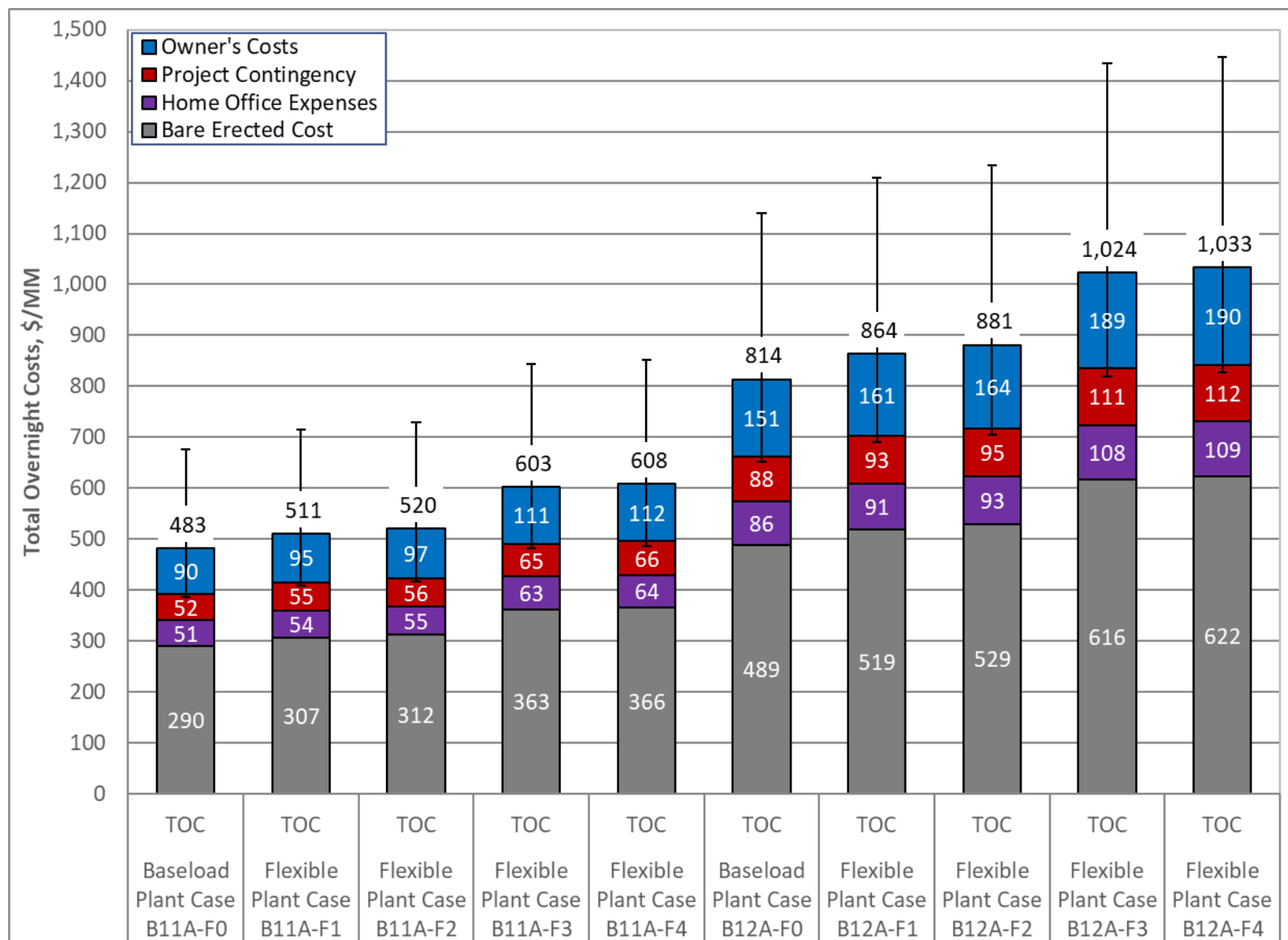
Exhibit ES-13. Relative total overnight cost impact for supercritical cases



The TOC cost components of each case are presented in Exhibit ES-14 and summarized in Exhibit ES-15.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit ES-14. Total overnight cost, by component, for all cases



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

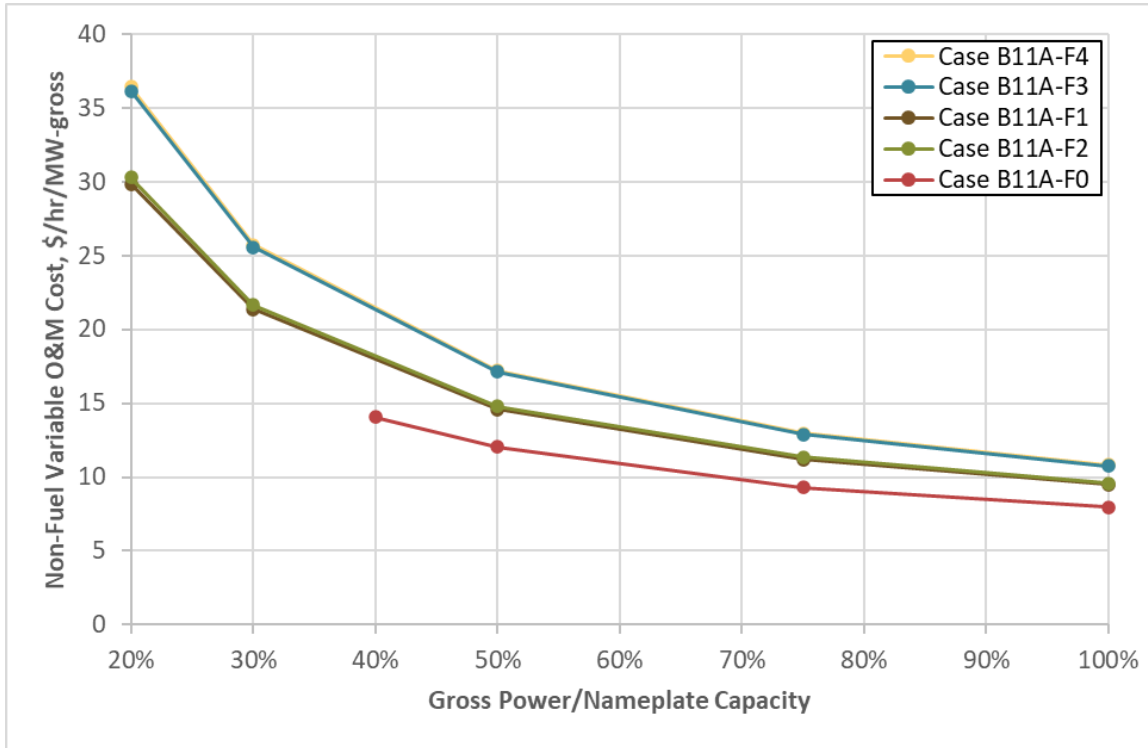
Exhibit ES-15. Summary of cost components for all cases

Cost	Pulverized Coal Boiler									
	Subcritical					Supercritical				
	B11A-F0	B11A-F1	B11A-F2	B11A-F3	B11A-F4	B12A-F0	B12A-F1	B12A-F2	B12A-F3	B12A-F4
Total Plant Cost (2018\$/MM)	393	416	423	491	496	662	703	717	835	843
Bare Erected Cost	290	307	312	363	366	489	519	529	616	622
Home Office Expenses	51	54	55	63	64	86	91	93	108	109
Project Contingency	52	55	56	65	66	88	93	95	111	112
Process Contingency	0	0	0	0	0	0	0	0	0	0
Total Overnight Cost (2018\$/MM)	483	511	520	603	608	814	864	881	1,024	1,033
Owner's Costs	90	95	97	111	112	151	161	164	189	190
Fixed Costs (2018\$/MM)	14	17	17	19	19	23	27	27	31	31
Variable Costs (2018\$/MM)	10 x CF	12 x CF	13 x CF	14 x CF	14 x CF	18 x CF	22 x CF	22 x CF	24 x CF	25 x CF
Fuel Costs (2018\$/MM)	27 x CF	26 x CF	26 x CF	26 x CF	26 x CF	49 x CF	47 x CF	47 x CF	47 x CF	47 x CF

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

The non-fuel variable operation and maintenance (O&M) costs are presented as a function of plant load on an hourly basis in Exhibit ES-16 and Exhibit ES-17 for subcritical and supercritical cases, respectively. These charts assume that the plant is operating at reduced loads 100 percent of the year (service factor of 1). If the service factor is reduced, the maintenance materials costs would be reduced.

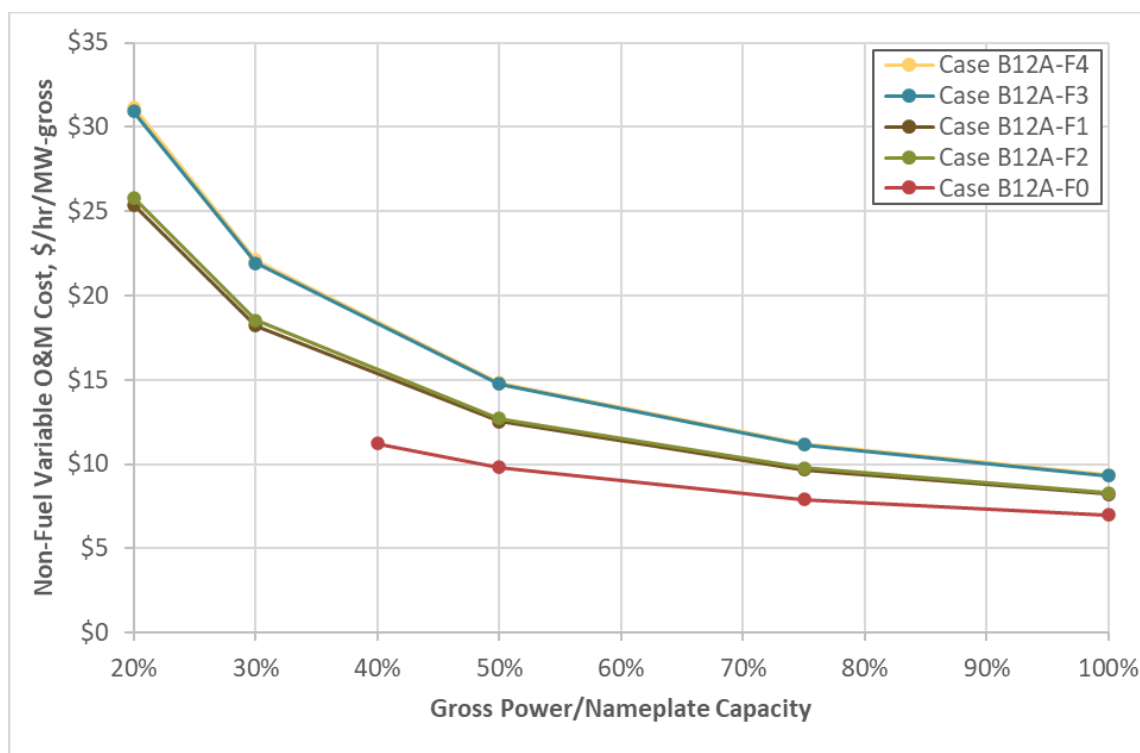
Exhibit ES-16. Non-fuel variable O&M costs as a function of plant load for subcritical cases



Note: The cost curves for Cases B11A-F3-F4 are overlapping

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit ES-17. Non-fuel variable O&M costs as a function of plant load for supercritical cases

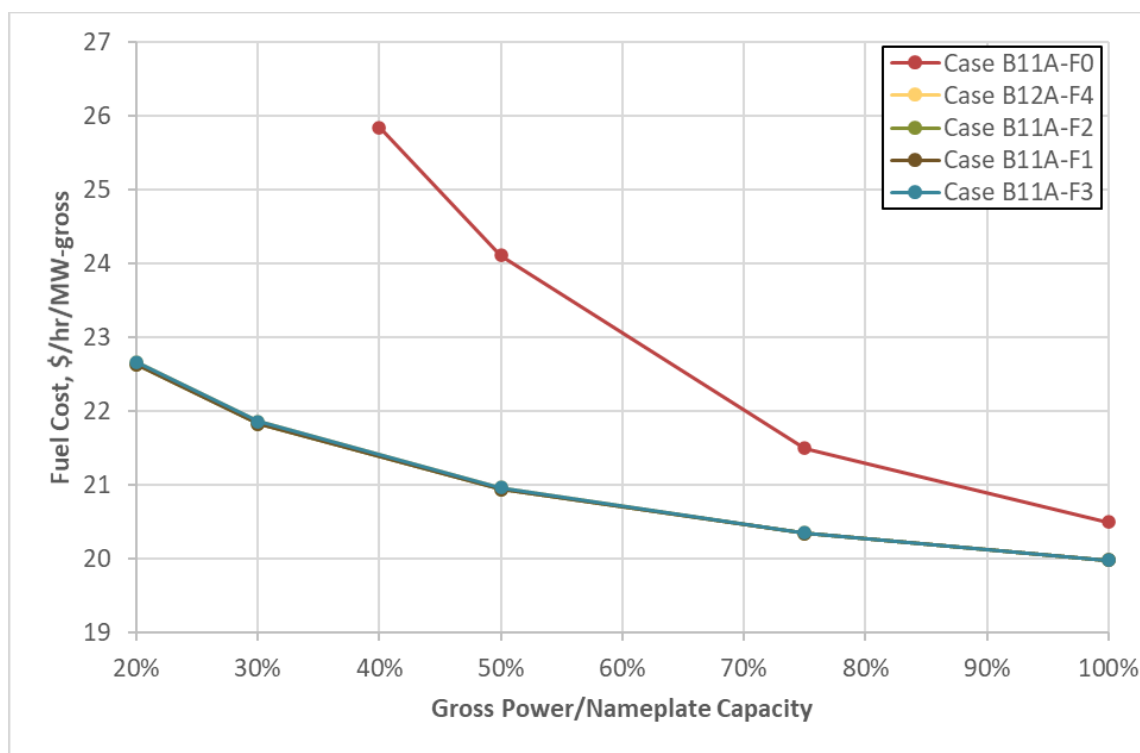


Note: The cost curves for Cases B12A-F3-F4 are overlapping

The fuel variable costs are presented as a function of plant load on an hourly basis in Exhibit ES-18 and Exhibit ES-19 for subcritical and supercritical cases, respectively. These charts assume that the plant is operating at reduced loads 100 percent of the year (service factor of 1). If the service factor is reduced, the maintenance materials costs would be reduced.

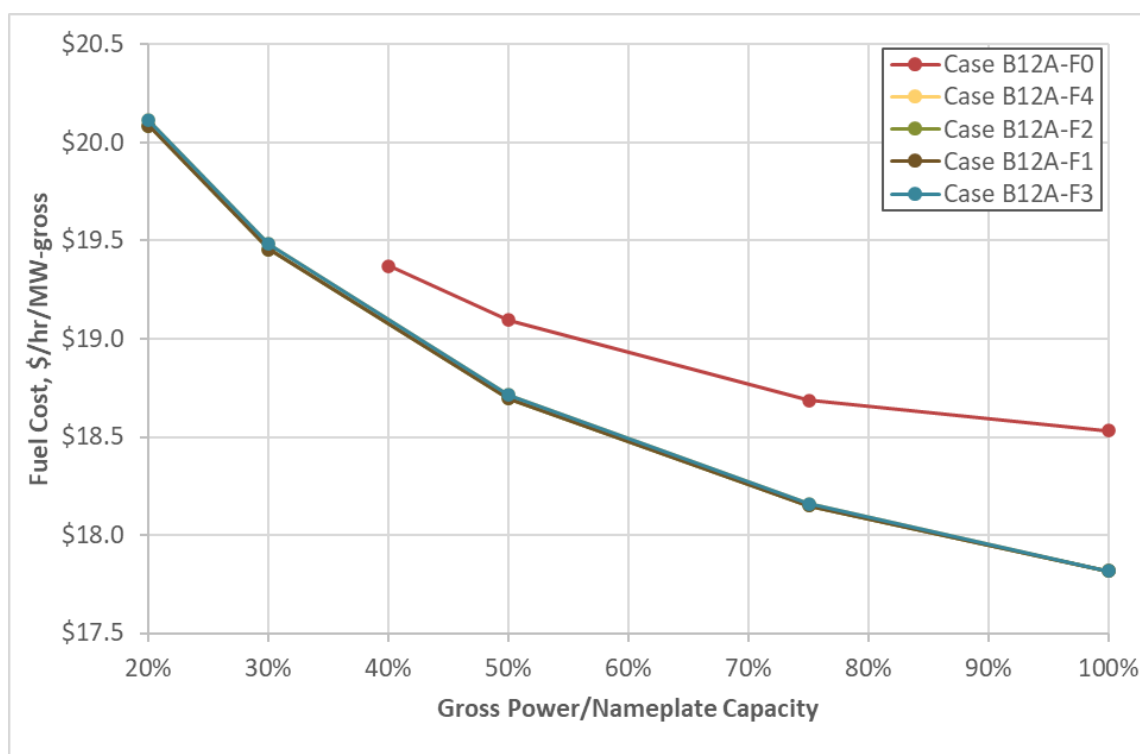
CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit ES-18. Fuel costs as a function of plant load for subcritical cases



Note: The cost curves for Cases B11A-F1-F2 and Cases B11A-F3-F4 are overlapping

Exhibit ES-19. Fuel costs as a function of plant load for supercritical cases



Note: The cost curves for Cases B12A-F1-F2 and Cases B12A-F3-F4 are overlapping

The key takeaways from this study are as follows:

- Of the flexibility metrics identified in this study through available literature, the minimum load, ramp rate, and startup time (cold to full load) appear to be the most critical for PC plants competing with other flexible generation assets in current power markets:
 - Minimum Load — The improvement (i.e., reduction) of minimum load allows for the flexible plant to dispatch at lower loads and reduce uncompensated costs during low or no dispatch periods; improvements in minimum load also eliminate frequency of shutdown and startup cycles, which contributes to an improved operating life and reduced O&M costs due to a decrease of thermal cycles.
 - Ramp Rate — Improvements in ramp rate allow the flexible plant to reach dispatchable load faster (improving total energy export) in addition to reducing load more quickly (reducing uncompensated costs during low dispatch periods); both capabilities contribute to the economic competitiveness of the flexible plant.
 - Startup Time (Cold to Full Load) — Reducing startup times reduces uncompensated costs during startup and improves unit operation economic competitiveness.
- Cases B11A-F3 and B12A-F3 represent the most flexible and efficient plant configurations presented in this report, with an associated TOC plant premium of 25 and 26 percent, respectively, over that of a baseload plant (Cases B11A-F0 and B12A-F0).
 - The most significant improvement in plant flexibility and efficiency is realized through the implementation of Tier 1 flexibility options—most notably the conversion to sliding pressure operation (subcritical only).
 - The second most significant improvement in plant flexibility and efficiency is realized through the implementation of Tier 3 flexibility options—most notably the addition of the VFD units.

RECOMMENDATIONS FOR FUTURE WORK

The intent of this study was to fully characterize the configuration, design, performance capabilities, and cost of subcritical and supercritical PC plants specifically designed for flexible operation. Among the analyses and literature items reviewed, there remain areas where future work (outside the scope of this study) is recommended to advance discussions/analyses targeting improved competitiveness of coal-fired EGUs. A list of these items designated as recommendations for future work is outlined below:

- Identify impacts of significantly increasing amount of advanced alloy usage in boiler tube applications and the associated impacts to cost/tertiary impacts to adjacent sub-systems such as boiler foundations and structural steel design.

- Identify second-tier market dispatch impacts; specifically, quantify the independent system operator/regional transmission organization impacts of multiple flexible coal plants operating in a specific region.
- Integrate regional-specific constraints on the plant to determine suitability.
- Perform additional sensitivity analyses of the impact of variation in coal constituents (e.g., carbon, sulfur, moisture, ash) and coal type on flexible plant design features and configuration (e.g., CFB vs PC firing sub-bituminous coal).
- Assess how the major plant features would translate to a physical “proof of concept” plant.
- Integrate highly advanced (not commercially proven) technology in the plant design to assess the impact on performance/cost.
- Identify specific plant configuration/design characteristics that could be changed to make the plant design “capture ready,” and ultimately incorporate post-combustion carbon capture systems into the designs.
- Integrate opportunity fuels (e.g., biomass, refuse-derived fuel) to improve plant economic viability.
- Identify how distributed energy resources, such as energy storage (batteries, thermal energy storage, etc.), could be incorporated in the reference plant design basis to improve plant flexibility and overall economic viability.
- Characterizing the effects (sensitivity) of variations in the flexible plants’ CF on the plants’ O&M cost(s).
- Development of normalized cost reporting bases (e.g., \$/kW) and cost of electricity (\$/kWh) estimates were omitted from this analysis. Consideration regarding the valuation of the flexibility metrics is also an opportunity for future work.

SPECIAL CONSIDERATIONS ON REPORTED COSTS

Capital Costs

The capital cost estimates documented in this report reflect an AACE Class 4 estimate with an uncertainty range of -20/+40 percent. One of the main objectives of this report is to provide a basis for technology comparison. Given this objective, the level of uncertainty in the capital estimates is acceptable. However, use of the capital estimates in an unintended way could magnify the uncertainty of the cost estimates. The final cost results reported for all cases are not intended to represent a real project-specific cost that would be expected in today’s markets. This is due to many factors (e.g., site assumptions, CFs) including the uncertainty in capital costs. In all cases, this report intends to represent the next commercial offering and relies on vendor cost estimates for component technologies.

Costs of Mature Technologies and Designs

The cost estimates for plant designs that only contain fully mature technologies, which have been widely deployed at commercial scale (e.g., PC power plants without CO₂ capture), reflect nth-of-a-kind (NOAK) on the technology commercialization maturity spectrum. The costs of such plants have dropped over time due to “learning by doing” and risk reduction benefits that result from serial deployments as well as from continuing research and development (R&D).

Costs of Emerging Technologies and Designs

The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., advanced materials) use the same cost estimating methodology as for mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that initial deployments of these plants may incur costs higher than those reflected within this report.

Other Factors

Actual reported project costs for all the plant types are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g., contracting strategy, local labor costs and availability, seismic conditions, water quality, financing parameters, local environmental concerns, weather delays) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends

Continuing research, development, and demonstration is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated herein.

1 INTRODUCTION

This report presents an independent assessment—using a systematic and transparent technical and economic approach—of the cost and performance of greenfield fossil energy power systems intended for flexible rather than baseload operation. This inaugural report addresses subcritical and supercritical pulverized coal (PC) plants without carbon dioxide (CO₂) capture; however, it is anticipated that additional plants, including those incorporating carbon capture and/or fueled by natural gas, will be added in the future. This study was partially guided by a thorough literature review of public sources, National Energy Technology Laboratory (NETL) internal sources, and Black & Veatch in-house data investigating flexible operation of PC plants. The objective was to leverage the already substantial knowledge base about flexible operation for the development of state-of-the-art PC plant cases that are designed to accommodate flexible operation within an electric grid having a high level of renewable generation.

1.1 GENERATING UNIT CONFIGURATIONS

This report considers ten pulverized coal (PC), Rankine cycle plants – five subcritical and five supercritical. All five subcritical PC cases have a gross output of 150 megawatt (MW) and all five supercritical PC cases have a gross output of 300 MW. The coal feed rate was varied in each case to maintain a constant gross steam turbine output and account for the changes in plant efficiency.

Each case presented in this report presents a plant that is designed with a certain number of “flexibility options”; these are design or operation and maintenance (O&M) strategies that are intended to improve plant flexibility. These flexibility options were assumed to be installed cumulatively, so each case contains several new flexibility options in addition to the flexibility options that were installed on the previously developed cases.

A summary of the plant configurations considered in this report is provided in Exhibit 1-1. Components for each plant configuration are described in more detail in the corresponding report sections for each case.

The balance of this report is organized as follows:

- Section 2 presents background information relevant to this study, including a comprehensive literature review, an overview of the flexibility metrics that were chosen for assessment of each case, and a comparative discussion of PC plant configurations.
- Section 3 provides an overview of PC plant O&M procedures, including general O&M, startup, and layup procedures.
- Section 4 provides the basis used for evaluating each of the PC cases.
- Section 5 describes the PC technologies modeled and presents the results for all PC cases, including the study summary.
- Section 6 presents key takeaways and recommendations for future work.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 1-1. Case descriptions

Case Name	B11A-F0	B11A-F1	B11A-F2	B11A-F3	B11A-F4	B12A-F0	B12A-F1	B12A-F2	B12A-F3	B12A-F4
Unit Cycle	PC									
Steam Cycle, psig/°F/°F	1,800/1,000/1,000					3,500/1,100/1,100				
Intended Operational Profile	Baseload	Flexible				Baseload	Flexible			
Flexibility Option Tiers in Plant Design	Baseload Options Only	Tier 1	Tiers 1 and 2	Tiers 1, 2, and 3	Tiers 1, 2, 3, and 4	Baseload Options Only	Tier 1	Tiers 1 and 2	Tiers 1, 2, and 3	Tiers 1, 2, 3, and 4
Number of New Flexibility Options	N/A	38	9	21	2	N/A	37 ^B	9	19 ^C	2
Total Number of Flexibility Options ^A	N/A	38	47	68	70	N/A	37	46	66	68
Oxidant	Air									
Sulfur Removal	FGD System/Gypsum									
PM Control	Baghouse									
NO _x Control	LNB w/OFA and SCR									
Process Water Treatment	Spray dryer evaporator									

^A Due to the cumulative method of applying the flexibility options, the total number of flexibility options is the sum of the current case and all prior cases

^B As all supercritical cases are sliding pressure, Flexibility option 59 “Steam turbine sliding-pressure operation” introduced in Tier 1 for subcritical cases is not applicable to supercritical cases

^C As all supercritical cases use a Benson boiler, Flexibility option 2 “decrease drum holding time to reduce drum diameter and drum wall thickness” introduced in Tier 3 for subcritical cases is not applicable to supercritical cases. Additionally, supercritical plants typically include a condensate polishing system. Therefore, Flexibility option 12 “Use of condensate polishing system to maintain cycle chemistry parameters during shutdown and layup periods and reduce startup times” introduced in Tier 3 for subcritical cases is not applicable to supercritical cases

2 BACKGROUND

Multiple reports, presentations, memoranda, and journal articles relevant to flexible plant operation and design were reviewed as part of this study. Summaries of the available literature and several case studies are provided in this section. Currently, the majority of available literature regarding operating power plants in a flexible regime focuses on design strategies for retrofit applications, with limited information regarding greenfield plants. However, it is expected that the retrofit design strategies would be equally beneficial for greenfield plants, if not more so, due to the costs associated with retrofitting existing plants; certain design strategies may be better suited for greenfield plants.

Flexible operation applies to a wide range of operating regimes for coal-fired power plants, but it can be stated that, in general, flexible operation entails extended periods of low-load operation, more rapid load ramping, and more frequent on-off cycling when compared to baseload operation.

2.1 LOW-LOAD OPERATION

The minimum load is the lowest stable load that the boiler can operate at, and is dependent on the specific plant configuration and coal type that is being fired. [13] It is important to note, however, that although low-load operation is typically limited by the boiler, sustained operation at low loads can have impacts throughout the entirety of the plant. [14] [15]

The ability to operate at very low loads is critical for plants that are required to operate in a flexible regime. [16] [17] A high minimum load will force plants to shutdown more often and, therefore, undergo more frequent startups. This can cause the plant to incur major expenses, from both lost generation and additional operation and maintenance O&M and capital costs that result from startups of the plant. Once a unit has been shutdown, there is a risk that the unit will remain down for an extended period of time before it has an opportunity to come back online. [16] Additionally, a lower minimum load allows for earlier transition to coal during startup, minimizing the use of auxiliary fuel. [18]

2.2 RAMPING AND ON-OFF CYCLING

Frequent ramping and on-off cycling are important requirements for flexible operation. Existing plants have traditionally controlled their ramp rate using rate limiters, which restrict the plant to a conservative ramp rate in an effort to mitigate damage to equipment. However, improving the ramp rate and startup performance of a plant, while also mitigating damage to equipment through flexible design strategies, will allow the plant to compete in more competitive and higher-value electricity markets. [19]

2.3 GENERAL IMPACTS OF FLEXIBLE OPERATION

There are three major damage mechanisms that can lead to component failure: creep, fatigue, and differential thermal expansion. [14] Creep is the deformation of a material due to constant,

extended exposure to stress levels below the fatigue limit of the material and is the dominant cause of damage during baseload operation. Fatigue is a consequence of fluctuating levels of stress (e.g., temperature, pressure, corrosion) due to transient operating conditions, and occurs during startups, shutdowns, and flexible operation of a plant. Differential thermal expansion is stress caused by the differential expansion of dissimilar metals, and can occur between dissimilar metal welds, or components with dissimilar metal parts and small tolerances. These stresses lead to crack initiation, propagation, and eventually fracture of components. [20]

Different plant components are affected by flexible operation in unique ways. Studies of existing plants operating in a flexible regime has helped to reveal the impacts of flexible operation on critical plant components. High-temperature and high-pressure (HP) areas in the plant, such as the boiler and steam turbine, are particularly vulnerable to damage from flexible operation because they require the use of thick-walled components that exacerbate the effects of thermal fatigue. [14]

2.4 DESIGN STRATEGIES FOR ENHANCING COAL PLANT FLEXIBILITY AND EFFICIENCY

The literature contains a wealth of information about the flexibility of existing coal plants and retrofit strategies for improvement. Review of industry experience makes it clear that improvements in flexibility should be examined using a cost-benefit analysis on an individual plant basis. However, in general, most plants would benefit from retrofits that improve flexibility of the boiler and steam turbine generator (STG). Plant-wide upgrade of instrumentation and control systems, along with improved operating procedures and maintenance protocols, are consistently reiterated as the most cost-effective strategies for improving the flexibility of a plant. Evaluation of available case studies reveals that many plants are concerned with improving their minimum load, so they are not forced to shut down during periods of low demand. The problems with achieving flexibility vary, but are generally associated with the boiler or steam turbine systems.

The literature is lacking information about flexibility improvement options for greenfield plant designs. Many retrofit options are applicable for greenfield applications, but it's possible and likely that a new build would have unique improvement opportunities that are not considered to be possible and/or economical in a retrofit scenario. Additionally, there is little quantitative information about cost-performance trade-offs for the flexibility improvement options that are discussed in the literature. This is valuable information for plant owners that could help prioritize evaluation of retrofit/design strategies for improving flexibility.

The flexibility options that are selected will firstly depend on whether it is being applied in a retrofit or greenfield scenario. The configuration of the plant, the expected generation profile, and, for a retrofit scenario, the remaining life of the plant, must all be taken into consideration. Certain design strategies will have an impact on specific flexibility metrics, so it is important for plant owners to carefully consider which design strategies will be most valuable for their specific situation. [18]

2.5 FLEXIBLE OPERATION – IMPACTS, LIMITATIONS, AND DESIGN STRATEGIES FOR MAJOR EQUIPMENT

2.5.1 Boiler

2.5.1.1 Low-Load Operation

State-of-the-art lignite plants typically have minimum boiler loads of 35–40 percent, while state of the art bituminous coal plants can reach minimum boiler loads as low as 20–25 percent. [16] [13] Operation below the minimum stable boiler load requires the use of auxiliary fuels, since flame stabilization begins to deteriorate at very low firing rates. Another issue with low-load operation is maintenance of main and reheat steam temperatures. [18] Improper steam temperatures can necessitate the use of steam attemperator sprays that reduce plant efficiency and cause damage from hot surface quenching. [14] [15]

When a supercritical boiler is operating below the Benson point (e.g., load at which all fluid entering the vertical steam separator is converted to steam), an additional boiler circulation pump is necessary in order to return water from the vertical steam separator drains back to the economizer inlet. The Benson point typically exists at approximately 30 to 35 percent load. [21]

Minimum boiler load is usually reached by shutting down mills and reducing the feed rate of the remaining operational mills. For plants that have a small number of larger mills, the minimum feed rate of the mills can be a limiting factor for the minimum boiler load. Furthermore, the mill and burner arrangement (i.e., whether the mills feed a horizontal or vertical line of burners) can impact the flame stability when operating with a reduced number of mills, and, in turn, impact the minimum boiler load. [14]

2.5.1.2 Ramping and On-Off Cycling

Load changes have a large impact on boiler components due to their inherent design requirements. The high operating temperatures and pressures in the boiler require the use of thick-walled components that experience thermal gradients during transient process conditions. All sections of the boiler, including the superheat, reheat, and economizer sections, experience accelerated damage due to thermal fatigue from temperature gradients and fluctuations. Differential thermal expansion can lead to failure of dissimilar metal welds, and difficulty in controlling water chemistry can lead to increased rates of flow-assisted corrosion (FAC). As a result, boiler tubes, headers, ties, and membrane walls will all suffer reduced lifetimes when a plant is required to undergo frequent ramping and on-off cycling. [15]

As the load response for once-through boilers adjusts both fuel firing and steam flow rates, the effects of cycling are more severe in supercritical units than subcritical units. [22] [23] For example, erosion from exfoliated deposits (e.g., magnetite) from the boiler tube surface has been reported at higher rates for supercritical plants than subcritical plants, becoming more pronounced at increasing rates of cycling. [23]

2.5.1.3 Design Strategies

Boiler design plays a critical role in the ability of a plant to operate flexibly. Due to its importance, boiler flexibility enhancements have received much attention from industry and this interest has led to a thorough evaluation of flexible design strategies and their associated trade-offs. An important consideration is the installation of improved flame detection sensors and more thermocouples within the boiler. Flexible operation can lead to unanticipated conditions (such as tube overheating) within the boiler that would go unnoticed without proper monitoring equipment. Flame stability also becomes a problem at low loads and zonal flame detection becomes ineffective, meaning direct flame detection should be used. [18]

Boiler flexibility can be improved by using updated firing systems. Use of a larger number of smaller-sized mills will allow for lower loads to be reached using one mill operation, which is achievable for most hard coal plants. [14] Additionally, having more mills active will improve flame stability, meaning smaller mills will allow for more stable firing at lower loads, resulting in more stable main and reheat steam temperatures, while simultaneously preventing temperature spikes that could lead to tube damage or failure. [24]

Another option is to replace the burners, ignitors, and control systems to optimize combustion at low loads and allow for an earlier switch from auxiliary startup fuel to coal. [18] More reliable ignition can be achieved using electric or plasma ignitors, and burners can be tuned or replaced with tilting burners that allow for control of the heat transfer between radiative and convective heating surfaces and improved steam and internal boiler temperature control. [18] Yet another option is utilization of an indirect firing system to eliminate inertia associated with operation of the coal mills. [13] Indirect firing requires an intermediate storage system for pulverized, pre-dried coal and allows for very low loads and rapid changes in firing rate. [25]

Mindful material selection and design will help to mitigate damage to the boiler from load changes and startups/shutdowns. The wall thickness of conventional thick-walled components can be reduced by using advanced creep-strength-enhanced ferritic steels, thereby minimizing thermal fatigue damage from temperature gradients within the metal. [26] These ferritic steels, such as P91 alloys, demonstrate high strength and high oxidation resistance up to temperatures of 1,112°F, and have demonstrated improved thickness requirements and thermal fatigue lives in components such as superheater coils, headers, and steam piping. [23]

Thermal fatigue can also be mitigated by switching from a two-line to a four-line design of the boiler pressure parts to reduce the header and separator wall thicknesses. [13] Additionally, dissimilar metal welds, which result in damage from differential thermal expansion, should be avoided or replaced. [27]

2.5.2 Steam Turbine

2.5.2.1 Low-Load Operation

At low loads, steam temperature decreases within the turbine due to throttling or sliding pressure effects⁴ and causes the steam phase transition zone to move upstream. [15] This leads to an increased risk of deposition in the low-pressure (LP) turbine, even if steam purity is maintained. [28] However, without careful control, low-load operation causes a decrease in steam purity (see Section 2.5.5), which further increases the risk of deposition in the turbine. Accelerated deposition on turbine components and decreased steam purity increases the risk of corrosion-related crack formation, which can shorten the lifespan of components. [29] In addition to increasing the risk of deposition, operation at low load can also lead to flutter vibration in the final stages of the LP turbine, which will cause fatigue damage to the blades. [15] Lastly, controlling the turbine via throttling can decrease the lifespan of the turbine control valve by more than 20 percent. [30]

In addition to component damage, the steam turbine suffers a substantial efficiency loss at reduced loads. The primary sources of efficiency loss within the steam turbine are the first high pressure (HP) stage and the last LP stage. The first HP stage suffers a loss of efficiency due to throttling losses, primarily when fixed-pressure operation is used. The last LP stage loses efficiency from non-optimal flow patterns, as well as increased exhaust losses. Furthermore, if steam temperatures are not maintained at low loads, this can further reduce the efficiency of the turbine. [29]

2.5.2.2 Ramping and On-Off Cycling

The steam turbine is similar to the boiler in that it operates at high temperatures and pressures, requiring the use of thick-walled components. During load changes and startups, the rapid shift in steam temperature causes a temperature mismatch between the steam and turbine components. This temperature mismatch can be managed through design strategies, but not entirely avoided. Thermal fatigue induced by changes in steam temperature will cause thermal fatigue to HP/intermediate-pressure (IP) turbine rotor forgings and thick-walled components such as HP/IP turbine casings and valve bodies. [15]

Rotating and stationary components within the turbine tend to expand at different rates when subjected to temperature changes. This can cause turbine rotors to expand or contract more rapidly than the surrounding stationary components, leading to axial rubs from the reduced clearance. In cases of load jumps larger than 25 percent, the ramp rate of a turbine is often restrained by thermal stresses in the HP/IP turbine rotors. Failure to control steam temperatures during load changes can also cause thermal stresses due to temperature mismatch. [29]

During startups (cold starts in particular), the turbine is subjected to an especially large temperature mismatch between the steam and turbine components. The severe thermal fatigue caused by this temperature mismatch can cause initiation and propagation of cracks in

⁴ Sliding pressure is the reduction of steam pressure with load to achieve stable temperatures in the first-stage turbine to reduce thermal stress on turbine components. [17]

various components. Generally, before a cold start, turbines must be heated (by bleeding small amounts of steam into the HP side of the turbine) to the rotor metal's fracture appearance transition temperature before introducing steam flow. If this is not done, a rotor burst could occur during startup. Another issue experienced during startup is speed cycling. Acceleration of the turbine from turning gear speed to synchronous speed subjects the turbine to centrifugal stresses in combination with thermal stresses. Lastly, ramping and on-off cycling leads to an increased risk of erosion and corrosion from changes in steam chemistry. Transient conditions in the boiler can also lead to boiler tube exfoliation; exfoliated solid particles can be carried downstream, causing solid particle erosion in the turbine, which primarily affects the HP control stage and the first reheat stage. The degree of solid particle erosion tends to increase with the degree of cycling and has been noted in industry as a major cause of heat rate degradation in supercritical turbines. [29] [23]

2.5.2.3 Design Strategies

The steam turbine is another critical plant component that must be considered when a plant operates in a flexible regime, since flexible operation of the steam turbine not only leads to component damage, but also reduces its efficiency. The primary mechanism of damage to the steam turbine is thermal fatigue that results from a mismatch between steam and turbine metal temperatures during load changes and startup/shutdown. This temperature difference can be controlled and minimized by upgraded turbine control systems, improved operator training, and by utilization of variable-pressure operation. Variable-pressure operation will also allow for more efficient operation at low loads by reducing throttling losses that occur with fixed-pressure operation and will avoid damage to the turbine control valves from frequent throttling. [29] For plants that operate at fixed pressure, and are unable to switch to variable-pressure operation, it is beneficial to use partial arc admission in the steam turbine to help minimize throttling losses at reduced loads. [15]

Steam turbine flexibility can also be improved by installing a main steam turbine bypass system that allows steam to bypass the HP turbine. This allows the rate of steam temperature change to be managed within the turbine, and effectively minimizes thermal fatigue that occurs during startup and shutdown. Along with this, a complement of thermocouples should be installed within the turbine to measure the temperatures and temperature differentials of critical components. It is also beneficial to use a steam-cooled outer casing for the HP turbine, which allows for casing wall thicknesses to be reduced. [14] For supercritical steam turbines, manufacturers have introduced separate steam chests and nozzle boxes to reduce thermal stresses during steady or transient operation. [22]

2.5.3 Selective Catalytic Reduction System

2.5.3.1 Low-Load Operation

The primary issues experienced by the selective catalytic reduction (SCR) during low-load operation are related to the formation of ammonium bisulfate (ABS). ABS forms at low loads when the economizer outlet temperature decreases below the ABS formation temperature (usually 285–305°C [545–581°F]). [15] Once formed, ABS can deposit in several areas, including

the SCR catalyst pores, the air preheater cold-end baskets, and the SCR ammonia injection components. Together, this will cause a decrease in the nitrogen oxides (NO_x) reduction level achieved by the SCR and lead to an increased pressure drop in the air preheater. [31]

2.5.3.2 Ramping and On-Off Cycling

Most issues associated with the SCR are a consequence of low flue gas temperatures that are experienced during low-load operation, discussed in Section 2.5.3.1. The act of ramping and startup/shutdown does not impose any unique challenges to the SCR system.

2.5.3.3 Design Strategies

Flexibility of the SCR system is dependent upon the ability of the boiler to maintain the proper flue gas exit temperature. This becomes a problem at low loads, but can be resolved by installing a water- or gas-side economizer bypass. This will allow the SCR to be operated at the proper conditions without sacrificing NO_x removal performance. [14] Retrofitting an economizer bypass is possible, but may be prohibitively expensive in some scenarios. In the case that an economizer bypass cannot be installed, it's possible to use injection of sodium sulfite or a dry sorbent to reduce sulfur trioxide (SO_3) levels upstream of the SCR. This will reduce the formation temperature of ABS and allow for operation at lower loads. It is also possible to "burn off" ABS formation if the temperature is increased sufficiently high after low-temperature operation. [32] However, this is not ideal and can result in reduced NO_x removal rates if the unit is forced to be sustained at a low load.

2.5.4 Flue Gas Desulfurization System

2.5.4.1 Low-Load Operation

When operating at low loads, plants usually run at higher excess air ratios, which increase the oxygen (O_2) concentration and decreases the sulfur dioxide (SO_2) concentration in the flue gas. This, combined with a lower flue gas flowrate and temperature, can have several effects on the flue gas desulfurization (FGD) system, including a lower SO_2 removal rate. The increase in the O_2/SO_2 ratio in the flue gas is compounded by the problem that limestone forced oxidation FGD systems typically operate with constant oxidation airflow that is not adjusted in line with the load. This can lead to much higher O_2/SO_2 ratios and correspondingly higher oxidation-reduction potentials (ORPs) in the absorber at low loads. The higher ORP causes manganese to oxidize into oxides of $\text{Mn}^{3+}/\text{Mn}^{4+}$, which are less soluble and may precipitate out of solution, causing scaling on the absorber walls and corrosion problems. The higher ORP will also cause other compounds to reach higher-oxidation states. This can lead to mercury being re-emitted, since it is more likely to be retained in solution. Additionally, selenium will be more soluble and difficult to remove from wastewater when oxidized to selenate. [33]

Another issue with operation of the FGD system at low load is maintenance of the water balance. The lower flue gas inlet temperature decreases the amount of evaporative losses at low load, meaning the makeup water flowrate must be reduced to avoid the need for purging excess water. If the makeup water flowrate is not properly adjusted, the solids recycle may be reduced causing lower-quality batches of gypsum to be produced. [15]

2.5.4.2 Ramping and On-Off Cycling

Most wet flue gas desulfurization (WFGD) systems are not equipped with controls that are capable of handling rapid load changes and, consequently, ramping can cause issues with control of FGD process reagent flows and lead to reduced SO₂ removal efficiency. [15]

Startup/shutdown can cause several complications to the FGD system, including changes in the FGD reaction tank slurry depending on the layup procedure. Additionally, when the particulate control device is offline during unit startup or shutdown to avoid acid gas condensation on particles, the fly ash will be carried over to the absorber and captured in the recycle slurry. Similarly, unburnt startup fuel can be carried over to the absorber and accumulate in the slurry. [33]

2.5.4.3 Design Strategies

In general, the flexibility of the FGD system can be improved by updating the control system and by including sensors to measure the ORP. Selecting appropriately-sized equipment is also important, since one of the most common problems is the inability to properly control reagent flows during flexible operation. [33] This can be solved by manually adjusting pumping rates, but automated control will allow for more efficient operation of the FGD system. A portion of the recycle pumps can be turned off during low-load operation to reduce auxiliary load, but this is only feasible for spray-type absorber towers; tray-type towers, on the other hand, have limited turndown capability while maintaining SO₂ removal efficiency. [34]

2.5.5 Steam Cycle Chemistry

2.5.5.1 Low-Load Operation

Operating at lower loads makes control of the water chemistry more difficult, and proper maintenance of water chemistry becomes more important due to sliding pressure or throttling effects, which result in lower steam pressure in the steam turbine. The condenser and deaerator both suffer performance issues at reduced load. The condenser suffers from several issues, such as insufficient steam flow for removal of non-condensables, and reduced vacuum pumps and air ejectors efficiency, air binding in areas of reduced steam flow, and sub-cooling of condensate. These issues can result in increased levels of dissolved oxygen and carbon dioxide (CO₂) in the condensate. This is especially problematic because these issues can occur without an indication of increased condenser in-leakage, making the issue difficult to detect. The deaerator may suffer from ammonia loss and inadequate deaeration if the steam temperature and pressure are too low, which can cause acidity (pH) control issues and an increase in dissolved oxygen levels. [28]

2.5.5.2 Ramping and On-Off Cycling

Most impurities in steam cycle are introduced via condenser leaks, water treatment chemicals, and chemicals from improper operation of demineralizers. [29] Once present, the thermal transients and changes in steam pressure from cyclic operation can result in many types of damage to components. One of the most severe issues that arises with changes in water

chemistry is corrosion. Corrosion can exhibit effects through many mechanisms, but cyclic operation often results in increased rates of flow-assisted corrosion (FAC), stress corrosion cracking (SCC), and underdeposit corrosion. [28]

FAC occurs when the protective iron oxide layer that forms on the surface of metals dissolves in solution. The iron oxide layer dissolves due to a change in solubility, which is a result of temperature fluctuations, pressure fluctuations, and water chemistry changes. The iron oxide layer will eventually reform, but continuous cycling of this process will cause thinning of tube walls and allow for other forms of corrosion to occur. SCC is caused by the formation of iron oxide within existing cracks. Iron oxide has a much greater volume than the base metal, and its formation causes the crack to expand. Underdeposit corrosion occurs when iron oxide forms heavy, uneven deposits in certain areas, which can result in hydrogen damage that leads to failure of the metal.

While boiler blowdown can be used to balance chemical upset situations in subcritical plants, supercritical plants typically do not include boiler blowdown. Therefore, the impact of water chemistry is more pronounced in supercritical plants than subcritical plants. [35]

2.5.5.3 Design Strategies

Issues associated with the steam cycle chemistry are clearly avoided by proper maintenance of the water cycle, along with appropriate shutdown and layup procedures. The first strategy for maintaining water chemistry should be keeping instrumentation functional and properly calibrated. This will allow for chemistry to be carefully monitored during transients and allow for issues to be quickly identified and resolved before damage occurs to equipment. Condensate and makeup water demineralizers should be regularly recharged to prevent ingress of sodium and chlorine and, in general, all water that is introduced into the steam cycle should be treated to meet the recommended turbine purity requirements. A common problem arises from condenser tube leaks that allow untreated water to enter the condensate system. This water can then be introduced into the cycle if used for attemperator or exhaust hood water sprays. [29]

Use of caustic washing solutions within the boiler and steam turbine during scheduled chemical cleanings should be avoided, even if very dilute solutions are used, since it is possible for these solutions to concentrate to dangerous levels regardless of the initial concentration. Instead, non-contaminating cleaning solutions should be used, and the steam turbine and other components should be isolated during cleaning of the boiler, condenser, piping, and feedwater heaters to avoid carryover of cleaning solutions into other equipment. [29]

When a plant switches from baseload to cyclic operation, new inspection points should be determined to monitor for appearance or progress of corrosion, erosion, or deposition in the steam path. System transient and process conditions that are experienced during flexible operation will result in water chemistry-related issues, even in areas that have historically remained unaffected. [28]

A common technique to preserve the boiler during layup procedures is the application of a nitrogen cap — where nitrogen is applied to provide an inert atmosphere. [36]

For subcritical boilers, it's common practice to drain the unit under a nitrogen cap when the expected shutdown duration is above 72 hours. Whereas, for shutdown durations below 72 hours, the boiler is kept above the saturation temperature and bottled (over 50 psi and over 300°F). [28]

For supercritical boilers, nitrogen is applied to maintain a steam pressure above 25 psig throughout the drainage and subsequent cooldown to ambient temperature when the expected shutdown duration is greater than 12 hours. Whereas, for shutdown durations below 12 hours, the boiler remains in circulation and a minimum allowable temperature is maintained. [36] [28]

2.5.6 Other Equipment

2.5.6.1 Low-Load Operation

Other equipment, such as the particulate control device, generator, and auxiliary equipment, are not substantially impacted by low-load operation. There is evidence that generators suffer damage from ramping and on-off cycling, but the information available is largely qualitative. [29] The only concern regarding particulate control devices is maintaining proper inlet gas temperatures to prevent acid gas condensation on particles, but this does not usually present a problem beyond startup/shutdown. [14]

At low loads, the auxiliary equipment is inherently less efficient due to off-design operation. This is often made worse by the use of fixed speed drives that draw more power than necessary, even at reduced loads. [14] The main auxiliary power consumers that traditionally use fixed speed drives are the main feedwater pumps, boiler draft fans, circulating water pumps, and steam cycle pumps. [34]

2.5.6.2 Ramping and On-Off Cycling

Generators and auxiliary equipment suffer damage from ramping and on-off cycling. Particulate control systems typically experience no performance issues, but baghouses need to either be taken offline or switched to use sacrificial compartments for brief periods during startup/shutdown, which can result in carryover of particulate matter to the FGD system. Generators suffer damage primarily due to repeated differential thermal expansion during cycling service. This can result in strain and rubbing on generator surfaces that leads to premature wear. [15] Continual starting/stopping of rotating equipment such as pumps and fans can accelerate wear and reduce component lifetime. [37]

For supercritical plants, variance in temperature and pressure during ramping and on-off cycling, as well as startup and shutdown, can yield transitions between subcritical and supercritical regimes. The transition between sub- and supercritical regimes yields highly nonlinear steam properties and heat transfer characteristics, and the highly complex configuration of feedwater heaters, coupled with sliding-pressure operation, leads to challenges in steam temperature control—typical control strategies may not be sufficient due to the time-delay nature of the boiler (slow steam-side dynamics versus fast fire-side dynamics resulting from thermal holdup in boiler tubes). [37]

2.5.6.3 Design Strategies

Cycling-related issues with the generator are usually addressed by insulating and epoxying key parts to reduce rubbing from differential expansion. [38] In addition, equipment should be installed to better monitor the status of the generator, so operators are warned before component failure. [29] As for particulate control devices, electrostatic precipitators do not suffer issues from flexible operation. Fabric filters may undergo moisture and acid dew points more often if the boiler is on-off cycled on a regular basis, but the use of sacrificial compartments during startup and shutdown will mitigate this damage. [34]

The part-load heat rate can be improved through several methods, such as installation of variable speed drives and improved operating schemes for equipment during part-load operation. Installation of variable speed drives should generally be prioritized to equipment in the following order: main feedwater pumps, boiler draft fans, circulating water pumps, and steam cycle pumps. Changes in operating philosophy will also allow for increased part-load efficiency. During extended low-load periods, it may be beneficial to shutdown redundant pumps/fans rather than run multiple at reduced loads. This, of course, depends on the number of redundant pumps in the plant, since it may take too long to bring another pump online if the only operational pump were to trip. [34]

With respect to steam temperature control in supercritical PC plants, a coordinated control strategy (CCS) is usually implemented as a supervisory control layer that leverages the regulatory control layer as various degrees of freedom to achieve the control objective. While the regulatory control layer consists of enough proportional-integral-derivative (PID) controllers to maintain nominal conditions, the CCS considers the synergies between the boiler and turbine and adjusts the inputs to the master controllers for the two units. [39]

2.6 CASE STUDIES

This section reviews case studies of existing plants that have been forced into flexible operating regimes. It is intended to highlight the damages that occur as a result of shifting operating profiles, while also revealing the major modifications, in both equipment and operating procedures, that plants have made to better accommodate flexible operation.

2.6.1 On-Off Cycling of a 480-MW Subcritical Plant

A 480-megawatt (MW) subcritical unit was designed as a baseload asset in the 1970s, but was forced to operate at around 50 percent capacity until the early 1990s due to displacement by nuclear power. Since the 1990s, the plant has been operating in a flexible manner (i.e., daily startup and shutdown, sometimes even twice daily). Over life, each coal unit at the plant has had an average of 1,759 starts, with 523 of those being cold starts. The major problems experienced at the plant are as follows [27]:

- Boiler tube failures from thermal fatigue, corrosion fatigue, and pitting
- Cracking in thick-walled components, such as headers and valves
- Cracking in dissimilar metal welds

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- Cracking of generator rotors due to “barring,” which occurs during turning gear operation
- Oxidation from exposure to air during startup and drainage. This also leads to dislodgement of solid oxides that caused solid particle erosion within the turbine
- Condenser tube leaks from thermal stresses that occur during startup and shutdown. The condenser eventually had to be re-tubed
- Turbine damage occurred from migration of turbine blade root locking shims. Minor damage also occurred from wet steam that results from startup, low-load operation, and poor layup procedure
- Re-wedge frequency on stator increased

To better accommodate the flexible operating regime, the plant owner made several physical and operational modifications. Physical modifications were made to several pieces of equipment, including [27]:

- Boiler: Metal overlays were added to water walls to minimize oxidation, tie bars on membrane walls were cut back to avoid corner tube failures, and membranes were cut back in various areas to reduce startup stresses. Buckstays were modified, and corner tubes were strategically replaced. Additionally, some metal fold expansion joints were replaced with fabric joints, and flow elements in the feed pump recirculation valve were replaced.
- Pulverizers were converted from a water deluge system to steam inert, and gear boxes were repaired.
- Turbines were improved by installing drains, upgrading the lubrication system, and modifying vacuum pumps and LP crossover bellows.
- Generators were protected by insulating and epoxying key parts to reduce rotor cracking. Continual tests were performed to monitor trends.
- Condenser tubes were sacrificially plugged at the top of the condenser due to low loads and water impingement. Stainless steel air removals were also installed, and several units were re-tubed.

It should be noted that the plant owner did not consider major capital and O&M expenditures, such as bypass systems or cross-connections between units, due to market conditions. Most of the modifications mentioned above were relatively small compared to more major flexibility retrofits (condenser modification was the largest capital investment, at about \$6–8 million/unit). However, the unit was already fairly well-suited to cycling service; therefore, major retrofits were not necessary. The unit operated using variable-pressure operation, and the boilers were horizontal and already included automated drains. This improves drainage compared to more common “pendant design” boilers. [27]

Modification of O&M procedures also played a critical role in the successful transition to flexible operation; it is estimated that, after the retrofits were completed, about 90 percent of cost

savings arose from modified operating procedures. The operating procedures that were considered included [27]:

- Forced cooling of the boiler: This was eventually stopped when it was clear that it was causing an increase in corrosion and thermal fatigue failures.
- Monitoring economizer inlet headers: Thermocouples were installed to monitor temperature differentials in the header. Cold feedwater was switched from an intermittent feed to a trickle feed to reduce the temperature differential between the metal and feedwater.
- Layup procedures: More stringent procedures for layup were put in place, depending on the length of time the unit was expected to be shut down.
- Pressure part management: All pressure parts were evaluated for potential mechanisms of degradation and failure.
- Boiler operating procedures: Several boiler O&M procedures were put in place to monitor and maintain the status of critical boiler parts.
- Temperature monitoring for turbine parts: Monitoring equipment was installed to safely limit ramp rates and monitor metal temperatures.
- Water chemistry maintenance: Chemistry staff are kept onsite at all hours, and an International Organization for Standardization (ISO) Standardized Chemistry Managed System was established.

2.6.2 Turndown Study of a 600-MW_{gross} Subcritical Plant

Southwest Power Pool performed a turndown study of a 600-megawatt-gross (MW_{gross}) subcritical drum unit operating in the Midwest and firing Powder River Basin coal. The first operational limit was found to be the SCR, which failed to achieve NO_x compliance at loads below about 40 percent, even after the installation of a flue gas-side economizer bypass. It was suggested that it would be especially challenging to maintain operating temperature in the winter. [40]

Switching to hybrid sliding pressure operation solved the issues with the turbine until loads of about 30 percent were reached. Below this, the turbine exhaust conditions were problematic, and the control valves still needed to be throttled to maintain load. Finding the optimal firing scenario (i.e., which mills to keep in operation) at all loads was identified as an important strategy for efficient operation at low loads. [40]

2.6.3 Development of Low-Load Capabilities on Two 1,170-MW_{gross} Supercritical Boilers

Duke Energy attempted to reach a load of 25 percent with two 1,170-MW_{gross} supercritical boilers. In the past, it has been limited to a low load of about 40 percent, but was usually operated well above 50 percent load. Below 40 percent load insufficient steam was available for steam ejectors to maintain condenser vacuum. A load of 30 percent was reached by using

vacuum pumps and auxiliary boilers to provide steam to the steam ejectors, but this resulted in slow ramp rates (2–4 MW/min) at low-load ranges. [40]

The SCR was put out of service at the minimum load of 30 percent, but it was indicated that there was no impact to the FGD system. Additional operator training was provided to integrate the operation of the new systems during low-load operation. In the future, the goal is still to reach a load of 25 percent, but this will likely require the use of natural gas cofiring to maintain flame stability and acceptable ramp rates. [40]

2.6.4 Intermountain Generating Station – Transition of Two 900-MWnet Subcritical Units to Cycling

Intermountain Power Service Corp is converting two 900-megawatt-net (MWnet) subcritical drum units to better accommodate cycling service. The units operate at fixed pressure and the steam turbines were modified with full-arc admission in 2002. The LP turbine rotors and blading were replaced in 2011 and 2013 for SCC mitigation. [40]

In 2016, Intermountain Power Service Corp anticipated that low-load operation would become a necessity. The taskforce was assigned with assessing the impact of low-load and cycling operation on equipment, developing guidelines for cyclic operation, and creating a vehicle for identifying, documenting, and implementing lessons learned from low-load operation. The recommended minimum load was about 40 percent, with the feasibility of operating at 30 percent being reserved for future analysis. Operation of the boiler at 40 percent load required the use of lower mills to maintain NO_x compliance and pressure control. This caused the lower mills outage rate to increase due to low firing rates causing accelerated damage. Additionally, they had to prepare for emergency repairs in case the bottom mills break down. [40]

The turbine control valve seats and disks suffered extensive damage from heavy throttling. To prevent further damage, it is planned to reduce the throttle pressure at minimum load and operate with one or two control valves fully closed. Additionally, material upgrades could be performed to improve erosion resistance of the control valve discs and seats. The last stage of the LP turbine suffered erosion damage, but it was no more severe than what is expected during normal operation. However, FAC began to impact several areas of the feedwater and boiler feed systems that were previously unaffected. [40]

Other measures were also required for achieving stable low-load operation, such as tuning of overfire air controls, installation of a combustion-quality monitoring system, and implementation of cold-weather, low-load operation guidelines for the cooling tower and circulating water pump. [40]

2.6.5 Minimum-Load Operation of Two Supercritical Units

After accumulating about 12,000 hours at minimum load over a period of eight years, the two units suffered extensive bull nose failures. It appeared that this was caused by long-term overheat damage. The overheat damage occurred due to departure from nucleate boiling while operating at minimum load, which required the unit to operate below the critical point. As an

immediate fix, the minimum load for each unit was raised. Eventually, partial nose replacement was completed, which cost the plant several million U.S. dollars (USD). [24]

2.6.6 Extended Shutdown of a Supercritical Unit

A supercritical unit accumulated about 8,000 hours of shutdown, and on most extended shutdowns forced cooling of the boiler was performed. Non-forced cooling shutdowns relied on vacuum drying of the reheater. Eventually, reheater tube leaks occurred due to pitting, and extensive damage occurred in the horizontal reheat sections. The only remedy was complete replacement of the horizontal reheater, which was estimated to cost several million USD. [24]

2.6.7 Minimum-Load Operation of a 150-MW Subcritical Unit

A 150-MW natural circulation subcritical unit built in the 1950s suffered extensive hydrogen damage in water wall tubing after two years of frequent low-load (<25 percent) operation. Prior to this incident, the boiler had suffered no failures for 10 years. A boiler circulation model was developed, and it revealed that, at low loads, a steam blanket developed on the rear wall tubes, which hindered heat transfer and caused elevated heat fluxes in this area. This was sufficient to create a long-term departure from nucleate boiling, which triggered localized hydrogen damage. [24]

2.6.8 Extended Shutdown of a 700-MW Supercritical Unit

A 700-MW supercritical unit suffered from tube failure during startup after a four-month shutdown. The cause for the failure was identified as SCC that occurred due to an inadequate layup procedure and salt contamination in the reheater. Additionally, the boiler tube material (304H) is susceptible to SCC. In the future, the plant plans to use 347H for tube replacements and adopt a more-protective layup procedure. [24]

2.6.9 On-Off Cycling of a 100-MW Subcritical Unit

A 100-MW subcritical drum unit suffered from FAC, causing a feedwater pipe to burst, which shut down the entire unit. The plant did have a FAC inspection program, but it was not sufficient for the level of cycling that the plant was undergoing. [24]

2.6.10 Minimum-Load Operation and Frequent Shutdown of Two 700-MW Supercritical Units

Two 700-MW once-through supercritical units with oxygenated treatment were forced to operate at low loads and frequently shut down. During routine turbine inspection on unit A, cracking was discovered on more than 90 percent of the last-stage LP buckets. Unit B was subsequently taken offline and suffered the same problem, but it was less severe. Laboratory analysis suggested it was due to SCC. The root identified as low-level contamination, combined with low-load operation and unprotected shutdown. It was concluded that the cation conductivity of the boiler should be kept below 0.06 $\mu\text{S}/\text{cm}$ at the effluent of the polisher to prevent SCC within the LP turbine. [24]

2.6.11 Retrofits in an Ultra-Supercritical Coal Plant

Nordjylland Unit 3, an ultra-supercritical coal-fired co-generation unit in Denmark, was commissioned in 1998 and designed for 30 years of operation. Nordjylland Unit 3 was operating primarily in full load and it could produce up to 380 MW of power and 420 MJ/s of heat via steam extraction. While it was designed to operate with ramp rates of 4 percent/min and a minimum load of 25%, the unit's operating profile was adjusted in response to the increase in variable renewable energy (VRE) in Denmark since it's been commissioned. Due to the unit's high efficiency and flexibility, a retrofit to improve the unit focused on optimizing the start-up process. The plant's coal pulverizers were refurbished to increase their output, the plant operations were optimized to continuously ramp from normal load to overload with a reduced number of pulverizers, an improved valve for bypassing the feed-water preheater was installed, and several software updates to the plant's master controller were made to further increase ramping. While the retrofitted upgrades did not require major investment, they resulted in the plant being able to operate with increased ramp rate. [41]

2.6.12 Flexible Coal and Co-generation in Hamburg

Moorburg Power Plant is a co-generation power plant with two 827-MW electricity generation units. The plant was forced to introduce new strategies for increased flexibility due to increased VRE and inability to obtain sufficient returns from baseload operation. The project took three key measures to increase flexibility. First, the minimum stable load was decreased from 35% to 26% in order to decrease the number of start-ups and shutdowns. Second, the control systems and operation modes were optimized to increase ramp rate; with both units in operation, the plant is now able to change load at 48 MW/min and up to 90 MW/min in special load ranges. Third, flue gas dampers were retrofitted to regulate the cooling of the plant after a shutdown, thus reducing start-up time at a later stage. With heat being maintained during long shutdown periods, cold starts became 20% faster, warm starts became 42% to 50% faster, and hot starts became 40% to 46% faster. [41]

2.6.13 Supercritical Unit with Turbine-Driven Feed Pumps

A simulation model representing an 868-MW supercritical PC plant with design steam conditions of 3,514.7 psia, 1000°F main steam temperature, and 1000°F hot reheat temperature and utilizing eight feedwater heating stages, two 60% turbine-driven boiler feed pumps, and three 50%-capacity condensate pumps was developed to analyze thermal models of the entire turbine cycle, including the turbine response, condenser, feedwater heaters, and pumps. When comparing turbine section efficiencies as a function of gross load for constant throttle-pressure operation, it was found that the HP turbine efficiency was the most correlation with load. At the nominal gross load, each turbine section's efficiency was between 86 and 88 percent. When gross load was reduced below 200 MW (approximately 176 MW), the LP and IP sections demonstrated efficiencies of 86.8 and 89.5 percent, respectively. The HP section turbine efficiency was reduced to approximately 80.9 percent, while the HP section turbine efficiency including the re-throttle valve was reduced to approximately 58 percent. Exhibit 2-1 gives the turbine section efficiencies at each load point analyzed.

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Exhibit 2-1. Supercritical PC plant turbine efficiency by turbine section at various loads

Load	100%	80%	60%	40%	20%
HP section efficiency with throttle valve (%)	86.3	84.2	79.2	69.6	58.0
HP section efficiency (%)	87.5	85.2	80.9	80.9	80.9
IP section efficiency (%)	87.3	87.7	88.1	88.5	89.5
LP section efficiency (%)	86.7	87.7	88.9	89.9	86.8

2.7 ASSESSMENT METRICS

Several metrics were identified to allow for assessment of the overall “flexibility” of each case. Exhibit 2-2 presents each of the assessment metrics that were identified from the literature review. The metrics are divided into two categories: 1) flexible plant metrics and 2) competitive plant metrics. The flexible plant metrics are those metrics that relate directly to the characterization of a flexible plant. Competitive metrics are other key metrics often considered when performing dispatch modeling to evaluate the economic competitiveness of an electricity-generating unit (EGU) project.

Exhibit 2-2. Assessment metric characterization

Assessment Metric
Plant Configuration: 150-MW Nominal, Subcritical PC Boiler and STG or 300-MW Nominal, Supercritical PC Boiler and STG, with ACC, SCR, PJFF, WFGD, ACI, and DSI
Flexible Metrics
Startup Time to Full Load, Hours Cold Start to Full Load, Hours Warm Start to Full Load, Hours Hot Start to Full Load, Hours
Ramp Rate, % per Minute
Minimum Stable Non-Emissions Compliant Load (no supplemental firing), % of BMCR
Minimum Stable Emissions-Compliant Load (no supplemental firing), % of BMCR
EGU Competitive Metrics
Design Life, Years
Full Load NPHR, Btu/kWh, HHV, [Net Plant Thermal Efficiency, % (HHV)]
Intermediate Load NPHR, Btu/kWh (HHV), [Net Plant Thermal Efficiency, % (HHV)]
Minimum Emission Compliant Load NPHR, Btu/kWh (HHV),

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Assessment Metric
Plant Configuration: 150-MW Nominal, Subcritical PC Boiler and STG or 300-MW Nominal, Supercritical PC Boiler and STG, with ACC, SCR, PJFF, WFGD, ACI, and DSI
[Net Plant Thermal Efficiency, % (HHV)]
Availability/Reliability Industry Average, NERC-GADS Data: Equivalent Availability Factor, % Equivalent Forced Outage Rate, % New Construction: Equivalent Availability Factor, % Equivalent Forced Outage Rate, %
Planned Outages Plant Maintenance Outage (Spring/Fall) Frequency, Outage/Year Duration, Days Plant/Boiler Frequency, Years/Outage Duration, Weeks Steam Turbine Generator Frequency, Years/Outage Duration, Weeks
EPC Capital Cost, \$/kW
Operation and Maintenance Plant Staff Requirements, No. of Personnel Fixed O&M Costs, \$/kW Non-Fuel Variable O&M Costs, \$/MWh
Number of Starts, per Year

2.7.1 Startup Time

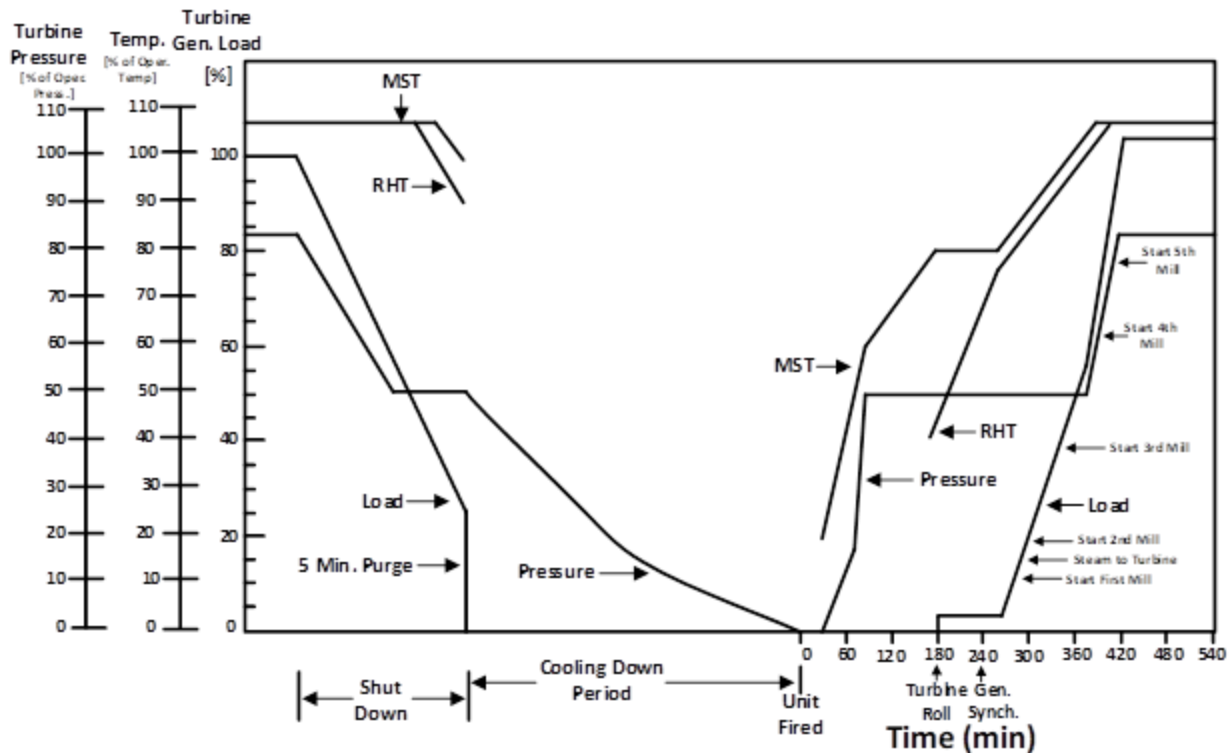
Startup time for a coal-fired electricity-generating unit (EGU) is defined by the number of hours required to bring a unit to full-load from being offline. The startup time for a plant is dependent on the number of hours it has been offline and the temperature to which it has been allowed to cool down. To account for this, startups are commonly defined as being either “cold,” “warm,” or “hot.” These categories are delineated by the number of hours a unit has been offline, as summarized below: [15]

- Cold Start – Offline greater than 48 hours
- Warm Start – Offline between 8 and 48 hours
- Hot Start – Offline less than eight hours

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To minimize thermal stresses a unit's equipment experiences during startup, the rate at which components can warm up ($^{\circ}\text{F}$ per min) are typically limited based on recommendations from the boiler and/or steam turbine original equipment manufacturer (OEM). Actual startup times would be based on project-specific equipment and could vary. An example coal plant startup curve is provided in Exhibit 2-3. This curve provides the composite startup for the plant, taking into consideration the startup time for the boiler, steam turbine, all other major plant components, and startup sequence requirements. Additional details regarding industry-aligned startup operation protocols aimed at improving unit availability and reducing cost are outlined in Section 3.2.

Exhibit 2-3. Example coal-fired power plant startup curve



Used with permission from Black & Veatch

2.7.2 Ramp Rate

The ramp rate of a unit defines the rate at which it can change load. Ramp rate is a critical metric when considering design and competitiveness of a flexible plant. A unit with a higher ramp rate will have a greater advantage in load-following capabilities and will be able to respond quicker to changes in electric grid power demands (i.e., changes in electric power usage) or support changes in electric grid power generation fluctuations (e.g., daily or hourly changes in the electric power generation capabilities common with wind, solar, and other renewable resources). A unit's ramp rate will be driven by multiple factors consisting of physical limitations, control system response limitations, stable and controllable operation (i.e., minimizing control system hysteresis), safety margins in design, and maintaining operation that

benefits equipment health and longevity. Ramp rate is often communicated as the ability to change load in percent load per minute. A typical ramp rate for a coal-fired electric power plant would fall within the range of 2–5 percent per minute. [35] The American Society of Mechanical Engineers (ASME) Power Test Code (PTC) 70, Ramp Rates, identifies ASME standard methods for testing the ramp rate of a unit.

2.7.3 Minimum Stable Load

For this study, minimum stable load is defined as the minimum load a unit can operate at with a stable coal flame that achieves flue gas outlet temperatures and final steam temperatures that do not inadvertently affect the performance of the plant or risk damage to the plant equipment. Often, a coal-fired EGU can introduce the igniters to the coal burner flame to increase the coal flame stability below the minimum stable load. This is often referred to as minimum stable load with supplemental firing. This study is not investigating the interrelation of emissions-compliance and supplemental firing and it will not be considered when targeting a lower achievable minimum load. Multiple literature sources and industry feedback agree that lowering a plant's minimum load, while being cognizant of not negatively impacting long-term unit health, is one of the most beneficial operational flexibility measures a plant can implement.

2.7.4 Design Life

The design life, defined as the expected useful operating life of the plant, is used for engineering design, equipment and material procurement, and evaluation of project economics of the plant. As the design life of the project increases, the required reliability of equipment and associated capital costs will be higher.

As demonstrated throughout industry, the actual operating life of a plant can exceed the design life of a plant. Actual operating life beyond the design life of a unit can be the result of design margins, enhanced O&M routines, renewal and replacement of equipment that has reached end of life, etc. Because of the broad range of equipment, along with modes of wear and failure, the discussion of power plant design life can be extensive unless focusing on key critical and capital cost-intensive components of a plant, such as the boiler and steam turbine island equipment.

Enhancing the design life of a flexible plant may be challenging given that flexible operation tends to negatively impact the design life compared to steady-state operation of a baseload plant. The goal of a flexible plant could be one where the design life is maintained competitive with a baseload plant by implementing design features that mitigate the impact flexible operation has on the plant's design life.

2.7.5 Net Plant Heat Rate

The net plant heat rate (NPHR) of a unit is a metric that is used to quantify the overall thermal efficiency of a power plant. The NPHR for a unit is the quotient of the total heat input into the unit's boiler (Btu/hr) and the net electrical power generated by the power plant (kW). In service, measurement of a unit's NPHR can be achieved by either an input/output method or heat-loss method, as outlined by ASME. The input/output method utilizes measurements of total coal

flow to the unit and measurement of electrical net output. This means calculating a unit's NPHR can present issues due to inaccuracies in instrumentation, especially with total coal flow, and the ability to accurately measure the actual coal heating value during the test. More robust means of calculating a unit's NPHR consist of the heat-loss method, which considers the losses in the boiler, STG, and the plant auxiliary loads. Either method provides accurate results when utilizing heat balance information. The following outlines the mathematical expressions for NPHR:

$$NPHR = \frac{Q_b}{NPO} \quad \text{Equation 1}$$

Where:

- Q_b = Heat input to boiler from fuel, Btu/hr (kJ/hr); corollary of fuel burn rate
- NPO = Net plant output, kW

NPHR, Heat Loss Method Calculation:

$$NPHR = \frac{NTHR}{\eta_b \left[1 - \frac{AP}{NTO} \right]} \quad \text{Equation 2}$$

Where:

- NTHR = Net Turbine Heat Rate, Btu/kWh (kJ/kWh)
- η_b = Boiler Efficiency, percent
- AP = Auxiliary Power, kW, exclusive of motor driven boiler feed pump power
- NTO = Net Turbine Output, kW, as measured at the electric generator terminals minus motor driven boiler feed pump power

The NPHR of a unit can be translated to the unit's thermal efficiency by use of the following formula:

$$\eta_P = \frac{C \times 100}{NPHR} \quad \text{Equation 3}$$

Where:

- η_P = Plant Thermal Efficiency
- C = Constant
 - C = 3,413 if NPHR is in Btu/kWh
 - C = 3,598 if NPHR is in kJ/kWh
- NPHR = Net plant heat rate

The specific means for arriving at a unit's NPHR are best outlined by the methods of the ASME PTC for power production facilities. The following identifies some of the key PTCs, which may be used in defining or diagnosing a plant's NPHR (additional available PTCs may apply):

- PTC 6, Steam Turbines
- PTC 6S, Procedures for Routine Performance Test of Steam Turbines
- PTC 46, Overall Plant Performance
- PTC 4, Fired Steam Generators
- PTC 4.2, Coal Pulverizers
- PTC 4.3, Air Heaters
- PTC 12.1, Closed Feedwater Heaters
- PTC 12.2, Steam Surface Condensers
- PTC 23, Atmospheric Water Cooling Equipment
- PTC 30, Air-Cooled Heat Exchangers
- PTC 30.1, Air-Cooled Steam Condensers

The NPHR of a unit will vary with load. By design, it is greatest at full load and will decrease as power plant load decreases. NPHR will also be at its greatest at “new and clean” conditions and will degrade over the life of the plant. Power plant outages and overhauls will recover a portion of the degraded NPHR, often causing the NPHR of a plant to form a degrading sawtooth curve over its lifetime.

2.7.6 Availability and Reliability

Plant availability and reliability can be described by statistical data accounting for the time the plant is available for generating electrical power and the time the plant is not available for power generation. Typically, the forced outage time the plant is not available for generating power is of greater concern than the time the plant is planned to be offline for routine maintenance and repairs. American National Standards Institute (ANSI) and Institute of Electrical and Electronics Engineers (IEEE) Standard 762, IEEE Standard Definitions for Use in Reporting Electric Generating Unit Reliability, Availability, and Productivity defines operating statistical metrics used to evaluate plant reliability and availability. [42] ANSI and IEEE provide a broad list of metric definitions for characterizing EGU reliability and availability, though industry focuses on a handful with the two primary metrics being plant Equivalent Availability Factor (EAF) and Equivalent Forced Outage Rate (EFOR), which are defined as follows:

- EAF: The maximum electric power generation that an EGU could provide if limited only by outages and de-rates.
- EFOR: The fraction of a given period in which an EGU is not available to provide electric power generation due to forced outages and forced deratings.

EAF and EFOR data for existing plants is available from the North American Electric Reliability Corporation – Generating Availability Data System (NERC-GADS), which collects and maintains generating availability data from participating EGUs. [43] EAF and EFOR would be expected to be better for a newly-constructed plant compared to those reported in NERC-GADS.

2.7.7 Planned Outages

Planned outages are outages that are scheduled by an EGU operator to inspect and conduct routine maintenance, repairs, rebuild, and refurbishment of power plant equipment to maintain overall plant equipment health, plant performance, and overall plant reliability and availability. Plant operators will schedule outage frequency and duration based on past plant operating

experience, to correct known issues, and to conduct OEM-recommended maintenance. The frequency and occurrence can vary between facilities, though some major pieces of equipment (e.g., STG) can have more common and predictable outage cycles. Operators will often coincide outages to minimize downtime.

During periods of low demand, such as the spring and fall, operators often take short multi-day to one-week outages to prepare a baseload plant for upcoming periods where plant demand may be higher. Often, items are addressed during these outages that may be considered a forced outage if the unit was brought offline to correct them. Such examples may be a tube leak or bearing vibration, which may not be severe enough to force an immediate shutdown but is closely monitored until the next planned outage to correct the malfunction. Enhanced maintenance routines, maintenance programs, and asset management programs can help improve and optimize planned outages and reduce the annual planned time an EGU is offline for planned outages. The number of planned outages for a flexible plant would likely be greater than a baseload unit due to the proactive maintenance practices needed to monitor and address the component wear that results from flexible operation.

2.7.8 EPC Capital Costs

Engineering, procurement, and construction (EPC) capital cost includes all costs associated with the project within the plant boundary. EPC costs typically include estimated cost for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs. EPC capital costs are exclusive of owner's costs, which include outside-the-plant boundary development costs, taxes, insurance, interest during construction, and owner's staff and facilities.

2.7.9 Operation and Maintenance

2.7.9.1 Plant Staff Requirements

The plant staff required to support the safe and reliable operation of an EGU can vary between plant owners, plant technology, and employed equipment. Plant staffing requirements are generally not a function of the overall plant capacity, but instead a function of the number of systems that must be monitored and maintained. As an example, a unit with a capacity of 100 MW will require nearly the same staff count as a unit with a capacity of 500 MW that employs the same major equipment configuration, thus demonstrating an optimal economy of scale for plant staffing requirements for larger units.

2.7.9.2 Fixed O&M Costs (\$/kW)

Fixed O&M costs are those costs that do not vary with the electrical generation of an EGU. Because these costs tend to remain fixed and independent of the energy generated by the plant, they are typically communicated on unitized dollars per kilowatt-year (\$/kW-yr) bases (cost per year, per kW of unit capacity). Similar to plant staffing, total fixed costs do not vary substantially among similar power plants of varying capacity. Therefore, the unitized fixed costs in dollars per kilowatt (\$/kW) for smaller EGUs will be much greater than larger units of a similar

configuration. However, additional automation and controls system functionality allows for reduction of onsite staff, and increased planned outage frequency will reduce major maintenance costs by significantly reducing costly forced outage repairs.

The following description lists the more common components of coal-fired EGU fixed costs:

- Staffing Labor
 - Operations Staff
 - Maintenance Staff
 - Technical Services Staff
 - Administration Staff
- Maintenance
 - Boiler
 - STG and Heat Rejection
 - Material Handling
 - Fuel Handling
 - Water and Wastewater Treatment Facilities
 - Wastewater Treatment
 - Air Quality Control Systems (AQCS)
 - Particulate Control System
 - Miscellaneous and Balance of Plant (BOP)
 - Steam Plant
 - Contract Labor and Services
- Other Expenses
 - Property Taxes
 - Insurance
 - Bonus and Incentive Pay
 - Office and Administrative Expenses (e.g., Telephone, computers)
 - Training

2.7.9.3 Non-Fuel Variable O&M Costs (\$/MWh)

Non-fuel variable O&M costs are those unit costs that vary with the electric power generation of an EGU and are exclusive of fuel costs. Because these costs tend to vary with the energy generated by the plant, they are typically communicated on a dollars per megawatt-hour (\$/MWh) basis (cost per unit of electric power generated). Unlike fixed costs, there are less economies of scale with variable costs. While the annual variable cost on a total dollar basis will vary among plants of varying capacity, the cost per unit of electric power generated will be similar, with some cost savings for larger units. Non-fuel variable O&M cost targets for a flexible plant would be expected to be lower than that of a baseload unit due to more frequent operation at reduced loads. Advanced control systems and plant tuning can help to reduce the cost of reagent usage during cyclic operation.

The following description lists the more common components of coal-fired EGU variable costs:

- Outage Maintenance
 - Turbine (Annualized)
 - Generator (Annualized)
 - Boiler (Annualized)
 - BOP (Annualized) per Unit
- Utilities and Consumables
 - Chemicals

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- Water and Wastewater Treatment
- Bottom and Fly Ash Disposal
- AQCS
 - Maintenance (Annualized)
 - Catalyst Replacement (Annualized)
 - Pulse-Jet Fabric Filter (PJFF) Bag Replacement (Annualized)
- Other BOP Chemicals
- AQCS Reagent Costs
 - AQCS Byproduct Disposal Costs

2.7.9.4 Number of Starts

The startup process represents the most rigorous operational periods for the plant's major equipment. Traditionally, baseload units are designed to minimize the number of annual starts, thereby limiting the number of thermal cycles undergone by the pressure parts. In addition to the stress and strain imposed on the plant equipment, each startup constitutes sunk costs (i.e., plant labor and consumables such as fuel and reagent) that must be compensated for in the operating revenue margins later in the operating period. Plants typically operate for several hours, consuming fuel and plant labor resources, before synchronizing to the grid. The annual number of starts, regardless of the "start type," will factor into the overall plant economic dispatch characteristics. A flexible plant would be designed to allow for an increased number of annual starts, a shorter start-period duration, and a lower "per start" cost than a traditional baseload unit.

2.8 PLANT FLEXIBILITY OPTIONS

A summary of options for improving plant flexibility, identified from literature sources and supplemented with Black & Veatch industry experience, is provided in Exhibit 2-4. The flexibility options are organized by the metric they impact the most, but options may provide positive benefits to more than one metric, and some options may be mutually exclusive to others. The secondary benefits of the flexibility options are outlined in Section 4.7.3, and any mutual exclusivities are identified in Section 4.7.2. The intent of outlining them here is to organize and summarize the options that were identified for improving plant flexibility, and to provide references where further detail about these options can be found.

Exhibit 2-4. Plant flexibility options

Assessment Metric	Plant Flexibility Options
	Flexible Metrics
Startup Time (Cold/Warm/Hot)	Boiler and High Energy Piping Systems - Flexibility Option 1: Use of advanced materials to reduce tube and pressure wall thickness requirements to improve rate of warmup [26] [15] [25] [44] [13] [18] [45] - Flexibility Option 2: Decrease drum holding time to reduce drum diameter and drum wall thickness^A (subcritical only) - Flexibility Option 3: Increase the number of headers to decrease header size and warmup time [13] [46] [47] - Flexibility Option 4: Installation of a package boiler for sparging steam supply (boiler drum warmup and/or supplemental steam supply to deaerator) to improve cold and warm starts [44] - Improve cold and warm start through furnace heating utilizing: - Flexibility Option 5: Small dedicated coal feeder, pulverizer, and burner level [44] - Flexibility Option 6: Small dedicated igniter fuel or alternative fuels [45] - Flexibility Option 7: Economizer and/or feedwater heater bypass [18] [15] [25] [32] [40] [14] [45] [44] - Flexibility Option 8: Application of a once-through Benson-type boiler^A (subcritical only) - Flexibility Option 9: Equipping the EGU with black start capability (e.g., high-capacity battery units, reciprocating engine units)^A - Flexibility Option 10: Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems [18] [15] [20] [44] - Flexibility Option 11: Draft system isolation and modifications to retain boiler heat as long as possible during shutdown periods [15] [44] - Flexibility Option 12: Use of condensate polishing system to maintain cycle chemistry parameters during shutdown and layup periods and reduce startup times (subcritical only) [44] [18] Steam Turbine Generator - Flexibility Option 13: Use of advanced materials to reduce turbine casing thickness and reduce STG warmup times [15] [45] - Flexibility Option 14: Turbine blade coatings for improved resistance to water impingement [29] - Flexibility Option 15: Implementing a main steam warmup line to accelerate pipe wall temperature rise during startup^A - Flexibility Option 16: Use of improved turbine seals to ensure correct clearances during startups [25] - Flexibility Option 17: Installation of additional thermocouples to measure the steam-metal temperature differentials [18] [14] [44] [29]

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Assessment Metric	Plant Flexibility Options
	- Flexibility Option 18: Use of electric-resistance heating blankets for the steam turbine casing sections to pre-heat the casing (also works to retain heat as well) [40] [18] - Flexibility Option 19: Use of a steam-cooled turbine outer casing to reduce casing thickness [25] [44]
Ramp Rate and Cycling	- Flexibility Option 20: Use of advanced creep strength enhanced materials [26] [15] [25] [44] [13] [18] [45] - Flexibility Option 21: Enhanced inspection and failure prediction [15] [44] - Flexibility Option 22: Enhanced water chemistry monitoring and system response to cycling [32] [28] - Flexibility Option 23: Implementation of a smaller, fast-response generation resource (e.g., reciprocating engine unit) to allow for additional power export ramping while allowing boiler to ramp according to prescribed time-based intervals (not utilized in flexible plant configuration due to effort to minimize auxiliary fuel use)^A - Flexibility Option 24: Avoid use of forced cooling during boiler shutdowns to mitigate boiler tube failures [44] - Flexibility Option 25: Replace all steam turbine driven pumps (e.g., BFW pump) with electric motor drives^A
Minimum Stable Load (Emissions/Non-Emissions Compliant; with/without Supplemental Firing)	Boiler Low Load - Flexibility Option 26: Low-load coal burner flame stabilization with igniters [13] - Flexibility Option 27: Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter [13] - Flexibility Option 28: Dedicated coal feeder, pulverizer, and burner level sized for lower-load operation [13] - Flexibility Option 29: Economizer gas-side and water-side bypass [18] [15] [25] [32] [40] [14] [45] - Flexibility Option 30: Air heater gas-side and air-side bypass [29] - Flexibility Option 31: SCR gas bypass^A - Flexibility Option 32: Converting a burner row to indirect firing [3] [5] [6] [7] [30] - Flexibility Option (not used): Use of tilting burners for better control of main and reheat steam temperatures (this flexibility option was not utilized, since it is only applicable to tangentially fired boilers) [6] - Flexibility Option 33: Intelligent soot blowing for managing heat transfer within the boiler [24] - Flexibility Option 34: Installation of direct flame detection sensors and more thermocouples to monitor temperatures within the boiler [18] [14] - Flexibility Option 35: Determination of the optimal boiler operating philosophy for each set load point (e.g., selection of which mills and burners should be active at each set load point) [24] [34] - Flexibility Option 36: Designing the boiler with a larger number of smaller-sized mills [18] [14] [24] [45]

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Assessment Metric	Plant Flexibility Options
	- Boiler Steam Offloading: - Flexibility Option 37: STG steam bypass to condenser [25] [15] [44] [14] [45] [18] - Flexibility Option 38: Cogeneration steam to neighboring facility (flexibility option not utilized in plant configuration due to regionally agnostic design intent) [48] Steam Turbine Low Load - Flexibility Option 39: Multi-train steam turbine generator (not utilized in flexible plant configuration due to technology complexity, anticipated high cost, and other steam-turbine-specific flexibility options being incorporated)^A - Flexibility Option 40: Dedicated low-load steam turbine generator (not utilized in flexible plant configuration due to technology complexity, anticipated high cost, and other steam-turbine-specific flexibility options being incorporated)^A - Flexibility Option 41: Application of “continuous coupled” last-stage blades to reduce flutter and dynamic stresses during low-load operation^A
EGU Competitive Metrics	
Design Life	- Flexibility Option 42: Implement best practices for layup procedures, depending on the duration of the offline period [28] - Flexibility Option 43: Use of FFA or FFP to protect equipment from corrosion during layup and operation [15] [28] [40] - Flexibility Option 44: Any measure, either equipment or operational, that reduces the number of start and stop thermal cycles of the EGU [45]
Heat Rate	Range of Load Improvements - Flexibility Option 45: Neural networks and online combustion optimizer [14] - Flexibility Option 46: Water cannons^A - Flexibility Option 47: Fuel additives for slagging and fouling mitigation^A - Flexibility Option 48: Coal drying system (flexibility option not utilized due to the coal type used in this study) [45] [14] - Flexibility Option 49: Auxiliary load optimization [34] [15] - Flexibility Option 50: Auxiliary load dispatch at low loads [34] [15] - Flexibility Option 51: Automated boiler blowdown and drains (i.e., full monitoring and operator control from control room) [18] [15] [20] [14] - Flexibility Option 52: Online performance monitoring [34] - Flexibility Option 53: Enhanced operator training and heat rate awareness [15] - Flexibility Option 54: Enhanced operator interfaced to monitor and diagnose plant heat rate issues (i.e., real-time heat rate calculation and efficiency loss prioritization) [15]

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Assessment Metric	Plant Flexibility Options
	- Flexibility Option 55: Limiting excess air (measured at economizer outlet) and air heater air in-leakage (measured at air heater flue gas outlet) to lowest practical levels (e.g., 12% excess air and 5% air heater air in-leakage)^A - Flexibility Option 56: Maintaining tight air heater outlet temperature target (e.g., 250°F) through use of upstream alkali (e.g., sodium bisulfate) injection^A - Flexibility Option 57: Self-cleaning condenser design with stable backpressure target (e.g., 1.5 inches of mercury)^A Partial Load Improvements - Flexibility Option 58: Steam turbine partial-arc admission (not utilized in flexible plant configuration due to technology complexity, anticipated high cost, and other steam-turbine-specific flexibility options being incorporated) [15] [24] - Flexibility Option 59: Steam turbine sliding-pressure operation (subcritical only) [44] [15] [25] [34] [29] - Flexibility Option 60: Application of variable speed drives on large electric motors [44] [13] [15] [34] [14] - Flexibility Option 61: For regenerative (rotating) air heaters, application of advanced air heater sealing systems that maintain low air in-leakage during startup and low-load operation^A - Flexibility Option (not numbered): Steam turbine-driven BFW pumps (option not utilized in flexible plant configuration; instead, Flexibility Option 25 was selected)^A
Availability/Reliability (Including Planned/Forced Outages)	- Flexibility Option 62: Full leveraging/utilization of the supplier's LTSA [40] - Flexibility Option 63: Full implementation of NERC-GADS Program for outage, trip, and malfunction tracking^A - Flexibility Option 64: Advanced training of operators to reduce errors and improve situational awareness [27] - Flexibility Option 65: Automated prioritization of plant alarm signals to allow for simplified triage of plant information received in the control room [15] [32] - Flexibility Option 66: Modify startup, shutdown, turndown, and ramping protocols to lower component fatigue stresses; for example, determine whether force cooling boiler is for economic reasons or simply to accommodate maintenance staff [44] - Flexibility Option 67: Reducing/eliminating dissimilar metal welds to the greatest extent practical [44] [40] [27] - Flexibility Option 68: Formal HEP and FAC monitoring programs as a part of an overall plant reliability, availability, and maintainability (i.e., RAM program) with data tracking and observation logging for benchmarking [28] [44] - Flexibility Option 69: Participation in steam turbine "rotor exchange programs" through the STG supplier; this program provides a new or re-furbished (identical) HP turbine rotor during scheduled turbine maintenance; reduces risk of cost and outage schedule overruns from maintenance outage findings^A
EPC Capital Cost	Flexibility Option 70: Targeted and limited deployment of advanced creep strength enhanced materials (i.e., controlling cost of advanced materials)^A

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Assessment Metric	Plant Flexibility Options
	- Flexibility Option 71: Reliability-based O&M program; reduces reactive (unplanned maintenance) and maintenance equipment premiums when needed for forced outage situations [44] [40] - Flexibility Option 72: Contracting structure (e.g., open-book EPC, turn-key EPC) of overall project^A - Flexibility Option 73: Reducing plant layout (plan) area and optimizing proximity of plant to major shipping and transportation modes (i.e., rail lines, rivers, oceans, etc.)^A
O&M (Plant Staff Requirements, Fixed O&M, Non-Fuel Variable O&M)	- Flexibility Option 74: Fully integrated online performance and conditional health assessment for major equipment categories^A - Flexibility Option 75: Advanced training for operators (e.g., professional certifications, onsite power plant simulator) [15] [37] - Flexibility Option 76: Additional plant automation and performance monitoring can lead to reduced plant staff requirements^A - Flexibility Option 77: Increasing plant staffing and/or reducing “hours per shift” to avoid operator fatigue and errors from cyclical operation [37] - Flexibility Option 78: Implement additional steam cycle instruments to improve cycle isolation during low-load conditions [15] - Flexibility Option 79: Reducing the number and/or total cumulative cost of each startup [45] - Flexibility Option 80: Utilization of electrode boiler for fast saturated steam production for supporting plant systems (evaluated on case-by-case basis)^A - Flexibility Option (not numbered): Commercial arrangement with a large steam purchase agreement off-taker; unit can supply steam at times where it is not economical to produce power (not utilized in plant configuration due to regionally agnostic design intent) [48]
Number of Starts	Flexibility Option 81: Investment in redundant and higher accuracy steam turbine casing metal temperature instruments; closer monitoring of these temperatures allows for more accurate tracking of design life and maintenance overhaul projections [14] [29]

^A Flexibility option sourced from Black & Veatch internal data, previous heat rate improvement studies for confidential clients, past cycling impact mitigation studies for confidential clients, or OEM literature

2.9 PLANT CONFIGURATION FOR FLEXIBLE OPERATION

General examples of configuration differences between a flexible plant and the baseload plant include:

- Modification of standard bulk material storage equipment (e.g., designing a flexible coal plant with one or more coal domes as opposed to an open-air coal pile for the purposes of optimizing land usage and controlling coal chemical constituents).
- Overall unit size (i.e., MW) will typically be larger for baseload plants due to their ability to fully leverage extended periods of full-load operation and correlating plant efficiency gains.
- For a highly flexible EGU, all large motors would be outfitted with either soft-start or variable-frequency drive (VFD) modules for improved efficiencies at reduced loads; these electrical components would not be of equal efficacy for a baseload unit that does not reduce load frequently. Moreover, these components would introduce additional efficiency losses for baseload units that frequently operate at or near full load.
- Flexible plants have a greater likelihood for dual flue gas duct trains for improved turndown performance of an AQCS and redundancy of flue gas trains (i.e., improved reliability).
- Plants designed for baseload will typically omit advanced alloy tube materials in the boiler radiant/convective sections due to the lower number of intended thermal cycles of the components; plants designed specifically for flexible service will employ more advanced alloy tube materials (e.g., Inconel 740H) to counteract the increased cycles/thermal fatigue.

The following subsections outline the competing technology for major PC process areas, and discuss the tradeoffs (e.g., flexibility, cost, and performance) associated with each technology type.

2.9.1 Coal-Fired Boiler Technology

Multiple boiler combustion technologies were assessed in this study; of these technologies, PC and circulating fluidized bed (CFB) boilers are the predominantly applied technologies. As outlined in this sub-section, the wall-fired PC boiler was selected for use in this study in all cases.

From an engineering standpoint, what often drives technology selection is a combination of engineering constraints, emissions regulations, O&M concerns, performance targets, reliability, and economics. The following provides a high-level look at key characteristic differences between PC and CFB boilers that are often evaluated as part of a technology selection assessment. For this task, a full assessment of detailed unit performance targets and calculations and plant economic viability parameters were not conducted due to the breadth of undefined project specifics, which could be critical in the selection basis, and which are outlined in subsequent sections. Rather, characteristics were evaluated qualitatively for a generic plant site firing bituminous coal.

Fuel Compatibility – CFB technology provides an advantage in its ability to burn a wider range of fuels including low-grade, low-heating value, high-moisture fuels. Because the assumed project fuel would be considered a quality grade of fuel, neither CFB nor PC boiler technology provides any realized advantages regarding fuel compatibility. The following provides an overview of potential fuel characteristics differentiating factors:

- **Moisture** – High-moisture fuels are a challenge to process and fire in a PC boiler. These challenges are reduced with a CFB boiler. The primary effects of moisture in coal are on boiler efficiency and pulverizer performance. The coal moisture content directly affects the latent heat losses of the boiler, thus decreasing the boiler efficiency and negatively affecting the NPHR. For a PC unit, higher-moisture coals present problems in terms of both grindability and pulverizer mill drying. Very high-moisture coals can require substantial upgrades to the pulverizer and hot air systems to achieve the drying needed to effectively burn the coal. With CFBs, pulverization of the coal is not required. Therefore, other than the effect on efficiency and associated NPHR, CFB boilers and their fuel preparation and firing systems are not nearly as affected by moisture concerns as are PC units. Other concerns with high-moisture coals include handling and transport and the possibility of spontaneous combustion with high-volatility subbituminous coals.
- **Ash** – Generally, PC boilers are not favorable to very high-ash fuels, and CFB boilers are not favorable to very low ash fuels. Compared to PC boilers, CFBs provide several advantages that lend themselves well to high-ash fuels. CFB units often rely upon the coal ash to supply bed material; therefore, coals with higher ash content would not require additional bed material other than the sorbent added for in-bed SO₂ reduction. Also, with a CFB, the typical ash split is 50/50, meaning that 50% of the ash would be removed as bed ash and 50% would be entrained in the flue gas and removed downstream as fly ash. Reducing fly ash loading on convective heat transfer pressure part surfaces, air heaters, and downstream equipment can reduce operating difficulties with ash accumulation and erosion and, as a result, overall O&M costs. In addition, the CFB boiler operates with combustion temperatures below the ash fusion temperature, and as such, the CFB also avoids ash slagging and fouling issues that are typical with PC combustion.
- **Sulfur** – The sulfur content of the coal is important for several reasons, but the most important is the potential to form SO₂ emissions when the coal is burned. With a PC unit, SO₂ can only be reduced by the post-combustion AQCS, whereas a CFB unit can use limestone in its bed material to capture sulfur, though in-bed capture of SO₂ can be limited to around 90% and additional SO₂ polishing may be required downstream of the CFB furnace to meet permitted SO₂ air emission limits.
- **Fixed Carbon/Volatile Matter** – The fixed carbon and volatile matter content characteristics of a coal are an important factor in the defining of a coal-fired boiler's combustion system. The fixed carbon to volatile matter content ratio, often referred to as the coal's "fuel ratio," helps characterize the "combustibility" of the coal. Coals with high fuel ratios (i.e., high fixed carbon to volatile matter) are considered less combustible. Fuels with low fuel ratios (i.e., more balanced fixed carbon to volatile

matter content) are considered easier to burn. Typically, a coal-fuel ratio of 1.5 is considered the dividing line between less-difficult and more-difficult combusting fuels. Beyond the fuel ratio, the magnitude of the volatile matter can impact the decision in selecting the boilers combustion system. Traditional PC boilers have difficulties firing coal with very low (typically less than 15%) volatile matter content.

Fuel Flexibility— PC is able to operate on a wide range of fuels, although the design constraints of those fuels must be incorporated into the initial design of the PC boiler. CFB boilers are capable of operating on a much wider range of fuels than a PC boiler. As noted, fuel flexibility or the ability to fire waste and opportunity fuels was not considered a significantly differentiating requirement due to the prescribed design coal.

Environmental — Both PC and CFB with the appropriate post-combustion AQCS are capable of meeting the most stringent air emissions requirements required in domestic and global markets. CFB does, however, provide some benefits to emissions mitigation because of the reduced emissions concentrations of its uncontrolled flue gas. Because of lower combustion temperatures, CFB produces less NO_x. With in-bed sorbent injection, SO₂ can be reduced in the CFB furnace. There is less fly ash carryover with a CFB, typically 50 percent compared to 80 percent for PC. Reduced uncontrolled flue gas emissions for CFB reduces the emissions loading on post-combustion AQCS and, depending on the environmental regulations the project must meet, may eliminate the need for some AQCS equipment.

Capital Costs — Both PC and CFB are highly capital-intensive projects. Boiler island costs are expected to be lower for PC compared to CFB by 1–3 percent. Total plant cost competitiveness is more difficult to characterize due to the varying suite of AQCS equipment employed for similarly sized PC/CFB units.

O&M Costs — In general, annual O&M costs for PC and CFB are competitive with a slight advantage for PC. Refractory is included in a CFB boiler, which introduces a potential costly/recursive O&M expense, if not properly designed and installed. If there is a potential for ash sales, PC provides an advantage if ash can be collected prior to the sorbent injection. With CFB, the fly ash will contain bed-reacted sorbent and is not likely to be suitable for beneficial reuse or sale.

Technology Maturity — Although PC boilers have seen far more operating hours than CFB boilers, CFB boilers below 300 MW would be considered as nearly technically mature, with proven and well-established operating experience. There is greater industry support and original equipment manufacturer (OEM) offerings for PC units.

Availability and Reliability — Neither technology, PC or CFB, has a significant advantage over the other in regard to availability or reliability. It is expected that a new CFB power plant that was well-operated would have similar availability and reliability factors as those of a PC boiler.

Flexibility and Load Ramping Capability — In regard to plant operation flexibility and ramp rates, PC boiler technology provides a marginal advantage. Both PC and CFBs have competitive turndown and ramping capabilities when considered in their initial design. However, startup times with a CFB unit will be longer, since more energy and time is required to heat up the bed material.

2.9.1.1 Sub, Super, and Ultra-Supercritical Experience and Basis

Both PC and CFB have been designed with subcritical, supercritical, and ultra-supercritical steam conditions. The distinction between the three are based on the outlet steam conditions of the boiler. When operating at a pressure lower than the critical point of water (21 MPa [3,200 psia]) the boiler is designated subcritical. When operating at a pressure beyond the critical point of water, the boiler is designated supercritical.

The increase in pressure from subcritical to supercritical conditions above the critical point of water (21 MPa/374°C [3,200 psia/705°F]) improves the Rankine cycle efficiency. This increase in efficiency comes at a cost, however, and the economics of the decision between subcritical and supercritical design will depend on the cost of fuel, expected CF of the unit, environmental factors, and the cost of capital. While there has been experimentation with higher operating temperatures, up until the past decade many of the supercritical units constructed were designed and operated with main and reheat steam temperatures between 538 and 565°C (1,000 and 1,050°F). Advancements in metal alloys have allowed for higher operating temperatures and pressures, creating a new class of “ultra-supercritical” boilers and steam turbines with higher main steam and reheat temperatures meeting or exceeding 593°C (1,100°F). In several Electric Power Research Institute (EPRI) documents, ultra-supercritical cycle design has been defined as having a steam pressure in excess of the critical point of water and steam temperatures equal or greater than 593°C (1,100°F). This definition of ultra-supercritical appears to be universally accepted in the United States.

The steam conditions selected as part of the design basis, and their associated system designs, are considered well-proven and established ranges for the boiler types available from boiler manufacturers in this size range. These steam conditions are applicable to PC and CFB boiler types. Subcritical PC boilers are arguably the most utilized boiler technology throughout the world and have been installed in capacities to support 25 MW to more than 1,000 MW. Supercritical PC units have generally been installed in larger capacity classes (i.e., typically greater than 300 MW). A limited number of CFB boilers have been installed in capacities of up to 550 MW; however, well-demonstrated capacities from many vendors do not extend appreciably further than 350 MW and are of a subcritical Rankine cycle.

Recently, Black & Veatch conducted an industry review of subcritical and supercritical PC units at 300 MW and below to better understand the availability and the utilization of both technologies. Black & Veatch contacted multiple international boiler and steam turbine suppliers as part of that review.

According to the responses Black & Veatch received from the technology suppliers, a supercritical PC plant would not likely be competitive or well-supported for below 300 MW. Experience records for all contacted vendors show limited background for supercritical PC technologies below the 300-MW class.

Based on Black & Veatch in-house data for CFB, there have only been a handful of supercritical plants built to date: a 460-MW unit in Poland (Lagisza Project, 2009), a 4 × 550-MW plant in South Korea (Samcheok Green Power Station, 2016), a 330-MW unit in Russia (Novocherkasskaya, 2012), and a 600-MW unit in China (Baima, 2013).

A review of these data ostensibly indicates a current trend for subcritical coal-fired technologies for units below 300 MW. For supercritical coal fired technologies the units would be 300 MW and larger.

In the past, the primary driving decision between subcritical and supercritical was the cost difference in materials and advanced fabrication and welding techniques for the boiler, steam turbine, and interconnecting piping, along with improved cycle water treatment systems. To justify these costs, there had to be an economic life-cycle benefit for the project realized through reduced life-cycle fuel savings from the improved 20% cycle efficiency.

While these economic factors still are important drivers, other drivers, such as project funding technology requirements, project interveners, permitting strategies, and perceived environmental benefits of increased efficiency, are playing greater roles in the selection between subcritical, supercritical, and ultra-supercritical.

The primary advantage of supercritical units is the relatively high boiler efficiencies, compared to subcritical units. However, subcritical units have the advantage of higher resistance to transients, upsets, and malfunctions (e.g., boiler tube leak) during normal operation. Also, subcritical boiler design allows for utilization of natural boiler circulation as opposed to forced circulation (i.e., additional pumps) required for supercritical units.

2.9.1.2 Wall- Versus Tangential-fired PC Boiler

Wall firing and tangential firing are the two primary methods of coal firing in a PC boiler furnace. With wall firing, burners are arranged on the walls of the furnace, and each burner creates an individual and separate flame. Small boilers typically have burners arranged on a single wall, while larger boilers will have burners arranged on two opposing walls. Alternatively, tangential-fired boilers have burners arranged in the corners of the furnace. The burners consist of coal and air nozzles that tangentially inject coal and air into the furnace, resulting in a single spinning fireball within the boiler furnace where the coal and air mix and the coal burns in suspension. Current pulverized fuel combustion technology also includes features to minimize unintended products of combustion. Low-NO_x burner (LNB) or air-fuel staging (overfire air [OFA]) can be used to reduce NO_x. Carefully controlling the air-fuel ratios are also important for reducing NO_x emission and controlling carbon monoxide (CO) emissions.

These two firing configurations offer their individual value-adding benefits, with wall-fired units exhibiting the majority of installations worldwide (i.e., operational familiarity) versus tangential-fired units. There are no major conflicts or system impacts by selecting either one of these two firing configurations. However, tangentially-fired coal units have been noted to provide benefits to turndown capabilities when compared to a wall-fired burner arrangement. [25]

Commercially proven market offerings are available from suppliers, listed in Section 4.9.3.3, for both wall-fired and tangential-fired PC furnaces. By comparison, there are more wall-fired boiler suppliers in the market than suppliers offering tangentially-fired boilers. In Black & Veatch's experience with coal boiler specification and procurement, typically a performance specification is drafted and issued irrespective of the firing technology (i.e., wall-fired or tangential-fired). The task of selecting the firing configuration is dependent on the boiler suppliers' proposal for

meeting the performance characteristics of the unit with whichever firing configuration is best suited to meet the project requirements. A wall-fired configuration was chosen for its broad installation base (market familiarity), enhanced opportunities for flexible firing scenarios (individual burner/burner row tuning capabilities), and state-of-the-art pre-combustion emissions controls capabilities.

2.9.1.3 Additional Boiler Technologies

Stoker boilers are often found in industrial applications firing waste or opportunity fuels, though they have been employed in utility applications firing coal in older generation facilities. The physical sizing limitations of stoker grates restrict the installation in capacity classes for larger modern utility-scale application.

Bubbling fluidized bed (BFB) boilers are well-proven and established technologies. However, they have had limited utilization in utility applications in recent decades and are not technically suited for the assumed plant capacities of 150 MW-gross and 300 MW-gross (BFBs are typically only applied up to approximately 100 MW).

2.9.2 NO_x Control Technology

Nitrogen oxides can be controlled post-combustion by either selective non-catalytic reduction (SNCR) or SCR systems. With SNCR, ammonia (NH₃) or urea is injected into the flue gas stream at an optimal temperature following combustion. NH₃ reacts with NO_x to form nitrogen and water vapor, while urea reacts with NO_x and oxygen to form nitrogen, water, and CO₂. NO_x reductions of up to 60 percent are achievable with SNCR system.

With SCR systems, a fixed-bed catalyst is housed in a catalyst vessel installed in the flue gas stream. For coal-fired EGUs, this is typically immediately downstream of the economizer (or upstream, depending on boiler flue gas design temperatures). The NH₃ is injected into the flue gas stream just prior to the catalyst via an NH₃ injection grid. The catalyst improves the reaction between NO_x and NH₃ to form nitrogen and water vapor. Removal efficiency of the SCR system is dependent on the inlet NO_x loading, but NO_x reductions of 60 percent and greater are achievable.

For both SCR and SNCR, careful design and operation (such as control of the reagent dosage and adequate mixing) is necessary to meet NH₃ emissions levels (referred to as ammonia slip).

Selection of one technology over the other is typically dependent on the required emissions limits for the project. SCR is the more capital-intensive reduction technology because of the catalyst module and initial catalyst. Therefore, SNCR would be selected if it were capable of meeting the required emissions limits. It is assumed that a newly installed coal-fired EGU would require an SCR system.

Lastly, when discussing pre-combustion NO_x mitigation, the application of LNBs and OFA ports would be equipped to the PC boiler to provide a multifaceted approach to NO_x control. The inclusion of LNB/OFA equipment in addition to an SCR system is common for PC units installed in current global markets. These pre-combustion and post-combustion strategies (LNB/OFA and

SCR, respectively) are considered supporting/supplemental to each other; these systems are not viewed as mutually exclusive.

An additional pre-combustion strategy for NO_x mitigation is flue gas recirculation (FGR). The principle of FGR for NO_x mitigation involves recirculating hot exhaust gas from the boiler exhaust ductwork, typically extracted near the economizer, and reintroducing it into the boiler windbox/burner air registers. The integration of this largely inert gas reduces the flame temperatures and thereby reduces the production of thermal NO_x production within the combustion process. It is not anticipated that a new EGU installation would utilize an FGR system if LNB/OFA equipment and SCR and/or SNCR systems were already utilized. For this reason, an FGR system was not incorporated into the reference plant design and is outlined here for informational purposes only.

2.9.3 SO₂ Control Technology

There are several methods of grouping available FGD process technologies. The following list shows the primary groups of FGD processes and the ranking of SO₂ removal efficiency from lowest to highest:

- Dry-based FGD process — Up to 70% removal efficiency
- Semi-dry lime-based FGD process — Greater than 92% removal efficiency
- Wet lime- and limestone-based FGD process — Greater than 95% removal efficiency

The above FGD processes utilize limestone, lime, or lime hydrate as a reagent to remove SO₂ from the flue gas stream. The following subsections provide further narrative and basis of selection for the SO₂ control technology.

2.9.3.1 Dry Scrubbing

Dry scrubbing was one of the first FGD methods used throughout global markets. In a dry scrubber, particles of an alkaline sorbent are injected into the flue gas. Dry FGD systems have SO₂ removal efficiencies in the range of 50 to 70 percent. The two most common dry FGD processes are furnace sorbent injection and duct sorbent injection.

Since dry FGD systems utilize very little water, wastewater treatment is not necessary. A dry byproduct is produced after the reaction of the SO₂ with the lime or lime hydrate reagent, and the byproduct is captured by a downstream particulate collection device. The dry byproduct is then collected, conditioned as necessary, and disposed in a landfill.

Because of the low-removal efficiency of a dry-based FGD system, it is not likely that it would be able to meet current or future SO₂ air emission limits.

2.9.3.2 Semi-Dry Scrubbing

Spray drying has been used in many industrial process industries since its introduction in the 1970s. Since then, the semi-dry lime FGD process has been one of the most widely applied FGD technologies. Many U.S. utilities have installed numerous semi-dry lime FGD systems on boilers using low-sulfur fuels. There are several variations of the semi-dry lime FGD process:

- Spray dryer absorber (SDA)
- Circulating dry scrubber (CDS)
- Flash dryer absorber
- Limestone injection into the furnace and reactivation of calcium

All four of the listed semi-dry FGD processes can achieve up to 92 percent SO₂ removal efficiency with higher efficiencies achievable from SDA and CDS. SDA and CDS FGD processes are the most common semi-dry-based FGD technologies.

SDA Semi-Dry Scrubbing

There are several variations of this process, but the most prevalent is the installation of one or more SDA vessels downstream of the coal-fired boiler's air heater but upstream of the particulate control equipment.

With SDA, a lime slurry is sprayed into the SDA vessel as an atomized mist. All current SDA designs use a vertical gas flow absorber. In all cases, atomizers are located in the roof of the absorber to create an umbrella of atomized reagent slurry through which the flue gas passes. The SO₂ in the flue gas is absorbed into the atomized droplets and reacts with the calcium of the lime slurry to form calcium sulfite (approximately two-thirds of the reaction products) and calcium sulfate (approximately one-third of the reaction products) with a small amount of calcium carbonate formed. Before the slurry droplet can reach the absorber wall, the water in the droplet evaporates and a dry particulate is formed. The dry particles are then collected in the downstream particulate control equipment with the fly ash for disposal. Electrostatic precipitators (ESPs) have been used downstream of an SDA. The use of a fabric filter provides the advantage of increased SO₂ removal efficiency due to the additional scrubbing that occurs within the fabric filter cake.

Despite the fact that water is introduced into this process, the slurry byproducts and collected fly ash from the particulate collection equipment are a dried solid. These solids usually come in the form of fly ash, calcium sulfate, calcium sulfite, and lime. This allows easier handling of the products that are sent for disposal. No dewatering is required, but the wastes typically are wetted for the control of fugitive dust emissions during transportation.

With the SDA technology, there is very limited commercial use for the combined byproduct/fly ash. Although the potential for sale of the fly ash is typically lost, it could be used for fill. When fly ash sales are desired, the fly ash would need to be removed by separate particulate collection equipment upstream of the SDA.

CDS Semi-Dry Scrubbing

This process uses a CFB of dry hydrated lime reagent for SO₂ removal. The flue gas enters multiple venturi nozzles at the base of a vertical reactor tower where it is humidified by a water mist from water injection nozzles before entering the circulating bed of powdered hydrated lime, fly ash, and recycled byproducts. The water is added separately from the lime but interacts in the fluidized bed.

The SO₂ in the flue gas reacts with the reagent in the suspended bed to form predominantly calcium sulfite. Because of the relatively high velocity of the flue gas through the reactor module, the treated flue gas carries entrained reagent and reaction products from the module to the downstream particulate control device where it is collected. The particulate control device is typically equipped with an integral mechanical separator at the inlet to reduce loading.

A portion of the collected solids are returned to the reactor by air slides to improve reagent utilization. The recirculation of solids also maintains the bed density needed for contact and removal of SO₂. As a result of abrasion and impacts with other particles in the flue gas, the reagent particles are broken up, exposing fresh reagent that increases utilization. Typically, reagent is circulated 35 to 50 times, providing a residence time of 30 or more minutes.

Collected solids that are not recirculated are directed to a silo for disposal.

The dried solids byproducts from this process consist of fly ash, reacted byproduct, and un-reacted lime. No dewatering is required, but the wastes are typically wetted for the control of fugitive dust emissions during transportation.

With CDS, there is very limited commercial use for the combined byproduct/fly ash. Although the potential for sale of the fly ash is typically lost, it could be used for fill. When fly ash sales are desired, the fly ash would need to be removed by separate particulate collection equipment upstream of the CDS.

2.9.3.3 Wet FGD Process

WFGD systems have demonstrated the capability to meet the strictest emissions limits while firing fuels ranging from low sulfur to very high sulfur. WFGD technology can achieve higher removal rates (greater than 95 percent removal) than those achievable by most common semi-dry FGD technologies.

Numerous suppliers offer a WFGD system. Most WFGD suppliers use a spray tower with countercurrent flue gas flow. Some suppliers include perforated trays to improve liquid-to-gas contact. A few FGD suppliers take an entirely different approach to the liquid-to-gas contact ratio in their absorber and have co-current flow or bubble flue gas through the liquid limestone slurry.

The overall process uses limestone slurry that is recirculated in an absorber/reaction tank to contact the flue gas flow stream in the FGD module. Sulfur dioxide is absorbed from the flue gas into the slurry liquid, where calcium sulfite and calcium sulfate are formed. Most recent wet limestone-based systems use forced oxidation of the byproduct solids to convert essentially all the calcium sulfite to calcium sulfate, which is commonly called "gypsum."

The desulfurization byproducts are discharged via a slurry bleed stream and are dewatered in hydrocyclones as the primary step, and then processed further in a vacuum filter or centrifuge as the secondary dewatering step. The resulting gypsum cake is then suitable for landfill disposal or commercial use, depending on the design of the system.

The wet FGD process has the effect of removing virtually all the chlorides from the flue gas stream. These chlorides concentrate in the liquid slurry. Concentrated chlorides in the slurry increase the corrosion potential and will affect materials of construction and equipment costs.

2.9.3.4 *SO₂ Control Technology Comparison and Selection*

Selection of one FGD control technology over the other is typically dependent on the required emission limits for the project. Generally speaking, there is a direct relationship between the removal efficiency of an FGD control technology and the capital cost of that technology. Therefore, an FGD technology with low-removal efficiency would be selected if it can meet the required emissions limits. Actual determination of the required FGD system for a specific project would be based upon many factors, including project fuel characteristics, fuel sulfur loading, permitting strategies, and the environmental authorities having jurisdiction for project approval. For this study, a WFGD system was utilized. A summary comparison of SDA, CDS, and WFGD is provided in Exhibit 2-5.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 2-5. Summary comparison of SDA, CDS, and WFGD technologies

Characteristic	WFGD	CDS	SDA ^A
Summary			
SO ₂ Removal Efficiency, %	95+	94+	92+
Life-Cycle Cost	Most Expensive	CDS and SDA are competitive with one another	CDS and SDA are competitive with one another
Potential Reagents	Limestone	• Lime (would require hydration) • Hydrated lime	Lime
Byproduct Disposal Alternatives	• Pond • Landfill • Reclamation • Commercial gypsum	• Landfill • Reclamation	• Landfill • Reclamation
Effects on Boiler	None	None	None
Effects on Other Generating Plant Equipment			
Fabric Filter	None	• Fabric Filter or ESP required downstream • Substantial increase in particulate load • Potential for acid condensation • Increased performance with fabric filter due to additional removal in filter cake	• Fabric Filter or ESP required downstream • Increase in particulate load • Potential for acid condensation • Increased performance with fabric filter due to additional removal in filter cake
ID Fans	• 1.5 to 2.0 kilopascals (kPa) (6.0 to 8.0 inches of water [in. H₂O]) increase in pressure • Located upstream of FGD	• 1.5 to 2.0 kPa (6.0 to 8.0 in. H₂O) increase in pressure • Reduction in volume due to upstream quenching of flue gas • Located downstream of FGD	• 1.2 to 1.7 kPa (4.8 to 6.8 in. H₂O) increase in pressure • Reduction in volume • Located downstream of FGD
Flue Gas Ductwork	Increased corrosion potential for downstream ductwork	Increased potential for buildup ahead of particulate control device	Increased potential for buildup ahead of particulate control device
Chimney Liner	• Potential for corrosion • Potential for acid mist rainout	None	None

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Characteristic	WFGD	CDS	SDA ^A
Effects on Generating Plant Operation			
Limitations on Operating Cycle	Much more complicated system, controlling slurry chemistry, water loading, and response to load swings requires advanced controls tuning	Needs a minimum of 50% of design flow, then ~45 minutes to stabilize	Needs a minimum operating temperature to begin scrubbing
Changes in Fly Ash Quality	None	FGD byproduct contaminates the fly ash; fly ash could be collected prior to FGD module	FGD byproduct contaminates the fly ash; fly ash could be collected prior to FGD module
Increased Consumption of Plant Utilities	- Significant increase in service water - Significant increase in auxiliary power	- Increase in service water - Medium increase in auxiliary power	- Increase in service water - Medium increase in auxiliary power
Changes in Wastewater for Plant	High chloride bleed stream	None	None
Effects on Other Pollutants			
SO ₃	Minimal removal	+90% removal	+90% removal
Mercury	85 to 90% of oxidized fraction (soluble in water)	Varies	Varies
Operating Experience			
Stage of Development	- Full commercial with many operating facilities - Available from several experienced vendors	- Full commercial with many operating facilities - Available from several experienced vendors	- Full commercial with many operating facilities - Available from several experienced vendors

^A SDA is not applicable to bituminous fuel

2.9.4 PM Control Technology

Two primary means for collecting particulate matter (PM) for coal-fired EGU flue gas is with dry ESPs or fabric filters. While the two technologies serve the same purpose, their means of PM collection are significantly different. The following subsections provide narrative summaries for ESPs and fabric filters followed by a technology comparison.

2.9.4.1 ESP

ESPs use transformer/rectifiers to energize “discharge electrodes” and to produce a high voltage direct current electrical field between the discharge electrodes and the grounded collecting plates. PM entering the electrical field acquires a negative charge and migrates to the grounded collecting plates. This migration can be expressed in engineering terms as an empirically determined effective migration velocity, but takes place in a turbulent flow regime with the particulate entrained within the turbulent gas patterns. Thus, the charged particles are collected when the combined effect of electrical attraction and gas flow patterns moves the charged PM close enough for it to attach to the collecting surfaces. A layer of collected particles forms on the collecting plates and is removed periodically by mechanically impacting or “rapping” the plates. The collected PM drops into hoppers below the precipitator and is removed by the ash handling system. Some particulate is also re-entrained and either collected in subsequent electrical fields or emitted from the ESP.

The required particulate removal efficiency, the expected electrical resistivity of the fly ash, and the expected electrical characteristics of the energization system determine the physical size of an ESP. Many parameters determine the ESP’s capability for particulate collection. The ability to charge PM particles is dependent on ash resistivity, which is a measure of how easily the particulate acquires an electric charge. Operating resistivity varies with flue gas moisture, SO_3 concentration, temperature, and particle chemical composition. As a result of particle resistivity being sensitive to these factors, ESPs can be affected greatly by changes in fuel or operating conditions.

2.9.4.2 Fabric Filter

Fabric filters are media filters through which flue gas passes to remove particulate matter. The advantage of fabric filters is predominately due to their ability to economically meet the low particulate emissions limits for a wide range of particulate loading and fuel characteristics. Fabric filters are not sensitive to fuel and operating changes like ESPs and are relatively insensitive to ash loadings and ash types, offering ideal coal flexibility. Fabric filters are also the choice technology when sorbent injection is used for air emission reduction, since the sorbent cake that forms on the fabric filter bags provides an additional surface for reaction and collection.

Cloth filter media is typically sewn into cylindrical tubes called bags. Each fabric filter may contain thousands of these filter bags. The filter unit is typically divided into compartments that allow online maintenance or bag replacement after a compartment is isolated. The number of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth ratio, and cleaning system design. Extra compartments for maintenance or offline

cleaning increase cost, but also increase reliability. Each compartment includes at least one hopper for temporary storage of the collected fly ash.

Fabric filters are generally categorized by their specific method of cleaning. The two predominant cleaning methods for utility applications are reverse gas fabric filter (RGFF) and pulse-jet fabric filter (PJFF).

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tube sheet that isolates the dirty flue gas plenum from the clean flue gas plenum.

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag, which dislodges the dust cake from the bag surface causing the dust to fall into the hopper. This cleaning can occur with the compartment online or offline.

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cake's filtering capability as woven fiberglass bags do. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

Initially, utility experience in the United States was almost exclusively limited to RGFFs. Although they are a reliable and effective emissions control technology, RGFFs have a relatively large footprint. On the other hand, PJFFs have a smaller footprint and lower capital cost when compared to a RGFF, with comparable performance and reliability. As a result, only PJFFs were considered for further evaluation.

2.9.4.3 PM Control Technology Comparison and Selection

Between a PJFF and an ESP, there are multiple primary characteristic differences that give an advantage to a PJFF. As discussed previously, a plant that employs both sorbent injection and a PJFF gains an advantage through additional air pollutant removal by the filter cake collected on the bag surface, and PJFFs are not as sensitive to changes in fuel characteristics or operating conditions. Considering the industry trends and the advantages associated with a PJFF, it was selected as the PM control technology for this study. A summary high-level comparison between ESPs and PJFFs is provided in Exhibit 2-6.

Exhibit 2-6. Summary comparison of ESP and PJFF technologies

Characteristic	ESP	PJFF
Ability to collect additional air pollutants from collected sorbent injection filter cake	No	Yes
High performance with varying fuels	No	Yes
Potential for greater collection efficiency	Base	Higher
Suitable for high fly ash loading	No	Yes
Flue gas pressure drop, bar (in. H ₂ O)	0.2–0.5 (0.8–2.0)	1.2–1.7 (4.8–6.8)
Energy demand (excluding induced draft fan)	High	Moderate
Energy demand (due to flue gas pressure drop)	Low	Moderate
Capital cost	Higher	Moderate
Operating/maintenance cost (relative)	Lower	Moderate
Technology compatible with a WFGD	Yes	Yes

2.9.5 Mercury Control Technology

Mercury can be controlled via the injection of powdered activated carbon (PAC) into the boiler flue gas stream. PAC injection typically involves injection of a lignite-based carbon compound into the flue gas upstream of the particulate control equipment. The PAC reacts with the mercury in the flue gas via adsorption of the mercury onto the surface of the PAC particles. The PAC particles are then removed from the flue gas stream and are collected with the fly ash in the particulate control device.

PAC injection is added upstream of particulate control devices, such as fabric filters or dry ESPs. PAC injection system performance is highly dependent on temperature; for optimal performance of a PAC injection system, the air heater outlet temperature should be below 325°F.

A higher carbon injection rate is required for PAC injection upstream of a dry ESP than is required for PAC injection upstream of a high air-to-cloth ratio PJFF. Black & Veatch in-house data and experience indicates that PAC injection upstream of a dry ESP can reduce mercury emissions by up to 60 percent for units that burn a subbituminous or lignite coal, and up to 80 percent for units that burn a bituminous coal. When the PAC is injected upstream of a PJFF, PAC injection systems can exceed 80 percent removal rates for units burning subbituminous coal or bituminous coal.

2.9.6 SO₃ Control Technology

Dry sorbent injection (DSI) has been extensively used to control SO₃ emissions and acid gases at coal-fired power plants. These systems utilize a sodium-based (e.g., trona or sodium bicarbonate) or calcium-based (e.g., hydrated lime) sorbent for the absorption and collection of SO₃. The sorbent is injected into the duct upstream of the particulate collection device.

2.9.7 Cooling System Technology

The plant configuration assessment considered four potential options for cycle heat rejection: mechanical draft cooling towers, hyperbolic cooling towers, once-through (river or reservoir) cooling, or an air-cooled condenser (ACC). The four heat rejection technologies all have suitable suppliers with suitable installation experience to not significantly differentiate the options based on installation experience or technology risk. Additionally, these suppliers would likely be capable of providing competitive performance guarantees for these heat rejection systems in addition to industry-aligned terms and conditions.

Hyperbolic cooling towers were eliminated based on cost, required area for installation, and reference plant size. The option of once-through cooling was also eliminated due to the narrow range of applicable locations (i.e., in immediate proximity of river or reservoir) and the maintenance and permitting challenges these systems are encumbered with. Use of once-through cooling via river or reservoir water sources requires stringent inspection of intake structures and transport piping to and from the water source. Seasonal variations in water source temperatures can impact plant performance and even impose forced load reductions based on temperature differentials outlined in the facility discharge permit. An example of this occurrence is rising river temperatures during the summer months reduces the available heat rejection capacity of the condenser, thereby imposing a forced load reduction on the EGU. Additionally, once-through cooling systems are susceptible to increased flora (e.g., trees and brush) and/or fauna (e.g., mussels and mollusks) macro-fouling during seasonal transition periods.

Wet mechanical draft cooling towers were another option considered. This equipment has been frequently utilized in NGCC plants, as well as PC plants over the past several decades.

Counteracting the installation experience of the wet mechanical draft cooling tower equipment is the increased overall plant water demand, moderate auxiliary load, potential for cooling tower “drift” complications, and increasingly stringent regulatory requirements for frequent water basin testing for contaminants/biological hazards (e.g., legionella bacteria).

Ultimately, the ACC equipment was selected based on geographical flexibility, reduced raw water demand, reduced environmental impact, and permitting requirements. The ACC generally reduces the facility water permitting logistics by not requiring continuous ground water, river water, and/or reservoir water use. Additionally, the ACC utilizes the benefit of a fully enclosed system, which eliminates the need for scheduled contaminant and biological hazard testing required for open-water storage basins typical for wet mechanical draft cooling towers at the expense of increase auxiliary loads and larger footprint.

Regarding overall reference plant flexibility, the ACC is not expected to introduce a flexibility bottleneck within the reference plant design. Past ACC installations have predominantly been utilized for NGCC units, which inherently have higher ramp rates and higher boiler load change (i.e., heat rejection) demands than even the highest cycling coal-fired units. The choice of an ACC is not anticipated to introduce prohibitive flexibility limitations more restrictive than those already imposed by the standard boiler components (e.g., waterwalls, headers, and drum).

3 OPERATION AND MAINTENANCE PROTOCOLS

Operation protocols include the day-to-day operation decisions made by facility operations personnel. A focus of this study included describing how operation protocols can contribute to improved plant performance, availability, and maintenance costs.

The areas related to operation protocols that have been proven to be directly tied to improved plant availability, performance reliability, and reduced maintenance costs are general plant operation protocols, startup procedures, and layup procedures. An overview of industry-leading operation protocols based on the literature review and Black & Veatch experience is outlined below.

3.1 GENERAL PLANT OPERATION PROTOCOLS

Applicable to almost all utility/merchant-scale units are the following general plant procedures/protocols that are obligatory for existing facilities to optimize performance reliability, reduce maintenance costs, remain aligned with industry peers, and maintain competitiveness from an overall plant performance perspective:

- Leveraging the supplier's long-term service agreement (LTSA) to the maximum extent practical for the major equipment categories. [49]
 - Successful front-end negotiation of LTSA with the major equipment suppliers (e.g., steam turbine, boiler, generator); it is critical to knowledgeably negotiate and confirm the LTSA scope that will cover all the major items, including access for spares.
 - Additionally, the LTSA should be actively managed, with the bulk of the monthly reporting, status updates, and site data collection performed by the OEM, not the plant staff; this information can include descriptions of upcoming maintenance intervals, accumulated maintenance hours, and other operational best practices recommended by the OEM.
- Utilizing industry-aligned supervisory control and data acquisition and a distributed control system (DCS) that allows for full monitoring and control of plant systems from a centralized control room.
- Implementation of protocols to arrange an annual third-party risk assessment to track progress and benchmark suitability of plant programs (e.g., fire safety, equipment overhaul schedules, plant maintenance documentation best practices); these annual benchmarks are standard at many EGUs.
- Deployment of heat rate monitoring systems that trend process parameters and apply algorithms to calculate recoverable losses in real-time. [15]
- Periodic (e.g., monthly) dissolved gas analyses of all major transformers to document trends and proactive identification of items requiring additional attention.
 - In lieu of manual sampling, real-time gas analyzers are also implemented for the EGU's major site transformers.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Boiler waterwall and convective tube assembly health monitoring and detailed maintenance tracking program.
- STG borescope at every annual inspection.
- Mandatory annual/bi-annual coupon sampling of the SCR catalyst to proactively identify catalyst poisoning and/or accelerated deactivation.
- Implementation of a regimented protocol for the high-energy piping (HEP) inspection program—characterized by focusing on major steam lines, samplings of boiler convective pass tube assemblies, and riser tubes to identify pitting, wall thinning, changes in material hardness, increasing material deposits, or any other trends that would negatively impact the availability of the unit.
- Implementation of a regimented protocol for the FAC inspection program—focuses on random, periodic samplings of areas most susceptible to FAC and tracking of observations/data over time to identify trends/vulnerable areas.
- If the reference unit utilizes regenerative (rotating) air heaters, implementation of a sliding average cold end temperature operating scheme ensures deposits within the air heater baskets remain within reach of the air heater soot blowers across the unit load range.
- Managing air in-leakage to the condensate system (e.g., vacuum pumps, steam jet air ejectors) is a low-capital cost project producing almost immediate benefits of maintaining a more stable condenser vacuum and reducing oxidation/corrosion on the interior condenser surfaces.
- Robust operator training program, including onsite plant simulator (plant virtualization) to enhance situational awareness among operators and provide other professional training opportunities.
- Suitable staffing to maintain an effective and consistent maintenance program that includes training of professionals to solidify succession planning and knowledge base at all staffing levels.
- Potential increase of staffing levels marginally above industry-aligned baseline figures to allow for maintenance program work-flow efficiency.
- Industry-aligned water treatment program, including, but not limited to, online water chemistry monitors, third-party review and technical guidance, redundant manual-grab samples, and one dedicated plant operations personnel tasked directly with tracking and monitoring boiler and sub-system water chemistry.
- Maintenance of condenser performance at low load by hot-well and condensate sparging, deoxygenated makeup water, repairing any air in-leakage, and degassed cation conductivity monitoring. [28]
- Suitably trained/certified maintenance personnel (e.g., ASME R-stamp welders) that can reduce reliance on third-party contractors for routine boiler maintenance and repairs.

- Implementation of state-of-the-art cyber-security protocols for all plant hardware interfaces and software platforms.

3.1.1 Mill Operation Philosophy

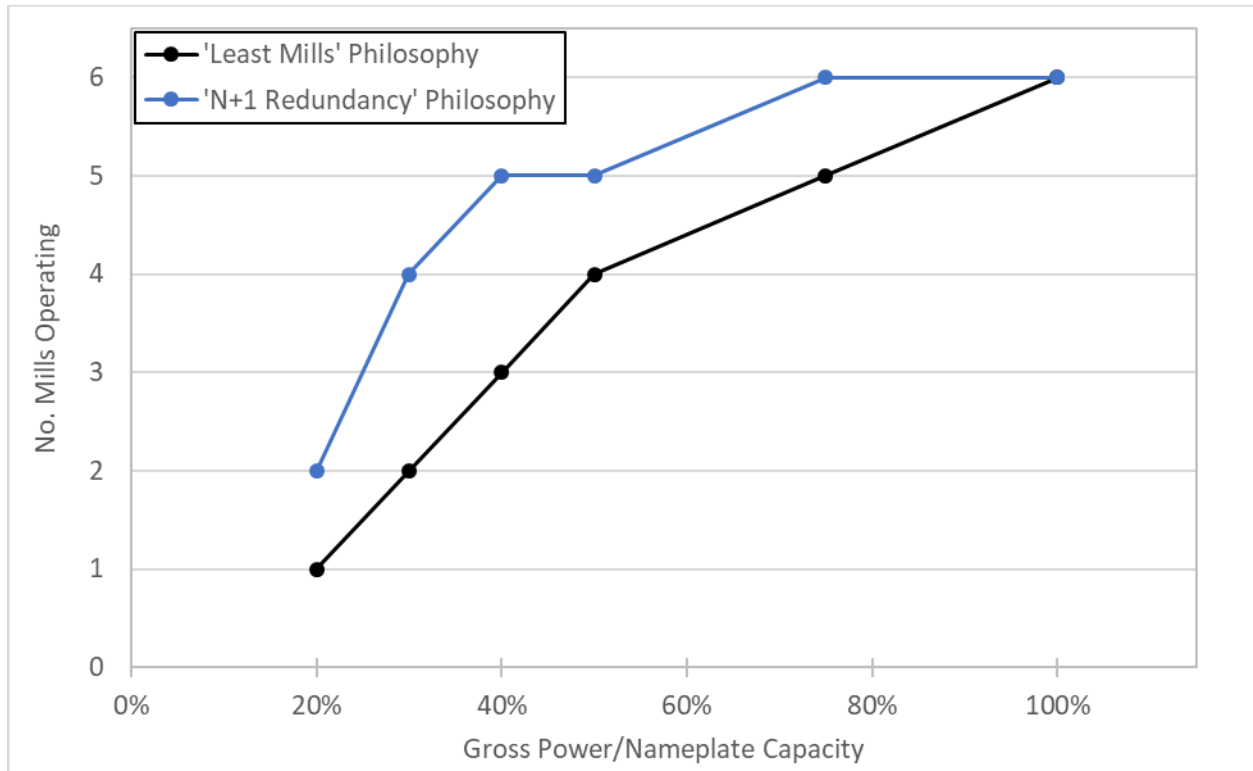
Safe and reliable operation of a plant at reduced loads will depend on unit-specific factors, such as the coal mill operation philosophy. The mill operation philosophy for high-cycling or ramping units will likely follow a unit-specific operational philosophy.

The mill operation philosophies outlined below are intended to be demonstrative. When looking to reduce load (i.e., begin the sequence of shutting off coal mills), typical unit operation dictates that the top-most row(s) of burners be turned off first, progressing from top to bottom for row shutoff. This “top-to-bottom” operational philosophy maximizes the furnace residence time and promotes the greatest degree of cooling for the semi-fluid ash particles prior to reaching the first tube assemblies (i.e., mitigation of slagging and fouling effects).

The competing mill operation schemes outlined in Exhibit 3-1 are characterized by the following definitions:

- **“Least Mills”** — Operators look to shutoff a mill at the earliest opportunity, which keeps other mills at maximum capacity with load being reduced for one mill at a time; operators willing to accept operational risk of single-mill operation at significantly reduced low-load (~20%) to improve heat rate and reduce auxiliary load. [18]
- **“N+1 Redundancy”** — Operators look for improved reliability and redundancy in the event of a mill trip; multiple mills will have their loads reduced simultaneously in order to keep as many mills online at one time as possible (satisfying the N+1 criteria), which provides greater mitigation (but not guaranteed elimination) of a boiler “loss of flame” event probability.

Exhibit 3-1. Plant demonstrative coal mill operation philosophies



3.2 STARTUP PROCEDURES AND PROTOCOLS

A flexible plant is more likely to undergo frequent startups when compared to traditional baseload units and, therefore, should be equipped with the following industry-leading features and protocols to facilitate successful, repeatable, and minimally impactful startup procedures:

- Enhanced control and monitoring of boiler feedwater (BFW) and condensate chemistry during startup is critical to plant reliability (specifically acidity); existing plants have used water chemistry “checkpoints” during startup to where the startup procedures include stipulations that require BFW chemistry to be within alignment throughout the unit startup. This strategy avoids bringing the unit up to operating temperatures only to trip on feedwater chemistry shortly thereafter.
- Boiler pH should be controlled with ammonia during startup and load changes. [28]
- Aligned with typical EGU best practices, plants have integrated into the procedures that the plant’s water chemistry engineer must be onsite during all unit startups to reduce startup chemistry variability and to reduce likelihood of boiler trips due to water chemistry parameter exceedances.
- Installing electric-resistance heating blankets on the HP and IP turbine casing allows for controlled and proactive pre-heating of the turbine casing, reducing thermal fatigue and resulting in faster start times.

- Certain utility units have implemented internally developed “scoring” metrics (e.g., total start time, fuel spent, and staffing level) to quantitatively analyze unit starts to reduce variability and standardize operations across all shifts and operators.
- Installation of an auxiliary package boiler to supply steam for deaerator and condenser sparging, turbine gland sealing, condenser air ejector and/or other smaller supporting components such as a reciprocating engine generator designed for black start capability.
- Supercritical Benson boiler design have many superior features to earlier generation supercritical units. Speed of startup, fewer thermal transients, the simplicity of the startup system, and the ability to easily cycle load.
- Water relief line valves from the water separator are sized and controlled to enable rapid response to the water swell shortly after initial firing to account for the steam bubbles that begin to form.
- During cold start the Boiler circulation pump (BCP) starts up and is controlled to approximately 20% BMCR flow. The Boiler feedwater pump adds approximately 5% BMCR flow for a total feedwater flow into the furnace path of 25% BMCR. During wet mode operation the control valves set BCP flow according to the set point programed by the separator tanks level.
- Reduced HP flash tank pressure set-points are used to maximize the steam available to ensure the minimum flow required at the superheater.
- The boiler load should not be held during wet/dry operation transition because the boiler operation may be unstable. The wet/dry transition is complete around 40-45% load depending boiler design.

3.3 LAYUP PROCEDURES AND PROTOCOLS

Similar to the diligence that industry-leading power generation facilities apply to startups, layup procedures are equally critical to the long-term health of the generation assets, operational reliability, and facility competitiveness. The following are examples of measures that can be implemented to reduce the negative impacts of layup periods on the critical plant systems (e.g., boiler, turbine, steam piping, condenser, and deaerator):

- Extended coal unit layup periods may result in extended coal storage programs, which increases the risk of bunker and silo fires; proactive systems such as nitrogen blanketing systems or reducing the per mill and per silo size will help reduce this risk.
- Installing electric heating blankets for all sections of the turbine casing allows for lengthening the turbine casing cooling process immediately following a shutdown.
- Control of pH during shutdown, layup, and startup is critical for preventing corrosion fatigue. [28]
- Application of film-forming amine (FFA) or film-forming product (FFP) reagents to counteract corrosion and/or fouling in the condensate and BFW systems; the addition of

these chemicals insulates the protective magnetite layer commonly found in the boiler condensate and feedwater system piping.

- Phosphate feed should be controlled based on solid alkali pH, not based on a target phosphate concentration. [28]
- Ammonia concentration should be corrected based on drum measurement. [28]
- Boiler water and steam cation conductivity (degassed) should be kept as low as possible during transient conditions. [28]
- The turbine steam path should be inspected for changes in deposition. [28]
- FAC inspection locations should be adjusted based on changes in susceptibility from flexible operation. [28]
- After a shutdown, deaerator performance can be maintained by using heaters or sparging steam during startup, and by ensuring adequate ammonia or amine is dosed when the deaerator is refilled. [28]
- Ensuring all riser and supply piping is drained. [28]
- Using a 'nitrogen blanketing' system to provide a protective (non-oxidizing) atmosphere for the internals of the condensate storage tank, boiler, and steam turbine during layup periods. Additionally, for dry layup periods where nitrogen blanketing is not utilized, pre-heated and dried air from the plant's air compressor system can be used to dry the interiors of the waterwall, convective pass, and the drum internals. This extra drying measure mitigates the likelihood of moisture accumulation, corrosion, and deposit formation during extended layup periods.
- Avoiding undergoing wet-layup conditions for any layup period longer than 24–48 hours.

4 GENERAL EVALUATION BASIS

For each of the plant configurations analyzed in this report, an Aspen Plus® (Aspen) model was developed and used to generate material and energy balances, which were, in turn, used to provide a design basis for items in the major equipment list.

The equipment list and material balances were used as the basis for generating the capital and operating cost estimates. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgment.

Plant flexibility was evaluated for each case through several flexibility metrics, and values for each flexibility metric were developed based upon industry references and Black & Veatch in-house data.

Capital and operating costs were estimated by Black & Veatch based on simulation results using an in-house database and conceptual estimating models. Costs were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design/build projects. All costs are reported in December 2018 dollars.

The balance of this section discusses the design basis common to all technologies, as well as environmental targets and cost assumptions used in this report. Technology-specific design criteria are covered in subsequent chapters.

4.1 SITE CHARACTERISTICS

All plants in this study are assumed to be located at a generic plant site in the midwestern United States, with site characteristics and ambient conditions presented in Exhibit 4-1 and Exhibit 4-2. The ambient conditions are the same as ISO conditions; the air composition is based on published psychrometric data. [50]

Exhibit 4-1. Site characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size, acres	39
Transportation	Rail or Highway
Ash Disposal	Off-site
Water	50% Municipal and 50% Ground Water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 4-2. Site ambient conditions

Parameter		Value
Elevation, ft		0
Barometric Pressure, psia		14.696
Average Ambient Dry Bulb Temperature, °F		59
Average Ambient Wet Bulb Temperature, °F		51.5
Design Ambient Relative Humidity, %		60
Minimum Temperature for Miscellaneous Cooling Loop Design, °F		-20
Air composition, mass %		
Nitrogen	N ₂	75.055
Oxygen	O ₂	22.998
Argon	Ar	1.280
Water	H ₂ O	0.616
Carbon Dioxide	CO ₂	0.050
Total		100.00

The land area assumes that 15 acres are required for the plant proper (including 5 acres for the coal pile), and the balance provides a buffer of approximately 250 ft to the fence line—the spacing of the fence line would be based on the noise emission requirements in the area and unit dispersion modeling.

In all cases, it was assumed that the boiler and the steam turbine are enclosed.

The quality of plant makeup water will vary dramatically from source to source (municipal versus ground water), as well as from site to site, and can be expected to vary significantly throughout any given site, particularly if ground water is utilized. In this study, 50 percent of the makeup water to the plant is sourced from a publicly owned treatment works (POTW), with the balance of the makeup water sourced from ground water. The assumed design makeup water composition is provided in Exhibit 4-3.

The following design parameters are considered site-specific and are not quantified for this report. Allowances for normal conditions and construction are included in the cost estimates.

- Flood plain considerations
- Existing soil/site conditions
- Water discharges and reuse
- Rainfall/snowfall criteria
- Seismic design
- Buildings/enclosures
- Local code height requirements
- Weather delays
- Other local environmental concerns
- Noise regulations

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 4-3. Design makeup water quality

Parameter	Ground Water (Range)	POTW Water (Range)	Makeup Water (Design Basis)
pH	6.6–7.9	7.1–8.0	7.4
Specific Conductance, $\mu\text{S}/\text{cm}$	1,096–1,484	1,150–1,629	1312
Turbidity, NTU		<50	<50
Total Dissolved Solids, ppm			906
M-Alkalinity as CaCO_3 , ppm^A	200–325	184–596	278
Sodium as Na, ppm	102–150	172–336	168
Chloride as Cl, ppm	73–100	205–275	157
Sulfate as SO_4 , ppm	100–292	73–122	153
Calcium as Ca, ppm	106–160	71–117	106
Magnesium as Mg, ppm	39–75	19–33	40
Potassium as K, ppm	15–41	11–21	18
Silica as SiO_2 , ppm	5–12	21–26	16
Nitrate as N, ppm	0.1–0.8	18–34	12
Total Phosphate as PO_4 , ppm	0.1–0.2	1.3–6.1	1.6
Strontium as Sr, ppm	2.48–2.97	0.319–0.415	1.5
Fluoride as F, ppm	0.5–1.21	0.5–0.9	0.8
Boron as B, ppm	0.7–0.77		0.37
Iron as Fe, ppm	0.099–0.629	0.1	0.249
Barium as Ba, ppm	0.011–0.52	0.092–0.248	0.169
Aluminum as Al, ppm	0.068–0.1	0.1–0.107	0.098
Selenium as Se, ppm	0.02–0.15	0.0008	0.043
Lead as Pb, ppm	0.002–0.1		0.026
Arsenic as As, ppm	0.005–0.08		0.023
Copper as Cu, ppm	0.004–0.03	0.012–0.055	0.018
Nickel as Ni, ppm	0.02–0.05		0.018
Manganese as Mn, ppm	0.007–0.015	0.005–0.016	0.009
Zinc as Zn, ppm	0.005–0.024		0.009
Chromium as Cr, ppm	0.01–0.02		0.008
Cadmium as Cd, ppm	0.002–0.02		0.006
Silver as Ag, ppm	0.002–0.02		0.006
Mercury as Hg, ppm	0.0002–0.001		3E-04

^A Alkalinity is reported as CaCO_3 equivalent, rather than the concentration of HCO_3 . The concentration of HCO_3 can be obtained by dividing the alkalinity by 0.82

4.2 COAL CHARACTERISTICS

The design coal is Illinois No. 6 with characteristics presented in Exhibit 4-4. The coal properties are from the Quality Guidelines for Energy System Studies (QGESS) document “Detailed Coal Specifications.” [51]

Exhibit 4-4. Design coal characteristics

Rank	Bituminous	
Seam	Illinois No. 6	
Proximate Analysis (weight %) ^A		
	As-Received	Dry
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Ultimate Analysis (weight %)		
	As-Received	Dry
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.15	0.17
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen ^B	7.02	7.91
Total	100.00	100.00
Heating Value		
	As Received	Dry
Higher Heating Value (HHV), kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
Lower Heating Value (LHV), kJ/kg (Btu/lb)	26,151 (11,252)	29,544 (12,712)

^A The proximate analysis assumes sulfur as volatile matter

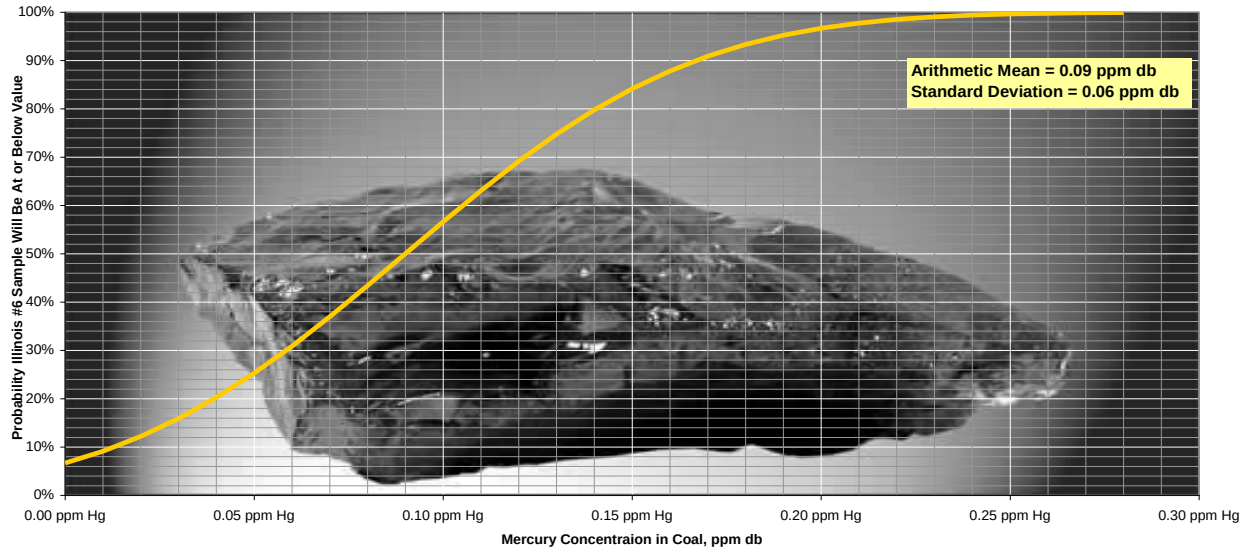
^B By difference

The chlorine content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 1,671 parts per million, weight, dry (ppmwd) with a standard deviation of 1,189 ppmwd based on coal samples shipped by Illinois mines. [52]

Based on the location of the Illinois No. 6 mine, along with the Herrin coal chlorine map published by the Illinois State Geological Survey [53], it was determined that Illinois No. 6 coal could be expected to have a chlorine content between 0.1 and 0.2 percent, on a dry basis. Therefore, the coal chloride content for this report was assumed to be the arithmetic mean value of 1,671 ppmwd.

The mercury content of 34 samples of Illinois No. 6 coal has an arithmetic mean value of 0.09 ppmw with standard deviation of 0.06 based on coal samples shipped by Illinois mines. [52] Hence, as illustrated in Exhibit 4-5, there is a 50 percent probability that the mercury content in the Illinois No. 6 coal would not exceed 0.09 ppmw. The coal mercury content for this report was assumed to be 0.15 ppmw, which corresponds to the mean plus one standard deviation and encompasses about 84 percent of the samples. It was further assumed that all the coal mercury (Hg) enters the gas phase and none leaves with the bottom ash. [54]

Exhibit 4-5. Probability distribution of mercury concentration in the Illinois No. 6 coal



4.3 NATURAL GAS CHARACTERISTICS

The use of natural gas was limited to the minimum extent practical for normal startup and shutdown of coal burners and stabilization of the burner flames at very low loads in accordance with National Fire Protection Association (NFPA) code requirements.

A sensitivity was completed in Section 5.8.1 where natural gas was also utilized as a supplemental fuel for keeping CO₂ emissions below the regulatory limit proposed by the December 2018 update to 111(b). [12]

The natural gas characteristics presented in Exhibit 4-6 are from the QGESS document "Specification for Selected Feedstocks," including the addition of methanethiol (mercaptan). [7], [55]

Exhibit 4-6. Natural gas composition

Component		Volume Percentage
Methane	CH ₄	93.1
Ethane	C ₂ H ₆	3.2
Propane	C ₃ H ₈	0.7
<i>n</i> -Butane	C ₄ H ₁₀	0.4
Carbon Dioxide	CO ₂	1.0
Nitrogen	N ₂	1.6
Methanethiol ^A	CH ₄ S	5.74x10 ⁻⁶
	Total	100.0
	LHV	HHV
kJ/kg (Btu/lb)	47,201 (20,293)	52,295 (22,483)
MJ/scm (Btu/scf)	34.52 (927)	38.25 (1,027)

^A The sulfur content of natural gas is primarily composed of added mercaptan (methanethiol [CH₄S]) with trace levels of hydrogen sulfide [55]

Note: Fuel composition is normalized, and heating values are calculated using Aspen

4.4 ENVIRONMENTAL TARGETS

4.4.1 Air Emissions Targets

Environmental targets were established as follows:

- Hg and hydrochloric acid (HCl) limits were set by the March 2013 update to the Utility Mercury and Air Toxics Standards (MATS). [56], [57]
- PM, SO₂, and NO_x limits were set by the February 2013 update to the New Source Performance Standards (NSPS). [57], [58]

The regulations differentiate between low rank and non-low rank coal types based on their heating value. Coals with a higher heating value (HHV) of greater than 8,300 Btu/lb on a moist, mineral-matter free basis are considered non-low rank. Therefore, Illinois No. 6 coal, with an HHV (moist, mineral-matter free) of 12,900 Btu/lb, is considered a non-low rank coal.

The emission limits imposed by MATS and NSPS that apply in this report are provided in Exhibit 4-7.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 4-7. MATS and NSPSEmission limits for SO₂, NO_x, PM, Hg, and HCl

Pollutant	Emission Target (lb/MWh-gross)
SO ₂	1.00
NO _x	0.70
PM, Filterable	0.09
Hg	3x10 ⁻⁶
HCl	0.010

These regulations apply to technologies that begin construction after May 3, 2011. Furthermore, these regulations state that [57], [59]:

Fossil fuel is defined as natural gas, oil, coal, and any form of solid, liquid, or gaseous fuel derived from such material.

Electric utility steam generating units (EGU) are defined as a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Fossil fuel-fired means an EGU that is capable of combusting more than 25 MW of fossil fuels. To be capable of combusting fossil fuels, an EGU would need to have these fuels allowed in its operating permit and have the appropriate fuel handling facilities on-site or otherwise available (e.g., coal handling equipment, including coal storage area, belts and conveyers, pulverizers, etc.; oil storage facilities).

Coal-fired electric utility steam generating units are defined as an EGU and meet the definition of “fossil fuel-fired,” which is that it burns coal for more than 10 percent of the average annual heat input during any three consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year.

Integrated gasification combined cycle electric utility steam generating units are defined as an EGU and meet the definition of “fossil fuel-fired,” which is that it burns a synthetic gas derived from coal and/or solid oil-derived fuel for more than 10 percent of the average annual heat input during any three consecutive calendar years or for more than 15 percent of the annual heat input during any one calendar year in a combined-cycle combustion turbine. No solid coal or solid oil-derived fuel is directly burned in the unit during operation.

Unit designed for low-rank virgin coal subcategory is defined as any coal-fired EGU that is designed to burn, and that is burning, non-agglomerating virgin coal having a calorific value (moist, mineral matter-free basis) of less than 19,305 kJ/kg (8,300 Btu/lb) that is constructed and operates at or near the mine that produces such coal.

Unit designed for coal $\geq 19,305$ kJ/kg ($\geq 8,300$ Btu/lb) subcategory is defined as any coal-fired EGU that is not a coal-fired EGU in the “unit designed for low rank virgin coal” subcategory.

Other regulations that could affect emissions limits from a new plant include the New Source Review permitting process and Prevention of Significant Deterioration. The New Source Review process requires installation of emission control technology, meeting either the Best Available Control Technology (BACT) determinations for new sources being in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate technology for sources being in areas not meeting ambient air quality standards (non-attainment areas). Environmental area designation varies by county and can be established only for a specific site location. Based on the Environmental Protection Agency’s (EPA) Green Book Non-attainment Area Map, relatively few areas in the midwestern United States are classified as “non-attainment”; therefore, the plant site for this report was assumed to be in an attainment area. [58]

4.4.1.1 Summary of Air Emissions Control Technologies

Exhibit 4-8 provides a summary of the control technology utilized to satisfy the air emission limits.

Exhibit 4-8. Air emissions control technologies

Pollutant	Control Technology
SO ₂	Wet limestone scrubber
NO _x	Low NO _x burners, OFA, and SCR
PM (Filterable)	Fabric filter
Hg	Co-benefit capture, dry sorbent injection ^A , activated carbon injection
HCl	SO ₂ surrogate ^B

^ALimits sulfur trioxide (SO₃) levels and their detrimental effects on activated carbon injection

^BSO₂ may be utilized as a surrogate for HCl measurement if the EGU utilizes an FGD system [60]

It was assumed that LNBs and staged OFA would limit NO_x production to 0.35 lb/MMBtu and that SCR technology would be 76–78 percent efficient at full load. By adjusting the ammonia flow rate and/or catalyst bed depth in the SCR, the NO_x emissions limit was able to be met exactly at all load points.

The wet limestone scrubber was assumed to be 98 percent efficient at all loads, which results in SO₂ emissions below the NSPS SO₂ limit. Current technology allows FGD system removal efficiencies in excess of 99 percent, but based on NSPS requirements, such high removal efficiency is not necessary.

The fabric filter was assumed to be capable of achieving an efficiency of greater than 99.9 percent. As the required efficiency was approximately 99.9 percent for each case, the efficiency was varied to meet the PM emissions limit exactly.

The mercury removal efficiency required to meet the emission limit is approximately 97–98 percent in each case. It was assumed that the total mercury removal rate resulting from the combination of pollution control technologies used (SCR, DSI, ACI, fabric filters, and FGD) would meet the limit exactly. DSI is required to limit the effects of SO₃ on Hg capture due to the high sulfur content of the coal in this study. Section 5.2.6 provides a detailed discussion regarding mercury removal and the various systems involved.

As there is no published federal emissions standard that establishes a CO emission target for PC EGUs, they are determined through the BACT process. To ensure CO production is minimized to the greatest extent practical, supplemental combustion controls and monitoring (e.g., excess air and economizer outlet oxygen) are included in this study.

4.4.2 Water Emissions Targets

EPA issued final Effluent Limitation Guidelines (ELG) and standards for the steam electric power generation point source category in December 2019, to strengthen controls on wastewater discharges. [61] The ELG are national technology-based NSPS derived from data collected from industry. They are intended to provide flexibility in implementation through use of technologies already installed and operating in the power industry. The federal standards established by this rule are the minimum discharge standards. As ELG are enforced under the National Pollutant Discharge Elimination System [62], more stringent water quality-based standards may be established by the local permitting authority; however, these additional requirements were not considered in this report.

The final ELG rule established new wastewater categories and discharge limits and updated discharge requirements for existing wastewater categories. The following are the new or updated categories in the rule:

- FGD wastewater
- Fly ash transport water
- Bottom ash transport water
- Landfill leachate
- Flue gas mercury control wastewater
- Non-chemical metal cleaning wastewater
- Wastewater from gasification of fuels such as coal and petroleum coke

Non-chemical metal cleaning wastewater was established as a new wastewater category in the updated ELG. However, new limits were not established for this category; therefore, treatment of this stream has not been evaluated in this report.

The landfill of plant byproducts is assumed to be outside the scope of the plants considered in this study; therefore, landfill leachate is not evaluated in this report.

For the cases considered in this study, both fly ash and bottom ash handling systems are assumed to be dry, and do not result in a water stream requiring treatment under ELG. Similarly, the flue gas mercury control approach of combined sorbent injection followed by carbon injection, does not generate a water stream for treatment. Therefore, only the FGD wastewater blowdown stream requires treatment.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Intermittent discharges (e.g., chemical metal cleaning wastewater), coal pile runoff, low volume waste (e.g., boiler blowdown), and cooling tower blowdown were assumed to be compliant with all applicable regulations with no additional treatment beyond conventional considerations.

The applicable wastewater discharge limits are shown in Exhibit 4-9.

Exhibit 4-9. New source treated FGD wastewater discharge limits [61]

Effluent Characteristic	Long-Term Average	Daily Maximum Limit	Monthly Average Limit ^A
Arsenic, ppb	4.0	4	-
Mercury, ppt	17.8	39	24
Selenium, ppb	5.0	5	-
Total Dissolved Solids, ppm	14.9	50	24

^AMonthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days

The limits are applied at the discharge, prior to commingling with other plant water systems.

In addition to federal regulations, state and local jurisdictions can impose even more stringent regulations on a new facility. However, since each new plant has unique environmental requirements, it was necessary to apply some judgment in setting the environmental targets for this report.

4.4.2.1 Summary of Water Emissions Control Technologies

A spray dryer is a technology commonly used in the power industry for FGD, which can be applied as a thermal evaporation process to treat wastewater. The feasibility of using a spray dryer evaporator as the sole treatment system in PC cases is limited by the flow rate of wastewater, as the cost and performance impact of the spray dryer increases with increasing wastewater flow rate. Section 5.2.8 provides a detailed discussion regarding the spray dryer as applied to the PC cases in this report.

4.4.3 Carbon Dioxide

EPA promulgated a New Source Performance Standard on October 23, 2015, for emissions of CO₂ for new fossil fuel-fired electric utility generating units; the limit for new steam generating units was set as 1,400 lb-CO₂/MWh-gross. [11] A December 2018 proposed update to 111(b) set the limit for new steam generating units based on size. For small-scale ($\leq 2,000$ MMBtu/hr heat input) PC plants, the limit is 2,000 lb-CO₂/MWh-gross, while that of larger ($> 2,000$ MMBtu/hr heat input) PC plants is 1,900 lb-CO₂/MWh-gross. [12] All subcritical cases within this study are classified as small-scale EGUs while all supercritical cases are subject to the larger-scale CO₂ emissions limit; no CO₂ capture systems are included.

This study assumes that all fuel-based carbon that is combusted (i.e., excluding unburned carbon) is converted to CO₂ in the flue gas. CO₂ is also generated from limestone in the FGD system.

While the CO₂ emissions for all cases are below the established limit at full load, the CO₂ emissions increase as the load decreases.

4.5 RAW WATER WITHDRAWAL AND CONSUMPTION

A water balance was performed for each case on the major water consumers in the process. The total water demand for each subsystem was determined, and internal recycle water available from various sources like condensate from flue gas was applied to offset the water demand. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is the water removed from the ground or diverted from a municipal source for use in the plant. Raw water consumption is also accounted for as the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products, or otherwise not returned to the water source from which it was withdrawn.

Raw water makeup was assumed to be provided 50 percent by a publicly owned treatment works (POTW) and 50 percent from ground water. Raw water withdrawal is defined as the water metered from a raw water source and used in the plant processes for all purposes, such as BFW makeup, slurry preparation makeup, and FGD system makeup. The difference between withdrawal and process water returned to the source is consumption. Consumption represents the net impact of the process on the water source.

BFW blowdown was assumed to be recycled to the FGD system with no treatment necessary.

The water balances presented in subsequent sections include the water demand of the major water consumers within the process, the amount provided by internal recycle, the amount of raw water withdrawal by difference, the amount of process water returned to the source, and the raw water consumption, again by difference.

4.6 PLANT CAPACITY

Historically, coal-fired electric power plants have demonstrated economies of scale for larger installations. U.S. installations of coal-fired power plants within the past decade have further demonstrated this trend. The selection of an electric power plant's overall capacity would be based on multiple factors, including but not limited to dispatch of the unit, the market it serves, the current and projected market demand, and how it would play into and support the overall electric power supply system.

For the purposes of this assessment, the plant capacity is not based on any specific installation, but rather a generic installation that could be translated to installations throughout the United States or other global locations.

The assumed nominal plant capacity of 150 MW-gross and 300 MW-gross were chosen for this study. This nominal plant size is supported by current Black & Veatch experience that indicates these plant sizes are well-aligned with the average size of similar units being installed in global markets and align well with the proven size ranges for subcritical and supercritical PC units. Additionally, the unit sizes are considered small enough to be applicable to a variety of global regions while being large enough to leverage economies of scale.

4.7 CASE SELECTION METHODOLOGY

4.7.1 Baseload Reference Plant

The flexible plant cases developed in this study and the coal units characterized in the Bituminous Baseline study (Cases B11A and B12A) would not be conceptually aligned well enough to allow for meaningful conclusions to be drawn from a comparison. [63] Therefore, a corollary of the flexible plant cases, referred to as the “baseload plants” (Cases B11A-F0 and B12A-F0), were established to serve as reference plants when cumulatively adding flexibility options to improve the plant’s flexibility metric performance.

The baseload plant designs were intended to be representative of modern units, purely operating at baseload, with the same gross capacity as their respective flexible plant cases. The objective was to develop plant cases that served as references that enabled meaningful comparisons with plants designed specifically for flexible operation.

Certain equipment and flexibility options that were included in the design basis for the flexible plant cases (e.g., ACC, reduced boiler operating pressure as compared to Case B11A, and mill type modification to vertical roller mills) were also included in the baseload plant designs, due to their general applicability to a standard baseload unit that would be expected for a new coal EGU installed in current markets.

The flexibility options that were assumed to be implemented in the Case B11A-F0 and B12A-F0 plant designs are shown in Exhibit 4-10. Although a plant designed for baseload operation would be expected to include these flexibility options, it is likely that the plant would implement many of them to a lesser degree than a flexible plant (e.g., a flexible plant would likely have a much more robust online performance monitoring system compared to a baseload plant). For this reason, these options are repeated in the flexibility option tiers, with the expectation that the flexible plant would utilize the flexibility option to a greater degree and put more focus on leveraging the flexibility option at reduced loads. Option 59 is only included in Case B12A-F0 as it is standard for supercritical coal plants to be designed with sliding-pressure operation. This flexibility option is included for Case B11A-F1 for the subcritical design.

Exhibit 4-10. Case B11A-F0 and Case B12A-F0 plant flexibility options

Flexibility Metric	Option	Cost Impact	Performance Impact	Description
Design Life	42	Low	High	Implement best practices for layup procedures, depending on the duration of the offline period
Heat Rate	52	Low	High	Online performance monitoring
Heat Rate	55	Low	High	Limiting excess air and air heater air in-leakage to lowest practical levels
Heat Rate	56	Low	High	Maintaining tight air heater outlet temperature target through use of upstream alkali (e.g., hydrated lime) injection
Heat Rate	59	Low	High	Steam turbine sliding-pressure operation (supercritical only)

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Flexibility Metric	Option	Cost Impact	Performance Impact	Description
Availability/Reliability	61	Low	High	Full leveraging/utilization of the supplier's long-term service agreement
Availability/Reliability	64	Low	Low	Advanced training of operators to reduce errors and improve situational awareness
Availability/Reliability	65	Low	Low	Automated prioritization of plant alarm signals to allow for simplified triage of plant information received in the control room
EPC Capital Cost	72	Low	High	Contracting structure (e.g., open-book EPC, turn-key EPC) of overall project

4.7.2 Selection of Flexibility Options

Of the flexibility options identified from the literature review (presented in Section 2.8), there are various interdependencies and trade-offs to consider when establishing the flexible plant designs. Exhibit 4-11 outlines these trade-offs and how they affect the consideration of various flexibility options.

Exhibit 4-11. Flexibility option trade-offs

Flexibility option	Trade-Off
Steam turbine sliding pressure operation (subcritical Tier 1, supercritical baseload – Flexibility Option 59)	The use of sliding pressure improves part load efficiency and heat rate; however, sliding pressure has been linked to negatively affecting ramp rate. [24] [40]
Use of advanced creep strength enhanced materials (Tier 3 – Flexibility Option 20)	The deployment of advanced creep-resistance and advanced strength materials (e.g., Inconel 740H) is noted as an option that can beneficially impact resistance to cycling fatigue and improve ramp rate, but would need to be employed on a targeted basis in order to control TPC.
Utilization of electrode boiler for fast saturated steam production for supporting plant systems (evaluated on case-by-case basis) (Tier 3 – Flexibility Option 80)	The flexible plant's electricity use during startup has the potential to increase (even over expected levels for the baseload plant) based on the design strategy of avoiding supplemental natural gas consumption (i.e., omitting natural-gas fired package boiler in favor of an electrode boiler for onsite supply of sparging steam). This is a trade-off where natural gas consumption is reduced in favor of purchasing grid-provided back-feed power during startup and offline periods when sparging steam is required.
Replace all steam turbine driven pumps (e.g., BFW pump) with electric motor drives (Tier 1 – Flexibility Option 25)	The use of steam turbine drives for the BFW pumps will provide an improvement to overall plant full load efficiency that is difficult to achieve with electric drives; however, the flexible plant designs would be expected to cycle load frequently enough to begin to exhibit the benefits of utilizing simplified electric drives (which also has the potential to reduce plant O&M costs).

Additionally, there were flexibility options considered to be mutually exclusive of other options. An outline of these mutually exclusive options is provided in Exhibit 4-12.

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Exhibit 4-12. Mutually exclusive flexibility options

Option Index No.	Option Description	Mutually Exclusive to Option	Additional Comments
Startup Time			
1	Use of advanced materials to reduce tube and pressure wall thickness requirements to improve rate of warm-up	70	This option is intended to be balanced against the cost-controlling intent of Option 70.
2	Decrease drum holding time to reduce drum diameter and drum wall thickness (subcritical only)	8	This option was carried due to its demonstrated ability to improve plant performance and flexibility as well as improvement of thermal cycling of the drum components.
4	Installation of a (natural gas-fired) package boiler for sparging steam supply (boiler drum warm-up and/or supplemental steam supply to deaerator)	80	This option was included in Tier 1, but was replaced with an electrode boiler for startup (Option 80) to further reduce dependency of the flexible plant on supplement (natural gas) fuel sources; the electrode boilers require less overall maintenance than a package boiler, demonstrate faster startup times, smaller footprint, and commercial viability with reputable suppliers.
5	Furnace heating utilizing small dedicated coal feeder, pulverizer, and burner level	6	This option was selected for incorporation due to its independence from supplemental fuels.
6	Small dedicated igniter fuel or alternative fuels	5	This option is omitted currently due to its reliance on supplemental fuel (e.g., natural gas).
8	Application of a once-through Benson-type boiler (subcritical only)	2	This option was omitted for the subcritical option due to being mutually exclusive with Option 2 in addition to being a disadvantageous option for the purposes of operational reliability and increasing the stringency of water chemistry requirements (as discussed in Section 5.1). The supercritical option utilizes a once-through Benson-type boiler for all cases.
13	Use of advanced materials to reduce turbine casing thickness and reduce STG warm-up times	70	This option is intended to be balanced against the cost-controlling intent of Option 70.
Ramp Rate and Cycling			
20	Use of advanced creep strength enhanced materials	70	This option is intended to be balanced against the cost-controlling intent of Option 70.

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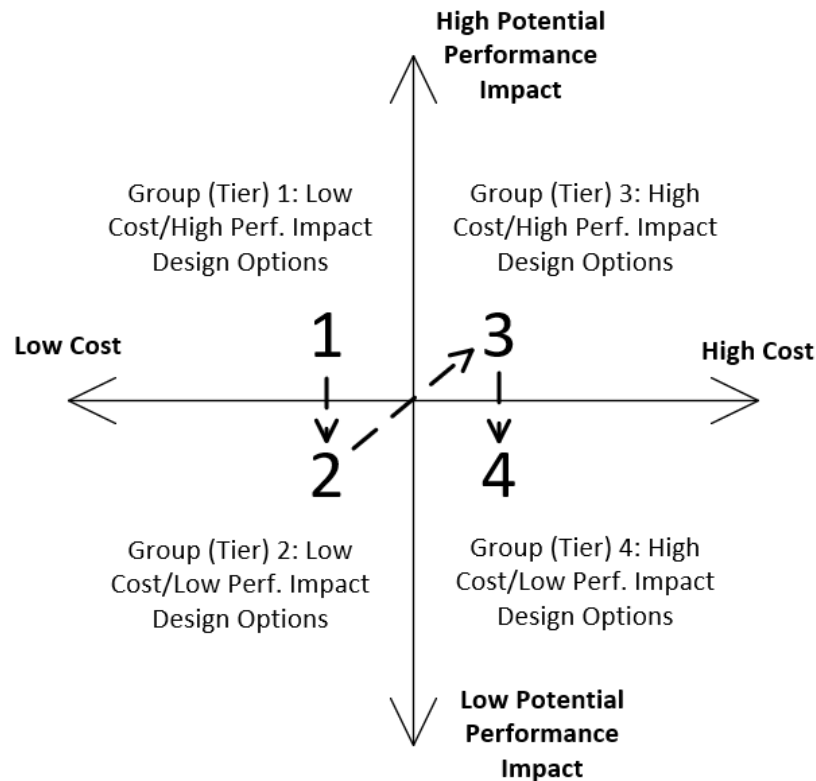
Option Index No.	Option Description	Mutually Exclusive to Option	Additional Comments
Minimum Stable Load (Emissions/Non-Emissions Compliant; without Supplemental Firing)			
26	Low-load coal burner flame stabilization with igniters	27	This option is omitted due to its reliance on supplemental fuel (e.g., natural gas).
27	Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter	26	This option was selected for incorporation due to its independence from supplemental fuels.
28	Dedicated coal feeder, pulverizer, and burner level sized for lower-load operation	27	This option was omitted as utilization of a dedicated burner level is already captured in Flexibility Option 27.
EPC Capital Cost			
70	Targeted and limited deployment of advanced creep strength enhanced materials (i.e., controlling cost of advanced materials)	1, 13, and 20	This option is viewed as contrary to options 1, 13, and 20; however, this is a plant design methodology option aimed at reasonably controlling costs that can be balanced with the implementation of advanced materials in the most cost-effective areas; for this reason, this option is included.
Operations & Maintenance (Plant Staff Requirements, Fixed O&M, Non-Fuel Variable O&M)			
76	Additional plant automation and performance monitoring can lead to reduced plant staff requirements	77	This option is kept within the flexible plant design due to the ability of reducing O&M costs through full utilization of the plant online performance monitoring system.
77	Increasing plant staffing and/or reducing 'hours per shift' to avoid operator fatigue/errors from cyclical operation [37]	76	This option was omitted due to the goal of increasing cost-competitiveness of the plant by reducing O&M costs to the greatest practical degree.
80	Utilization of electrode boiler for fast saturated steam production for supporting plant systems (evaluated on case-by-case basis)	4	This option was included in place of the water-wall (natural gas-fired) package boiler for startup (Option 4) so as to further reduce dependency on supplement natural gas fuel sources; the electrode boilers require less overall maintenance than a package boiler, demonstrate faster startup times, smaller footprint, and commercial viability with reputable suppliers.

4.7.3 Flexible Plants

The development of the various flexible plant design bases depended on which flexibility options would be implemented. Given that the identified flexibility options span a wide spectrum, from operator training to installation of advanced technology solutions (e.g., sliding-pressure operation), a methodology for grouping the options for tiered or cumulative performance modeling was developed.

Following the concept of the Kano model, a four-quadrant matrix was developed to group the various flexibility options based on cost and potential performance impact, which were evaluated on a qualitative basis of “low” to “high” for the purposes of establishing straightforward groupings of options. Exhibit 4-13 provides a graphical depiction of the Kano methodology utilized to group the options and to establish a hierarchy of which tier would be implemented in the hierarchy of cases.

Exhibit 4-13. Kano model for establishing plant flexibility option hierarchy and analysis cases



For the purposes of the techno-economic evaluation of the flexible plants, the flexibility options were implemented in the following order:

- Tier 1 Options: Low-Cost, High-Performance Impact
- Tier 2 Options: Low-Cost, Low-Performance Impact

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- Tier 3 Options: High-Cost, High-Performance Impact
- Tier 4 Options: High-Cost, Low-Performance Impact

These designations were applied relatively (within each flexibility metric's list of potential options) and assigned based on information collected during the literature review, as well as Black & Veatch experience based on analysis of these options in the past for other EGUs looking into retrofit opportunities for improving flexibility.

The designation of the "Low/High" cost designation was based on a greenfield "nth" plant implementation philosophy. This philosophy dictates that the operational maturity of the technology is expected to reduce the "cost curve" typical of less-proven technologies and configurations.

The order of the implementation for the flexibility option tiers outlined above focused on minimizing total plant cost to the greatest extent practical. For this reason, the "low-cost, low-performance impact" options were prioritized ahead of the "high-cost, high-performance impact" options. Having established the groupings of the tiers, the following cases were outlined to characterize the cumulatively added flexibility options:

- Cases B11A-F1 and B12A-F1 – Flexible Plant: Tier 1 Options
- Cases B11A-F2 and B12A-F2 – Flexible Plant: Tier 1 and Tier 2 Options
- Cases B11A-F3 and B12A-F3 – Flexible Plant: Tier 1, Tier 2, and Tier 3 Options
- Cases B11A-F4 and B12A-F4 – Flexible Plant: Tier 1, Tier 2, Tier 3, and Tier 4 Options

Exhibit 4-14 through Exhibit 4-17 outline the flexibility options that were assumed to be included in tiers 1–4.

Exhibit 4-14. Tier 1 flexibility options (low-cost, high-performance impact)

Flexibility Metric	Option	Description
Startup Time	4	Steam sparging
Startup Time	5	Furnace heating utilizing small dedicated coal feeder, pulverizer, and burner level
Startup Time	7	Economizer and/or feedwater heater bypass
Startup Time	9	Equipping the EGU with black start capability (e.g., reciprocating engine units)
Startup Time	11	Draft system isolation and modifications to retain boiler heat as long as possible during shutdown periods
Startup Time	15	Main steam warmup line to accelerate pipe wall temperature rise during startup
Startup Time	17	Additional thermocouples to measure the steam-metal temperature differentials
Startup Time	18	Electric-resistance heating blankets for the steam turbine casing sections to pre-heat the casing (also works to retain heat as well)

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Flexibility Metric	Option	Description
Ramp Rate and Cycling	22	Enhanced water chemistry monitoring and system response to cycling
Ramp Rate and Cycling	24	Avoid use of forced cooling during boiler shutdowns to mitigate boiler tube failures
Ramp Rate and Cycling	25	Replace all steam turbine driven pumps (e.g., BFW pump) with electric motor drives
Minimum Stable Load	29	Economizer gas-side and water-side bypass
Minimum Stable Load	30	Air heater gas-side and air-side bypass
Minimum Stable Load	31	SCR gas bypass
Minimum Stable Load	35	Determination of the optimal boiler operating philosophy for each set load point
Minimum Stable Load	36	Designing the boiler with a larger number of smaller sized mills
Minimum Stable Load	41	Application of 'continuous coupled' last stage blades to reduce flutter and dynamic stresses during low-load operation
Design Life	42	Implement best practices for layup procedures, depending on the duration of the offline period
Design Life	43	Use of FFA or FFP to protect equipment from corrosion during layup and operation
Heat Rate	52	Online performance monitoring
Heat Rate	54	Enhanced operator interface to monitor and diagnose plant heat rate issues
Heat Rate	55	Limiting excess air and air heater air in-leakage to lowest practical levels
Heat Rate	56	Maintaining tight air heater outlet temperature target through use of upstream alkali (e.g., hydrated lime) injection
Heat Rate	57	Self-cleaning condenser design with stable backpressure target
Heat Rate	59	Steam turbine sliding pressure operation (subcritical only)
Heat Rate	61	Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low-load operation
Availability/Reliability	62	Full leveraging/utilization of the supplier's LTSA
Availability/Reliability	63	Full implementation of NERC-GADS Program for outage, trip, and malfunction tracking
Availability/Reliability	66	Modify startup, shutdown, turndown, and ramping protocols to lower component fatigue stresses
Availability/Reliability	67	Reducing or eliminating dissimilar metal welds to the greatest extent practical

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Flexibility Metric	Option	Description
EPC Capital Cost	71	Reliability-based operations and maintenance program; reduces reactive (unplanned maintenance) and maintenance equipment premiums when needed for forced outage situations
EPC Capital Cost	72	Contracting structure (e.g., open-book EPC or turn-key EPC) of overall project
EPC Capital Cost	73	Reducing plant layout (plan) area and optimizing proximity of plant to major shipping/transportation modes
O&M	74	Fully integrated online performance and conditional health assessment for major equipment categories
O&M	75	Advanced training for operators (e.g., professional certifications and onsite power plant simulator)
O&M	76	Additional plant automation and performance monitoring can lead to reduced plant staff requirements
O&M	78	Implement additional steam cycle instruments to improve cycle isolation during low-load conditions
Number of Starts	81	Investment in redundant and higher accuracy steam turbine casing metal temperature instruments; closer monitoring of these temperatures allows for more accurate tracking of design life and maintenance overhaul projections

Exhibit 4-15. Tier 2 flexibility options (low-cost, low-performance impact)

Flexibility Metric	Option	Description
Startup Time	10	Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems
Minimum Stable Load	27	Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
Minimum Stable Load	34	Installation of direct flame detection sensors and more thermocouples to monitor temperatures within the boiler
Heat Rate	49	Auxiliary load optimization
Heat Rate	50	Auxiliary load dispatch at low loads
Heat Rate	51	Automated boiler blowdown and drains (i.e., full monitoring and operator control from control room)
Heat Rate	53	Enhanced operator training and heat rate awareness
Availability/Reliability	64	Advanced training of operators to reduce errors and improve situational awareness
Availability/Reliability	65	Automated prioritization of plant alarm signals to allow for simplified triage of plant information received in the control room

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Exhibit 4-16. Tier 3 flexibility options (high-cost, high-performance impact)

Flexibility Metric	Option	Description
Startup Time	1	Use of advanced materials to reduce tube and pressure wall thickness requirements to improve rate of warmup
Startup Time	2	Decrease drum holding time to reduce drum diameter and drum wall thickness (subcritical only)
Startup Time	3	Increase the number of headers to decrease header size and warmup time
Startup Time	12	Use of condensate polishing system to maintain cycle chemistry parameters during shutdown and layup periods and reduce startup times (subcritical only)
Startup Time	13	Use of advanced materials to reduce turbine casing thickness and reduce STG warmup times
Startup Time	14	Turbine blade coatings for improved resistance to water impingement
Startup Time	19	Use of a steam-cooled turbine outer casing to reduce casing thickness
Ramp Rate and Cycling	20	Use of advanced creep strength enhanced materials
Ramp Rate and Cycling	21	Enhanced inspection and failure prediction
Minimum Stable Load	32	Converting a burner row to indirect firing
Minimum Stable Load	33	Intelligent soot blowing for managing heat transfer within the boiler
Minimum Stable Load	37	STG steam bypass to condenser
Design Life	44	Any measure (either equipment or operational) that reduces the number of start/stop thermal cycles of the EGU
Heat Rate	45	Neural networks and online combustion optimizer
Heat Rate	47	Fuel additives for slagging/fouling mitigation
Heat Rate	60	Application of variable speed drives on large electric motors
Availability/Reliability	68	Formal HEP and FAC monitoring programs as a part of an overall plant reliability, availability and maintainability (i.e., RAM program) with data tracking and observation logging for benchmarking
Availability/Reliability	69	Participation in steam turbine 'rotor exchange programs' through the STG supplier
EPC Capital Cost	70	Targeted and limited deployment of advanced creep strength enhanced materials (i.e., controlling cost of advanced materials)
O&M	79	Reducing the number and/or total cumulative cost of each startup
O&M	80	Utilization of electrode boiler for fast saturated steam production for supporting plant systems (evaluated on case-by-case basis)

Exhibit 4-17. Tier 4 flexibility options (high-cost, low-performance impact)

Flexibility Metric	Option	Description
Startup Time	16	Use of improved turbine seals to ensure correct clearances during startups
Heat Rate	46	Use of water cannons to improve range of load

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The qualitative interdependencies between the identified flexibility options is outlined in Exhibit 4-18 through Exhibit 4-21. The qualitative, cross-metric mapping is intended to convey that various flexibility options may exhibit benefits to multiple flexibility metrics.

As a note for the qualitative interdependency table outlined in Exhibit 4-18 through Exhibit 4-21, the designator “P” is used to designate the “Primary” flexibility metric that a specific option was originally assigned/grouped under; for any additional qualitative interdependencies and cross-metric benefits, the designator “X” is used to denote the flexibility options benefit to other flexibility metrics.

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Exhibit 4-18. Tier 1 flexibility options – qualitative interdependencies for flexibility metrics

Tier 1 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Steam sparging (Tier 1 – Flexibility Option 4)				X	P			X	X
Furnace heating utilizing small dedicated coal feeder/pulverizer/burner level (Tier 1 – Flexibility Option 5)	X	X		X	P			X	
Economizer and/or feedwater heater bypass (Tier 1 – Flexibility Option 7)		X		X	P			X	
Equipping the EGU with black start capability (e.g., reciprocating engine units) (Tier 1 – Flexibility Option 9)			X		P			X	X
Draft system isolation/modifications to retain boiler heat as long as possible during shutdown periods (Tier 1 – Flexibility Option 11)			X	X	P		X	X	X
Main steam warmup line to accelerate pipe wall temperature rise during startup (Tier 1 – Flexibility Option 15)					P		X	X	X
Additional thermocouples to measure the steam-metal temperature differentials (Tier 1 – Flexibility Option 17)			X	X	P				X
Electric-resistance heating blankets for the steam turbine casing sections to pre-heat the casing (also works to retain heat as well) (Tier 1 – Flexibility Option 18)			X		P		X		X
Enhanced water chemistry monitoring and system response to cycling (Tier 1 – Flexibility Option 22)		X	X	P				X	X
Avoid use of forced cooling during boiler shutdowns to mitigate boiler tube failures (Tier 1 – Flexibility Option 24)			X	P			X	X	X
Replace all steam turbine driven pumps (e.g., BFW pump) with an electric motor drives (Tier 1 – Flexibility Option 25)			X	P	X	X	X		X
Full leveraging/utilization of the supplier's LTSA (Tier 1 – Flexibility Option 62)			X			X	X		P

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Tier 1 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Full implementation of NERC-GADS Program for outage, trip, and malfunction tracking (Tier 1 – Flexibility Option 63)			X				X		P
Modify startup, shutdown, turndown, and ramping protocols to lower component fatigue stresses (Tier 1 – Flexibility Option 66)		X	X	X	X		X	X	P
Reducing/eliminating dissimilar metal welds to the greatest extent practical (Tier 1 – Flexibility Option 67)			X	X		X		X	P
Economizer gas-side/water-side bypass (Tier 1 – Flexibility Option 29)		P		X	X		X	X	
Air heater gas-side/air-side bypass (Tier 1 – Flexibility Option 30)		P		X	X			X	
SCR gas bypass (Tier 1 – Flexibility Option 31)		P			X			X	
Determination of the optimal boiler operating philosophy for each set load point (Tier 1 – Flexibility Option 35)	X	P	X				X		X
Designing the boiler with a larger number of smaller sized mills (Tier 1 – Flexibility Option 36)		P		X	X			X	X
Application of “continuous coupled” last stage blades to reduce flutter and dynamic stresses during low-load operation (Tier 1 – Flexibility Option 41)		P	X	X					X
Implement best practices for layup procedures, depending on the duration of the offline period (Tier 1 – Flexibility Option 42)			P		X		X	X	X
Use of film forming amines/products to protect equipment from corrosion during layup and operation (Tier 1 – Flexibility Option 43)			P				X	X	X
Online performance monitoring (Tier 1 – Flexibility Option 52)	P	X	X	X	X	X	X	X	X
Enhanced operator interface to monitor and diagnose plant heat rate issues (Tier 1 – Flexibility Option 54)	P		X				X		X

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Tier 1 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Limiting excess air and air heater air in-leakage to lowest practical levels (Tier 1 – Flexibility Option 55)	P	X					X		
Maintaining tight air heater outlet temperature target through use of upstream alkali (e.g., hydrated lime) injection (Tier 1 – Flexibility Option 56)	P	X		X					X
Self-cleaning condenser design with stable backpressure target (Tier 1 – Flexibility Option 57)	P	X	X						X
Steam turbine sliding pressure operation (subcritical only) (Tier 1 – Flexibility Option 59)	P	X			X			X	X
Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low-load operation (Tier 1 – Flexibility Option 61)	P	X			X			X	X
Reliability-based operations and maintenance program; reduces reactive (unplanned maintenance) and maintenance equipment premiums when needed for forced outage situations (Tier 1 – Flexibility Option 71)			X			P	X		X
Contracting structure (e.g., open-book EPC, turn-key EPC) of overall project (Tier 1 – Flexibility Option 72)						P			
Reducing plant layout (plan) area and optimizing proximity of plant to major shipping/transportation modes (Tier 1 – Flexibility Option 73)						P	X		
Fully integrated online performance and conditional health assessment for major equipment categories (Tier 1 – Flexibility Option 74)			X	X			P	X	X
Advanced training for operators (e.g., professional certifications, onsite power plant simulator) (Tier 1 – Flexibility Option 75)	X			X	X		P	X	X
Additional plant automation/performance monitoring can lead to reduced plant staff requirements (Tier 1 – Flexibility Option 76)	X			X	X		P		X

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Tier 1 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Implement additional steam cycle instruments to improve cycle isolation during low-load conditions (Tier 1 – Flexibility Option 78)	X	X					P		X
Investment in redundant/higher accuracy steam turbine casing metal temperature instruments; closer monitoring of these temperatures allows for more accurate tracking of design life/maintenance overhaul projections (Tier 1 – Flexibility Option 81)			X	X	X		X	P	X

Exhibit 4-19. Tier 2 flexibility options – qualitative interdependencies for flexibility metrics

Tier 2 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems (Tier 2 – Flexibility Option 10)		X		X	P			X	X
Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter (Tier 2 – Flexibility Option 27)		P			X			X	X
Installation of direct flame detection sensors and more thermocouples to monitor temperatures within the boiler (Tier 2 – Flexibility Option 34)		P		X	X		X	X	X
Auxiliary load optimization (Tier 2 – Flexibility Option 49)	P	X					X		
Auxiliary load dispatch at low loads (Tier 2 – Flexibility Option 50)	P	X					X		

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Tier 2 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Automated boiler blowdown and drains (full monitoring and operator control from control room) (Tier 2 – Flexibility Option 51)	P	X		X	X				X
Enhanced operator training and heat rate awareness (Tier 2 – Flexibility Option 53)	P			X	X		X	X	X
Advanced training of operators to reduce errors and improve situational awareness (Tier 2 – Flexibility Option 64)	X		X	X		X	X	P	P
Automated prioritization of plant alarm signals to allow for simplified triage of plant information received in the control room (Tier 2 – Flexibility Option 65)			X	X	X		X		P

Exhibit 4-20. Tier 3 flexibility options – qualitative interdependencies for flexibility metrics

Tier 3 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Use of advanced materials to reduce tube and pressure wall thickness requirements to improve rate of warmup (Tier 3 – Flexibility Option 1)		X	X	X	P		X		X
Decrease drum holding time to reduce drum diameter and drum wall thickness (subcritical only) (Tier 3 – Flexibility Option 2)				X	P			X	X
Increase the number of headers to decrease header size and warmup time (Tier 3 – Flexibility Option 3)				X	P			X	X

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Tier 3 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Use of condensate polishing system to maintain cycle chemistry parameters during shutdown/layup periods and reduce startup times (subcritical only) (Tier 3 – Flexibility Option 12)			X		P		X	X	X
Use of advanced materials to reduce turbine casing thickness and reduce STG warmup times (Tier 3 – Flexibility Option 13)			X	X	P	X		X	X
Turbine blade coatings for improved resistance to water impingement (Tier 3 – Flexibility Option 14)		X	X	X	P			X	X
Use of a steam-cooled turbine outer casing to reduce casing thickness (Tier 3 – Flexibility Option 19)			X	X	P	X		X	X
Use of advanced creep strength enhanced materials (Tier 3 – Flexibility Option 20)	X		X	P	X		X	X	X
Enhanced inspection and failure prediction (Tier 3 – Flexibility Option 21)			X	P			X		X
Converting a burner row to indirect firing (Tier 3 – Flexibility Option 32)		P			X			X	X
Intelligent soot blowing for managing heat transfer within the boiler (Tier 3 – Flexibility Option 33)	X	P		X			X		
STG steam bypass to condenser (Tier 3 – Flexibility Option 37)		P		X	X			X	X
Any measure (either equipment or operational) that reduces the number of start/stop thermal cycles of the EGU (Tier 3 – Flexibility Option 44)			P				X		X
Neural networks and online combustion optimizer (Tier 3 – Flexibility Option 45)	P	X		X			X	X	X
Fuel additives for slagging/fouling mitigation (Tier 3 – Flexibility Option 47)	P	X		X			X	X	X
Application of variable speed drives on large electric motors (Tier 3 – Flexibility Option 60)	P						X	X	X
Formal HEP/FAC monitoring programs as a part of an overall plant reliability, availability and maintainability (i.e., RAM program) with data tracking and observation logging for benchmarking (Tier 3 – Flexibility Option 68)			X				X		P

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Tier 3 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Participation in steam turbine ‘rotor exchange programs’ through the STG supplier (Tier 3 – Flexibility Option 69)			X			X	X		P
Targeted/limited deployment of advanced creep strength enhanced materials (i.e., controlling cost of advanced materials) (Tier 3 – Flexibility Option 70)						P			
Reducing the number and/or total cumulative cost of each startup (Tier 3 – Flexibility Option 79)					X		P	X	X
Utilization of electrode boiler for fast saturated steam production for supporting plant systems (evaluated on case-by-case basis) (Tier 3 – Flexibility Option 80)		X		X	X		P	X	X

Exhibit 4-21. Tier 4 flexibility options – qualitative interdependencies for flexibility metrics

Tier 4 Flexibility Options – Qualitative Interdependencies	Heat Rate	Minimum Stable Load	Design Life	Ramp Rate & Cycling	Startup Time	Plant Capital Cost	O&M Cost	No. of Annual Starts	Availability/Reliability
Use of improved turbine seals to ensure correct clearances during startups (Tier 4 – Flexibility Option 16)		X			P			X	X
Use of water cannons to improve range of load (Tier 4 – Flexibility Option 46)	P			X					X

4.8 MODELING METHODOLOGY

The cases developed for the various plant design bases include steady-state performance at full- and discrete, part-load operating points (including minimum load). To reflect the expected variances of the baseload and flexible plants at various loads, the following discrete load points were established for subcritical and supercritical options to serve as the basis for performance modeling:

- Baseload Plant: 100%, 75%, 50%, and 40%
- Flexible Plants: 100%, 75%, 50%, 30%, and 20%

Full and part load performance was modeled for each case by incorporating performance curves into the Aspen steady state model.

The plant performance curves were intended to reflect the behavior of key process parameters and equipment at part-load operating conditions. They were developed by fitting a line or second-degree polynomial curve to the values that were generated for key parameters at each discrete load point.

The values used to generate the plant performance curves (provided in Appendix A) were developed based on data from published reports, information obtained from vendors and users of the technology, performance data from design and build utility projects, and/or best engineering judgment.

Because the values were fit to a curve rather than entered discretely into the model, some parameters (such as excess air) may differ slightly from the discrete values that are presented in the performance curve tables. Additionally, it should be noted that the behavior of the key process parameters between, and beyond, the discrete load points is not guaranteed to be accurate.

While many of the performance curves remained unchanged between cases, several were modified, as necessary, to reflect changes in the conceptual design or operational protocols of the case.

4.8.1 Low-Load Limiting Factors Overview

The low-load capabilities of the plant design are a critical factor to the operational and economic competitiveness of a coal-fired EGU that is operating in a high-cycling regime.

The low-load of the flexible plant can be categorized as “sustained” or “achievable.” The purpose of this differentiation is to outline the reasonable bounds on low-load operation for the conceptual plant design. The low-load capabilities of the plant will factor significantly into the economic analysis and overall viability of the plant. It has been demonstrated in the past that OEMs can provide commercial guarantees for full-load points and part-load points within standard equipment supply contractual requirements.

Currently, most projects include one full load performance guarantee point (typically associated with 100 percent of rated load), one intermediate guarantee point (potentially in the range of

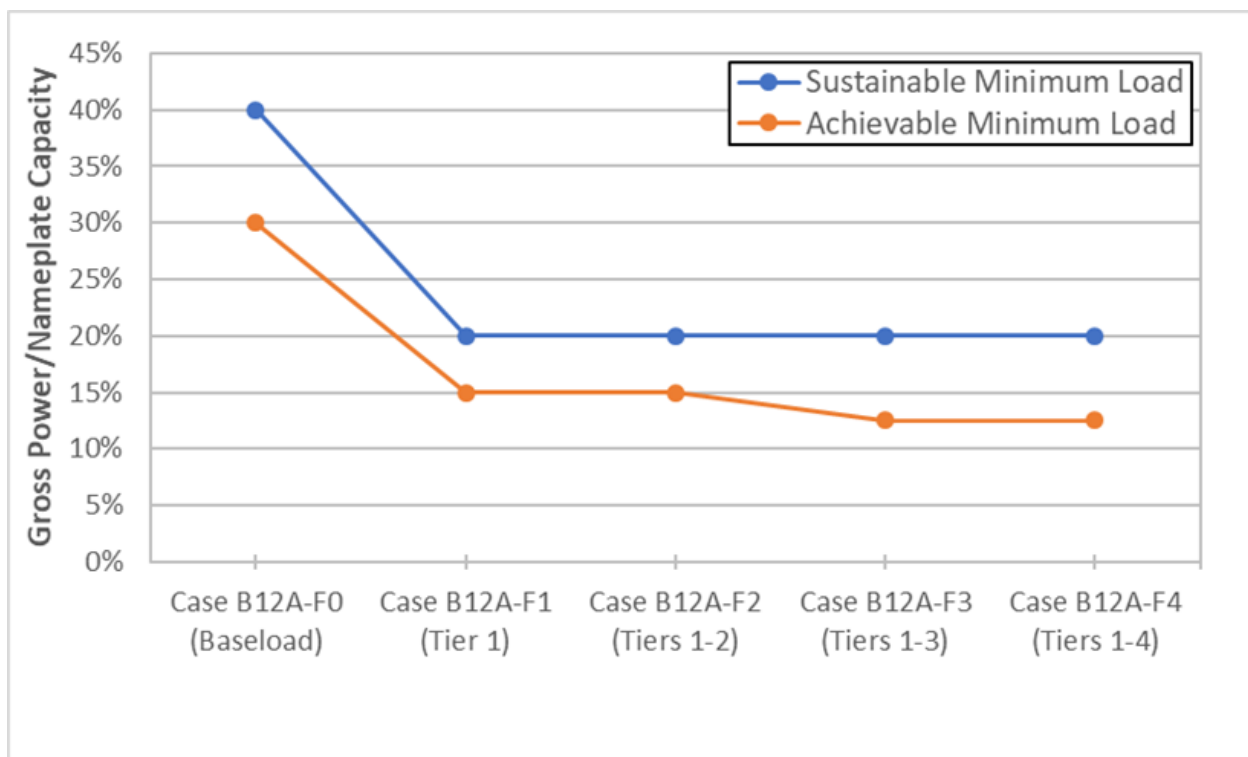
60–75 percent of rated load) and one minimum load guarantee point (if desired by the end user). For most coal units, this minimum load guarantee point is less than 75 percent load, but likely greater than 50 percent load.

It is considered reasonable for an end user to be able to negotiate commercial guarantees for minimum-load points on a project-specific basis with major equipment suppliers (e.g., boiler, steam turbine, and ACC). It is anticipated that the end-user's contractual structure and agreement with the EPC contractor will also affect the commercial performance guarantees of the plant. The ability of the major equipment suppliers to provide commercial performance guarantees at the sustained and/or achievable minimum-load points outlined in this study were not confirmed with the major equipment suppliers, due to the conceptual nature of the design bases developed.

These indicative minimum load estimates assume no supplemental (e.g., natural gas or fuel oil) firing. The definitions differentiating the two categories of load points presented in Exhibit 4-22 are outlined below.

- **Sustainable Load** — Operating point that is tenable for an indefinite period of time (between outages)
- **Achievable Load** — Operating point that is tenable for a shorter period of time (<12 hours) in order to withstand atypical operating conditions (e.g., overnight operation, equipment malfunction, and weather events affecting grid dispatch)

Exhibit 4-22. Sustained and achievable minimum load



Note: results apply to subcritical and supercritical

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The breakpoints outlined in Exhibit 4-22 are characterized and supported by the following bases:

- Baseload Plant — Case B11A-F0 and Case B12A-F0
 - Lowest achievable load shown is representative of an aggressive minimum load for a standard baseload unit design (omitting any/all special features)
 - Maintaining the standard design philosophy of the baseload plant design basis — the potential leading limiting factors will be SCR and FGD operation and steam turbine valve throttling
- Flexible Plant — Case B11A-F1 and Case B12A-F1 (Tier 1)
 - Reduction in sustained and achievable minimum load due largely to increasing the number of coal mills, switching to the electric-driven BFW pump, gas- and water-side bypasses, excess air reduction, and sliding-pressure operation
 - Online performance monitoring and diagnostics expected to lessen the burden on operators to manage the stability of the various plant systems during high turndown operation
- Flexible Plant — Case B11A-F2 and Case B12A-F2 (Tiers 1–2)
 - No notable or significant changes in sustained or achievable minimum load from the addition of Tier 2 flexibility options
 - Advanced operator training (e.g., certification), situational awareness, and prioritization of plant alarms would be critical to ensuring stable and safe operation of the EGU during high turndown conditions
- Flexible Plant — Case B11A-F3 and Case B12A-F3 (Tiers 1–3)
 - Reduction in achievable minimum load due largely to the VFD equipment, indirect firing, and intelligent soot blowing
 - No reduction in sustained minimum load
- Flexible Plant — Case B11A-F4 and Case B12A-F4 (Tiers 1–4)
 - No notable/significant changes in sustained or achievable minimum load from the addition of Tier 4 flexibility options

The above plot assumes no supplemental fuel use and all safety-related operational limitations (e.g., NFPA 85) are satisfied. Additionally, emissions reduction is assumed to meet the site-specific permit requirements. Balancing mill operation and emissions controls equipment and thresholds is critical for low-load operation.

As outlined above, specific flexibility options have been grouped and implemented in consecutive and cumulative design cases; however, specific constraints exist that will limit any coal-fired EGU, regardless of technological capabilities. These operational and regulatory limitations include, but are not limited to, factors such as the EGU's permit structure, industry

standards and protocols for prudent unit operation, and site- and owner-specific operational factors (e.g., mill operation philosophy).

The EGUs potential permit structure is not outlined in the scope of this analysis due to the regionally agnostic nature of the plant's location. As an overview, the EGU's permit structure can range from a flexible "Annual Emissions Limit" to a more restrictive "24-Hour Emissions Limit" basis.

The flexible plant would likely target structuring the air emissions permit in a manner that maximizes "operational flexibility" (i.e., preferring a longer-term emissions control basis, such as a cumulative annual basis). However, these factors can only be ascertained accurately once a project site is selected.

Second, industry standards and protocols have also implemented limitations on coal-fired EGUs in the past. As an example, NFPA 85 (Boiler and Combustion Systems Hazard Code) mandates the minimum air flow through coal-fired boilers at approximately 20–30 percent of full-load air flow for "safe" operation of the boiler. This guideline for minimum air flow is intended to establish an industry-wide basis for best practices and recommended operational limits for safe unit operation.

Lastly, the site- and owner-specific mill operation philosophy is an example of a factor that will determine the level of load reduction that the EGU owner and the operators are comfortable with. The most significant issue with EGU operation and mill operation philosophy is how much mill redundancy is preferred by the operators as load reduces, given that a "loss of flame" event is a serious plant fault ("trip") scenario with potential equipment health and safety implications. Owners and operators who sacrifice mill redundancy would conceptually be able to further reduce load by utilizing fewer operating mills—thereby further reducing auxiliary power at low load while assuming additional operational risk of a boiler loss of flame incident. Additional discussion and details outlining the various competing mill operation regimes for coal-fired EGUs looking to improve turndown capabilities is outlined in Section 3.1.1.

4.8.2 Performance Summary Metrics

This section details the methodologies of several metrics reported in the performance summaries of the PC cases.

Steam Generator Efficiency

The steam generator efficiency is equal to the amount of heat transferred in the boiler divided by the thermal input provided by the coal. This calculation is represented by the equation:

$$SGE = \frac{BH}{CH}$$

Where:

- SGE – steam generator efficiency
- BH – boiler thermal output
- CH – coal thermal input

The heat transferred in the boiler is provided by the Aspen models, and the thermal input of the coal is the product of the coal feed rate and the heating value of the coal.

4.8.2.1 Steam Turbine Efficiency

The steam turbine efficiency is calculated by taking the steam turbine power produced and dividing it by the difference between the thermal input and thermal consumption. This calculation is represented by the equation:

$$STE = \frac{STP}{TI}$$

Where:

- STE – steam turbine efficiency
- STP – steam turbine power
- TI – thermal input

The thermal input is considered the main steam and energy added during reheat.

4.8.2.2 Steam Turbine Heat Rate

The steam turbine heat rate is calculated by taking the inverse of the steam turbine efficiency. This calculation is represented by the equation:

$$STHR = \frac{1}{STE} * 3,412$$

Where:

- STHR – steam turbine heat rate, Btu/kWh
- STE – steam turbine efficiency, fraction

4.9 COST ESTIMATING METHODOLOGY

Detailed information pertaining to topics such as contracting strategy; engineering, procurement, and construction (EPC) contractor services; estimation of capital cost contingencies; owner's costs; cost estimate scope; economic assumptions; finance structures; and levelized cost of electricity are available in the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." [9] Select portions are repeated in this report for completeness.

Critical assumptions for the capital cost estimates presented in this report include the following:

- Estimates were developed on the nth-of-a-kind (NOAK) basis. That is, all cost estimates were intended to reflect the cost reduction that would be seen after widespread technology deployment. Cost premiums that would be expected for first-of-a-kind technologies (e.g., certain advanced materials) are not reflected in the cost estimates.
- All major equipment components and features are based on commercially-proven technology from reputable suppliers; no non-standard designs are required.

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- Equipment design parameters were selected in a manner targeting values for which performance guarantees could be reasonably secured with the reputable suppliers.

Capital Costs:

The capital cost estimates documented in this report reflect an AACE Class 4 estimate with an uncertainty range of -20/+40 percent. One of the main objectives of this report is to provide a basis for technology comparison. Given this objective, the level of uncertainty in the capital estimates is acceptable. However, use of the capital estimates in an unintended way could magnify the uncertainty of the cost estimates. The final cost results reported for all cases are not intended to represent a real project-specific cost that would be expected in today's markets. This is due to many factors (e.g., site assumptions, CFs) including the uncertainty in capital costs. In all cases, this report intends to represent the next commercial offering and relies on vendor cost estimates for component technologies.

The capital cost estimates documented in this report reflect different uncertainty ranges than those reported for the Bituminous Baseline PC unit cost estimates. The reason for this change is the smaller plant size, the fewer number of PC installations in the past ten years, and the location(s) of those PC installations. The total error band has increased, with a net shift upwards (toward the positive end of the spectrum) when compared to the cost estimate categorization of Case B11A. [63]

Costs of Mature Technologies and Designs:

The cost estimates for plant designs that only contain fully mature technologies, which have been widely deployed at commercial scale reflect NOAK on the technology commercialization maturity spectrum. The costs of such plants have dropped over time due to "learning by doing" and risk reduction benefits that result from serial deployments as well as from continuing R&D.

Costs of Emerging Technologies and Designs:

The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., advanced materials) use the same cost estimating methodology as for mature plant designs, which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application. Thus, it is anticipated that initial deployments may incur costs higher than those reflected within this report.

Other Factors:

Actual reported project costs are also expected to deviate from the cost estimates in this report due to project- and site-specific considerations (e.g., contracting strategy, local labor costs, seismic conditions, water quality, financing parameters, local environmental concerns, and weather delays) that may make construction more costly. Such variations are not captured by the reported cost uncertainty.

Future Cost Trends:

Continuing research, development, and demonstration is expected to result in designs that are more advanced than those assessed by this report, leading to costs that are lower than those estimated herein.

4.9.1 Capital Costs

As illustrated in Exhibit 4-23, this report defines capital cost at four levels: BEC, EPCC, TPC, and TOC. BEC, EPCC, TPC, and TOC are “overnight” costs and are expressed in “base-year” dollars. The base year is the first year of capital expenditure.

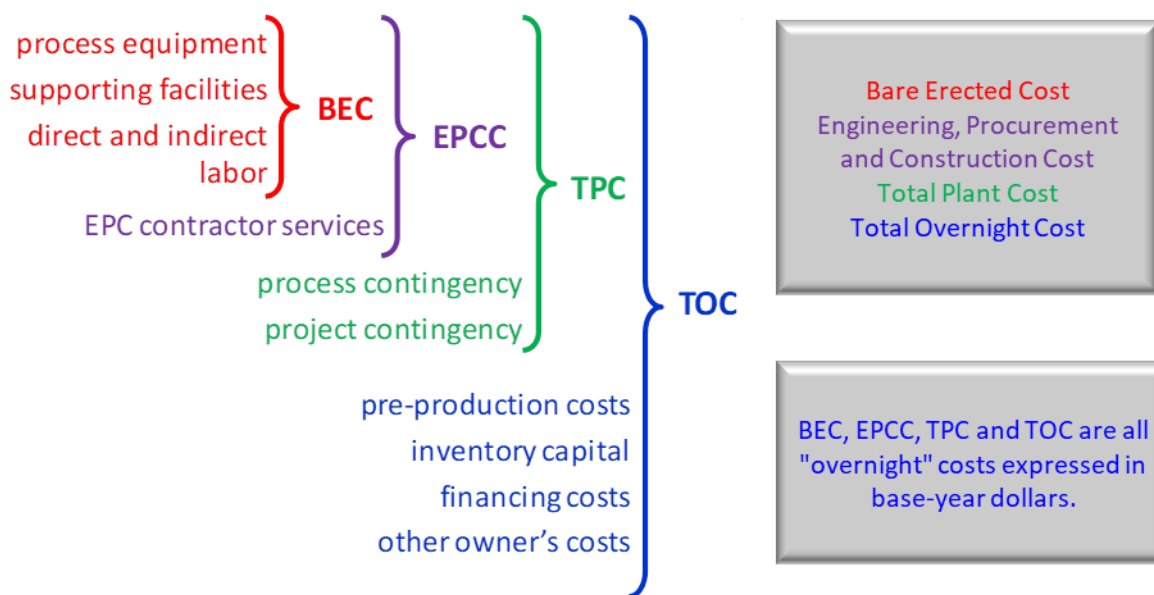
The Bare Erected Cost (BEC) comprises the cost of process equipment, on-site facilities and infrastructure that support the plant (e.g., shops, offices, labs, roads), and the direct and indirect labor required for its construction and/or installation. The cost of EPC services and contingencies are not included in BEC.

The Engineering, Procurement and Construction Cost (EPCC) comprises the BEC plus the cost of services provided by the EPC contractor. EPC services include: detailed design, contractor permitting (i.e., those permits that individual contractors must obtain to perform their scopes of work, as opposed to project permitting, which is not included here), and project/construction management costs.

The Total Plant Cost (TPC) comprises the EPCC plus project and process contingencies.

The Total Overnight Cost (TOC) comprises the TPC plus all other overnight costs, including owner’s costs. TOC does not include escalation during construction or interest during construction.

Exhibit 4-23. Capital cost levels and their elements



4.9.1.1 Cost Estimate Basis and Classification

The TPC and O&M costs for each of the cases in the report were estimated by Black & Veatch using an in-house database and conceptual estimating models. Costs were further calibrated using a combination of adjusted vendor-furnished data and scaled estimates from previous design and build projects.

4.9.1.2 System Code-of-Accounts

The costs are grouped according to a process- and system-oriented code of accounts. This type of code-of-account structure has the advantage of grouping all reasonably allocable components of a system or process, so they are included in the specific system account. This would not be the case had a facility, area, or commodity account structure been chosen instead.

4.9.1.3 Estimate Scope

The estimates represent a complete power plant facility on a generic site. The plant boundary limit is defined as the total plant facility within the “fence line” including coal receiving and water supply system but terminating at the high voltage side of the main power transformers.

4.9.1.4 Capital Cost Assumptions

Black & Veatch developed the capital cost estimates for each plant using the company’s in-house database and conceptual estimating methodology. This database and approach are maintained by Black & Veatch as part of a commercial power plant design base of experience for similar equipment in the company’s range of power and process projects. The baseload plant estimate served as the reference estimate for the subsequent flexible plant cases to reflect the major component additions, equipment modifications, and sub-system configuration changes.

Other key estimate considerations include the following:

- Labor costs are based on Midwest, Merit Shop. The estimating models are based on U.S. Gulf Coast and the labor has been factored to Midwest. Labor cost data sourced from recent projects and proprietary Black & Veatch in-house references and cost databases.
- The estimates are based on a competitive bidding environment, with adequate skilled craft labor available locally.
- Labor is based on a 50-hour work-week (5-10s). No additional incentives such as per-diem allowances or bonuses have been included to attract craft labor.
- While not included at this time, labor incentives may ultimately be required to attract and retain skilled labor depending on the amount of competing work in the region, and the availability of skilled craft in the area at the time the projects proceed to construction.
- The estimates are based on a greenfield site.
- The site is considered to be Seismic Zone 1, relatively level, and free from hazardous materials, archeological artifacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.
- Engineering and Construction Management are estimated based on Black & Veatch’s historical experience in designing and building power projects. The cost, as a percentage of BEC is 17.5 percent, which was selected such that the final total cost calculated is

representative of Black & Veatch's historical engineering and construction management costs for similar plant types. These costs consist of all home office engineering and procurement services as well as field construction management costs. Site staffing generally includes a construction manager, a resident engineer, a scheduler, and personnel for project controls, document control, materials management, site safety, and field inspection.

4.9.1.5 Price Fluctuations

During the writing of this report, the prices of equipment and bulk materials fluctuated as a result of various market forces. Some reference quotes pre-dated the 2018-year cost basis while others may be considered more historical. All vendor quotes used to develop these estimates were adjusted to December 2018 dollars accounting for the price fluctuations. In-house monthly/quarterly escalation rates provided by Black & Veatch were used as needed for these adjustments. While these overall indices are nearly constant, it should be noted that the cost of individual equipment types may still deviate from the December 2018 reference point. For these escalation rates and other rates use for cost modifications, Black & Veatch utilized existing in-house data based on current construction and procurement industry sources that provide industry-based guidelines.

4.9.1.6 Cross-comparisons

In all technology comparison studies, the relative differences in costs are often more significant than the absolute level of TPC. This requires cross-account comparison between technologies to review the consistency of the direction of the costs.

In performing such a comparison, it is important to reference the technical parameters for each specific item, as these are the basis for establishing the costs. Scope or assumption differences can quickly explain any apparent anomalies.

4.9.1.6.1 Process Contingency

This report contains no emerging technologies, and therefore applies no process contingencies. Future revisions may include technologies which necessitate the inclusion of process contingencies at the appropriate subsystem levels to account for expected but undefined costs, which can be a challenge for emerging technologies.

4.9.1.7 Owner's Costs

Detailed explanation of the owner's costs is available in the QGESS document "Cost Estimation Methodology for NETL Assessment of Power Plant Performance." [9] Owner's costs are split into three categories: pre-production costs, inventory capital, and other costs.

Pre-production allocations are expected to carry the specific plants through substantial completion, and to commercial operation. Substantial completion is intended to represent the transfer point of the facility from the EPC contractor (development entity) to the end user or owner, and is typically contingent on mutually acceptable equipment closeout, successful completion of facility-wide performance testing, and full closeout of commercial items.

Two examples of what could be included in the “other” owner’s costs are rail spur and switch yard costs.

Switch yard costs are dependent on voltage, configuration, number of breakers, layout, and air-insulated versus gas-insulated. As a rule of thumb, a 345-kV switchyard (air-insulated, ring bus) would cost roughly \$850,000 per breaker.

On-site only rails (excludes long runs) would be expected to cost in the range of \$850,000 to \$950,000 per mile (relatively flat level terrain) plus the costs of any switches or turnouts (approximately \$50,000 each) and road crossings (approximately \$300 per linear foot).

4.9.2 Operation and Maintenance Costs

The production costs or operating costs and related maintenance expenses (O&M) pertain to those charges associated with operating and maintaining the power plants over their expected life. These costs include:

- Operating labor
- Maintenance — material and labor
- Administrative and support labor
- Consumables
- Fuel
- Waste disposal
- Co-product or by-product credit (that is, a negative cost for any by-products sold)

There are two components of O&M costs: fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation. Taxes and insurance are included as fixed O&M costs, totaling 2 percent of the TPC.

4.9.2.1 Operating Labor

Operating labor cost was determined based on the number of operators required for each specific case. The average base labor rate used to determine annual cost is \$38.50/hour. The associated labor burden is estimated at 30 percent of the base labor rate.

4.9.2.2 Maintenance Material and Labor

Maintenance cost was evaluated based on relationships of maintenance cost to initial capital cost. This represents a weighted analysis in which the individual cost relationships were considered for each major plant component or section. The flexible plant cases maintenance material and labor costs were assessed at a higher percentage than the baseload plant. This increase was implemented due to the higher frequency maintenance procedures and protocols typically implemented by cycling-duty plants based on Black & Veatch experience.

4.9.2.3 Administrative and Support Labor

Labor administration and overhead charges are assessed at a rate of 25 percent of the burdened O&M labor.

4.9.2.4 Consumables

The cost of consumables, including fuel, is determined based on individual rates of consumption, the unit cost of each specific consumable commodity, and the plant annual operating hours.

Due to the expected operational profile of the plants developed in this study, the variable operating costs (consumables, waste disposal, by-products, and fuel) are expressed as a function of average annual capacity factor. It should be noted that these calculations assume the plant is operating at 100 percent load during dispatch; the calculations do not compensate for the efficiency penalty that is experienced during low load operation. Accurately characterizing the change in variable operating costs is identified as a future work objective in Section 6.1.

Formulas for calculating major consumables such as fuel and sorbent were taken from technology-specific energy and mass balance diagrams developed for each plant application. Other consumables were evaluated based on the quantity required using reference data.

The quantities for initial fills and daily consumables were calculated on a 100 percent operating capacity basis. Initial fills of the consumables, fuels and chemicals, may be accounted for directly in the O&M tables or included with the equipment pricing in the capital cost. Where applicable, the O&M tables state where this cost is included on a case-by-case basis.

4.9.2.5 Waste Disposal

Waste quantities and disposal costs are determined and evaluated similarly to the consumables. Non-hazardous waste is disposed of at a rate of \$41.90/tonne (\$38.00/ton).

4.9.2.6 Co-Products and By-Products

By-product quantities are also determined similarly to the consumables. However, due to the variable marketability of these by-products, specifically gypsum, no credit was taken for their potential salable value.

It should be noted that by-product credits and/or disposal costs could potentially be an additional determining factor in the choice of technology for some companies and in selecting some sites. A high local value of the product can establish whether added capital should be included in the plant costs to produce a particular co-product. Ash may also be a potential by-product in certain markets; however, due to the ACI, the fly ash may not be marketable. As stated above, these material streams are considered waste in this report with a concomitant disposal cost.

4.9.3 Construction Modularization

4.9.3.1 Modularization Limitations – Shipping Constraints

Shipping constraints are outlined in Exhibit 4-24 and are the most prominent limiter to modularization potential of equipment. Road, rail, and barge/ship delivery methods are the most common delivery methods for plant equipment. In extreme conditions, packages and materials have been air-lifted into sites by means of cargo- or heavy-freight helicopters designed for such packages.

Exhibit 4-24. Shipping logistics size and weight constraints

Shipment Method ^{A, B}	Typical Size Constraints ^C	Typical Weight Constraints
Over-Road Shipments	Height (H): 20 feet Width (W): 15–20 feet Length (L): 50–100 feet	Less than 40 tons ^D
Rail Shipments	H: 20 feet W: 15 feet L: 35 feet	Less than 715 tons
Ship/Barge Shipments ^A	H: 50 feet W: 20 feet L: 50–100 feet	Over 1,000 tons
Aerial-Cargo Shipments	H: 20 feet W: 15–20 feet L: 50 feet	Less than 15 tons

^A Ship/barge shipments reduce the amount of over-road shipment time and complications; however, packages that are transported a portion of the distance to site via barge/ship would still be subject to road restrictions and limitations for the balance of the transport to site

^B Shipping logistics constraints provided in this table are demonstrative and provided for discussion purposes; the outlined constraints do not account for route-specific transportation considerations (including studies and analyses) that would be required to be completed prior to shipment

^C H/W/L parameters provided are intended to be representative

^D 1 ton = 2,000 pounds

4.9.3.2 Modularization Opportunity Areas

Highly modularized plant designs are typically seen in NGCC, natural gas simple cycle, oil and gas industry applications, and renewable energy generation applications (e.g., solar, battery storage).

For this analysis of flexible coal plant configuration and design, construction modularization optimization was interpreted in the sense of identifying areas to maximize shop fabrication with the goal of reducing construction costs and schedule.

The assessment of modularization potential was intended to analyze the degree to which modularization (e.g., offsite fabrication of equipment or sub-systems, or laydown area

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preassembly, in whole or part) and associated construction time and/or cost savings may apply to the plants evaluated in this study.

Exhibit 4-25 outlines areas where, based on Black & Veatch experience and industry trends, high- and low-modularization potential exists within the evaluated plant configurations.

Exhibit 4-25. High/low modularization potential comparisons

High-Modularization Potential	Low-Modularization Potential
• Supporting skid equipment (e.g., lubricating oil equipment, fuel gas pressure reduction, jacking oil equipment, reagent preparation and conditioning skids, and emissions monitoring equipment) • Boiler economizer tube assemblies • Recuperative (e.g., shell and tube) boiler air heaters (if selected) • Coal storage and conveying • Small- or moderate-sized fans and pumps • Electrical and controls equipment (e.g., MCCs and pre-engineered PLC buildings) • Low-volume civil and structural works (e.g., small retaining walls) • Site security logistics and tollgates (e.g., craft turnstiles depot and security checkpoints) • Containerized contractor equipment storage onsite • Feedwater heaters • Air-cooled condenser	• Boiler waterwall tubes and panels^A • Boiler superheat and reheat tube assemblies • Regenerative (rotating) air heaters (if selected) • AQCS equipment modules and reactors (e.g., WFGD vessel and SCR reactor) • Large-volume civil and structural works (e.g., foundations, rebar, and piles) • Large fan categories (e.g., PA, FD, and ID fans) • Structural steel members • Flue gas ductwork • Stack • Steam Turbine

^A Standard industry erection practices for large coal units already include a high level of onsite fabrication of boiler tube panels at grade

Due to typical equipment manufacturer requirements and design, it is unlikely any of the major pump or fan categories (e.g., boiler feed pumps, condensate pumps, primary air fans, forced draft fans, and induced draft fans) would be shipped with the housing components and rotor components pre-assembled. The housing components and supporting skid assemblies typically ship separately from the rotor and shaft assembly facility, the latter of which has more strict material protection and shipping preparation requirements.

The AQCS is another limiting factor to modularization. AQCS construction costs and process control complexity increases as the number of parallel AQCS trains increases. The smaller-sized trains would conceptually help with turndown, but those effects could potentially be countered by the prohibitive installation cost and maintenance requirements. The construction modularization potential was focused on the plant size evaluated in this study (150–300 MW); potential opportunities for modularization will change depending on size of the unit.

4.9.3.3 Major Equipment Category Suppliers

A focus of this study was to assess appropriate commercial offerings of reputable equipment suppliers that pertain to the plant configuration. The term “commercial offering” is intended to capture processes or technologies that are currently offered for sale by the reputable equipment supplier, or design firm (including but not limited to either as discrete equipment, technology licenses, or design services), in addition to the willingness of that same entity to provide performance guarantees with industry-acceptable terms and conditions.

The following suppliers outlined in Exhibit 4-26 are pre-approved Black & Veatch suppliers for the large equipment packages that would be included in the commercial plant configuration. Pre-approved Black & Veatch suppliers have been technically assessed and meet the financial criteria as set forth by Black & Veatch’s global equipment procurement department. While this list is a representation of the common suppliers identified for the specific equipment categories outlined, other suppliers that are equally suitable may be available.

Exhibit 4-26. Major equipment category suppliers

Equipment	Suppliers
PC Boiler Island	- AC Boiler - Babcock & Wilcox - Babcock Power - Riley - Doosan - Foster Wheeler - GE - IHI - MHPS
Combustion Air and Flue Gas Fan	- Boldrocchi - Howden - Process Barron - Robinson Fans - TLT Turbo - Twin City Clarage
BFW Pump	- Ebara Machinery - Flowserve - Gould's - Hyundai - Kirloskar Brothers Limited - KSB Incorporated - Sulzer - Torishima Pump
Steam Turbine Generator	- Doosan Heavy Industries - Dresser Rand - Fuji - GE - Mitsubishi - Hitachi - Siemens - Toshiba
ACC	- Babcock & Wilcox SPIG - Beijing Longyuan Cooling - Dongfang Steam Turbine Works - Eneixo US - Evapco BLCT Dry Cooling - GEI Industrial - Holtec International - Kelvion - KNM Group - Research Cottrell Dry Cooing - SPX Dry Cooling
Deaerator	- Kansas City Deaerator Company - Sterling Deaerator Company - Stork
Medium Voltage Motors	- ABB - Siemens

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Equipment	Suppliers	
	• Baldor • General Electric • Hitachi • Hyundai • Regal Beloit • Reliance	• TECO - Westinghouse Motor Co. • TMEIC • WEG • Marathon • HICO • Laurence Scott
Motor Variable Frequency Drives	• ABB Inc. • Benshaw Inc. • EATON Corporation • GE Energy	• Larsen & Toubro • Rockwell Automation • Siemens Industry Inc. • Toshiba
SCR System	• Andritz Environmental Solutions • Babcock & Wilcox • Babcock Power • Braden Manufacturing • Foster Wheeler	• Fuel Tech • Hitachi • IHI • LP Amina
SCR Catalyst	• ASM • BASF • Criterion • Cormetech	• Euro • Johnson Matthey • SUD Chemie • MHPS
PJFF	• Amec Foster Wheeler • Andritz Environmental Solutions • Babcock & Wilcox • Clyde Bergemann	• Hamon • SPE Amerex • Tensar International
WFGD	• Amec Foster Wheeler • Babcock & Wilcox • Babcock Power Environmental • GE-Alstom	• Hamon Research Cottrell • Marsulex • MHPS • Siemens Environmental
PAC Systems	• ADA-ES • Clyde Bergemann • Nol-Tec	• Norit • UCC
SO ₃ Capture (Sorbent) Systems	• ADA-ES • Clyde Bergemann	• Nol-Tec • UCC

4.9.4 Startup and Shutdown Costs

4.9.4.1 Methodology

Costs associated with startup and shutdown were calculated for baseload plant cases (Case B11A-F0, Case B12A-F0) and Tier 4 cases (Case B11A-F4, Case B12A-F4) to determine the range of costs with different levels of flexibility considered in the design. Costs were calculated from start to synchronization and from start to full load for hot, warm, and cold starts (for shutdown, from full load to desynchronization and from full load to turning gear). Variable O&M costs were weighted throughout the startup or shutdown event to determine the operating costs accumulated during each event. House energy consumed during the event was calculated in the same way.

Natural gas is used as a startup fuel below 30% steam turbine load with coal considered for higher load points. For the purposes of these startup costs calculations, it was assumed that the transition between fuels occurs instantaneously at 30% steam turbine load. In reality, the transition from natural gas to coal is a gradual one, but the 30% steam turbine load point is typically near the middle of the transition. An electric auxiliary boiler was included for Tier 4 cases to supply warming and sparging steam. The electricity costs for the auxiliary boiler were included in the Tier 4 case calculations.

There are additional startup cost considerations that are not included in this cost analysis that would affect the plant. Plants with high cycling or increased frequency of large load swings can have higher O&M costs, more frequent outages, decreased reliability, and a higher probability of component fatigue failures. The costs associated with these potential issues are difficult to predict and may take several years to materialize in the plant. More frequent inspections, real time performance monitoring, and designing for cycling can help to mitigate these risks.

4.9.4.2 Historical Context

Black & Veatch considered several in-house coal plant references to determine normal startup and shutdown curves, durations, and procedures. These references were used to tune baseload plant cases and ensure that their startup and shutdown conditions are typical and within the normal range for actual industry references. Tier 4 cases are inherently harder to predict as there are currently no plants that include all their design characteristics to increase flexibility, but the Black & Veatch references were used to the extent possible to help to reduce the uncertainty range of the Tier 4 cases' startup and shutdown cost estimates.

Significant variance was observed in the time required for coal plants to achieve the appropriate water chemistry and whether this time was included in the startup duration. The requirements vary based on the individual plant including the amount of blowdown/leakages, incoming water quality, water treatment systems, and drum type (water chemistry requirements are more stringent in plants with once-through Benson-type boilers). The costs calculated in this report assume acceptable water chemistry at the time of the start.

These costs should be considered representative, and would vary based on the final plant design, fuel cost, requirements of OEMs, etc.

5 PULVERIZED COAL RANKINE CYCLE PLANTS

Ten PC fired, Rankine cycle, power plant configurations were evaluated in this study and the results are presented in this section. Each design is based on a market-ready technology that is assumed to be commercially available at the time the project commences. All designs employ a one-on-one configuration comprising a state-of-the art PC steam generator firing Illinois No. 6 coal and a steam turbine.

All five subcritical cases are evaluated without CO₂ capture on a common 150 MW_{gross} basis while all five supercritical cases are evaluated without CO₂ capture on a common 300 MW_{gross} basis. The constant gross output sizing basis for the same steam conditions is selected because it provides for a meaningful side-by-side comparison of the results. The boiler and steam turbine industry ability to match unit size to a custom specification has been commercially demonstrated enabling common gross output comparison of the cases in this study.

Steam conditions were selected based on Black & Veatch experience with PC plants of this size, standard breakpoints in the steam pressure design of large boilers and steam turbines (e.g., 2,400 psig, 1,800 psig, 1,200 psig), in addition to the known boiler and steam turbine OEMs; the steam turbine OEM would be expected to provide commercial guarantees for a project in the United States with subcritical and supercritical units at a nominal rating and firing Illinois No. 6 coal. [64] Based on these determining factors, the following single-reheat steam conditions were selected for the study:

- 12.4 MPa/538°C/538°C (1,800 psia/1,000°F/1,000°F)
- 24.1 MPa/593°C/593°C (3,500 psia/1,100°F/1,100°F)

These steam conditions and the unit size range were aligned with Black & Veatch experience with the most recent subcritical and supercritical PC units being installed in global markets—primarily China and South America. These unit sizes (150 MW_{gross}, 300 MW_{gross}) and steam conditions are considered industry-aligned and applicable to a unit configuration that current OEMs would be capable of providing competitive commercial guarantees.

The evaluation basis details, including site ambient conditions, fuel composition and the emissions control basis, are provided in Section 4 of this report.

5.1 PLANT CONFIGURATION SELECTION METHODOLOGY

As part of the study, a plant configuration was developed for establishing a general design basis for assessing the unit's cost, performance, and flexibility metrics. The determination of the assumed plant capacity is presented in Section 4.6. A summary of the overall plant configuration technology options considered in this study is provided in Exhibit 5-1. More detailed discussion of plant configuration and the competing technologies was provided in Section 2.9.

Exhibit 5-1. Overall plant configuration technology options

Technology	Summary	Configuration Selection
Stoker, Subcritical	Physical sizing limitations of stoker grates restrict the installation in capacity classes for larger modern utility-scale application. Often found in industrial applications firing waste or opportunity fuels, though have been employed in utility applications firing coal in older generation facilities.	
BFB, Subcritical	Typically installed in 25- to 100-MW capacity classes. BFB was the first advent of the fluidized bed combustion technologies and has less industry focus compared to CFB.	
CFB, Subcritical	Typically installed in 25- to 300-MW capacity classes. Subcritical installations of CFB are well-proven and well-established. Often the selected boiler technology for challenging fuels, projects that make use of opportunity fuels, or where a higher degree of fuel flexibility is a project requirement; high load variability often negatively impacts the refractory lining inside the boiler exhaust gas dust separators.	
CFB, Supercritical	Limited experience with only a handful of worldwide installations.	
PC, Subcritical	Very well-proven and well-established technology. In the past, has been the favored technology for firing subbituminous and bituminous fuel. Have been commercially installed in capacity ranges of 50–1,000 MW. Selected as the basis of the configuration due to increased OEM support, proven experience, and controllability. Supplemental discussion of the boiler technology options and justification of the configuration is provided in Section 2.9.1.	PC Boiler, Subcritical, Drum Type
PC, Subcritical, Once-Through	Does not include a steam drum. Requires higher-purity condensate. Startup times may be reduced without the need to warm up a drum. Could be considered more challenging to control than a subcritical drum type boiler and is more susceptible to system upsets and transients.	
PC, Supercritical	Very well-proven and well-established technology. In the past, has been the favored technology for firing subbituminous and bituminous fuel. Given the added cost and market demands, installations have primarily been in the 500+ MW capacity classes. Recent market conditions, regulatory or financing requirements, and project interveners/public perception have resulted in OEM offerings down to the 300-MW class. There is limited support and installation below a 300-MW class.	PC Boiler, Supercritical, Once-Through
PC, Ultra-Supercritical	Proven and established technology; though limited in experience compared to subcritical or supercritical. Similar to supercritical, past installations have been primarily in the 500+ MW capacity classes, though from market drivers, OEMs are offering ultra-supercritical technology down to a 300-MW class. There is limited support and no known installations below a 300-MW class.	

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Technology	Summary	Configuration Selection
Steam Turbine Generator and Rankine Cycle Heat Rejection		
Air Quality Control Systems, Post-Combustion		
NO _x Control		
SNCR/SCR	The selection of the post-combustion NO _x control technology is highly driven by the amount of NO _x reduction required. Both SNCR and SCR systems have been employed to reduce post-combustion NO _x emissions. With SNCR, ammonia or urea is injected into the boiler furnace or boiler backpass to reduce NO _x emission. With an SCR, ammonia or urea is injected upstream of a catalyst in the backpass of a boiler. The addition of a catalyst to the process improves the reaction between the NO _x and reagent, but at an added capital cost. It is not likely that SNCR alone would be sufficient to meet future permitted air emission limits for NO _x . Additional discussion of the NO _x control technology options is included in Section 2.9.2.	SCR
SO ₂ Control		
Dry-Based/Semi-Dry Based/WFGD	Many different technologies have been employed to control SO ₂ . Those technologies are generally divided among dry-, semi-dry, and wet-based technologies based on the means by which the control reagent is introduced to the flue gas stream. Circulating FGD scrubbers and WFGD scrubbers have the greatest proven SO ₂ removal efficiency, with WFGD having the greatest capability though the highest capital cost. The selection of one technology over the other is commonly driven by the sulfur content of the design fuel, subsequent post-combustion SO ₂ FGD scrubber loading, and the SO ₂ reduction required to meet the permitted air emission limits. It was assumed that a future permitted coal-fired EGU would be required to employ an SO ₂ reduction technology with the greatest capability of SO ₂ removal; therefore, WFGD was assumed as the basis of the configuration. These various FGD systems, including performance/cost trade-offs, are outlined in Section 2.9.3.	WFGD
PM Control		
PJFF	PJFFs provide a greater level of PM control over a wide range of load and range of fuels. Because a PJFF is, in effect, a filter, operating and fuel characteristics have little impact on the operating performance of a PJFF. A PJFF also provides enhanced control of heavy metals when PAC is utilized for mercury control. The cake of unreacted PAC on the surface of the PJFF bags provides improved mercury control and can reduce the PAC injection requirements. Additional discussion of the PM control technology options is provided in Section 2.9.4.	PJFF
ESP	ESPs function by charging the PM particles and attracting them to a collection plate of an opposite charge. ESPs are sensitive to the operating conditions and characteristics (e.g., ash resistivity) of the fuel. ESPs have a well-proven history and track record, though modern plants generally employ PJFFs for the advantages described above.	

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Technology	Summary	Configuration Selection
Mercury (Hg) Control		
Fuel Additives	Fuel additives have been used to control Hg, which is then captured in existing AQCS control equipment. Fuel additives are typically offered by proprietary suppliers and applied between the coal yard and mill-specific coal silos.	
PAC Injection	Injection of PAC into the boiler flue gas exhaust duct upstream of the unit's particulate collection system can be used for the capture of Hg. PAC is the most common and effective means of reducing Hg levels to those required for environmental compliance. Additional discussion of the available Hg control technology options is outlined in Section 2.9.5.	PAC Injection
SO₃ Control		
Sorbent Injection	Duct sorbent injection is the primary method of controlling SO ₃ . Different sorbents can be selected based on project requirements, sorbent performance, sorbent pricing, and local availability. Additional discussion of the available SO ₃ control technology options is outlined in Section 2.9.6.	Sorbent Injection for SO ₃
BOP Systems		
BOP Systems	Standard design and selection for the baseload plant and flexible plant configurations. For this assessment, it is assumed that the arrangement of the BOP systems presents no differentiating factors in the assessment of the flexible plant metrics and flexibility attributes. Section 5.2.13 outlines additional discussion regarding specific BOP systems and an overview of the BOP system(s) configuration determinations that were outside the scope of this study.	Refer to Section 5.2.13

Following the discussion of the major plant configurations options outlined above, the overall plant configurations proposed are summarized below:

- Boiler — Subcritical PC boiler with circulating evaporator and drum (wall-fired, two-pass) or
- Boiler — Once-through supercritical PC boiler (wall-fired, two-pass)
- STG — HP/IP/LP reheat condensing STG on a single shaft; sliding pressure operation
- ACC for steam cycle heat rejection
- AQCS:
 - SCR for NO_x control
 - WFGD for SO₂ control
 - PJFF for PM control
 - PAC injection for Hg control
 - Sorbent injection for SO₃ control

5.2 COMMON PROCESS AREAS

The baseload and flexible plants have process areas that are common to each plant configuration, such as coal receiving and storage, emissions control technologies, and power generation. As detailed descriptions of these process areas in each case section would be burdensome and repetitious, they are presented in this section for general background information. This section only presents the process areas that were selected for incorporation into the final plant design; for information about competing technologies, and for further justification of the selections made for the plant design basis, see Section 2. The performance features of these sections are then presented in the case-specific sections.

5.2.1 Coal, Activated Carbon, and Sorbent Receiving and Storage

The function of the Coal Receiving and Storage system is to unload, convey, prepare, and store the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to and including the slide gate valves at the outlet of the coal storage silos. The system is designed to support short-term operation at the 5 percent over pressure/valves wide open (OP/VWO) condition (16 hours) and long-term operation of 90 days or more at the maximum continuous rating.

The scope of the sorbent receiving and storage system includes truck roadways, turnarounds, unloading hoppers, conveyors and the day storage bin.

Operation Description — The coal is delivered to the site by 100-car unit trains comprising 91 tonne (100 ton) rail cars. The unloading is done by a trestle bottom dumper, which unloads the coal into two receiving hoppers. Coal from each hopper is fed directly into a vibratory feeder. The 8 cm x 0 (3" x 0) coal from the feeder is discharged onto a belt conveyor. Two conveyors with an intermediate transfer tower are assumed to convey the coal to the coal stacker, which

transfer the coal to either the long-term storage pile or to the reclaim area. The conveyor passes under a magnetic plate separator to remove tramp iron and then to the reclaim pile.

Coal from the reclaim pile is fed by two vibratory feeders, located under the pile, onto a belt conveyor, which transfers the coal to the coal surge bin located in the crusher tower. The coal is reduced in size to 2.5 cm x 0 (1" x 0) by the coal crushers. The coal is then transferred by conveyor to the transfer tower. In the transfer tower, the coal is routed to the tripper that loads the coal into one of the six boiler silos.

Limestone is delivered to the site using 23 tonne (25 ton) trucks. The trucks empty into a below grade hopper where a feeder transfers the limestone to a conveyor for delivery to the storage pile. Limestone from the storage pile is transferred to a reclaim hopper and conveyed to a day bin.

Brominated PAC is delivered to the site in 9 tonne (10 ton) batches by self-unloading pneumatic trucks. The carbon is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The carbon level in the silo is measured by system instrumentation.^e

Hydrated lime is delivered and distributed in a manner very similar to that of the PAC. The hydrated lime is delivered in 11 tonne (12.5 ton) batches.^e

5.2.2 Steam Generator and Ancillaries

The steam generator for subcritical PC plants in this study is a drum-type, wall-fired, balanced draft, natural circulation, totally enclosed water-cooled dry bottom furnace, with superheater, reheater, economizer and air preheater.

The steam generator for the supercritical PC plants is a once-through, spiral-wound, Benson-boiler, wall-fired, balanced draft type unit with a water-cooled dry bottom furnace. It includes a superheater, reheater, economizer, and air preheater.

The combustion systems for both the subcritical and supercritical steam conditions are equipped with LNBs and OFA.

5.2.2.1 Scope

The steam generator includes the following for both subcritical and supercritical PCs, except where otherwise indicated:

• Drum-type evaporator (subcritical only)	• Startup circuit, including integral separators (supercritical only)	• Water cooled furnace, dry bottom
• Once-through type steam generator (supercritical only)		• Two-stage superheater
		• Reheater

^e The description of PAC and hydrated lime unloading were sourced from a quote provided by United Conveyor Corporation (UCC) to NETL, unless otherwise noted. The information relates to a mercury control system designed by UCC.

- Economizer
- Spray type desuperheater Soot blower system
- Air preheaters (Ljungstrom type)
- Coal feeders and pulverizers
- Low NOx Coal burners and natural gas igniters/ warm-up system
- OFA system
- Forced draft (FD) fans
- Primary air (PA) fans
- Induced draft (ID) fans

5.2.2.2 Feedwater and Steam

5.2.2.2.1 Feedwater

The function of the feedwater system is to pump the feedwater from the deaerator storage tank through the HP feedwater heaters to the economizer. For cases that utilize a turbine-driven feedwater pump (Cases B11A-F0 and B12A-F0), one turbine-driven feedwater pump sized at 100 percent capacity is provided to pump feedwater through the HP feedwater heaters, and one 25 percent motor-driven BFW pump is provided for startup. For cases that utilize an electric driven feedwater pump, one motor-driven feedwater pump sized at 100 percent capacity is provided to pump feedwater through the HP feedwater heaters, and the same feedwater pump is used for startup. The pumps are provided with inlet/outlet isolation valves, and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by automatic recirculation valves, which are a combination check valve in the main line and in the bypass, bypass control valve, and flow sensing element. The suction of the boiler feed pump is equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Pneumatic level control valves control normal drain level in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

The deaerator is a horizontal, spray tray type with internal direct contact stainless steel vent condenser and storage tank.

For cases that utilize a turbine-driven FW pump, the boiler feed pump turbine is driven by main steam up to 60 percent plant load. Above 60 percent load, extraction from the IP turbine exhaust provides steam to the boiler feed pump steam turbine.

5.2.2.2.2 Steam Generation

For the subcritical steam system, feedwater enters the economizer, recovers heat from the combustion gases exiting the steam generator, and then passes to the boiler drum, from where it is distributed to the water wall circuits enclosing the furnace. After passing through the lower and upper furnace circuits and steam drum in sequence, the steam passes through the

convection enclosure circuits to the primary superheater and then to the secondary superheater.

The steam then exits the steam generator en route to the HP turbine. Steam from the HP turbine exhaust returns to the steam generator as cold reheat and returns to the IP turbine inlet as hot reheat.

For the supercritical steam system, feedwater enters the bottom header of the economizer and passes upward through the economizer tube bank, through stringer tubes, which support the primary superheater, and discharges to the economizer outlet headers. From the outlet headers, water flows to the furnace hopper inlet headers via external downcomers. Water then flows upward through the furnace hopper and furnace wall tubes. From the furnace, water flows to the steam water separator. During low load operation (operation below the Benson point), the water from the separator is returned to the economizer inlet with the boiler recirculating pump. Operation at loads above the Benson point is once through.

Steam flows from the separator through the furnace roof to the convection pass enclosure walls, primary superheater, through the first stage of water attemperation, to the furnace platens. From the platens, the steam flows through the second stage of attemperation and then to the intermediate superheater. The steam then flows to the final superheater and on to the outlet pipe terminal. Two stages of spray attemperation are used to provide tight temperature control in all high temperature sections during rapid load changes.

Steam returning from the turbine passes through the primary reheater surface, then through crossover piping containing inter-stage attemperation. The crossover piping feeds the steam to the final reheater banks and then out to the turbine. Inter-stage attemperation is used to provide outlet temperature control during load changes.

5.2.2.2.1 Main and Reheat Steam

The main steam system conveys HP steam, which exits the boiler superheater through a motor-operated stop/check valve and a motor-operated gate valve, to the HP turbine stop valves via a single line. The HP turbine receives HP steam from the steam generator, and the exhaust is routed back to the reheater in the steam generator. The reheater system conveys cold reheat steam from the HP turbine exhaust, through a motor-operated isolation gate valve and a flow control valve and enters the boiler reheater. The reheater system then conveys hot reheat steam exiting the boiler reheater outlet, through a motor-operated gate valve, to the IP turbine stop valves. The IP turbine exhaust is routed to the LP turbine where final steam expansion occurs before it is exhausted to a condenser. Along the steam turbine path, steam is extracted for feedwater and deaerator heating to improve Rankine cycle efficiency.

5.2.2.2.3 Steam Turbine

There are multiple configurations in which a STG can be arranged. For EGUs utilizing steam from a coal-fired boiler, steam turbines are commonly arranged with a triple pressure reheat condensing single shaft STG.

For partial-load operation, design features can be incorporated into the STG, such as partial-arc steam admission or sliding-pressure operation. While constant-pressure operation is regarded as having a broader installation basis in the market and higher ramp rate capabilities, sliding-pressure operation is more common in supercritical units and has more optimal partial-load efficiency.

Both operating schemes are considered commercially proven with an established supplier base and proven global installations. There is no differentiation between constant/sliding-pressure operation in regard to likelihood of securing suitable performance guarantees from applicable OEMs; both operating schemes would be capable of securing competitive and industry-aligned performance guarantees from the OEM.

The subcritical baseload plant (Case B11A-F0) operates under constant-pressure, since a baseload unit would not realize the benefits of sliding pressure operation, whereas the supercritical baseload plant (Case B12A-F0) operates under sliding-pressure, since it is considered common practice. All flexible plant cases operate under sliding-pressure, due to the partial-load efficiency benefits, reduced thermal stresses, and enhanced control of steam turbine temperatures.

5.2.2.2.4 Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- From HP turbine extraction to heater 7 (and 8 in supercritical cases)
- From IP turbine extraction to heater 6 and the deaerator (heater 5)
- From LP turbine extraction to heaters 1, 2, 3, and 4

The turbine is protected from overspeed on turbine trip, from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc non-return valves located in all extraction lines except the lines to the LP feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

5.2.2.2.5 Condensate

The function of the condensate system is to pump condensate from the condenser to the deaerator and through the LP feedwater heaters. Each system consists of one main ACC, two variable speed electric motor-driven vertical condensate pumps each sized for 50 percent capacity, four LP heaters, and one deaerator with storage tank.

Condensate is delivered to a common discharge header through two separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line

discharging to the condenser is provided downstream of the gland steam condenser to maintain minimum flow requirements for the gland steam condenser and the condensate pumps.

LP feedwater heaters 1 through 4 are 50 percent capacity, parallel flow, and are in the condenser neck. All remaining feedwater heaters are 100 percent capacity shell and U-tube heat exchangers. Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Pneumatic level control valves control normal drain levels in the heaters. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Pneumatic level control valves control dump line flow.

5.2.2.3 Air and Combustion Products

Combustion air from the FD fans is heated in Ljungstrom type air preheaters, recovering heat energy from the exhaust gases exiting the boiler. This air is distributed to the burner windbox as secondary air. Air for conveying PC to the burners is supplied by the PA fans. This air is heated in the Ljungstrom type air preheaters to permit drying of the PC, and a portion of the air from the PA fans bypasses the air preheaters to be used for regulating the outlet coal/air temperature leaving the mills.

The PC and air mixture flows to the coal nozzles at various elevations of the furnace. The hot combustion products rise to the top of the boiler and pass through the superheater, reheater, economizer, SCR, DSI manifold, and air preheater. The gases exit the steam generator at this point and flow to the activated carbon injection (ACI) manifold, fabric filter, ID fan, FGD system, and stack. The flexible plant arrangements utilize an air preheater combustion air bypass, an air preheater flue gas bypass, an economizer gas-side bypass, and an SCR reactor gas bypass to allow for faster startup, improved air and flue gas temperature control, and improved draft system equipment protection.

5.2.2.4 Fuel Feed

The crushed Illinois No. 6 bituminous coal is fed through feeders to each of the mills (pulverizers), where its size is reduced to approximately 72 percent passing 200 mesh and less than 0.5 percent remaining on 50 mesh. [65] The PC exits each mill via the coal piping and is distributed to the coal nozzles in the furnace walls using air supplied by the PA fans. For the flexible plant cases that utilize indirect firing, an intermediate pulverized coal storage silo stores the finely ground coal for firing, typically during low load conditions. This prepared coal is diverted from the main burner and stored in a separate silo until the indirect firing system is required. The indirect firing system functions by blowing the stored pulverized coal through the annulus of the existing burners using a dedicated blower, and thus is combusted with a significantly smaller burner level heat release than the standard burner's typical turndown limitation.

The normalized power consumption of the pulverizer system is estimated as approximately constant between the various plant designs due to the shifting number of mills and the size of the mills varying proportionally as the number of mills decreases or increases. Exhibit 5-2

presents the number of mills utilized for each case, along with the normalized pulverizer auxiliary load.

Exhibit 5-2. Pulverizer auxiliary load versus number of mills

Case	Reference Plants [63]		Baseload Plants		Flexible Plants	
	B11A	B12A	B11A-F0	B12A-F0	B11A-F1 – B11A-F4	B12A-F1 – B12A-F4
Unit Size, MW _{gross}	687	685	150	300	150	300
Number of Mills Installed	6	6	4	4	6	6
Pulverizer Auxiliary Load, kW/tph-coal (as received)	10	10	10	10	10	10

5.2.2.5 Ash Removal

The furnace bottom comprises several hoppers, with a clinker grinder under each hopper. The hopper design incorporates a dry seal trough and are of welded steel construction, lined with refractory and block insulation for personnel safety and heat retention. Each hopper is paired with a pneumatic bottom ash transport line and is fully isolatable, with shutoffs downstream of the screw feeder and upstream of the clinker grinder, for ease of maintenance. The description of the balance of the bottom ash handling system is presented in Section 5.2.12. The steam generator incorporates fly ash hoppers under the economizer outlet and air preheater outlet.

5.2.2.6 Burners

A subcritical boiler of 150 MW_{gross} capacity employs approximately 10 to 12 coal nozzles arranged at multiple elevations, while a supercritical boiler of 300 MW_{gross} capacity employs approximately 12 to 16 coal nozzles. Each burner is designed as a low-NO_x configuration, with staging of the coal combustion to minimize NO_x formation. In addition, OFA nozzles are provided to further stage combustion and thereby minimize NO_x formation.

Natural gas-fired pilot torches are provided for each coal burner for ignition, warm-up, and flame stabilization at startup and low-loads.

5.2.2.7 Dry Sorbent Injection

The hydrated lime injection manifold is located directly before the air preheaters. This SO₃ control system is discussed in detail in Section 5.2.6.

5.2.2.8 Air Preheaters

Each steam generator is furnished with two vertical-shaft Ljungstrom regenerative type air preheaters. These units are driven by electric motors through gear reducers.

5.2.2.9 Soot Blowers

The soot blowing system utilizes an array of 50 to 150 retractable nozzles and lances that clean the furnace walls and convection surfaces with jets of HP steam. The blowers are sequenced to provide an effective cleaning cycle depending on the coal quality and design of the furnace and convection surfaces. The enhanced sootblower operating scheme, referred to as “intelligent sootblowing,” uses enhanced sensors such as strains gauges on the boiler stringer support rods or acoustic pyrometers to determine localized furnace areas where sootblowing is needed. Standard sootblowing schemes are based on a timed rotation of all sootblowers within the furnace; this configuration can be damaging to the furnace since areas that do not need cleaning go through unnecessary cleaning cycles, which abrade the exterior tube or pipe wall surface. Electric motors drive the soot blowers through their cycles.

5.2.3 NO_x Control System

The plants are designed to achieve the environmental target of 0.70 lb/MWh-gross. Two measures are taken to reduce the NO_x. The first is a combination of LNBs and the introduction of staged OFA in the boiler. The LNBs and OFA reduce the boiler emissions to about 0.35 lb/MMBtu.

The second measure taken to reduce the NO_x emissions is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NO_x to N₂ and H₂O. The SCR system consists of three subsystems: reactor vessel, ammonia storage and injection, and gas flow control. For subcritical cases, the SCR system is designed for approximately 78 percent reduction with 2 ppmv ammonia slip at the end of the catalyst life. For supercritical cases, the SCR system is designed for approximately 76 percent reduction with 2 ppmv ammonia slip at the end of the catalyst life.

The SCR capital costs are reported separately from the boiler costs; the cost for the initial load of catalyst is broken down separately in the O&M cost table.

SNCR was considered for this application. However, with the installation of the LNBs and OFA system, the boiler exhaust gas contains relatively small amounts of NO_x, which makes removal of the quantity of NO_x with SNCR to reach the emissions limit difficult. SNCR works better in applications that contain medium to high quantities of NO_x and require removal efficiencies in the range of 40 to 60 percent. Because of the catalyst used, SCR can achieve higher efficiencies with lower concentrations of NO_x.

5.2.3.1 SCR Operation Description

The reactor vessel is designed to allow proper retention time for the ammonia to contact the NO_x in the boiler exhaust gas. Ammonia is mixed with dilution air before injection, and the mixture is injected into the gas path immediately prior to entering the reactor vessel. The catalyst contained in the reactor vessel enhances the reaction between the ammonia and the NO_x in the gas. Catalysts consist of various active materials such as titanium dioxide, vanadium pentoxide, and tungsten trioxide. The operating range for vanadium/titanium-based catalysts is 260°C (500°F) to 455°C (850°F). In the flexible cases, the boiler is equipped with an economizer

bypass to provide flue gas to the reactors at the desired temperature during periods of low flow rate, such as low load operation. Also included with the reactor vessel is soot blowing equipment used for cleaning the catalyst.

The ammonia storage and injection system consist of the unloading facilities, bulk storage tank, vaporizers, dilution air skid, and injection grid.

The flue gas flow control consists of ductwork, dampers, and flow straightening devices required to route the boiler exhaust to the SCR reactor and then to the air heater. The economizer bypass and associated dampers for low load temperature control are also included.

5.2.4 Activated Carbon Injection

The PAC injection manifold is located directly before the baghouse. [66] This system will be discussed in detail in Section 5.2.6.

5.2.5 Particulate Control

The fabric filter (i.e., baghouse) consists of two separate single-stage, in-line, multi-compartment units. Each unit is of high (0.9–1.5 m/min [3–5 ft/min]) air-to-cloth ratio design with a pulse-jet on-line cleaning system. The ash is collected on the outside of the bags, which are supported by steel cages. The dust cake is removed by a pulse of compressed air. The bag material is polyphenylensulfide with intrinsic Teflon Polytetrafluoroethylene coating. [67] The bags are rated for a continuous temperature of 180°C (356°F) and a peak temperature of 210°C (410°F). Each compartment contains several gas passages with filter bags, and heated ash hoppers supported by a rigid steel casing. The fabric filter is provided with necessary control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

The use of ACI and DSI increases the calcium content of the fly ash and adds an additional burden to the fabric filter. The addition of calcium is not expected to increase the leaching of trace metals from the fly ash significantly.

Fly ash from bituminous-fired plants (Class F fly ash) is sometimes sold for use as filler material in concrete mixtures. The use of Class F fly ash for concrete manufacture is not as common as the use of Class C fly ash (from high-calcium-containing coals); the latter is more valuable as a replacement for Portland cement in concrete mixtures. Class F fly ash must have a low unburned carbon content to be used in cement mixtures. The inclusion of activated carbon and hydrated lime (or, rather, the CaSO_4 reaction product) will render the fly ash unsuitable for use in concrete mixtures.

5.2.6 Mercury Removal^f

Mercury removal is partially achieved through flue gas reactions between mercury and available halogens and carbon.

The fraction of chlorine, and other halogens in the coal, impacts the amount of mercury oxidized in the SCR and air preheater. As oxidized mercury is removed by the fabric filter and FGD system, the chlorine content of the coal can have a significant impact on the mercury removal rate of the plant. Data presented by Reaction Engineering International suggests that as coal chlorine concentrations increase, up to 500 ppmwd, the fraction of oxidized mercury increases rapidly. However, the rate of mercury oxidation diminishes at chlorine concentrations above 500 ppmwd. [68]

The rate of mercury oxidation is also affected by the ammonia concentration. Since the SCR is operated more aggressively for NO_x control, the ammonia levels increase and the fraction of oxidized mercury decreases. [69]

In this study, it is assumed that 1.5 percent of the coal carbon is unreacted in the PC boiler. The unburned carbon rate would be expected to reduce (i.e., improve) as unit load reduces; this improved carbon burnout is typically attributed to slower furnace gas velocities and longer residence times at reduced loads. This unburned carbon both promotes mercury oxidation and adsorbs mercury on the surface of the fabric filter. The unburned carbon, combined with the HCl in the flue gas, is sufficient to promote high levels of oxidized Hg and overall Hg removal in the plant. [70]

Depending on the chemistry in the FGD system, a portion of the oxidized mercury that is captured by the scrubber could be reduced to elemental mercury and re-emitted. By minimizing the amount of mercury entering the FGD system, and through careful operation of the scrubber, the risk of periodic spikes in mercury re-emissions can be minimized.

The FGD system parameters such as oxidation reduction potential of the scrubber slurry, halogen concentration in the scrubber slurry, the form of Hg in the slurry (i.e., liquid or solid), and the effect of sulfite concentration were examined by Babcock and Wilcox for their impact on Hg re-emissions. It was concluded that sulfite concentration in the slurry was the most cost-effective parameter that can be controlled as a strategy to minimize mercury re-emission. [71]

Without mitigation, the concentration of SO₃ in the flue gas is estimated to be 59 ppmvd at the air preheater inlet at full-load. This elevated SO₃ concentration is the result of combusting a relatively high sulfur coal (2.82 wt%) and from oxidation across the SCR. This SO₃ concentration would be expected to reduce with load, which corresponds to an increase in excess air. While the SO₃ formation rate would be expected to decrease with decreasing flue gas temperature, it is expected that this effect is countered by the reduction in flow rate.

The presence of SO₃ significantly inhibits Hg adsorption, as SO₃ is preferentially adsorbed onto carbon. This effect was demonstrated in a testing program conducted at the Mercury Research

^fMuch of the text, descriptions, and images within this section were sourced, with permission, from a quote provided by UCC to NETL, unless otherwise noted. The information relates to a mercury control system designed by UCC. The quote also provided all images credited to them.

Center using an ESP-configured system with an activated carbon injection rate of 10 lb/MMacf upstream of the air preheater at 300°F, which showed that at SO₃ levels above 20 ppm, less than 50 percent mercury removal was achieved (at SO₃ levels above 10 and 3 ppm, less than 70 and 80 percent mercury removal was achieved, respectively). [72] Therefore, dry sorbent injection is included in the PC plant designs to reduce the SO₃ levels to approximately 5 ppmvd at the air preheater inlet, as discussed in Section 5.2.6.1.

EPA used a statistical method to calculate the Hg co-benefit capture from units using a “best demonstrated technology” approach, which for bituminous coals was considered to be a combination of a fabric filter and an FGD system. The statistical analysis resulted in a co-benefit capture estimate of 86.7 percent with an efficiency range of 83.8 to 98.8 percent. [73] EPA’s documentation for their Integrated Planning Model provides mercury emission modification factors (EMF) based on 190 combinations of boiler types and control technologies. The EMF is simply one minus the removal efficiency.

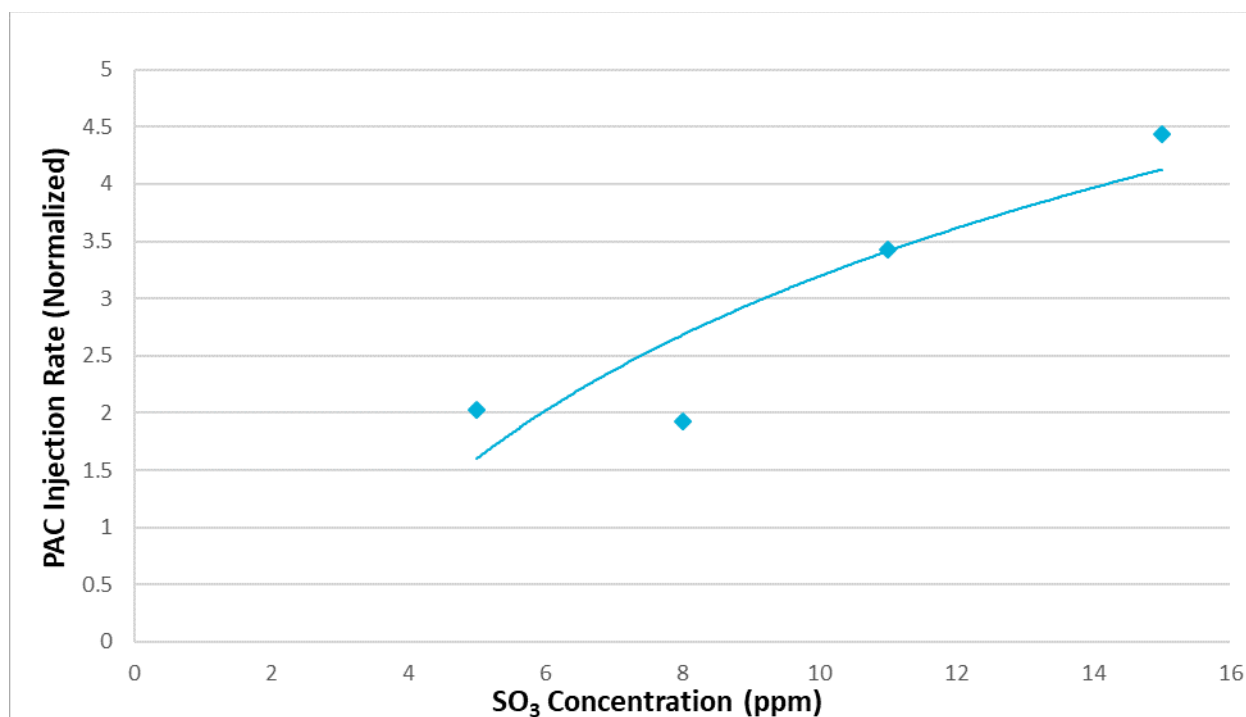
For PC boilers (as opposed to cyclones, stokers, fluidized beds, and ‘others’) with a fabric filter, SCR and FGD system, the EMF is 0.1, which corresponds to a removal efficiency of 90 percent; [74] the average reduction in total Hg emissions developed from EPA’s Information Collection Request data on U.S. coal-fired boilers using bituminous coal, fabric filters, and FGD system is 98 percent. [75] The referenced sources bound the co-benefit Hg capture for bituminous coal units employing SCR, a fabric filter, and an FGD system between 83.8 and 98 percent. It was assumed that the co-benefit potential of the equipment utilized in the PC cases of this report is 90 percent, as it is near the mid-point of the previously mentioned range, and it also matches the value used by EPA in their Integrated Planning Model.

The Hg removal rate required to comply with the Hg emission limit (Section 4.4) is calculated to be approximately 97–98 percent. Therefore, the potential co-benefit Hg capture rate (90 percent) of the systems utilized in the PC cases is not sufficient to achieve compliance with applicable regulations. A cost and performance estimate was obtained from United Conveyor Corporation (UCC), which applies ACI and DSI to increase the overall Hg removal rate in the plant.

5.2.6.1 Dry Sorbent Injection

Exhibit 5-3 provides data from a full-scale DSI/ACI test conducted by UCC on a midwestern coal-fired unit, which demonstrates the impact of SO₃ concentration (at the PAC injection point) on the PAC injection rate required to achieve a given Hg removal rate. The exhibit and data contained was supplied by UCC in the quote provided to NETL.

Exhibit 5-3. Effect of SO_3 concentration on PAC injection rate



As shown in Exhibit 5-3, higher SO_3 concentrations in the flue gas require significantly greater injection rates of PAC. Therefore, the DSI system considered in this report, with enhanced hydrated lime as the sorbent, targets an SO_3 concentration of 5 ppmvd at the air preheater inlet, with an SO_3 concentration of 2 ppmvd at the outlet of the fabric filter.

As the flue gas temperature must be maintained above the acid dew point temperature, locating the injection point upstream of the air preheater allows for a lower operating temperature (289°F versus 337°F) and higher overall plant efficiency, compared to a plant with no DSI or DSI downstream of the air preheater. Additionally, the reduction in operating temperature increases the Hg removal efficiency of carbon.

Since standard hydrated lime sorbents generally cannot achieve SO_3 removal rates greater than approximately 90 percent, the high level of SO_3 reduction required necessitates the use of an enhanced hydrated lime product to achieve the necessary Hg removal rate.

While DSI is included specifically to remove SO_3 from the flue gas, the enhanced hydrated lime also removes SO_2 and HCl, as shown in Exhibit 5-4. The rates shown are the total removal to the fabric filter outlet/FGD inlet, not the air preheater inlet.

Exhibit 5-4. Pollutant removal efficiency versus hydrated lime injection rate

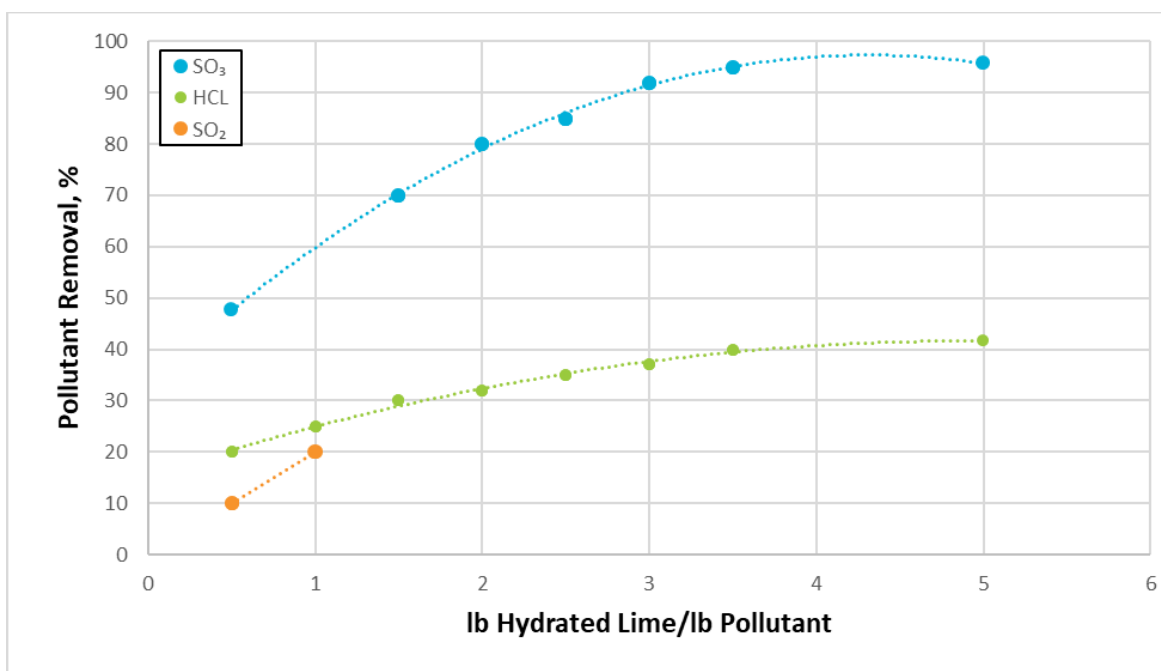


Exhibit 5-4 demonstrates that approximately 3.5 lb of enhanced hydrated lime/lb of SO₃ is required to reduce the SO₃ concentration to 2 ppmvd at the outlet of the fabric filter (approximately 96.6 percent removal rate). At this injection rate, the enhanced hydrated lime is expected to also remove approximately 1 percent of SO₂ and 30 percent of HCL.

The expected SO₂ reduction is very low, since SO₂ is a much weaker acid gas than SO₃ and HCL. In addition, the baseline SO₂ levels are far higher than either the SO₃ or HCL levels.

5.2.6.1.1 Operation Description

As shown in Exhibit 5-5, the DSI system is based on dilute-phase, pneumatic conveying of hydrated lime at a metered rate from a bulk storage silo to the flue gas ductwork where it mixes with the flue gas and reacts with the SO₃ to form CaSO₄, which is captured in the fabric filter.

The sorbent is typically delivered in 25,000-lb batches by self-unloading pneumatic trucks equipped with manually operated discharge valves. The sorbent is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The sorbent level in the silo is measured by system instrumentation.

Silos are typically 14-foot diameter with skirt support, made of carbon steel and are designed to be shipped in one piece. Storage silos are often aerated with dry air through a fluidizing system to ensure reliable feeding. Silos usually have two or more outlets and are equipped with weigh hoppers to provide loss-in-weight monitoring and feed control.

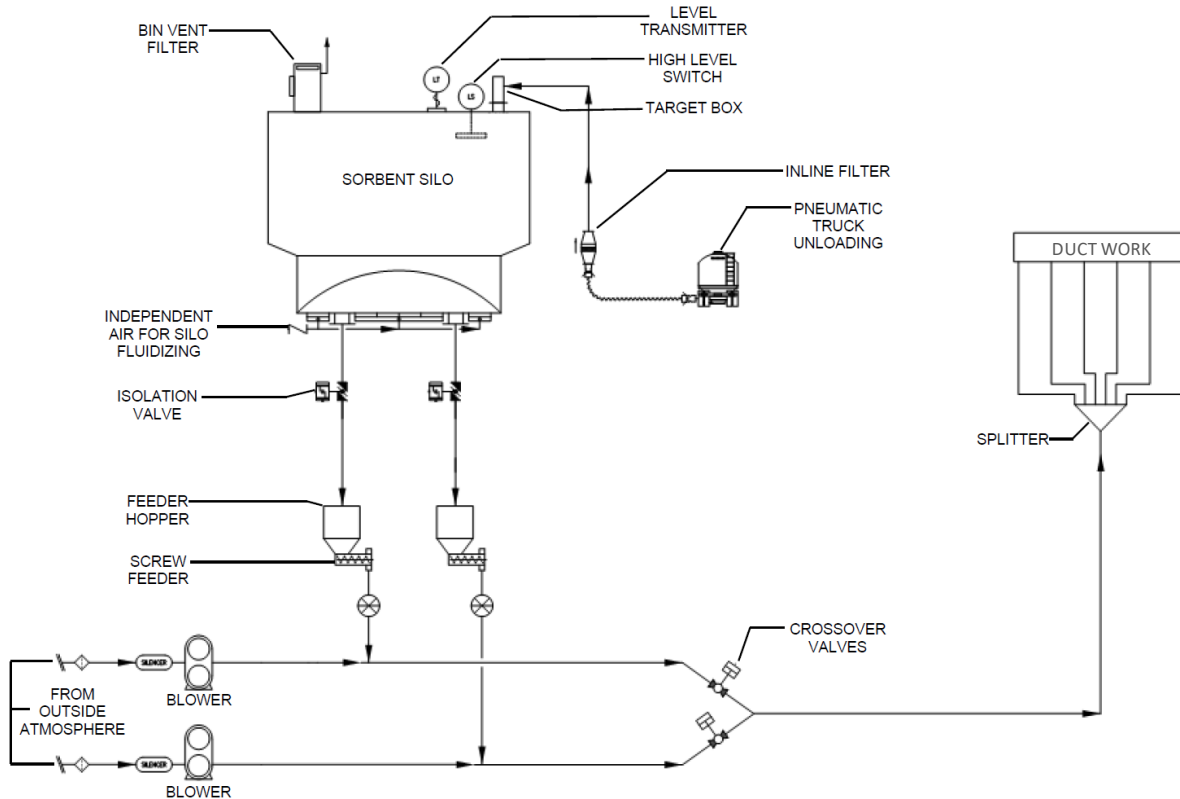
The silo roof equipment includes a bin vent filter, relief valve, and level transmitters. The bin vent filter is enabled when the unloading system is started to filter this airflow and vent it to the atmosphere.

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Compressed air is delivered to the fluidizing stones located in the chisel bottom of the silo. The fluidizing of the material in conjunction with the 60-degree silo cone promotes mass flow of the sorbent out of the silo.

The fluidized sorbent is then transferred from the silo by a rotary valve into the feeder hopper where it is temporarily stored until conveyed by the screw feeder into the intake tee. The speed of the screw feeder determines the feed rate into the intake tee. Sorbent is fed through the intake tee directly into the conveying air stream.

Exhibit 5-5. Typical DSI injection process flow diagram



Used with permission from UCC

Material fed from the storage silo typically discharges into one conveying line. The discharge of material is aided by the silo fluidizing system. Each silo discharge line has a carbon steel weigh hopper equipped with load cells. The weigh hopper is vented via a small bin vent filter located on the weigh hopper. The material is metered from the weigh hopper using a variable speed rotary vane feeder.

The silo fluidizing systems promotes constant fluid flow to the silo outlet by introducing air through a porous media. Cloth media is in trays on the silo floor and around the outlets.

The pressure blower provides an air stream for conveying sorbent from the storage silo to a splitter and lances for duct injection. Two 100 percent blowers are provided in a typical system for redundancy. Pressure blowers are on non-elevated common bases, and come complete with

a v-belt motor, inlet filter, inlet and discharge silencers, discharge check valve, discharge relief valve, discharge pressure gauge, and pressure transmitter.

The conveying lines are mild steel and are provided with a combination of flange and groove-less Victaulic couplings. The conveying line after the splitter is made of a gum rubber material handling hose designed for abrasion resistance.

The DSI system is typically monitored and controlled by the DCS. The feed rate of the system can be adjusted in the following ways:

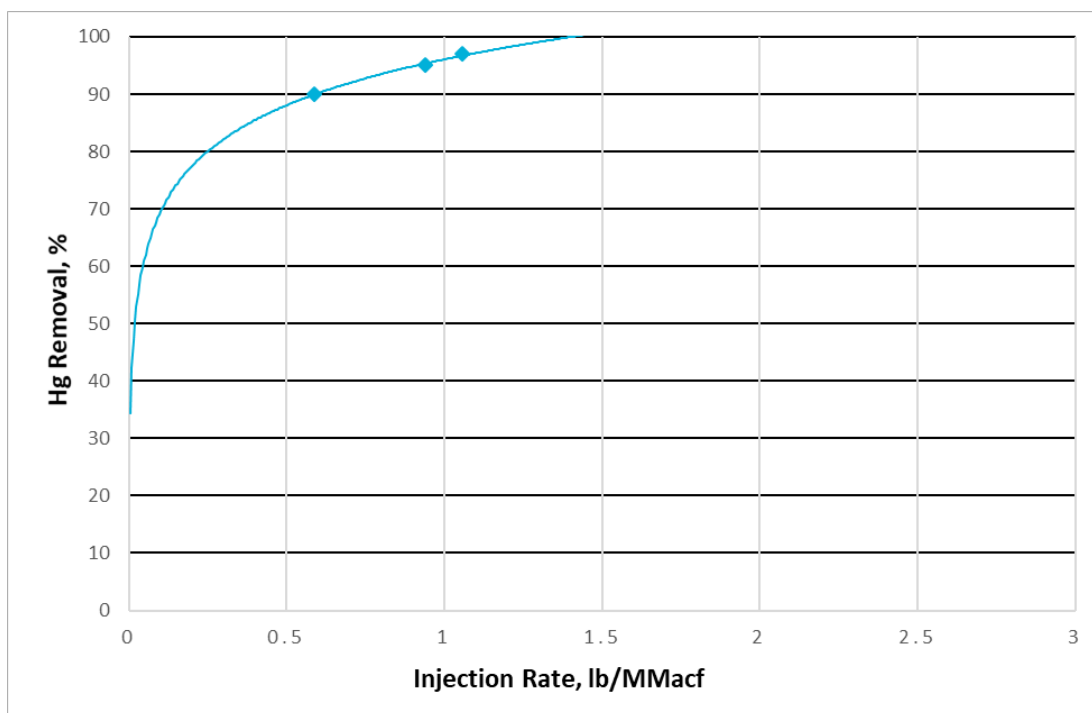
- Flat Rate (one continuous rate)
- Boiler Load Following (varies feed rate proportional to boiler load)
- Flue Gas Following (varies feed rate proportional to flue gas flow)

5.2.6.2 Activated Carbon Injection

By reducing the SO_3 with DSI (Section 5.2.6.1), most of the Hg will be oxidized in the SCR and removed in the fabric filter and FGD system. Therefore, only a minimal amount of brominated PAC is injected upstream of the fabric filter to ensure the desired Hg emission rate is achieved.

Exhibit 5-6, provided by UCC, presents a typical performance curve for plants utilizing an SCR and a fabric filter firing bituminous coal. The points highlighted represent 90, 95, and 97 percent Hg removal.

Exhibit 5-6. Mercury removal versus PAC injection rate for Case B12A



To meet the mercury emission limit, brominated PAC is injected at a rate of approximately 1.0 lb/MMacf in all PC cases.

5.2.6.2.1 Operation Description

As shown in Exhibit 5-7, the ACI system is based on dilute-phase, pneumatic conveying of activated carbon at a metered rate from a bulk storage silo to the flue gas ductwork where it mixes with the flue gas and absorbs Hg and SO₃, which is captured in the fabric filter.

The activated carbon is typically delivered in 20,000 lb batches by self-unloading pneumatic trucks equipped with manually operated discharge valves. The carbon is unloaded from the truck via an on-board compressor into the dry, welded-steel storage silo where the displaced air is vented through a silo vent filter. The carbon level in the silo is measured by system instrumentation.

Silos are typically 14-foot diameter with skirt support, made of carbon steel and are designed to be shipped in one piece. Storage silos are often aerated with dry air through a fluidizing system to ensure reliable feeding. Silos usually have two or more outlets and are equipped with weigh hoppers to provide loss-in-weight monitoring and feed control.

The silo roof equipment includes a bin vent filter, relief valve, and level transmitters. The bin vent filter is enabled when the unloading system is started to filter this airflow and vent it to the atmosphere.

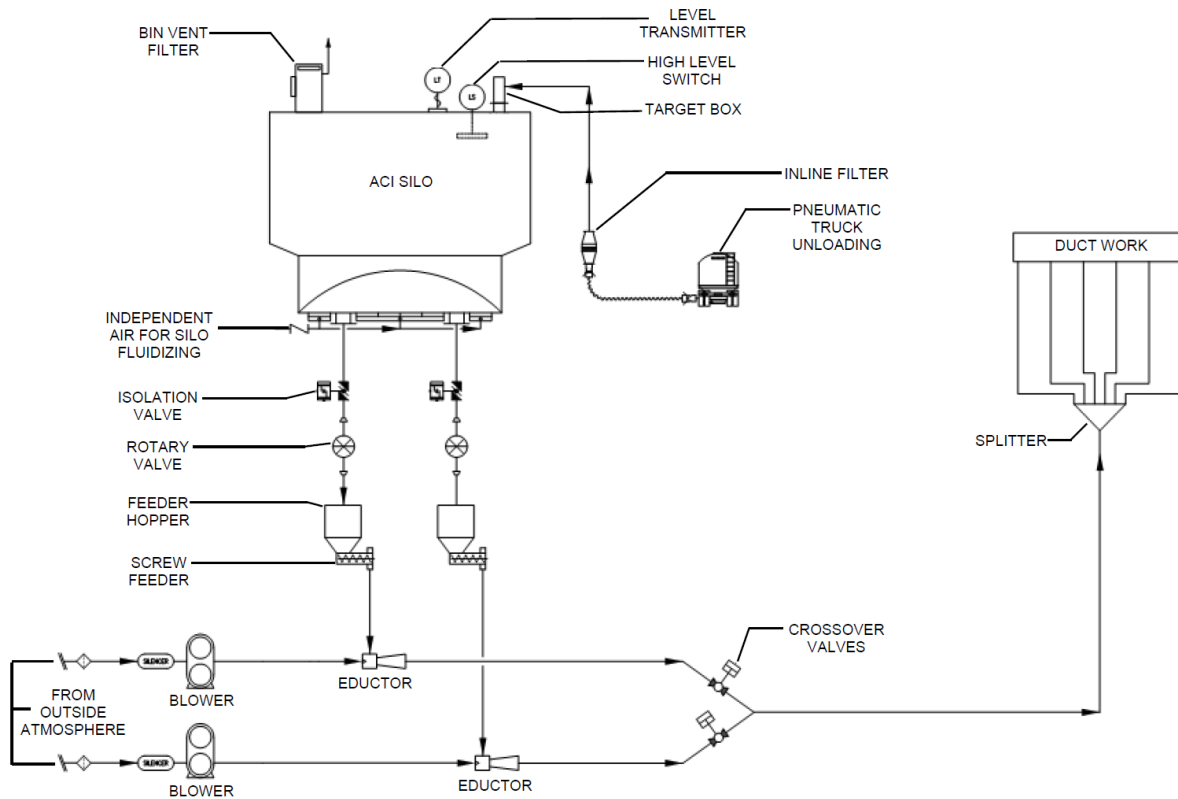
Compressed air is delivered to the fluidizing stones located in the chisel bottom of the silo. The fluidizing of the material in conjunction with the 60-degree silo cone promotes mass flow of the sorbent out of the silo.

The fluidized carbon is then transferred from the silo by a rotary valve into the feeder hopper where it is temporarily stored until conveyed by the screw feeder into the drop tube. The speed of the screw feeder determines the feed rate into the drop tube. Carbon is fed through the drop tube directly into the eductor suction port.

Motive air, provided by low-pressure blowers and fed into the eductors, produces a vacuum at the suction port. This helps draw the carbon and air into the mixing zone directly downstream of the eductor discharge. The carbon is transported through the piping system and is distributed to an array of injection lances specifically designed to disperse the carbon across the cross section of the flue gas ductwork.

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Exhibit 5-7. Typical ACI injection process flow diagram



Used with permission from UCC

Material fed from the storage silo typically discharges into one conveying line. The discharge of material is aided by the silo fluidizing system. Each silo discharge line has a carbon steel weigh hopper equipped with load cells. The weigh hopper is vented via a small bin vent filter located on the weigh hopper. The material is metered from the weigh hopper using a screw feeder.

The silo fluidizing systems promotes constant fluid flow to the silo outlet by introducing air through a porous media. Cloth media is in trays on the silo floor and around the outlets.

The pressure blower provides an air stream for conveying carbon from the storage silo to a splitter and lances for duct injection. Two 100 percent blowers are provided in a typical system for redundancy. Pressure blowers are on non-elevated common bases, and come complete with a v-belt motor, inlet filter, inlet and discharge silencers, discharge check valve, discharge relief valve, discharge pressure gauge, and pressure transmitter.

The conveying lines are mild steel and are provided with a combination of flange and groove-less Victaulic couplings. The conveying line after the splitter is made of a gum rubber material handling hose designed for abrasion resistance.

The ACI system is typically monitored and controlled by the DCS. The feed rate of the system can be adjusted in the following ways:

- Flat Rate (one continuous rate)

- Boiler Load Following (varies feed rate proportional to boiler load)
- Flue Gas Following (varies feed rate proportional to flue gas flow)
- Mercury Emission Following (varies feed rate to keep the Hg emission concentration below a given set point)

5.2.7 Flue Gas Desulfurization

The FGD system is a wet limestone forced oxidation positive pressure absorber non-reheat unit, with wet-stack, and gypsum production. The function of the FGD system is to scrub the boiler exhaust gases to remove the SO₂ prior to release to the environment. In all cases, the sulfur removal efficiency is 98 percent and HCl removal rate is 99 percent in the FGD unit. To minimize the required capacity and cost of specialized FGD wastewater treatment equipment, the FGD system will be designed with materials capable of handling up to 20,000 ppm of chlorides.

While the FGD system in this study produces gypsum suitable for wallboard production, changes in coal or limestone characteristics or modifications to the FGD system or dewatering system could impact the gypsum composition. Exhibit 5-8 provides the specification limits for gypsum used in wallboard and cement production, as well as typical characteristics of landfilled gypsum. The cases in this study do not consider a sale credit or a waste disposal cost for gypsum.

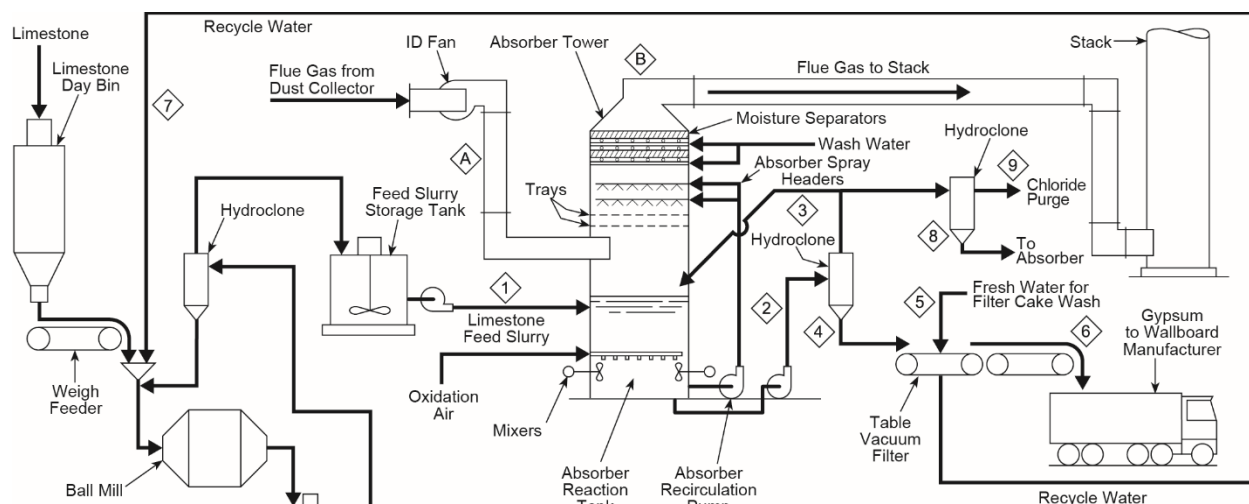
Exhibit 5-8. Typical disposal- and commercial-grade gypsum characteristics and limits

End Use	Disposal*	Wallboard	Cement
Moisture, % max	<20	<10	<14
CaSO ₄ •2H ₂ O, % min	80–95+	>95	85–88
CaSO ₃ •½H ₂ O, % max	<1–2+	0.5–1.0	
SiO ₂ , % max	<1–3+	1.0	2.0
Fe ₂ O ₃ , % max		1.5	1.0
Al ₂ O ₃ , % max			1.0
Fly ash, % max	<1–3+	1.0	
Total insolubles, % max	<5–20+	3.5	<15
Water soluble Cl ⁻ , ppm max	2,000–50,000	100–120	50,000
Total dissolved solids, ppm max	5,000–150,000	600	
Mean particle size, µm	<20–90+	20–75	

* Disposal gypsum characteristics are based on a range of potential limestone supplies

The scope of the FGD system is from the outlet of the ID fans to the stack inlet. Exhibit 5-9 provides a process flow diagram of a typical wet limestone forced oxidation positive pressure absorber non-reheat FGD system. [76] The descriptions in Section 5.2.7.1 through Section 5.2.7.5 align with this diagram.

Exhibit 5-9. WFGD process flow diagram



Used with permission from The Babcock & Wilcox Company

5.2.7.1 Limestone Handling and Reagent Preparation System

The function of the limestone reagent preparation system is to grind and slurry the limestone delivered to the plant. The scope of the system is from the day bin up to the limestone feed system. The system is designed to support continuous base load operation.

5.2.7.1.1 Operation Description

Each day bin supplies a 100 percent capacity ball mill via a weigh feeder. The wet ball mill accepts the limestone and grinds the limestone to 90 to 95 percent passing 325 mesh (44 microns). Water is added at the inlet to the ball mill to create limestone slurry. The reduced limestone slurry is then discharged into a mill product tank. Mill recycle pumps, two per tank, pump the limestone water slurry to an assembly of hydrocyclones and distribution boxes. The slurry is classified into several streams, based on suspended solids content and size distribution.

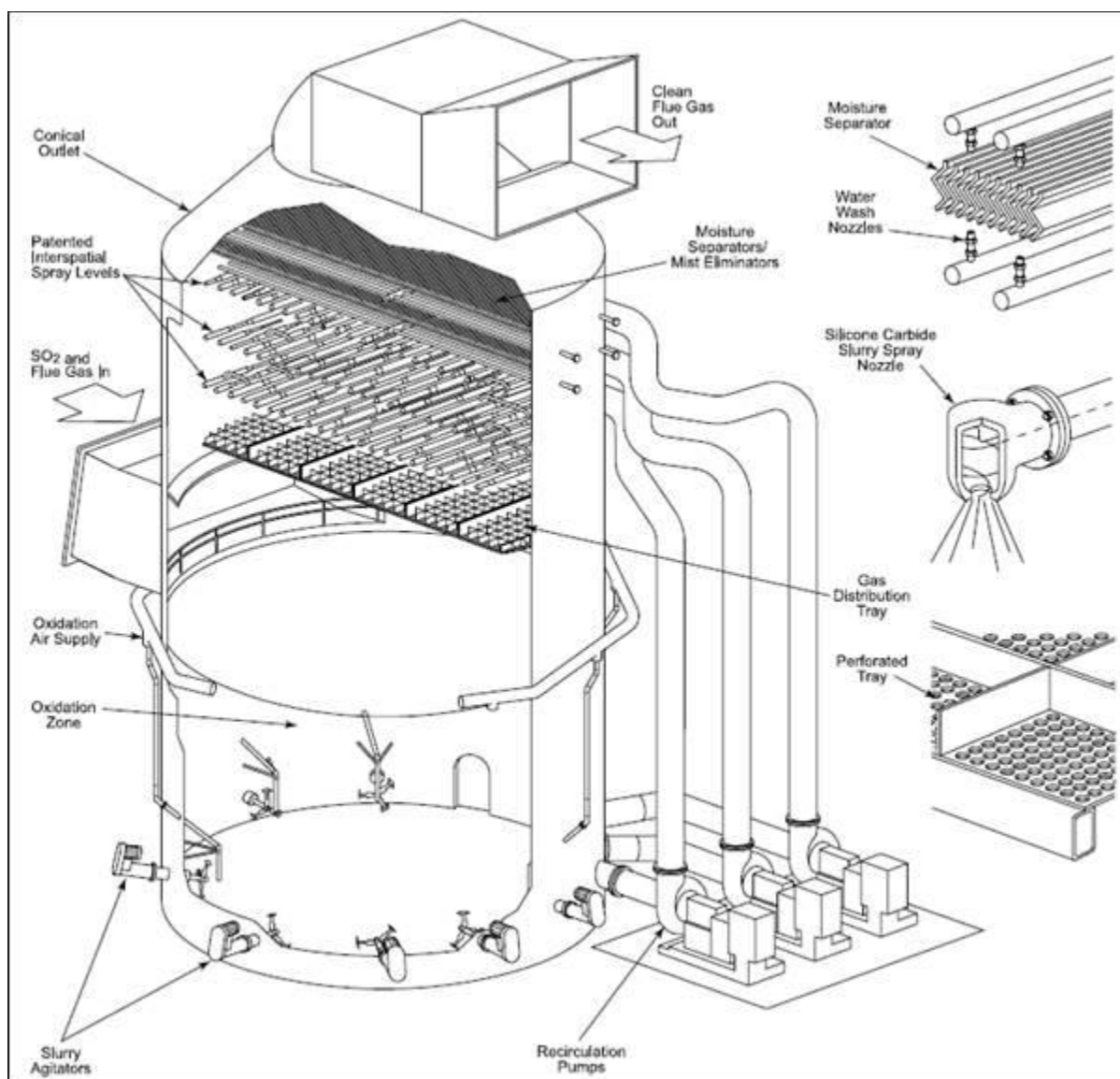
The hydrocyclone underflow with oversized limestone is directed back to the mill for further grinding. The hydrocyclone overflow with correctly sized limestone is routed to a feed slurry storage tank. Reagent distribution pumps direct slurry from the tank to the absorber module.

5.2.7.2 FGD Scrubber

The description of the FGD scrubber vessel follows Exhibit 5-9. Additional detail for the absorber vessel cross section is presented in Exhibit 5-10 for reference. [76]

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Exhibit 5-10. Cross section of the WFGD absorber vessel



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Upon entering the bottom of the absorber vessel, the gas stream is subjected to an initial quenching spray of reagent. The gas flows upward through the spray zone, which provides enhanced contact between gas and reagent. Multiple spray elevations with header piping and nozzles maintain a consistent reagent concentration in the spray zone. Continuing upward, the reagent-laden gas passes through several levels of moisture separators. These consist of chevron-shaped vanes that direct the gas flow through several abrupt changes in direction, separating the entrained droplets of liquid by inertial effects. The scrubbed flue gas exits at the top of the absorber vessel and is routed to the plant stack.

The scrubbing slurry falls to the lower portion of the absorber vessel, which contains a large inventory of liquid. Oxidation air is added to promote the oxidation of calcium sulfite contained in the slurry to calcium sulfate (gypsum). Multiple agitators (mixers) operate continuously to

prevent settling of solids and enhance mixture of the oxidation air and the slurry. Recirculation pumps recirculate the slurry from the lower portion of the absorber vessel to the spray level. Spare recirculation pumps are provided to ensure availability of the absorber.

The absorber chemical equilibrium is maintained by continuous makeup of fresh reagent, and blowdown of byproduct solids via the bleed pumps (not labeled in Exhibit 5-9). A spare bleed pump is provided to ensure availability of the absorber. The byproduct solids are routed to the byproduct dewatering system. The circulating slurry is monitored for pH and density.

Scrubber bypass or reheat, which may be utilized at some older facilities to ensure the exhaust gas temperature is above the saturation temperature, is not employed in this reference plant design because new scrubbers have improved mist eliminator efficiency, and detailed flow modeling of the flue interior enables the placement of gutters and drains to intercept moisture that may be present and convey it to a drain. Consequently, raising the exhaust gas temperature above the full load FGD discharge temperature of 57°C (135°F) is not necessary. At very low loads, the FGD discharge temperature was assumed to gradually decrease to 54°C (130°F) due to changes in the flue gas composition (i.e., higher O₂ content as load is decreased.).

5.2.7.3 Byproduct Dewatering

The function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is gypsum dewatering producing wallboard grade gypsum. The scope of the system is from the bleed pump discharge connections to the gypsum storage pile.

5.2.7.3.1 Operation Description

The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids on a continuous basis as byproducts from the SO₂ absorption process. Maintenance of the quality of the recirculating slurry requires that a portion be withdrawn and replaced by fresh reagent. This is accomplished on a continuous basis by the bleed pumps pulling off byproduct solids and the reagent distribution pumps supplying fresh reagent to the absorber.

Gypsum (calcium sulfate) is produced by the injection of oxygen into the calcium sulfite produced in the absorber tower sump. The bleed from the absorber contains approximately 20 wt% gypsum. The absorber slurry is pumped by an absorber bleed pump to a primary dewatering hydrocyclone cluster. The primary hydrocyclone performs two process functions. The first function is to dewater the slurry from 20 wt% to 50 wt% solids. The second function of the primary hydrocyclone is to perform a CaCO₃ and CaSO₄•2H₂O separation. This process ensures an overall limestone stoichiometry of 1.03. This system reduces the overall operating cost of the FGD system. The underflow from the hydrocyclone flows into the filter feed tank (not shown in Exhibit 5-9), from which it is pumped to a horizontal belt vacuum filter (represented as a table vacuum filter in Exhibit 5-9). Two 100 percent filter systems are provided for redundant capacity.

5.2.7.4 Hydrocyclones

The hydrocyclone is a simple and reliable device (no moving parts) designed to increase the slurry concentration in one step to approximately 50 wt%. This high slurry concentration is necessary to optimize operation of the vacuum belt filter.

The hydrocyclone feed enters tangentially and experiences centrifugal motion so that the heavy particles move toward the wall and flow out the bottom. Some of the lighter particles collect at the center of the cyclone and flow out the top. The underflow is thus concentrated from 20 wt% at the feed to 50 wt%.

Multiple hydrocyclones are used to process the bleed stream from the absorber. The hydrocyclones are configured in a cluster with a common feed header. The system has two hydrocyclone clusters, each with five 15 cm (6 inch) diameter units. Four cyclones are used to continuously process the bleed stream at design conditions, and one cyclone is spare.

Cyclone overflow and underflow are collected in separate launders. The overflow from the hydrocyclones still contains about 5 wt% solids, consisting of gypsum, fly ash, and limestone residues and is sent back to the absorber.

The remainder of the overflow is fed to a secondary hydrocyclone, where the resulting underflow is returned to the absorber and the overflow is blown down to the process water treatment system, for chloride control (represented as chloride purge in Exhibit 5-9). The flow to the secondary hydrocyclones is controlled to maintain a chloride concentration of 20,000 ppmw in the blowdown.

The underflow of the primary hydrocyclones flows into the filter feed tank from where it is pumped to the horizontal belt vacuum filters.

5.2.7.5 Horizontal Vacuum Belt Filters

The secondary dewatering system consists of horizontal vacuum belt filters. The pre-concentrated gypsum slurry (50 wt%) is pumped to an overflow pan through which the slurry flows onto the vacuum belt. As the vacuum is pulled, a layer of cake is formed. The cake is dewatered to approximately 90 wt% solids as the belt travels to the discharge. At the discharge end of the filter, the filter cloth is turned over a roller where the solids are dislodged from the filter cloth. This cake falls through a chute onto the pile prior to the final byproduct uses. The required vacuum is provided by a vacuum pump. The filtrate is collected in a filtrate tank that provides surge volume for use of the filtrate in grinding the limestone. Filtrate that is not used for limestone slurry preparation is returned to the absorber.

5.2.7.6 FGD Wastewater Quality

The blowdown stream from the FGD must be treated under the ELG regulations, as stated in Section 4.4.2. The design wastewater composition for the FGD blowdown considered is provided in Exhibit 5-11. The design water quality is based on a survey of plants burning bituminous, high sulfur coal [77] [78] and on internal information from Black & Veatch projects. Exhibit 5-11 includes a range of values, an average, and the final selected composition.

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Exhibit 5-11. FGD wastewater quality

Parameter	FGD Wastewater (Range)	FGD Wastewater (Average)	FGD Wastewater (Final)
pH	5.5–7.4	6.6	7.2
Chemical oxygen demand, ppm	304–1,060	682	350
Biological oxygen demand, ppm	21–1,370	422	500
Specific Conductance, $\mu\text{S}/\text{cm}$	5,990–32,000	9,595	32,000
Ammonia as N, ppm	1.5–31.5	8.4	10
Suspended Solids, ppm	4,970–25,300	13,888	15,000
Total Dissolved Solids, ppm	4,740–44,600	21,310	43,494
Chloride as Cl, ppm	832–28,800	9,966	20,000
Sulfate as SO_4 , ppm	1,290–11,900	4,212	7,600
Calcium as Ca, ppm	751–5,370	2,791	5,370
Magnesium as Mg, ppm	176–7,000	2,728	6,000
Sodium as Na, ppm	59–5,340	998	2900
Boron (total), ppm	3.0–626	220	430
Potassium as K, ppm	35–684	226	250
M-Alkalinity as CaCO_3 , ppm ^A	131–625	275	200
Iron (total), ppm	3.4–824	200	290
Aluminum (total), ppm	1.0–289	93	150
Silica as SiO_2 , ppm	1–91	33	100
Manganese (total), ppm	1.58–225	32.1	60
Nitrate/Nitrite as N, ppm	1.0–54.5	20.5	30
Total Kjeldahl Nitrogen, ppm	6.2–51.6	19.2	20
Carbon, ppm			8
Phosphorus, ppm	0.05–10.5	4.61	7
Nickel (total), ppm	0.447–6.0	2.05	5
Selenium (total), ppm	0.651–8.66	2.75	5
Zinc (total), ppm	0.31–9.04	3.23	6
Barium (total), ppm	0.588–11.900	3.330	5
Titanium (total), ppm	0.377–8.18	2.57	4
Vanadium (total), ppm	0.078–1.58	0.67	1.3
Fluorine, ppm			1
Arsenic (total), ppm	0.0599–3.000	0.799	1.4

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Parameter	FGD Wastewater (Range)	FGD Wastewater (Average)	FGD Wastewater (Final)
Copper (total), ppm	0.0376–2.130	0.788	1.4
Lead (total), ppm	0.0312–4.000	0.896	1.3
Molybdenum (total), ppm	0.065–1.340	0.59	0.9
Mercury (total), ppm	0.0164–1.070	0.255	0.7
Chromium, ppm	0.176–1.380	0.777	1
Cobalt, ppm			0.1
Lithium, ppm			0.1
Beryllium (total), ppm	0.0036–3.000	0.438	0.140
Cadmium (total), ppm	0.00484–0.238	0.0728	0.140
Thallium (total), ppm	0.00633–0.300	0.0864	0.140
Antimony (total), ppm	0.00923–0.0518	0.0269	0.040
Uranium, ppm			0.03
Thorium, ppm			0.02
Tin, ppm			0.01

^AAlkalinity is reported as CaCO₃ equivalent, rather than the concentration of HCO₃. The concentration of HCO₃ can be obtained by dividing the alkalinity by 0.82

The FGD blowdown wastewater composition will be dependent on several factors, including composition of the coal, makeup water quality, flue gas treatment systems upstream of the FGD, plant operation (e.g., transient or part-load) and other factors. The wastewater quality defined above will form the basis for discussion of the Spray Dryer Evaporator system, discussed in Section 5.2.8.

5.2.8 Process Water Systems

5.2.8.1 Process Water Sources

As discussed in Section 4.4.2, the only system producing a wastewater stream that must be treated for compliance with the ELGs is the FGD system. A detailed process description of the FGD system is provided in Section 5.2.7.

Miscellaneous process wastewater treatment for non ELG compliance streams is described in Section 5.2.8.2.3.

5.2.8.2 Process Water Treatment

The updated ELG established FGD wastewater as a new category, with discharge limits that must be met. The FGD wastewater is sourced from the overflow of the secondary hydrocyclone, as described in Section 5.2.7.3, with a composition described in Section 5.2.7.6.

A variety of technologies are currently installed at PC plants to treat FGD wastewater, including surface impoundments, chemical precipitation, biological treatment, zero liquid discharge (ZLD) operating practices, evaporation ponds, and constructed wetlands. Approximately 37 percent of PC plants currently utilize ZLD operating practices. [79] [77]

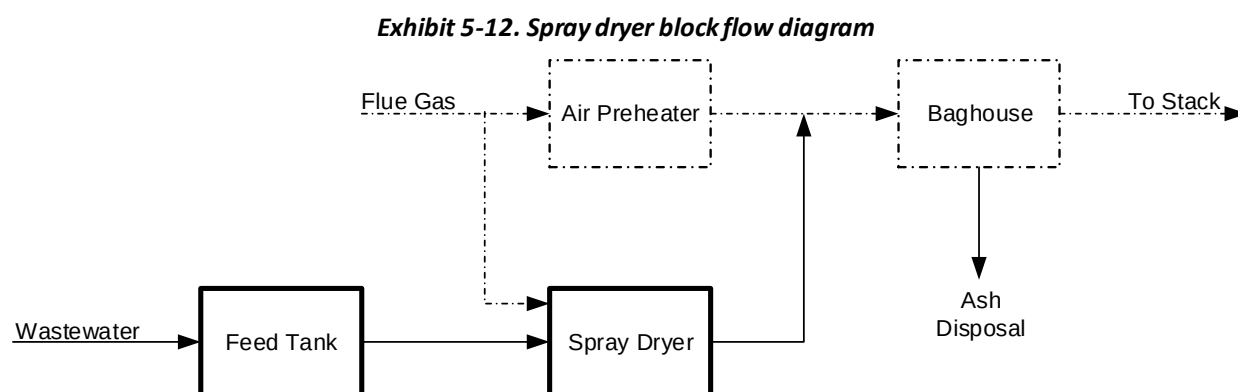
While multiple process configurations were assessed for feasibility of complying with the ELG, given this study's intention of maintaining general applicability of the cases presented, and the prevalence of utilizing ZLD operating practices in existing PC plants, systems that would enable ZLD were selected in all cases, specifically a spray dryer evaporator.

5.2.8.2.1 Spray Dryer Evaporator

A spray dryer is a technology commonly used in the power industry for flue gas desulfurization, which can also be applied as a thermal evaporation process to treat wastewater. A spray dryer evaporator was constructed and is currently operating at Kansas City Power & Light's Iatan Plant Unit 2. Operation of the spray dryer evaporator has been described as straightforward, with periodic maintenance performed. [80] The feasibility of using a spray dryer evaporator as the sole treatment system in PC cases is limited by the flowrate of wastewater, as the cost and performance impact of the spray dryer increases with increasing wastewater flowrate. Typically, a spray dryer for FGD wastewater is limited to approximately 150–200 gpm, depending on the flue gas conditions. As the system is designed based on flow rate, the solids concentration of the FGD wastewater does not impact the sizing of the system.

Spray dryers typically require a flue gas temperature above 600°F. A slipstream of flue gas is taken upstream of the air preheater for use as the heat source to evaporate the wastewater, which is sprayed into a tall cylindrical vessel using rotary atomizers. The heat from the slipstream is used to evaporate the wastewater, which contains dissolved and suspended solids, to produce a humidified gas stream containing additional suspended particulates. The humidified gas stream is returned downstream of the air preheater and the combined flue gas passes through a baghouse, which removes most of the suspended solids.

Exhibit 5-12 provides a simplified block flow diagram of the spray dryer evaporation process.



The atomizers and size of the spray dryer vessel are designed so that the wastewater mist droplets are evaporated before reaching the vessel wall. Therefore, the vessel is constructed of carbon steel without concerns for corrosion. However, the wall must be monitored to ensure

there is no temperature drop, which is an indication that moisture is reaching the wall and can cause corrosion issues.

5.2.8.2.2 Alternative Treatment Methods

There are several alternative treatment options for compliance with the ELG regulations, spanning a range of technology maturation on a technology readiness scale. Of the more mature routes, deep-well injection and evaporation ponds were also considered.

Deep-well injection is a proven technology in municipal and industrial applications that discharges wastewater under pressure into underground porous rock formations through Class 1 wells. Strata of impermeable rock are used to protect underground sources of drinking water from the injected wastewater. A survey of the local geology is, therefore, required to determine the depth to which the well must be drilled and ultimately operated. Capital cost for the equipment and the electrical power consumed by the system would depend on the depth of the well. Disposal of wastewater by this method is regulated and requires that the facility apply for and receive a permit.

Based on the potentially adverse impacts to surface water and groundwater, geological and legal restrictions, and increasing disposal costs, deep well injection was excluded from further evaluation as a viable treatment option in this study.

Evaporation ponds can be constructed to dispose of wastewater if sufficient plot space is available, which is greatly impacted by local ambient conditions. A key determining factor in assessing the viability of an evaporation pond at a specific location is the difference between average rainfall and average evaporation at that location, as the pond needs to be large enough to contain the volume of the discharged wastewater, as well as rain water. In addition, the pond must have enough surface area to allow for average evaporation rates to be equal to or greater than the total inflow of water.

Parts of the Midwest region could be considered a cold, semi-arid climate, which indicates that the summers can be either warm or hot, but the winters tend to be colder, compared to hot, semi-arid or hot, arid climates. Therefore, winter evaporation would be less available. Moreover, other parts of the Midwest region fall into humid, subtropical and humid, continental climate types. The humidity and higher rainfall averages compared to the arid climates are not favorable for the installation of evaporation ponds. Therefore, evaporation ponds were excluded from further evaluation as a viable treatment option in this study.

While both evaporating ponds and deep-well injection offer low-cost solutions with low auxiliary loads, neither option addresses water consumption, and in many regions of the country the availability of fresh water is limited—therefore, it is desirable to restrict the consumption of, and discharge into the available fresh water. By recycling what would otherwise be water discharge, the amount of water withdrawal required can be reduced considerably.

5.2.8.2.3 Wastewater Treatment

An onsite wastewater treatment facility treats all runoff, cleaning wastes, and backwash. It is anticipated that the treated water will be suitable for discharge into existing systems and be within EPA standards for suspended solids, oil and grease, pH, and miscellaneous metals.

The wastewater treatment system is minimal and consists, primarily, of neutralization and oil/water separators (along with the associated pumps, piping, etc.).

5.2.9 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing of the fly ash and bottom ash produced on a daily basis by the boiler, along with the hydrated lime and activated carbon injected for mercury control (discussed in Section 5.2.6), and dissolved solids from the spray dryer evaporator that are disposed of with the fly ash (discussed in Section 5.2.8.2.1). The scope of the system is from the baghouse hoppers, air heater and economizer hopper collectors, and bottom ash hoppers to the separate bottom ash/fly ash storage silos and truck filling stations. The system is designed to support short-term operation at the 5 percent OP/VWO condition (16 hours) and long-term operation at the 100 percent guarantee point (90 days or more).

The fly ash collected in the baghouse and the air heaters is conveyed to the fly ash storage silo. A pneumatic transport system using LP air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The bottom ash from the boiler is fed into a series of dry storage hoppers, each equipped with a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. Accumulated bottom ash discharged from the hoppers passes through the clinker grinder, then to a screw feeder and finally to a pneumatic ash conveying system for transport to the bottom ash silos, before being transferred to trucks for offsite disposal.

Ash from the economizer hoppers is pneumatically conveyed to the fly ash storage silos and pyrites (rejected from the coal pulverizers) are conveyed using water on a periodic basis to the dewatering system (i.e., dewatering bins) for offsite removal by truck.

The wet sluicing for the pyrite system is not an explicit requirement of the NFPA, but it is viewed as a risk mitigation measure to avoid accidental ignition of combustible materials clinging to the mill rejects. This can also come into effect when a mill trips and the solids contained therein need to be safely removed from the mills. Wet sluicing of the mill rejects further reduces potential ignition of this coal that is being swept from the mills. The water used for wet sluicing is regarded as low volume waste water, which is not specifically regulated under the ELG guidelines, and is assumed to be treated for the pyrites within the plant's standard low volume waste water treatment facility.

5.2.10 Power Generation

The steam turbine is designed for long-term operation (90 days or more) at maximum continuous rating with throttle control valves 95 percent open. It is also capable of a short-term operation at 5 percent OP/VWO condition (16 hours).

For the subcritical cases, the steam turbine is a tandem compound type, consisting of HP-IP-two LP (double flow) sections enclosed in three casings, designed for condensing single reheat operation, and equipped with non-automatic extractions and four-flow exhaust. The turbine drives a hydrogen-cooled generator. The turbine has emergency DC motor-operated lube oil pumps, and main lube oil pumps, which are driven off the turbine shaft. [81] The exhaust pressure is 76.2 mm (3 in) Hg in the single pressure condenser. There are seven extraction points. The condenser is two-shell, transverse, single pressure with divided waterbox for each shell.

The steam-turbine generator systems for the supercritical plants are similar in design to the subcritical systems. The differences include steam cycle conditions and steam extractions points. The subcritical design has seven steam extraction points, whereas the supercritical plant has eight extraction points.

Turbine bearings are lubricated by a closed waterloop, which is air-cooled, pressurized oil system. Turbine shafts are sealed against air in-leakage or steam blowout using a labyrinth gland arrangement connected to a LP steam seal system. The generator stator is cooled with a CL water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters, and deionizers, all skid-mounted. The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft.

5.2.10.1.1 Operation Description

The turbine stop valves, control valves, reheat stop valves, and intercept valves are controlled by an electro-hydraulic control system. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at the conditions provided in Exhibit 5-13.

Exhibit 5-13. Steam conditions

Steam Conditions				
Steam Parameter	Subcritical		Supercritical	
	Baseload	Flexible	Baseload	Flexible
Main Pressure, MPa (psig)	12.4 (1,800)	12.4 (1,800)	24.1 (3,500)	24.1 (3,500)
Main Temperature, °C (°F)	538 (1,000)	538 (1,000)	593 (1,100)	593 (1,100)
Reheat Temperature, °C (°F)	538 (1,000)	538 (1,000)	593 (1,100)	593 (1,100)

The steam initially enters the turbine near the inlet of the HP turbine section, flows through the turbine, and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at the conditions provided in Exhibit 5-13. After passing through the IP section, the steam enters a crossover pipe, which transports the

steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser. The last stages of the LP sections operate as condensing turbines with a full load exhaust moisture content ranging from 5.0 percent to 7.5 percent (modern units can typically tolerate up to 12 percent moisture).

For a constant pressure design (as in B11A-F0) the turbine is designed to operate at constant inlet steam pressure over the entire load range. A sliding pressure design (as in B12A-F0 and all flexible cases) allows the inlet steam pressure to reduce during part load operation.

5.2.11 Energy Storage

This study does not include the integration of energy storage in any of the plant configurations.

5.2.12 Cooling System

An ACC uses forced-draft convective cooling to cool the LP exhaust steam back to condensate, representing the thermodynamic “bottom” of the Rankine cycle. For the “A-frame” ACC structure, the LP exhaust steam naturally rises through the top pipe of the ACC A-frame. The LP steam is then circulated through the tube bundles where it is cooled and condensed. The condensate is collected at the bottom legs of the A-frame and routed to the inlet of the condensate pumps. The convective cooling within the ACC is produced by large diameter (typically around 30-38 ft) fans that draw in ambient air through the base of the ACC structure. This forced-draft ambient air is then discharged to atmosphere directly above the ACC with wind screens and baffles in place to prevent recirculation of the heated air.

The ACC units are typically shown elevated off the ground by 30–58+ ft in order to provide unrestricted air flow to the fans and to prevent personnel safety issues due to induced suction into the fans if placed too close to the ground. The multiple circuits (i.e., steam pipes on top of the ACC units) are designed to allow for even distribution of the LP steam across the various tube bundle circuits.

An operational advantage of the ACC is the various cells (i.e., fans) can be controlled independently to modulate ACC auxiliary power consumption based on ambient conditions. When ambient temperatures are low fewer fans are needed to induce cooling of the tube circuits. Higher ambient temperatures require additional fans to be in service to ensure the necessary cooling duty is achieved. The operation of the ACC cell fans is typically automated within the plant DCS; the ACC internal steam pressure is the typical control signal for the number of fans in operation and the operating duty of each fan.

One maintenance-related item specific to ACC units is the susceptibility to exterior macro-fouling under site-specific conditions. The most commonly experienced macro-fouling of ACC units is attributable to local vegetation sources (e.g., soft/light cottonwood seeds) and/or refuse sources (e.g., excess of paper refuse circulating in the air). It can be noted that this macro-fouling is typically mitigated by seasonal water washing of the exterior heat transfer surfaces.

5.2.13 Balance of Plant

The balance of plant components consists of the accessory electric plant, ducting and stack, buildings and structures, instrumentation and control, and miscellaneous systems as described below.

5.2.13.1 Accessory Electric Plant

The accessory electric plant consists of switchgear and control equipment, emergency generator equipment (single fuel: natural gas), station service equipment, conduit and cable trays, and wire and cable. It also includes the main power transformer, required foundations, and standby equipment.

5.2.13.2 Ducting and Stack

One stack is provided with a single fiberglass-reinforced plastic (FRP) liner. The stack is constructed of reinforced concrete. The stack is 122 m (400 ft) high for adequate particulate dispersion.

5.2.13.3 Buildings and Structures

Foundations are provided for the support structures, pumps, tanks, and other plant components. The following buildings are included in the design basis:

- Steam turbine building
- Boiler building
- Administration and service building
- Makeup water and pretreatment building
- Coal crusher building
- Continuous emissions monitoring building
- Pump house and electrical equipment building
- Guard house
- Runoff water pump house
- Industrial waste treatment building
- FGD system building

5.2.13.4 Instrumentation and Control

An integrated plant-wide control and monitoring DCS is provided. The DCS is a redundant microprocessor-based, functionally distributed system. The control room houses an array of multiple video monitor and keyboard units. The monitor and keyboard units are the primary interface between the generating process and operations personnel. The DCS incorporates plant monitoring and control functions for all the major plant equipment. The DCS is designed to provide 99.5 percent availability. The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100 percent. Startup and shutdown routines are implemented as supervised manual procedures, with operator selection of modular automation routines available.

5.2.13.4.1 State-of-the-Art Sensors and Controls

With the evolving operating portfolios demanded from traditional generation assets, the means of controlling and monitoring generation assets has evolved. Installing advanced instrumentation and control systems can increase efficiency and flexibility, giving faster ramp rates and lower minimum loads. Modern control systems allow for better management of turbine temperatures and clearances, whole-plant self-learning predictive systems, and combined operation of multiple units. [25] It would be expected that flexible (high cycling) plants would implement a majority of the state-of-the-art sensors and controls schemes outlined in the list below. Based on Black & Veatch experience, baseload units would be expected to implement a significantly smaller number of the options listed below, with the most likely feature being online performance monitoring, but to lesser degree of sophistication than a higher cycling plant. Outlined below are examples of established mechanisms by which state-of-the-art controls are improving the performance optimization of coal-fired units:

- Implementation of artificial intelligence, machine learning, and/or neural networks (sometimes referred to as online performance monitoring and optimization) to collect, process, and analyze data to identify sub-optimal trends in sub-process performance; additional benefits of online performance monitoring and diagnostics include:
 - Providing a proactive versus reactive methodology to facility maintenance
 - Increasing reliability/availability with early detection and resolution of equipment issues
 - Creating a critical “team link” between operations personnel, maintenance personnel, information technology personnel, and plant management
 - Rapidly identifying and returning lost capacity margins
- Online boiler optimization through real-time combustion air balancing/tuning via flow meters installed in burner air annulus
- Real-time, fully automated coal sampling and chemical analysis; typically, applicable to units that blend coal supplies to reach target constituent (e.g., ash, moisture, chlorine) levels during different operating periods
- Intelligent soot blowing (e.g., acoustical pyrometers and strain gauges on boiler stringer rods)
- Application of state-of-the-art condensate, feedwater, circulating water online chemistry analyzers, including automated dosing and automatic chemistry data trending to rapidly identify non-compliant process chemistry conditions, and water chemistry exceedances and malalignment would be coded in the DCS as priority alarms to the control room
- Prioritization of combustion and air quality control system tuning over a range of unit conditions as opposed to just at a design operating point (i.e., gain scheduling) [15]
- Working closely with plant control engineers to continually check and validate the dead band and compression settings for the plant’s data historian; sub-optimal dead band and

compression settings can cause adverse control parameter swings, system over-corrections, and destabilization (i.e., control system hysteresis)

Implementation of these and other control system improvements and updates has been demonstrated to improve stable minimum load (e.g., 40 percent for some baseload coal-fired plants, based on Black & Veatch experience with similar PC plants), in addition to providing more advanced process control capability to manage reagent process flow and achieve target oxides of sulfur removal for a variety of conditions. [15] Modern control systems allow for better management of turbine temperatures and clearances, whole-plant self-learning predictive systems, and combined/coordinated operation of multiple units. [25]

5.2.13.5 *Miscellaneous Systems*

Miscellaneous systems consisting of service air, instrument air, and service water are provided. The start-up fuel for the boiler and fuel for the reciprocating engine generator is assumed to be natural gas. Fuel for the auxiliary boiler in cases B11A-F1, B11A-F2, B12A-F1, and B12A-F2 is also assumed to be natural gas. Cases B11A-F3, B11A-F4, B12A-F3, and B12A-F4 utilize an electrode auxiliary boiler. All truck roadways and unloading stations inside the fence area are provided. The miscellaneous cooling loads are served by independent, industrial scale electric-powered heat exchangers with fully enclosed air-to-glycol (45 percent solution of glycol and water) heat rejection circuits. The majority of the plant building lighting would be expected to be light-emitting diode elements due their energy efficiency. The types of flow-measuring instruments utilized throughout the plant would vary depending on the system measured (i.e., air, water, steam, etc.) but would be typically either a venturi, orifice or hot wire anemometer. All large motors and electrical enclosures would be expected to be fully air-cooled due to the plant size. The auxiliary, package-style boiler (or any onsite sparging steam supply source) would be sized appropriately to provide saturated steam during startup and shutdown periods. The actuation method (i.e., pneumatic actuation or electric actuation) for various sub-system control valves or dampers would depend on the duty of the control valve or damper; electric actuation provides precision, and pneumatic actuation provides speed and force.

5.3 SUBCRITICAL BASELOAD PLANT CASE

This section contains an evaluation of plant design for Case B11A-F0, which is based on a subcritical baseload PC plant with a nominal gross output of 150 MWe. The plant uses a single reheat 12.4 MPa/538°C/538°C (1,800 psia/1,000°F/1,000°F) cycle.

The balance of this section is organized as follows:

- Key Assumptions is a summary of study and modeling assumptions relevant to Case B11A-F0.
- Sparing Philosophy is provided for Case B11A-F0.
- Process Description provides an overview of the technology operation as applied to Case B11A-F0. The systems that are common to all PC cases were covered in Section 5.2 and only features that are unique to Case B11A-F0 are discussed further in this section.

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- Performance Results provides the main modeling results from Case B11A-F0, including the full load performance summary, part load performance summary, environmental performance, carbon/sulfur balances, water balance, energy and mass balance diagrams and energy balance table.
- Major Equipment List provides an itemized list of major equipment for Case B11A-F0 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case B11A-F0.
- Impact of Plant Capacity on Configuration, Performance, and Cost provides a comparison between Case B11A-F0 (150 MW_{gross}) and Case B11A (687 MW_{gross}) from the Bituminous Baseline. [63]

5.3.1 Key System Assumptions

System assumptions for Case B11A-F0 compiled in Exhibit 5-14. Some of these parameters vary as the plant reduces load. For the values of process parameters that vary with load, refer to the Case B11A-F0 performance curves in Appendix A.1.

Exhibit 5-14. Subcritical baseload PC plant study configuration matrix

Parameter	Case B11A-F0
Steam Cycle, MPa/°C/°C (psia/°F/°F)	12.4/538/538 (1,800/1,000/1,000)
Steam Turbine	Constant-Pressure Main Steam, Triple-Pressure (HP/IP/LP), Single-Reheat, Single-Shaft, Condensing
Coal	Illinois No. 6
Condenser Type	Air Cooled
Condenser Pressure, mm Hg (in. Hg)	76.2 (3)
Auxiliary Cooling	Ancillary Air-to-Glycol Cooling Loops
Feedwater Pump	Turbine-Driven
Fan Drives	Static Frequency
Boiler Efficiency, HHV %	87.5
Stack Temperature, °C (°F)	57 (135)
SO ₂ Control	Wet Limestone Forced Oxidation
FGD Efficiency, % ^A	98
FGD Blowdown Treatment (ELGs)	Spray dryer evaporator
NO _x Control	LNB w/OFA, SCR
SCR Efficiency, % ^A	78.3
Ammonia Slip (end of catalyst life), ppmv	2
Particulate Control	Fabric Filter
Fabric Filter Efficiency, % ^A	99.9
Ash Distribution, Fly/Bottom	80%/20%
SO ₃ Control	DSI
Mercury Control	Co-benefit Capture and ACI

^ARemoval efficiencies are based on the flue gas content

5.3.1.1 Balance of Plant – Case B11A-F0

The balance of plant assumptions for Case B11A-F0 are presented in Exhibit 5-15.

Exhibit 5-15. Case B11A-F0 balance of plant assumptions

Parameter	Value
Cooling System	Air-Cooled Condenser
Fuel and Other Storage	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	30 days
Hydrated lime	7 days
Activated carbon	7 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	24,000 V
Grid Interconnection voltage	345 kV
Water and Waste Water	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and deionized water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day).
Water Discharge	Blowdown will be treated for chloride and metals and discharged to the spray dryer evaporator.

5.3.2 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC subcritical boiler (1 x 100%)

- Two SCR reactors (2 x 50%)
- One DSI system (1 x 100%)
- One ACI system (1 x 100%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)

5.3.3 Process Description

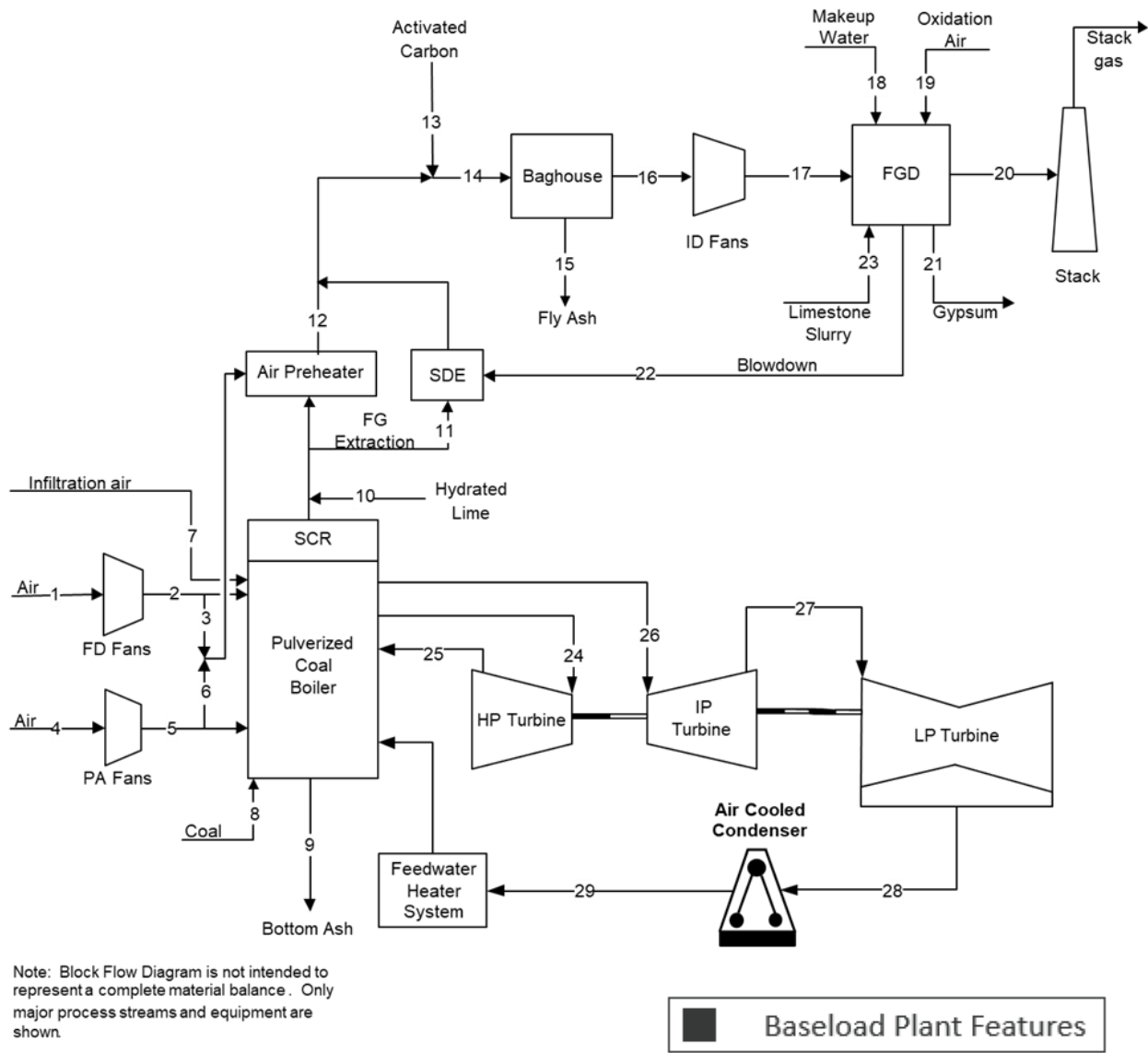
In this section the subcritical baseload PC process is described. The system description follows the block flow diagram (BFD) in Exhibit 5-16 and stream numbers reference the same exhibit. Exhibit 5-17 provides process data for the numbered streams in the BFD. Full stream tables are only provided for the 100 percent load point.

Coal (stream 8) and PA (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the OFA, is provided by the FD fans (stream 1). The boiler operates at a slight negative pressure so air leakage is into the boiler, and the infiltration air is accounted for in stream 7. Streams 3 and 6 show Ljungstrom air preheater leakages from the FD and PA fan outlet streams to the boiler exhaust.

Flue gas exits the boiler through the SCR reactor where ammonia is injected to reduce NO_x compounds, followed by hydrated lime injection (stream 10) for the reduction of SO₃. A small flue gas stream is extracted for use in the spray dryer evaporator (stream 11). The flue gas then passes through the combustion air preheater (where the air preheater leakages are introduced) and, at full load, is cooled to 143°C (289°F) (stream 12) before PAC is injected (stream 13) for mercury reduction. The flue gas then passes through a fabric filter for particulate removal (stream 16). At full load, an ID fan increases the flue gas temperature to 156°C (312°F) and provides the motive force for the flue gas (stream 17) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 18), oxidation air (stream 19), limestone slurry (stream 23) and product gypsum (stream 21). The clean, saturated flue gas exiting the FGD unit (stream 20) passes to the plant stack and is discharged to the atmosphere. The FGD blowdown (stream 22) is sent to the spray dryer evaporator where extracted flue gas (stream 11) is used to evaporate the FGD blowdown stream. The spray dryer evaporator outlet gas stream is recombined into the flue gas path after the air preheater, and before PAC injection.

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Exhibit 5-16. Case B11A-F0 block flow diagram, subcritical baseload unit



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-17. Case B11A-F0 stream table, subcritical baseload unit

	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	16,098	16,098	530	2,841	2,841	587	321	0	0	0
V-L Flowrate (kg/hr)	464,546	464,546	15,299	81,979	81,979	16,929	9,263	0	0	3
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	53,677	1,143	289
Temperature (°C)	15	21	21	15	23	23	15	15	1,316	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	36.30	36.30	30.23	38.73	38.73	30.23	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-91.51	-91.51	-97.58	-89.08	-89.08	-97.58	-2,119.02	1,312.68	-13,402.95
Density (kg/m ³)	1.2	1.3	1.3	1.2	1.3	1.3	1.2	---	---	1,003.6
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015
V-L Flowrate (lb _{mol} /hr)	35,490	35,490	1,169	6,263	6,263	1,293	708	0	0	0
V-L Flowrate (lb/hr)	1,024,148	1,024,148	33,728	180,732	180,732	37,323	20,422	0	0	6
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	118,337	2,521	638
Temperature (°F)	59	70	70	59	74	74	59	59	2,400	59
Pressure (psia)	14.7	15.6	15.6	14.7	16.0	16.0	14.7	14.7	14.3	14.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	15.6	15.6	13.0	16.7	16.7	13.0	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-39.3	-39.3	-42.0	-38.3	-38.3	-42.0	-911.0	564.3	-5,762.2
Density (lb/ft ³)	0.076	0.079	0.079	0.076	0.080	0.080	0.076	---	---	62.650

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-17. Case B11A-F0 stream table, subcritical baseload unit, cont'd

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction										
Ar	0.0087	0.0088	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081
CO ₂	0.1463	0.1379	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0889	0.0844	0.0000	0.0918	0.0000	0.0918	0.0918	0.9967	0.0099	0.1512
HCl	0.0001	0.0001	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
N ₂	0.7312	0.7336	0.0000	0.7277	0.0000	0.7277	0.7277	0.0000	0.7732	0.6801
O ₂	0.0226	0.0332	0.0000	0.0325	0.0000	0.0325	0.0325	0.0000	0.2074	0.0360
SO ₂	0.0021	0.0020	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.1148	0.0000	0.0000	0.0006	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0001	0.8852	0.0000	0.0000	0.0028	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	968	19,366	0	20,497	1	20,496	20,496	2,855	866	22,916
V-L Flowrate (kg/hr)	28,785	574,909	0	606,713	132	606,577	606,577	52,237	24,998	658,494
Solids Flowrate (kg/hr)	248	4,671	12	4,977	4,980	0	0	469	0	0
Temperature (°C)	384	143	15	143	143	143	156	27	15	57
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	---	---	289.08	302.74	---	30.23	297.86
AspenPlus Enthalpy (kJ/kg) ^B	-2,278.03	-2,399.41	-6.79	-2,459.22	-1,001.46	-2,471.50	-2,457.84	-15,764.00	-97.58	-2,944.15
Density (kg/m ³)	0.5	0.8	---	0.8	2,150.2	0.8	0.9	1,002.4	1.2	1.1
V-L Molecular Weight	29.738	29.687	---	29.600	104.953	29.596	29.596	18.297	28.857	28.735
V-L Flowrate (lb _{mol} /hr)	2,134	42,694	0	45,188	3	45,185	45,185	6,294	1,910	50,521
V-L Flowrate (lb/hr)	63,460	1,267,457	0	1,337,573	292	1,337,274	1,337,274	115,162	55,111	1,451,730
Solids Flowrate (lb/hr)	546	10,298	26	10,972	10,979	0	0	1,035	0	0
Temperature (°F)	724	289	59	289	289	289	312	80	59	135
Pressure (psia)	14.3	14.0	14.7	14.0	14.0	13.8	15.1	14.7	14.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	---	---	124.3	130.2	---	13.0	128.1
AspenPlus Enthalpy (Btu/lb) ^B	-979.4	-1,031.6	-2.9	-1,057.3	-430.5	-1,062.6	-1,056.7	-6,777.3	-42.0	-1,265.8
Density (lb/ft ³)	0.033	0.052	---	0.051	134.232	0.051	0.054	62.580	0.076	0.067

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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Exhibit 5-17. Case B11A-F0 stream table, subcritical baseload unit, cont'd

	21	22	23	24	25	26	27	28	29
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	49	163	673	24,433	22,588	22,588	20,372	16,723	20,669
V-L Flowrate (kg/hr)	878	3,019	12,133	440,175	406,920	406,920	367,008	301,268	372,356
Solids Flowrate (kg/hr)	7,895	46	5,194	0	0	0	0	0	0
Temperature (°C)	15	57	15	534	333	538	343	46	46
Pressure (MPa, abs)	0.10	0.10	0.10	12.13	2.97	2.68	0.71	0.01	1.53
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	3,437.77	3,074.24	3,544.72	3,148.87	2,445.48	195.06
AspenPlus Enthalpy (kJ/kg) ^B	-12,513.34	-15,495.45	-14,994.25	-12,542.52	-12,906.05	-12,435.57	-12,831.43	-13,534.82	-15,785.23
Density (kg/m ³)	880.9	979.4	1,003.7	35.5	11.3	7.3	2.5	0.1	990.3
V-L Molecular Weight	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	107	360	1,484	53,866	49,797	49,797	44,913	36,868	45,567
V-L Flowrate (lb/hr)	1,935	6,656	26,748	970,419	897,106	897,106	809,115	664,181	820,905
Solids Flowrate (lb/hr)	17,405	101	11,450	0	0	0	0	0	0
Temperature (°F)	59	135	59	994	631	1,000	650	115	115
Pressure (psia)	14.7	14.7	14.7	1,760.0	431.4	388.2	103.0	1.5	222.3
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	1,478.0	1,321.7	1,524.0	1,353.8	1,051.4	83.9
AspenPlus Enthalpy (Btu/lb) ^B	-5,379.8	-6,661.8	-6,446.4	-5,392.3	-5,548.6	-5,346.3	-5,516.5	-5,818.9	-6,786.4
Density (lb/ft ³)	54.996	61.143	62.658	2.217	0.708	0.454	0.158	0.005	61.822

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

5.3.4 Case B11A-F0 – Full Load Performance Results

At full load, the plant produces a net output of 140 MWe at a net plant efficiency of 34.6% (HHV basis). Full load performance for Case B11A-F0 is summarized in Exhibit 5-18. Exhibit 5-19 presents a detailed breakdown of auxiliary power requirements at full load.

Exhibit 5-18. Case B11A-F0 plant performance summary

Performance Summary	
Percent Load	100%
Total Gross Power, MWe	150
Nameplate Capacity, MWe	150
Total Auxiliaries, MWe	10
Total Auxiliaries, % of Gross Power	6.6%
Net Power, MWe	140
HHV Net Plant Efficiency, %	34.6%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,393 (9,851)
LHV Net Plant Efficiency, %	35.9%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,024 (9,501)
HHV Boiler Efficiency, %	87.5%
LHV Boiler Efficiency, %	90.7%
Steam Turbine Cycle Efficiency, %	42.4%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,494 (8,050)
Condenser Duty, GJ/hr (MMBtu/hr)	715 (677)
As-Received Coal Feed, kg/hr (lb/hr)	53,677 (118,337)
Limestone Sorbent Feed, kg/hr (lb/hr)	5,194 (11,450)
HHV Thermal Input, kWt	404,592
LHV Thermal Input, kWt	390,234
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)
Excess Air, %	20.0%

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Exhibit 5-19. Case B11A-F0 plant power summary

Power Summary	
Percent Load	100%
Steam Turbine Power, MWe	150
Total Gross Power, MWe	150
Nameplate Capacity	150
Auxiliary Load Summary	
Activated Carbon Injection, kWe	8
Air Cooled Condenser Fans	1,790
Ancillary Glycol Cooling Loops	250
Ash Handling, kWe	181
Baghouse, kWe	24
Boiler Feedwater Pump, ^A kWe	0
Coal Handling and Conveying, kWe	120
Condensate Pumps, kWe	211
Dry Sorbent Injection, kWe	15
Flue Gas Desulfurizer, kWe	830
Forced Draft Fans, kWe	830
Ground Water Pumps, kWe	14
Induced Draft Fans, kWe	2,390
Miscellaneous Balance of Plant, ^{A,B} kWe	1,250
Primary Air Fans, kWe	204
Pulverizers, kWe	590
SCR, kWe	9
Sorbent Handling & Reagent Preparation, kWe	250
Spray Dryer Evaporator, kWe	59
Steam Turbine Auxiliaries, kWe	350
Transformer Losses, kWe	480
Total Auxiliaries, MWe	10
Net Power, MWe	140

^A Boiler feed pumps are turbine-driven

^B Includes plant control systems; lighting; heating, ventilation, and air conditioning (HVAC); and miscellaneous low-voltage loads

5.3.4.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B11A-F0 is presented in Exhibit 5-20. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-20. Case B11A-F0 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	376 (415)	0.337 (0.742)
NO _x	0.033 (0.076)	355 (391)	0.318 (0.700)
Particulate	0.004 (0.010)	46 (50)	0.041 (0.090)
Hg	1.40E-7 (3.26E-7)	0.002 (0.002)	1.36E-6 (3.00E-6)
CO ₂	86 (201)	934,996 (1,030,656)	837 (1,846)
CO ₂ ^C	-	-	896 (1,975)
mg/Nm ³			
Particulate Concentration ^{D,E}	13.33		

^A Calculations based on an 85% capacity factor

^B Emissions based on gross power, except where otherwise noted

^C CO₂ emissions based on net power instead of gross power

^D Concentration of particles in the flue gas after the baghouse

^E Normal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.35 lb/MMBtu using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 78.3 percent to about 0.08 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and FGD system) is 95.2 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 5-21. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-21. Case B11A-F0 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	34,216 (75,434)	Stack Gas	34,270 (75,553)
Air (CO ₂)	79 (174)	FGD Product	41 (89)
PAC	12 (26)	Baghouse	421 (928)
FGD Reagent	527 (1,162)	Bottom Ash	102 (226)
Total	34,834 (76,796)	Total	34,834 (76,796)

Exhibit 5-22 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-22. Case B11A-F0 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	1,345 (2,966)	FGD Product	1,265 (2,789)
		Stack Gas	26 (58)
		Baghouse	54 (119)
Total	1,345 (2,966)	Total	1,345 (2,966)

Exhibit 5-23 shows the water balance for Case B11A-F0.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is reused as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from ground water. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-23. Case B11A-F0 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Desulfurizer Makeup	0.6 (148)	0.1 (20)	0.5 (128)	–	0.5 (128)
Deaerator Vent	–	–	–	0.0 (3.9)	0.0 (-3.9)
Condenser Makeup	0.1 (24)	–	0.1 (24)	–	0.1 (24)
BFW Makeup	0.1 (24)	–	0.1 (24)	–	0.1 (24)
Cooling Tower	–	–	–	–	–
BFW Blowdown	–	–	–	–	–
Total	0.6 (172)	0.1 (20)	0.6 (152)	0.0 (3.9)	0.6 (148)

5.3.4.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown below for the Case B11A-F0 PC boiler, the FGD unit, and steam cycle as shown in Exhibit 5-24 and Exhibit 5-25.

An overall plant energy balance is provided in tabular form in Exhibit 5-26. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-18) is calculated by multiplying the power out by the full load generator efficiency of 98.5 percent.

Exhibit 5-24. Case B11A-F0 energy and mass balance, subcritical PC boiler

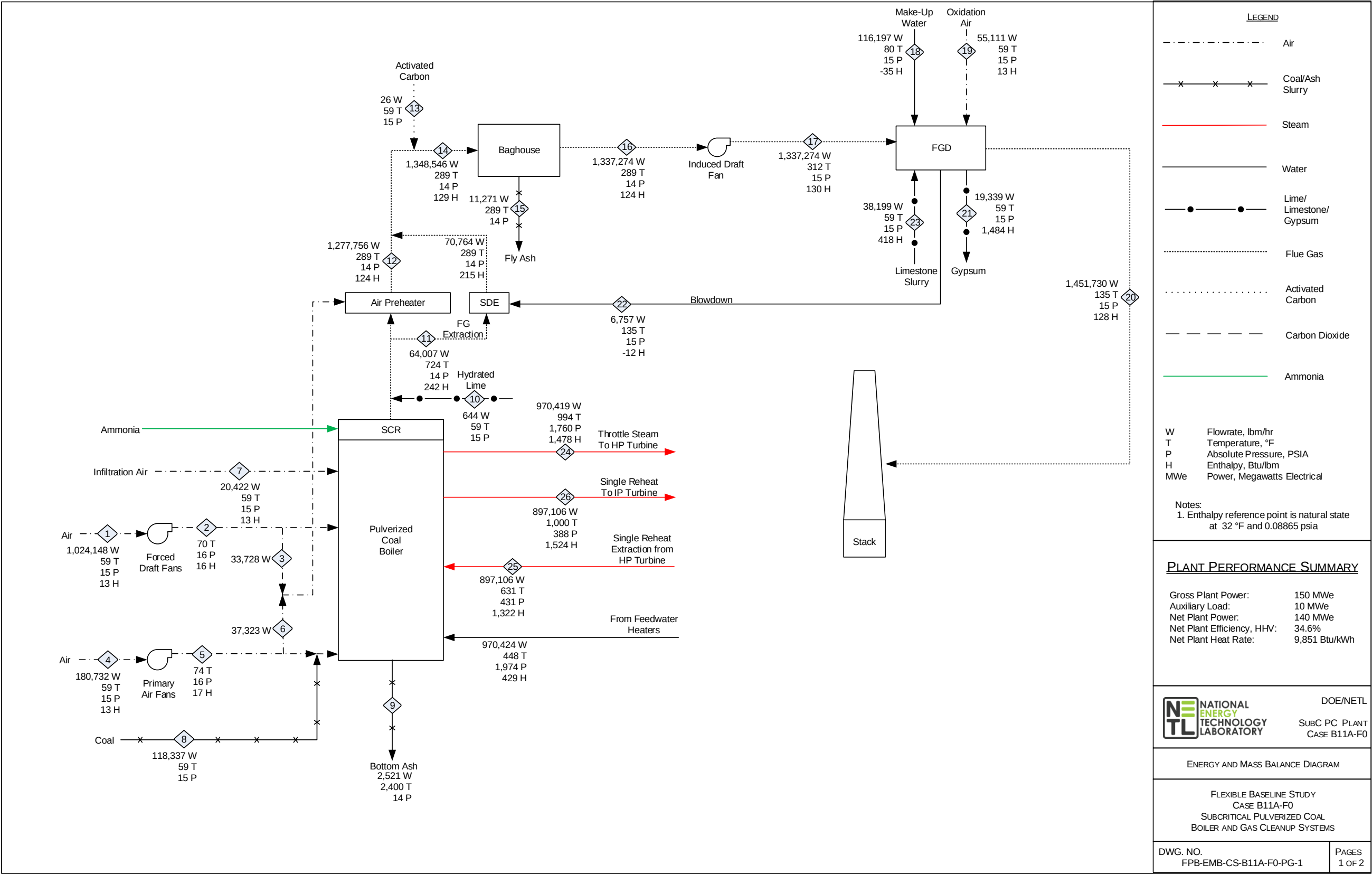
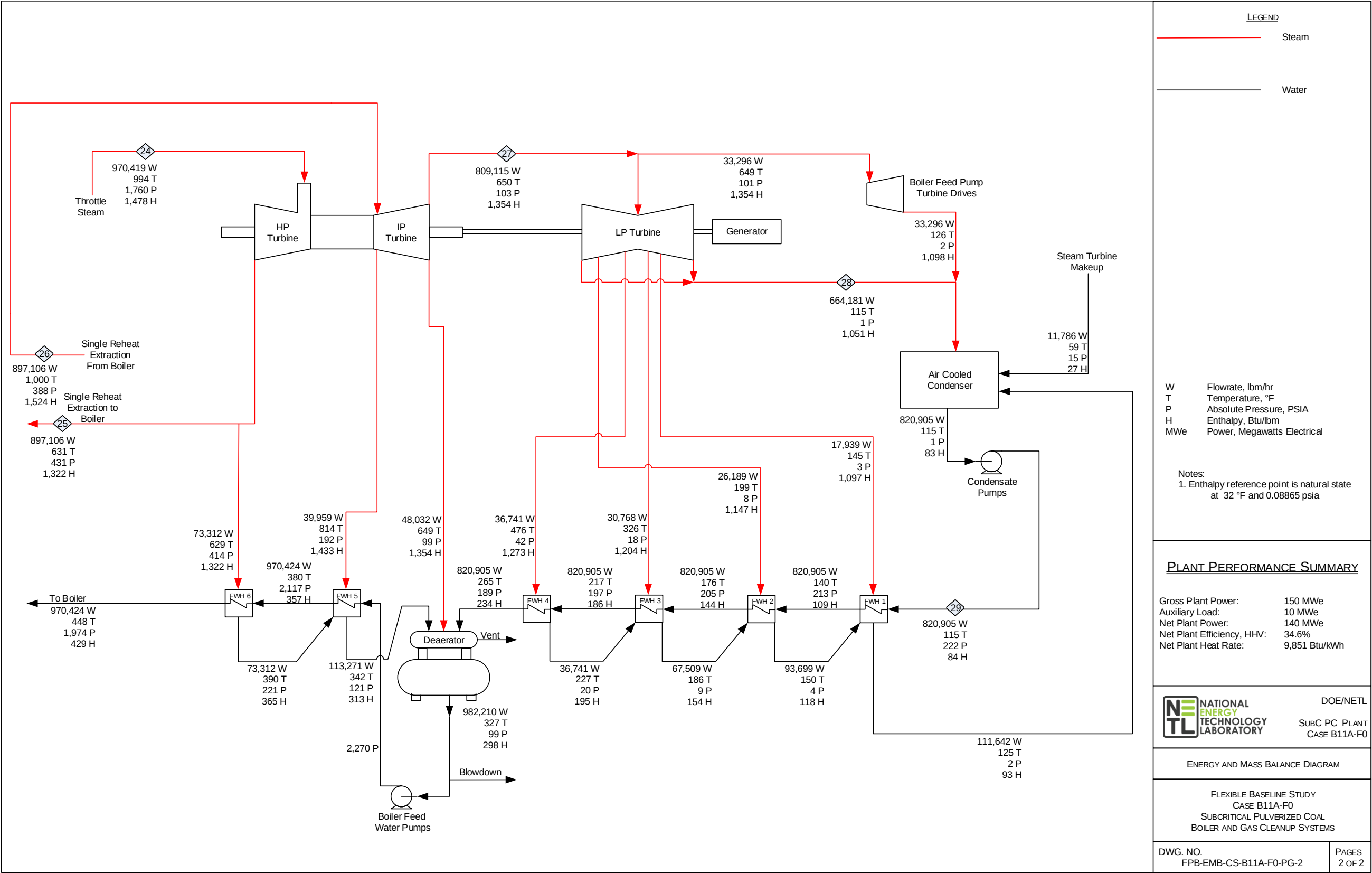


Exhibit 5-25. Case B11A-F0 energy and mass balance, subcritical steam cycle



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-26. Case B11A-F0 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	1,457 (1,381)	1.2 (1.2)	–	1,458 (1,382)
Air	–	17 (16)	–	17 (16)
Raw Water Makeup	–	2.2 (2.0)	–	2.2 (2.0)
Limestone	–	0.1 (0.1)	–	0.1 (0.1)
Auxiliary Power	–	–	35 (34)	35 (34)
Total	1,457 (1,381)	20 (19)	35 (34)	1,512 (1,433)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	1.5 (1.4)	–	1.5 (1.4)
Fly Ash	–	0.5 (0.5)	–	0.5 (0.5)
Stack Gas	–	196 (186)	–	196 (186)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Gypsum	–	0.5 (0.5)	–	0.5 (0.5)
Motor Losses and Design Allowances	–	–	8.8 (8.3)	8.8 (8.3)
Air Cooled Condenser Load ^A	–	715 (677)	–	715 (677)
Blowdown Streams and Deaerator Vent	–	3.7 (3.5)	–	3.7 (3.5)
<i>Ambient Losses^B</i>	–	40 (38)	–	40 (38)
Power	–	–	540 (512)	540 (512)
Total	0.0 (0.0)	957 (907)	549 (520)	1,506 (1,427)
<i>Unaccounted Energy^C</i>	–	–	–	6.7 (6.3)

^A Includes condenser load only

^B Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^C By difference

5.3.5 Case B11A-F0 – Part Load Performance Results

Plant performance results are summarized at each discrete load point in Exhibit 5-27. Exhibit 5-28 displays a detailed breakdown of the auxiliary power requirement at each discrete load point. Air emissions at each discrete load point are summarized in Exhibit 5-29.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-27. Case B11A-F0 part load plant performance summary

Performance Summary				
Percent Load	100%	75%	50%	40%
Total Gross Power, MWe	150	113	75	60
Nameplate Capacity, MWe	150	150	150	150
Total Auxiliaries, MWe	10	9	7	6
Total Auxiliaries, % of Gross Power	6.6%	7.7%	9.5%	10.7%
Net Power, MWe	140	104	68	54
HHV Net Plant Efficiency, %	34.6%	32.6%	28.5%	26.2%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,393 (9,851)	11,047 (10,471)	12,644 (11,985)	13,718 (13,002)
LHV Net Plant Efficiency, %	35.9%	33.8%	29.5%	27.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,024 (9,501)	10,655 (10,099)	12,196 (11,559)	13,231 (12,541)
HHV Boiler Efficiency, %	87.5%	87.5%	87.6%	87.6%
LHV Boiler Efficiency, %	90.7%	90.7%	90.8%	90.8%
Steam Turbine Cycle Efficiency, %	42.4%	40.4%	35.9%	33.5%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,494 (8,050)	8,920 (8,454)	10,016 (9,494)	10,733 (10,173)
Condenser Duty, GJ/hr (MMBtu/hr)	715 (677)	561 (532)	428 (406)	373 (353)
As-Received Coal Feed, kg/hr (lb/hr)	53,677 (118,337)	42,260 (93,168)	31,613 (69,695)	27,092 (59,729)
Limestone Sorbent Feed, kg/hr (lb/hr)	5,194 (11,450)	4,098 (9,034)	3,078 (6,785)	2,643 (5,827)
HHV Thermal Input, kWt	404,592	318,539	238,286	204,210
LHV Thermal Input, kWt	390,234	307,235	229,830	196,963
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)	0.004 (1.2)	0.005 (1.3)	0.005 (1.4)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)	0.004 (1.1)	0.005 (1.3)	0.005 (1.4)
Excess Air, %	20.0%	22.1%	26.9%	29.7%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-28. Case B11A-F0 part load plant power summary

Power Summary				
Percent Load	100%	75%	50%	40%
Steam Turbine Power, MWe	150	113	75	60
Total Gross Power, MWe	150	113	75	60
Nameplate Capacity	150	150	150	150
Auxiliary Load Summary				
Activated Carbon Injection, kWe	8	6	5	4
Air Cooled Condenser Fans, kWe	1,790	1,780	1,250	1,010
Ancillary Glycol Cooling Loops, kWe	250	250	250	250
Ash Handling, kWe	181	141	104	88
Baghouse, kWe	24	19	14	12
Boiler Feedwater Pump ^A kWe	0	0	0	0
Circulating Water Pumps, kWe	0	0	0	0
Coal Handling and Conveying, kWe	120	90	70	60
Condensate Pumps, kWe	211	140	96	83
Cooling Tower Fans, kWe	0	0	0	0
Dry Sorbent Injection, kWe	15	11	7	5
Flue Gas Desulfurizer, kWe	830	770	830	830
Forced Draft Fans, kWe	830	690	530	440
Ground Water Pumps, kWe	14	11	9	8
Induced Draft Fans, kWe	2,390	1,930	1,470	1,250
Miscellaneous Balance of Plant, ^B kWe	1,250	1,250	1,250	1,250
Primary Air Fans, kWe	204	175	142	106
Pulverizers, kWe	590	470	350	300
SCR, kWe	9	8	7	6
Sorbent Handling and Reagent Preparation, kWe	250	197	148	127
Spray Dryer Evaporator, kWe	59	47	35	30
Steam Turbine Auxiliaries, kWe	350	350	350	350
Transformer Losses, kWe	480	360	240	200
Total Auxiliaries, MWe	10	9	7	6
Net Power, MWe	140	104	68	54

^A BFW pumps are turbine-driven

^B Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-29. Case B11A-F0 part load air emissions summary

Emissions Summary				
Percent Load	100%	75%	50%	40%
SO ₂ , kg/MWhgross (lb/MWhgross)	0.337 (0.742)	0.354 (0.781)	0.399 (0.880)	0.428 (0.945)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	837 (1,846)	880 (1,939)	989 (2,180)	1,061 (2,338)
CO ₂ , kg/MWhnet (lb/MWhnet)	896 (1,975)	953 (2,101)	1,093 (2,410)	1,187 (2,618)
Particulate Concentration, ^{A,B} mg/Nm ³	13.33	12.49	10.72	9.79

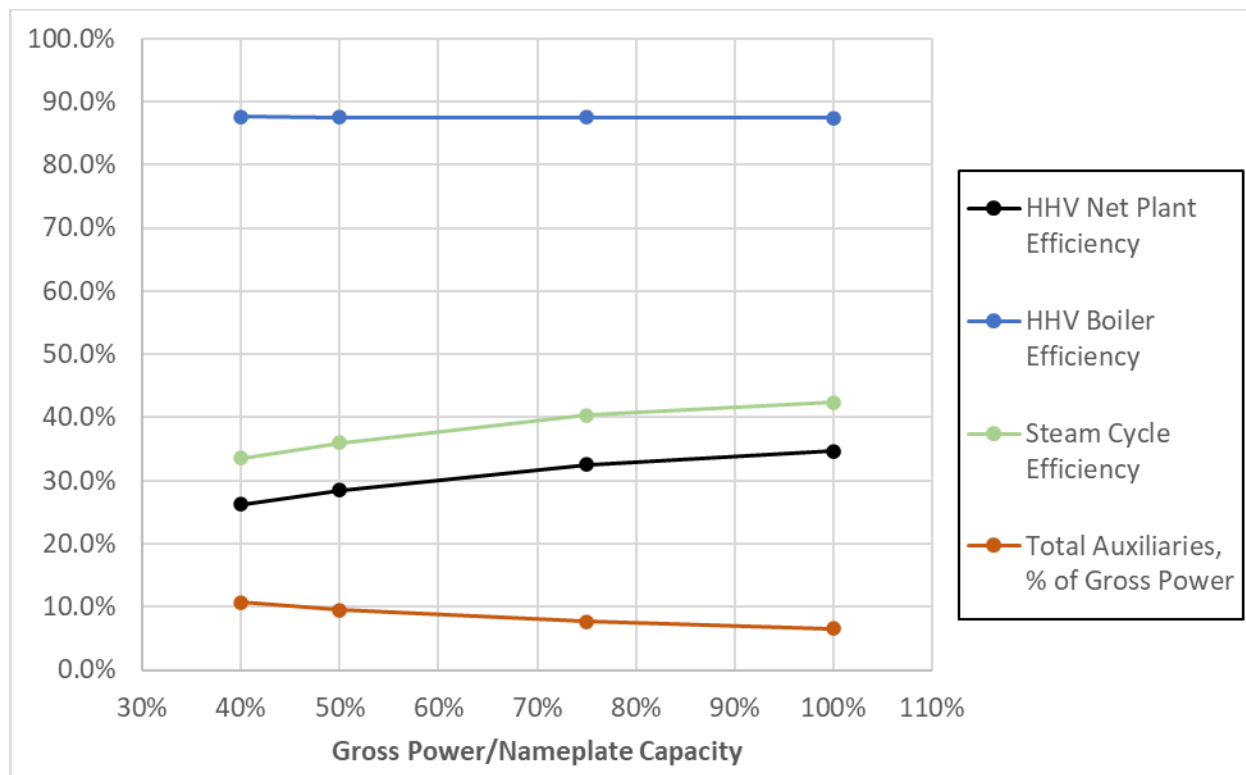
^A Concentration of particles in the flue gas after the baghouse

^B Normal conditions given at 32°F and 14.696 psia

Case B11A-F0 air emissions remained below the environmental target emission limits across the entire load range. Hg, NO_x, and PM emissions are maintained at constant levels across the load. SO₂ emissions increase as load is reduced but are kept below the environmental target emission limit.

Exhibit 5-30 displays the Case B11A-F0 itemized efficiencies (HHV net plant efficiency, HHV boiler efficiency, and steam cycle efficiency) and normalized auxiliary power consumption across the load range.

Exhibit 5-30. Case B11A-F0 part load itemized efficiencies



The decrease in part load net plant efficiency is primarily attributable to two key factors: 1) a decrease in the part load steam cycle efficiency, and 2) an increase in the normalized auxiliary power consumption. Conversely, boiler efficiency slightly improves as load is reduced.

The decrease in the part load steam cycle efficiency is an expected occurrence that is exacerbated by constant pressure operation. As the load is reduced, the main steam pressure remains constant while the throttle steam pressure is reduced to maintain a relatively constant volumetric flow through the steam turbine. This requires the BFW pump to maintain a steady outlet pressure, even when throttle steam pressure is reduced. Furthermore, expansion of main steam through the throttle valve causes unrecoverable throttle losses that further reduce the efficiency of the steam cycle.

Several competing effects impact boiler efficiency as the load is reduced. In general, reduced loads lead to lower flowrates through the boiler, thereby increasing residence time. The increased residence time lowers the unburned carbon rate, which contributes to the increase in reduced load boiler efficiency. Moreover, SO_3 formation rates tend to decrease as load is reduced, allowing for lower air preheater flue gas outlet temperatures while maintaining a constant acid gas condensation approach temperature.

Natural circulation boilers tend to absorb a constant rate of Btus even when load is reduced; this, along with the increased air to fuel ratio that results from increased excess air, leads to a drop in the radiant zone outlet temperature of the boiler, which negatively impacts the boiler

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

efficiency. However, the net impact of these factors results in a slight increase in boiler efficiency as load is reduced.

5.3.6 Case B11A-F0 – Major Equipment List

Case B11A-F0 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	10 tonne (10 ton)	2	1
9	Feeder	Vibratory	40 tonne/hr (50 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	90 tonne/hr (100 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	40 tonne (50 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Transfer Tower No. 2	Enclosed	N/A	1	0
16	Coal Silo w/ Vent Filter and Slide Gates	Field erected	200 tonne (200 ton)	3	0
17	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 2 tonne (2 ton) Feeder - 10 kg/hr (30 lb/hr)	1	0
18	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 50 tonne (60 ton) Feeder - 320 kg/hr (710 lb/hr)	1	0
19	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	22 tonne/hr (24 tph)	1	0
21	Limestone Conveyor No. 1	Belt	22 tonne/hr (24 tph)	1	0
22	Limestone Reclaim Hopper	N/A	4 tonne (5 ton)	1	0
23	Limestone Reclaim Feeder	Belt	17 tonne/hr (19 tph)	1	0
24	Limestone Conveyor No. 2	Belt	17 tonne/hr (19 tph)	1	0
25	Limestone Day Bin	w/ actuator	69 tonne (76 ton)	2	0

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Case B11A-F0 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	15 tonne/hr (16 tph)	4	0
2	Coal Pulverizer	Rotary (Vertical)	15 tonne/hr (16 tph)	4	0
3	Limestone Weigh Feeder	Gravimetric	6 tonne/hr (6 tph)	1	1
4	Limestone Ball Mill	Rotary	6 tonne/hr (6 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	22,700 liters (6,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	380 lpm @ 10m H ₂ O (100 gpm @ 40 ft H ₂ O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	90 lpm (30 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	124,000 liters (33,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	260 lpm @ 9 m H ₂ O (70 gpm @ 30 ft H ₂ O)	1	1

Case B11A-F0 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	353,000 liters (93,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,900 lpm @ 200 m H ₂ O (1,800 gpm @ 600 ft H ₂ O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	490,000 kg/hr (1,080,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	8,100 lpm @ 1,800 m H ₂ O (2,100 gpm @ 6,100 ft H ₂ O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	2,400 lpm @ 1,800 m H ₂ O (600 gpm @ 6,100 ft H ₂ O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	200,000 kg/hr (450,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	200,000 kg/hr (450,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	200,000 kg/hr (450,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	200,000 kg/hr (450,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	480,000 kg/hr (1,070,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	480,000 kg/hr (1,070,000 lb/hr)	1	0

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Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	37 GJ/hr (35 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	14,600 lpm @ 30 m H ₂ O (3,900 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	150 lpm @ 20 m H ₂ O (40 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	150 lpm @ 270 m H ₂ O (40 gpm @ 880 ft H ₂ O)	2	1
22	Filtered Water Pumps	Stainless steel, single suction	350 lpm @ 50 m H ₂ O (90 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	340,000 liter (90,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 500 m ³ /min (17,570 acfm) @ 384°C (724°F) & 0.1 MPa (14 psia) Blowdown - 30 lpm (10 gpm) @ 20,018 ppmw Cl ⁻	2	1

Case B11A-F0 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	480,000 kg/hr steam @ 12.0 MPa/534°C/538°C (1,070,000 lb/hr steam @ 1,745 psig/994°F/1,000°F)	1	0
2	Primary Air Fan	Centrifugal	45,000 kg/hr, 600 m ³ /min @ 107 cm WG (99,000 lb/hr, 21,700 acfm @ 42 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	256,000 kg/hr, 3,500 m ³ /min @ 76 cm WG (563,000 lb/hr, 123,200 acfm @ 30 in. WG)	2	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
4	Induced Draft Fan	Centrifugal	334,000 kg/hr, 6,800 m ³ /min @ 116 cm WG (736,000 lb/hr, 241,800 acfm @ 46 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	630,000 kg/hr (1,390,000 lb/hr)	2	0
6	SCR Catalyst	—	—	3	0
7	Dilution Air Blower	Centrifugal	20 m ³ /min @ 108 cm WG (900 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	27,000 liter (7,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	5 lpm @ 90 m H ₂ O (1 gpm @ 300 ft H ₂ O)	2	1

Case B11A-F0 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	334,000 kg/hr (736,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	11,000 m ³ /min (400,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	66,000 lpm @ 65 m H ₂ O (17,000 gpm @ 210 ft H ₂ O)	3	1
4	Bleed Pumps	Horizontal centrifugal	1,100 lpm (290 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	190 m ³ /min @ 0.3 MPa (6,630 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	270 lpm (70 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	9 tonne/hr (10 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	170 lpm @ 13 m H ₂ O (40 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	110,000 lpm (30,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	390 lpm @ 21 m H ₂ O (100 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	10 kg/hr (30 lb/hr)	1	0
13	Hydrated Lime Injectors	---	320 kg/hr (710 lb/hr)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case B11A-F0 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	122 m (400 ft) high x 3.1 m (10 ft) diameter	1	0

Case B11A-F0 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	156 MW 12.0 MPa/534°C/538°C (1745 psig/994°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	170 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Air-Cooled Condenser	Forced draft, direct, A-frame air-cooled condenser	790 GJ/hr (750 MMBtu/hr), Condensing temperature 46°C (115°F), Ambient temperature 15°C (59°F)	1	0

Case B11A-F0 – Account 9: Auxiliary Cooling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Glycol Cooling Loops	Industrial grade, air to glycol, closed loop heat exchanger	10 GJ/hr (14 MMBtu/hr) heat duty	5	0

Case B11A-F0 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	1.3 tonne/hr (1.4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	12	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	5 m ³ /min @ 0.2 MPa (178 scfm @ 24 psi)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Fly Ash Silo	Reinforced concrete	330 tonne (370 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	30 tonne/hr (30 tph)	1	0

Case B11A-F0 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 160 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 9 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 2 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B11A-F0 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers, alarm management, HMI's, data historian, hard-wired control interface panels, and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor cabinets with redundant input/output, I/O cabinets, various I/C buses	Spare 25% I/O and processor bandwidth	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant	1	0

5.3.7 Case B11A-F0 – Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-31 shows a detailed breakdown of the capital costs; Exhibit 5-32 shows the owner's costs, along with the TOC; Exhibit 5-33 shows the initial and annual O&M costs; and Exhibit 5-34 shows the startup and shutdown costs.

The estimated TPC of the Case B11A-F0 plant is \$393 million. The project contingency is 13.3 percent of the TPC.

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Exhibit 5-31. Case B11A-F0 total plant cost summary

Case:		B11A-F0	Subcritical PC Baseload Plant				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
1		Coal & Sorbent Handling								
1.1	Coal Receive & Unload	\$267	\$0	\$120	\$0	\$387	\$68	\$0	\$68	\$523
1.2	Coal Stackout & Reclaim	\$876	\$0	\$196	\$0	\$1,072	\$188	\$0	\$189	\$1,448
1.3	Coal Conveyors	\$9,304	\$0	\$2,214	\$0	\$11,518	\$2,016	\$0	\$2,030	\$15,564
1.4	Other Coal Handling	\$1,036	\$0	\$218	\$0	\$1,254	\$219	\$0	\$221	\$1,694
1.5	Sorbent Receive & Unload	\$61	\$0	\$18	\$0	\$79	\$14	\$0	\$14	\$107
1.6	Sorbent Stackout & Reclaim	\$331	\$0	\$60	\$0	\$391	\$68	\$0	\$69	\$528
1.7	Sorbent Conveyors	\$588	\$128	\$142	\$0	\$858	\$150	\$0	\$151	\$1,159
1.8	Other Sorbent Handling	\$35	\$8	\$18	\$0	\$61	\$11	\$0	\$11	\$82
1.9	Coal & Sorbent Handling Foundations	\$0	\$430	\$567	\$0	\$997	\$175	\$0	\$176	\$1,348
	Subtotal	\$12,497	\$566	\$3,553	\$0	\$16,616	\$2,908	\$0	\$2,929	\$22,452
2		Coal & Sorbent Preparation & Feed								
2.1	Coal Crushing & Drying	\$569	\$0	\$109	\$0	\$678	\$119	\$0	\$120	\$916
2.2	Prepared Coal Storage & Feed	\$1,915	\$0	\$412	\$0	\$2,327	\$407	\$0	\$410	\$3,144
2.5	Sorbent Preparation Equipment	\$251	\$11	\$51	\$0	\$313	\$55	\$0	\$55	\$423
2.6	Sorbent Storage & Feed	\$405	\$0	\$153	\$0	\$557	\$98	\$0	\$98	\$753
2.9	Coal & Sorbent Feed Foundation	\$0	\$160	\$141	\$0	\$301	\$53	\$0	\$53	\$407
	Subtotal	\$3,139	\$171	\$866	\$0	\$4,177	\$731	\$0	\$736	\$5,644
3		Feedwater & Miscellaneous BOP Systems								
3.1	Feedwater System	\$826	\$1,417	\$708	\$0	\$2,952	\$517	\$0	\$520	\$3,988
3.2	Water Makeup & Pretreating	\$1,376	\$138	\$780	\$0	\$2,294	\$401	\$0	\$539	\$3,234
3.3	Other Feedwater Subsystems	\$560	\$184	\$174	\$0	\$918	\$161	\$0	\$162	\$1,241
3.4	Service Water Systems	\$410	\$783	\$2,536	\$0	\$3,729	\$653	\$0	\$876	\$5,258
3.5	Other Boiler Plant Systems	\$168	\$61	\$152	\$0	\$381	\$67	\$0	\$67	\$515
3.6	Natural Gas Pipeline and Start-Up System	\$892	\$38	\$29	\$0	\$959	\$168	\$0	\$169	\$1,296
3.7	Waste Water Treatment Equipment	\$2,305	\$0	\$1,413	\$0	\$3,717	\$651	\$0	\$874	\$5,242
3.8	Spray Dryer Evaporator	\$4,228	\$0	\$2,448	\$0	\$6,676	\$1,168	\$0	\$1,569	\$9,413
3.9	Miscellaneous Plant Equipment	\$51	\$7	\$26	\$0	\$83	\$15	\$0	\$20	\$117
	Subtotal	\$10,816	\$2,627	\$8,266	\$0	\$21,709	\$3,799	\$0	\$4,796	\$30,304
4		Pulverized Coal Boiler & Accessories								
4.9	Pulverized Coal Boiler & Accessories	\$63,020	\$0	\$41,155	\$0	\$104,175	\$18,231	\$0	\$18,361	\$140,767
4.10	Selective Catalytic Reduction System	\$5,279	\$0	\$3,447	\$0	\$8,726	\$1,527	\$0	\$1,538	\$11,792
4.11	Boiler Balance of Plant	\$280	\$0	\$183	\$0	\$462	\$81	\$0	\$81	\$625
4.12	Primary Air System	\$333	\$0	\$217	\$0	\$550	\$96	\$0	\$97	\$744
4.13	Secondary Air System	\$692	\$0	\$452	\$0	\$1,144	\$200	\$0	\$202	\$1,546

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B11A-F0	Subcritical PC Baseload Plant				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
4.14	Induced Draft Fans	\$1,297	\$0	\$847	\$0	\$2,145	\$375	\$0	\$378	\$2,898
4.15	Major Component Rigging	\$22	\$0	\$14	\$0	\$36	\$6	\$0	\$6	\$49
4.16	Boiler Foundations	\$0	\$96	\$85	\$0	\$181	\$32	\$0	\$32	\$244
	Subtotal	\$70,923	\$96	\$46,401	\$0	\$117,420	\$20,549	\$0	\$20,695	\$158,664
5		Flue Gas Cleanup								
5.2	WFGD Absorber Vessels & Accessories	\$20,989	\$0	\$4,488	\$0	\$25,477	\$4,458	\$0	\$4,490	\$34,426
5.3	Other FGD	\$73	\$0	\$82	\$0	\$155	\$27	\$0	\$27	\$210
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$595	\$131	\$585	\$0	\$1,311	\$229	\$0	\$231	\$1,772
5.9	Particulate Removal (Bag House & Accessories)	\$627	\$0	\$395	\$0	\$1,023	\$179	\$0	\$180	\$1,382
5.12	Gas Cleanup Foundations	\$0	\$42	\$37	\$0	\$78	\$14	\$0	\$14	\$106
5.13	Gypsum Dewatering System	\$187	\$0	\$32	\$0	\$219	\$38	\$0	\$39	\$296
	Subtotal	\$22,472	\$173	\$5,619	\$0	\$28,263	\$4,946	\$0	\$4,981	\$38,191
7		Ductwork & Stack								
7.3	Ductwork	\$0	\$188	\$130	\$0	\$318	\$56	\$0	\$56	\$430
7.4	Stack	\$2,526	\$0	\$1,468	\$0	\$3,993	\$699	\$0	\$704	\$5,396
7.5	Duct & Stack Foundations	\$0	\$51	\$61	\$0	\$112	\$20	\$0	\$26	\$158
	Subtotal	\$2,526	\$239	\$1,659	\$0	\$4,423	\$774	\$0	\$786	\$5,983
8		Steam Turbine & Accessories								
8.1	Steam Turbine Generator & Accessories	\$22,048	\$0	\$2,479	\$0	\$24,527	\$4,292	\$0	\$4,323	\$33,141
8.2	Steam Turbine Plant Auxiliaries	\$456	\$0	\$969	\$0	\$1,425	\$249	\$0	\$251	\$1,925
8.3	Condenser & Auxiliaries ^A	\$11,353	\$0	\$3,852	\$0	\$15,205	\$2,661	\$0	\$2,680	\$20,545
8.4	Steam Piping	\$10,014	\$0	\$4,058	\$0	\$14,072	\$2,463	\$0	\$2,480	\$19,015
8.5	Turbine Generator Foundations	\$0	\$57	\$94	\$0	\$151	\$26	\$0	\$35	\$213
	Subtotal	\$43,870	\$57	\$11,452	\$0	\$55,379	\$9,691	\$0	\$9,769	\$74,839
9		Cooling Water System								
9.6	Component Cooling Water System ^B	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
	Subtotal	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
10		Ash & Spent Sorbent Handling Systems								
10.6	Ash Storage Silos	\$300	\$0	\$917	\$0	\$1,217	\$213	\$0	\$214	\$1,644
10.7	Ash Transport & Feed Equipment	\$1,125	\$0	\$1,115	\$0	\$2,240	\$392	\$0	\$395	\$3,027
10.9	Ash/Spent Sorbent Foundation	\$0	\$202	\$248	\$0	\$449	\$79	\$0	\$106	\$633
	Subtotal	\$1,425	\$202	\$2,280	\$0	\$3,906	\$684	\$0	\$715	\$5,304
11		Accessory Electric Plant								
11.1	Generator Equipment	\$791	\$0	\$596	\$0	\$1,387	\$243	\$0	\$244	\$1,874
11.2	Station Service Equipment	\$1,433	\$0	\$123	\$0	\$1,556	\$272	\$0	\$274	\$2,103
11.3	Switchgear & Motor Control	\$2,296	\$0	\$398	\$0	\$2,694	\$471	\$0	\$475	\$3,640
11.4	Conduit & Cable Tray	\$0	\$308	\$887	\$0	\$1,194	\$209	\$0	\$210	\$1,614
11.5	Wire & Cable	\$0	\$595	\$1,064	\$0	\$1,659	\$290	\$0	\$292	\$2,242

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B11A-F0	Subcritical PC Baseload Plant				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
11.6	Protective Equipment	\$17	\$0	\$58	\$0	\$75	\$13	\$0	\$13	\$101
11.7	Standby Equipment	\$194	\$0	\$179	\$0	\$372	\$65	\$0	\$66	\$503
11.8	Main Power Transformers	\$2,109	\$0	\$43	\$0	\$2,152	\$377	\$0	\$379	\$2,908
11.9	Electrical Foundations	\$0	\$55	\$140	\$0	\$195	\$34	\$0	\$46	\$274
	Subtotal	\$6,838	\$958	\$3,487	\$0	\$11,283	\$1,975	\$0	\$2,000	\$15,258
12 Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	\$172	\$0	\$31	\$0	\$202	\$35	\$0	\$36	\$274
12.3	Steam Turbine Control Equipment	\$178	\$0	\$20	\$0	\$198	\$35	\$0	\$35	\$268
12.5	Signal Processing Equipment	\$172	\$0	\$31	\$0	\$202	\$35	\$0	\$36	\$274
12.6	Control Boards, Panels & Racks	\$53	\$0	\$32	\$0	\$85	\$15	\$0	\$15	\$114
12.7	Distributed Control System Equipment	\$1,683	\$0	\$300	\$0	\$1,984	\$347	\$0	\$350	\$2,680
12.8	Instrument Wiring & Tubing	\$155	\$124	\$497	\$0	\$777	\$136	\$0	\$137	\$1,050
12.9	Other Instrumentation & Controls Equipment	\$185	\$0	\$429	\$0	\$614	\$108	\$0	\$108	\$830
	Subtotal	\$2,599	\$124	\$1,340	\$0	\$4,063	\$711	\$0	\$716	\$5,490
13 Improvements to Site										
13.1	Site Preparation	\$0	\$120	\$2,556	\$0	\$2,675	\$468	\$0	\$629	\$3,772
13.2	Site Improvements	\$0	\$656	\$867	\$0	\$1,523	\$266	\$0	\$358	\$2,147
13.3	Site Facilities	\$541	\$0	\$567	\$0	\$1,108	\$194	\$0	\$260	\$1,563
	Subtotal	\$541	\$776	\$3,990	\$0	\$5,306	\$929	\$0	\$1,247	\$7,482
14 Buildings & Structures										
14.2	Boiler Building	\$0	\$3,767	\$3,311	\$0	\$7,078	\$1,239	\$0	\$1,247	\$9,564
14.3	Steam Turbine Building	\$0	\$3,808	\$3,547	\$0	\$7,355	\$1,287	\$0	\$1,296	\$9,938
14.4	Administration Building	\$0	\$340	\$360	\$0	\$700	\$122	\$0	\$123	\$946
14.6	Water Treatment Buildings	\$0	\$97	\$88	\$0	\$184	\$32	\$0	\$33	\$249
14.7	Machine Shop	\$0	\$153	\$102	\$0	\$254	\$45	\$0	\$0	\$299
14.8	Warehouse	\$0	\$119	\$119	\$0	\$237	\$42	\$0	\$42	\$321
14.9	Other Buildings & Structures	\$0	\$86	\$73	\$0	\$159	\$28	\$0	\$28	\$214
14.10	Waste Treating Building & Structures	\$0	\$137	\$414	\$0	\$551	\$96	\$0	\$97	\$744
	Subtotal	\$0	\$8,506	\$8,012	\$0	\$16,518	\$2,891	\$0	\$2,866	\$22,275
	Total	\$178,031	\$14,494	\$97,221	\$0	\$289,745	\$50,705	\$0	\$52,357	\$392,808

^AACC; ^B Component cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
FLEXIBLE OPERATION

Exhibit 5-32. Case B11A-F0 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$3,213
1-Month Maintenance Materials	\$369
1-Month Non-Fuel Consumables	\$313
1-Month Waste Disposal	\$192
25% of 1-Month Fuel Cost at 100% CF	\$561
2% of TPC	\$7,856
Total	\$12,504
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$5,102
0.5% of TPC (spare parts)	\$1,964
Total	\$7,066
Other Costs	
Initial Cost for Catalyst and Chemicals	\$506
Land	\$117
Other Owner's Costs	\$58,921
Financing Costs	\$10,606
Total Overnight Costs (TOC)	\$482,527

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-33. Case B11A-F0 initial and annual operating and maintenance costs

Case:	B11A-F0 – Subcritical PC Baseload Plant			Cost Base:	Dec 2018
Plant Size (MW, gross):	150	Heat Rate-net (Btu/kWh):		9,853	
Operating & Maintenance Labor					
Operating Labor				Operating Labor Requirements per Shift	
Operating Labor Rate (base):	38.50	\$/hour		Skilled Operator:	1.0
Operating Labor Burden:	30.0	% of base		Operator:	3.0
Labor O-H Charge Rate:	25.0	% of labor		Foreman:	1.0
				Lab Techs, etc.:	1.0
				Total:	6.0
Fixed Operating Costs					
					Annual Cost (\$)
Annual Operating Labor:					\$2,630,628
Maintenance Labor:					\$2,509,883
Administrative & Support Labor:					\$1,285,128
Property Taxes and Insurance:					\$7,856,152
Total:					\$14,281,791
Variable Operating Costs					
					Annual Cost (\$)
Maintenance Material:					\$4,429,206 x CF
Consumables					
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)
Water (/1000 gallons):	0	109	\$1.90	\$0	\$75,850 x CF
Makeup and Waste Water Treatment Chemicals (ton):	0	0.326	\$550.00	\$0	\$65,406 x CF
Brominated Activated Carbon (ton):	0	0.312	\$1,600.00	0	\$182,044 x CF
Enhanced Hydrated Lime (ton):	0	7.73	\$240.00	0	\$677,336 x CF
Limestone (ton):	0	137	\$22.00	\$0	\$1,103,366 x CF
Ammonia (19 wt%, ton):	0	13.6	\$300.00	\$0	\$1,484,443 x CF
SCR Catalyst (ft³):	3,371	3.08	\$150.00	\$505,640	\$168,547 x CF
Subtotal:				\$505,640	\$3,756,992 x CF
Waste Disposal					
Fly Ash (ton):	0	135	\$38.00	\$0	\$1,875,954 x CF
Bottom Ash (ton):	0	30.3	\$38.00	\$0	\$419,513 x CF
SCR Catalyst (ft³):	0	3.08	\$2.50	\$0	\$2,809 x CF
Subtotal:				\$0	\$2,298,276 x CF
By-Products					
Gypsum (ton):	0	209	\$0.00	\$0	\$0
Subtotal:				\$0	\$0
Variable Operating Costs Total:				\$505,640	\$10,484,474 x CF
Fuel Cost					
Illinois Number 6 (ton):	0	1,420	\$51.96	\$0	\$26,930,773 x CF
Fuel Costs Total:				\$0	\$26,930,773 x CF

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-34. Case B11A-F0 Synchronization startup and shutdown costs

Event to Synchronization		Hot Start	Warm Start	Cold Start	Shutdown
Energy and Duration					
Energy Produced	MWh	-	-	-	-
Duration	hr	1.2	2.3	5.4	0.2
NG Heat Input (HHV)	MMBtu	325	680	1,526	50
Coal Heat Input (HHV)	MMBtu	-	-	-	-
House Energy Consumed	MWh	1.6	3.3	7.4	0.2
Aux Boiler Heat Input (HHV)	MMBtu	25.9	51.8	103.6	-
Costs					
Variable O&M Cost	\$	200	400	800	-
Natural Gas Cost	\$	1,500	3,200	7,200	200
Coal Cost	\$	-	-	-	-
House Energy Cost	\$	100	200	400	-
Total Cost for Event	\$	1,800	3,800	8,400	200

Exhibit 5-35. Case B11A-F0 full load startup and shutdown costs

Event to Full Load		Hot Start	Warm Start	Cold Start	Shutdown
Energy and Duration					
Energy Produced	MWh	132.2	190.4	418.9	161.3
Duration	hr	3.5	6.0	13.0	3.0
NG Heat Input (HHV)	MMBtu	681	1,244	2,133	698
Coal Heat Input (HHV)	MMBtu	1,613	2,347	5,607	1,707
House Energy Consumed	MWh	11.4	17.9	38.6	12.0
Aux Boiler Heat Input (HHV)	MMBtu	51.8	103.6	207.2	-
Costs					
Variable O&M Cost	\$	1,300	2,000	4,400	1,400
Natural Gas Cost	\$	3,200	5,900	10,300	3,100
Coal Cost	\$	3,600	5,200	12,500	3,800
House Energy Cost	\$	700	1,100	2,300	700
Total Cost for Event	\$	8,800	14,200	29,500	9,000

5.3.8 Impact of Plant Capacity on Configuration, Performance, and Cost

This section is intended to highlight the major configuration, performance, and cost differences that result from a change in plant capacity. Case B11A-F0 (150 MW gross) is compared to Case B11A (687 MW gross) from Revision 4 of the Bituminous Baseline study. Both cases are intended to reflect a state-of-the-art subcritical bituminous coal plant designed for baseload operation, with the main differing design criteria being the capacity of the plant. Therefore, they provide a valuable basis for understanding the effect of capacity on plant configuration, performance, and cost.

5.3.8.1 Subcritical Plant Configuration

The major Case B11A-F0 equipment modifications and summaries of the process description updates relative to Case B11A are outlined in the following items:

- **Broad-scale reduction of equipment sizes due to the reduced plant size (from 687 MW-gross to 150 MW-gross).**
- **Account 1 — Coal and Sorbent Handling**
 - Number of conveyors reduced from 5 to 3 to reflect what would be expected for a smaller capacity plant
- **Account 2 — Coal and Sorbent Preparation and Feed**
 - Mill type changing from “ball-type” to “vertical roller”; mill quantity is expected to reduce to 4
 - Bulk-stock coal fed into vertical roller mill directly from the gravimetric feeders; vertical-roller mills provide operational simplicity benefits as compared to ball-type mills, based on Black & Veatch experience
 - Horizontal “table” rotates with three stationary (spring-compressed) rollers used to grind coal to adequate size to be entrained in primary air flow and then transported to coal burners
 - Mills equipped with pyrites/rejects hopper
- **Account 3 — Feedwater and Miscellaneous Systems and Equipment**
 - Fuel oil system onsite would be eliminated on the basis of cost and unnecessary fuel redundancy; it is not typical for a plant this size to equip and maintain two supplemental fuel sources and systems
- **Account 5 — Flue Gas Cleanup**
 - Operating quantity of recirculation pumps reduced from 5 to 3
- **Account 7 — Ducting and Stack**
 - Stack size likely to be reduced to 400-ft height and 10-ft diameter (stack material type likely to remain consistent)

- Final stack characteristics (height/exit velocity) would be determined by permit and dispersion modeling
- **Account 8 — Steam Turbine Generator and Auxiliaries**
 - Steam turbine design pressure reduced from 2,400 pounds per square inch, gauge (psig), to 1,800 psia.
 - No significant process changes due to the reduced operating pressure
 - ACC replacing the B11A “surface condenser”
 - LP turbine outlet routes directly to the upper channel of the A-frame ACC
 - Cooling fan “cells” draw air through the A-frame tube channels to fully condense steam in the separate “leg channels” at the bottom of the ACC
 - Condensate pumps draw suction from the condensed liquid
 - Use of an ACC is not due to the reduced plant size. It was selected for this study to maintain “regional agnosticism”
- **Account 9 — Cooling Water System**
 - ACC replacing the Case B11A wet mechanical draft cooling tower
 - Utilization of an ACC requires air-to-glycol cooling loops to be installed for handling miscellaneous cooling loads
- **Account 10 — Ash and Spent Sorbent Handling System**
 - Operating quantity of baghouse hoppers reduced from 24 to 12

Additionally, a 150-MW plant would likely retain few (if any) major equipment spares (e.g., boiler waterwall panels, tube assemblies, spare steam turbine rotors, spare bearing liners). The baseload and flexible plant designs maintain similar number of PA, FD, and ID fans and BFW pump units. One major equipment category where the sparing philosophy is most notably modified from the Case B11A reference plant design is the type and number of coal mills utilized.

Unlike Case B11A, Case B11A-F0 does not include an economizer bypass in the plant design. Case B11A is designed with some consideration for daily or weekly cycling, whereas Case B11A-F0 is intended to reflect a plant designed purely for baseload operation. [63] While the economizer bypass can provide benefits during startup and shutdown processes, the baseload plant by definition would be experiencing very few startup or shutdown periods throughout the year. Therefore, the marginal benefit to flue gas temperature control upstream of the SCR afforded by the operation of an economizer gas-side bypass would not be able to demonstrate significant cost savings or operational improvements for the 150 MW gross baseload plant.

Apart from these areas where major equipment supply quantities were modified, no other equipment category was subject to a modification of the sparing (e.g., 2x100 percent) philosophy already established in the Case B11A design. [63]

5.3.8.2 Performance

Performance for Case B11A and Case B11A-F0 are summarized in Exhibit 5-36. Exhibit 5-37 presents a detailed breakdown of Case B11A and Case B11A-F0 auxiliary power requirements. Part load performance results are not provided for either case, since part load performance results have not been generated for Case B11A.

Exhibit 5-36. Baseload plant performance summary comparison: Case B11A and Case B11A-F0

Performance Summary		
Case	B11A	B11A-F0
Percent Load	100%	100%
Total Gross Power, MWe	687	150
Nameplate Capacity, MWe	687	150
Circulating Water Pumps, kWe	5,690	0
Cooling Tower Fans, kWe	2,940	0
ACC Fans, kWe	0	1,790
Balance of Plant, kWe	28,010	8,065
Total Auxiliaries, MWe	37	10
Total Auxiliaries, % of Gross Power	5.3%	6.6%
Net Power, MWe	650	140
HHV Net Plant Efficiency, %	38.6%	34.6%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,318 (8,832)	10,393 (9,851)
LHV Net Plant Efficiency, %	40.1%	35.9%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,987 (8,518)	10,024 (9,501)
HHV Boiler Efficiency, %	88.1%	87.5%
LHV Boiler Efficiency, %	91.3%	90.7%
Steam Turbine Cycle Efficiency, %	46.3%	42.4%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,770 (7,365)	8,494 (8,050)
Condenser Duty, GJ/hr (MMBtu/hr)	2,789 (2,644)	715 (677)
As-Received Coal Feed, kg/hr (lb/hr)	223,189 (492,047)	53,677 (118,337)
Limestone Sorbent Feed, kg/hr (lb/hr)	21,590 (47,598)	5,194 (11,450)
HHV Thermal Input, kWt	1,682,291	404,592
LHV Thermal Input, kWt	1,622,591	390,234
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.038 (10.0)	0.004 (1.1)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.030 (7.9)	0.004 (1.1)
Excess Air, %	20.3%	20.0%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-37. Baseload plant power summary comparison: Case B11A and Case B11A-F0

Power Summary		
Case	B11A	B11A-F0
Percent Load	100%	100%
Steam Turbine Power, MWe	687	150
Total Gross Power, MWe	687	150
Nameplate Capacity	687	150
Auxiliary Load Summary		
Activated Carbon Injection, kWe	30	8
Air Cooled Condenser Fans, kWe	0	1,790
Ancillary Glycol Cooling Loops, kWe	0	250
Ash Handling, kWe	710	181
Baghouse, kWe	100	24
Boiler Feedwater Pump, ^A kWe	0	0
Circulating Water Pumps, kWe	5,690	0
Coal Handling and Conveying, kWe	480	120
Condensate Pumps, kWe	720	211
Cooling Tower Fans, kWe	2,940	0
Dry Sorbent Injection, kWe	60	15
Flue Gas Desulfurizer, kWe	3,450	830
Forced Draft Fans, kWe	2,090	830
Ground Water Pumps, kWe	590	14
Induced Draft Fans, kWe	8,560	2,390
Miscellaneous Balance of Plant, ^B kWe	2,250	1,250
Primary Air Fans, kWe	1,640	204
Pulverizers, kWe	3,350	590
SCR, kWe	40	9
Sorbent Handling and Reagent Preparation, kWe	1,040	250
Spray Dryer Evaporator, kWe	250	59
Steam Turbine Auxiliaries, kWe	500	350
Transformer Losses, kWe	2,150	480
Total Auxiliaries, MWe	37	10
Net Power, MWe	650	140

^A BFW pumps are turbine-driven

^B Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

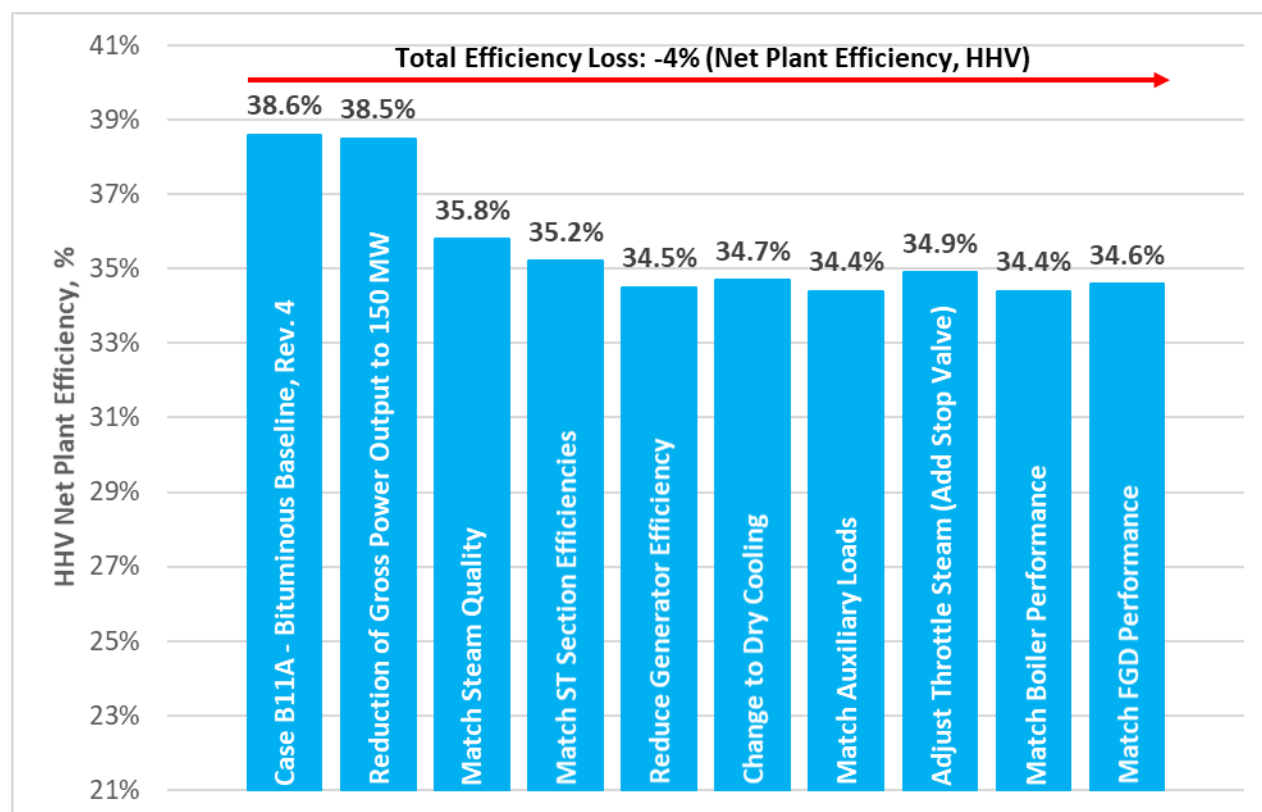
Normalized water consumption is substantially lower in Case B11A-F0 due to the use of an ACC. Case B11A utilizes a recirculating wet cooling tower rather than an ACC; this allows for an improvement in net plant efficiency by way of a reduced condenser operating pressure, but requires substantial water withdrawal. Furthermore, use of a recirculating wet cooling tower requires a circulating water system to deliver cooling water to the condenser and auxiliary cooling systems. This circulating water system can be eliminated if an ACC is used in lieu of a wet cooling system.

The auxiliary power requirement of the Case B11A cooling system is reflected in the power requirement of the circulating water system and cooling tower fans, while the auxiliary power requirement of the Case B11A-F0 cooling system is reflected in power requirement of the ACC fans. However, comparison of auxiliary power requirement alone does not give an adequate representation of their relative performance, since cooling type also has a notable impact on condenser operating pressure.

Case B11A-F0 has a notably lower net plant efficiency when compared to Case B11A. Several factors contribute to this, including lower temperature and pressure steam conditions (i.e., lower steam cycle efficiency), the use of dry cooling, and a higher normalized auxiliary power consumption. In addition, smaller rotating equipment (e.g., pumps, fans, turbines) tends to have lower efficiencies than their larger-scale counterparts.

A waterfall chart is provided in Exhibit 5-38, which illustrates the individual impacts various differences between Cases B11A and B11A-F0 have on the net plant efficiency.

Exhibit 5-38. Subcritical PC Comparison - Case B11A to FPB Case B11A-F0



5.3.8.2.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B11A-F0 and Case B11A is presented in Exhibit 5-39. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-39. Case B11A-F0 part load air emissions summary

Emissions Summary		
Case	B11A	B11A-F0
SO ₂ , kg/MWhgross (lb/MWhgross)	0.306 (0.674)	0.337 (0.742)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	767 (1,691)	837 (1,846)
CO ₂ , kg/MWhnet (lb/MWhnet)	811 (1,787)	896 (1,975)
Particulate Concentration ^{A,B} , mg/Nm ³	14.54	13.33

^A Concentration of particles in the flue gas after the baghouse

^B Normal conditions given at 32°F and 14.696 psia

NO_x, particulate, and mercury emissions are reduced to exactly meet regulatory limits, and consequently are equivalent between Case B11A-F0 and Case B11A. Case B11A-F0 has higher SO₂ emissions due to the constant removal rate of the wet FGD system; the lower net plant efficiency leads to a higher normalized formation of SO₂ in the boiler, causing a higher rate of emission. Similarly, Case B11A-F0 CO₂ emissions are higher due to the lower net plant efficiency.

5.3.8.3 Cost Results

Due to plant size changes and configuration differences (e.g., ACC instead of a water-cooled condenser), various cost account line items were omitted from the Case B11A-F0 capital cost estimates when compared to Case B11A. [63] Exhibit 5-40 presents a summary of the specific cost account categories that were omitted compared to Case B11A, and the justification for their omission.

Exhibit 5-40. Cost account deviations for small-scale plants, relative to 687 MW gross plants [63]

Cost Account Number	Cost Account Description	Justification for Omission
9.1	Cooling Towers	Use of cooling towers omitted from all capital cost cases (cases 0–4) due to the use of an ACC, which replaces the wet mechanical draft cooling tower utilized in the Bituminous Baseline [63] cost estimates.

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Cost Account Number	Cost Account Description	Justification for Omission
9.2	Circulating Water Pumps	Circulating water pumps omitted due the use of the ACC, which handles all cycle heat rejection. Smaller-duty component cooling throughout the plant (previously served by the circulating water system) are served by individual closed loop glycol-based cooling systems.
9.3	Circulating Water System Auxiliaries	See Account 9.2
9.4	Circulating Water Piping	See Account 9.2
9.5	Circulating Water System Foundations	See Account 9.2
14.5	Circulation Water Pumphouse	See Account 9.2

The capital and O&M costs presented for Case B11A-F0 do not have reference cases for simple comparison or scaling within the Bituminous Baseline. [2] Furthermore, the Case B11A-F0 plant size is well outside the applicable range for scaling plant system costs via the methodologies and parameters outlined in the QGESS capital cost scaling methodologies report. [82] For this reason, a comparison between the flexible plant TPC figures and scaled Case B11A costs would not provide a suitable comparison basis to draw any relevant conclusions.

However, the analysis was performed to address any discrepancies when comparing Case B11A-F0 costs estimates with the cost estimates of Case B11A scaled per the QGESS methodology. Upon comparison, it was clear that several Case B11A-F0 cost accounts were lower than predicted. The reasons for these account variations are addressed below for the accounts where the differential is most prominent:

- Account 1 (Coal and Sorbent Handling) and Account 2 (Coal and Sorbent Preparation and Feed) — Material selection, standardized equipment designs (e.g., rollers and conveyor belts), and broader supplier base typically reduce costs for material handling systems applicable to PC plants in the 150 MW size range; additionally, the opportunity for prefabrication of silos allows for significant cost reduction of these Account 1 and 2 systems.
- Account 7 (Ductwork & Stack) — For PC plants in the 150 MW size range, higher degrees of modularization of major duct sections and the stack are possible; additionally, step changes in standard supplier offerings (e.g., being able to utilize pre-fabricated and pre-insulated duct sections) also contribute to more competitive sub-system costs; a concrete stack is utilized for the flexible plant configuration due to plant size (MW) and

potential for stack height variations due to air permit dispersion modeling (taller stack requirements would likely require concrete).

- Account 10 (Ash & Spent Sorbent Handling Systems) — Similar to contributing factors to the cost competitiveness of Account 1 and Account 2 discussed above, the ash and spent storage system costs would be expected to be lower for a PC plant in the 150 MW size range (compared to the scaled Case B11A costs) due to step-change improvements in pre-fabricated supplier offerings and more standardized designs.
- Account 11 (Accessory Electric Plant) — The step change in system design, number of available suppliers, and competitive supplier market for smaller sized motor control centers (MCCs), VFDs, switchgear panels, and other accessory electric plant components would be expected to contribute to a reduction of Account 11 costs for Case B11A-F0 when compared to a larger scale PC plant's costs.
- Account 12 (Instrumentation & Control) — The application of advanced control systems and instrumentation is included in the estimated cost for Account 12 within Case B11A-F0; the cost premium for these 'advanced control techniques' and equipment are not as severely impactful to Account 12 cost due to their commercial availability, competitive supplier market, increasing standardization of hardware and software components, and various OEM mergers and acquisitions leading to increasingly competitive and modularized offerings; Account 12 within Case B11A accounted for 1.6 percent of the TPC (\$20,475,000 of \$1,306,806,000) and the Account 12 cost for Case B11A-F0 is approximately 1.4 percent (\$5,490,000 of \$392,808,000), which is considered to be reasonable given the more highly modularized systems for the Case B11A-F0 plant size and the previously identified items regarding the competitive supplier market and technology maturity.
- Account 13 (Site Improvement) — The significant reduction of site size contributes to a step-change reduction in the cost for site improvement(s) for a PC plant in the 150 MW size range compared to a scaled cost from a larger scale plant.
- Account 14 (Buildings & Structures) — As reflected in the capital cost summary tables, the Circulation Water Pumphouse was omitted due to the ACC replacing the wet mechanical draft cooling tower.
- 'Maintenance Material and Labor' costs in Case B11A [2] are 1.6 percent of TPC, distributed 40 percent to labor and 60 percent to material; all flexible plant cases match the distribution; Case B11A-F0 matches the 1.6 percent of TPC total.
- The number of 'Per-Shift' staff was reduced to align with 'total head count' figures and general staffing rules-of-thumb for similar sized plants (150 MW) based on Black & Veatch experience; plants of this size range will not typically have multiple lab techs staffed per shift; fewer techs would be expected to handle the amount of lab/processing data necessary for plant operations; 'Skilled Operators' are typically differentiated from 'Operators' by years of experience and ability to manage complex operational scenarios (e.g., startup, heavy cycling, emergency shutdowns).

- The SCR catalyst make-up rate would be expected to be consistent with a larger plant size due to the similar operating conditions (i.e., temperatures and normalized gas velocity across the catalyst and the likely similarity in chemical composition of the catalyst regardless of plant size (e.g., 687 MW or 150 MW).

5.4 SUBCRITICAL FLEXIBLE PLANT CASES

This section contains an evaluation of plant designs for B11A-F1, B11A-F2, B11A-F3, and B11A-F4, which are based on a subcritical flexible PC plant with a nominal gross output of 150 MWe. The plant uses a single reheat 12.4 MPa/538°C/538°C (1,800 psia/1,000°F/1,000°F) cycle.

The balance of this section is organized as follows:

- Key Assumptions is a summary of study and modeling assumptions relevant to cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4.
- Sparing Philosophy is provided for B11A-F1, B11A-F2, B11A-F3, and B11A-F4.
- Process Description provides an overview of the technology operation as applied to Case B11A-F1. The systems that are common to all PC cases were covered in Section 5.2 and only features that are unique to Case B11A-F1 are discussed further in this section.
- Performance Results provide the main modeling results from Case B11A-F1, including the full load performance summary, part load performance summary, environmental performance, carbon/sulfur balances, water balance, energy and mass balance diagrams and energy balance table.
- Major Equipment List provides an itemized list of major equipment for Case B11A-F1 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provide a summary of capital and operating costs for Case B11A-F1.
- Process Description, Performance Results, Major Equipment List and Cost Estimates are discussed for cases B11A-F2, B11A-F3, and B11A-F4.

5.4.1 Key System Assumptions

System assumptions for cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4, subcritical flexible PC plant with tiers 1–4 flexibility options, are compiled in Exhibit 5-41. Some of these parameters vary as the plant reduces load. For the values of process parameters that vary with load, refer to the cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4 performance curves in Section A.2 through Section A.5.

Exhibit 5-41. Subcritical flexible PC plant study configuration matrix

Case	B11A-F1	B11A-F2	B11A-F3	B11A-F4
Steam Cycle, MPa/°C/°C (psia/°F/°F)	12.4/538/538 (1,800/1,000/1,000)			
Steam Turbine	Sliding-Pressure Main Steam, Triple-Pressure (HP/IP/LP), Single-Reheat, Single-Shaft, Condensing			
Coal	Illinois No. 6			

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Case	B11A-F1	B11A-F2	B11A-F3	B11A-F4
Condenser Type	Air Cooled			
Condenser Pressure, mm Hg (in. Hg)	76.2 (3)			
Auxiliary Cooling	Ancillary Air-to-Glycol Cooling Loops			
Feedwater Pump	Motor-Driven, Hydraulic Coupling		Motor-Driven, VFD	
Fan Drives	Static Frequency		VFD	
Boiler Efficiency, HHV %	87.5			
Stack Temperature, °C (°F)	57 (135)			
SO ₂ Control	Wet Limestone Forced Oxidation			
FGD Efficiency, % ^A	98			
FGD Blowdown Treatment (Effluent Limitation Guidelines)	Spray dryer evaporator			
NO _x Control	LNB w/OFA, SCR			
SCR Efficiency, % ^A	77.7			
Ammonia Slip (end of catalyst life), ppmv	2			
Particulate Control	Fabric Filter			
Fabric Filter Efficiency, % ^A	99.9			
Ash Distribution, Fly/Bottom	80%/20%			
SO ₃ Control	DSI			
Mercury Control	Co-benefit Capture and ACI			

^ARemoval efficiencies are based on the flue gas content

5.4.1.1 Balance of Plant – Cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4

The balance of plant assumptions are common for cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4 and are presented in Exhibit 5-42.

Exhibit 5-42. Cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4 balance of plant assumptions

Parameter	Value
Cooling System	Air-Cooled Condenser
Fuel and Other Storage	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	30 days
Hydrated lime	7 days
Activated carbon	7 days
Plant Distribution Voltage	
Motors below 1 hp	110/220V

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Parameter	Value
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V
Steam and CT generators	24,000 V
Grid Interconnection voltage	345 kV
<u>Water and Waste Water</u>	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and deionized water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day).
Water Discharge	Blowdown will be treated for chloride and metals and discharged to the spray dryer evaporator.

5.4.2 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC subcritical boiler (1 x 100%)
- Two SCR reactors (2 x 50%)
- One DSI system (1 x 100%)
- One ACI system (1 x 100%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)

5.4.3 Process Description

The subcritical flexible PC process description is nearly identical to the subcritical baseload PC process description (see Section 5.3.3), so it is not repeated here.

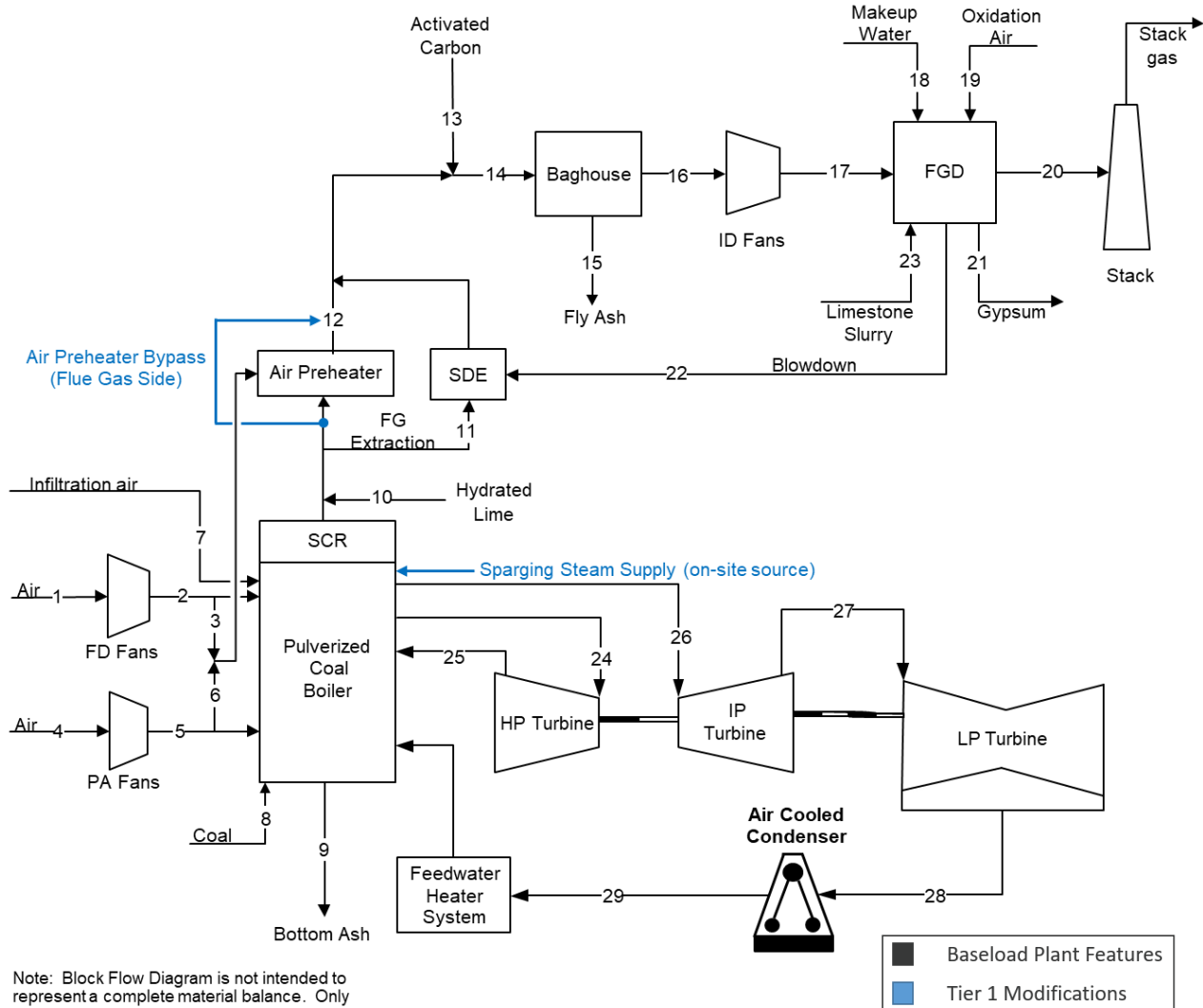
5.4.4 Case B11A-F1 – PC Subcritical Flexible Plant with Tier 1 Flexibility Options

The plant configuration for Case B11A-F1, subcritical flexible plant with Tier 1 flexibility options, is similar to Case B11A-F0. Major modifications to the plant include the installation of a flue gas side air preheater bypass, and installation of a sparging steam supply system. The full list of Tier 1 flexibility options was presented in Exhibit 4-14. The nominal gross plant output was maintained at 150 MW.

5.4.5 Case B11A-F1 – Full Load Performance Results

The BFD for Case B11A-F1 is shown in Exhibit 5-43. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 5-44. Full stream tables are only provided for the 100 percent load point.

Exhibit 5-43. Case B11A-F1 block flow diagram



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-44. Case B11A-F1 stream table, subcritical unit with Tier 1 flexibility options

	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	15,690	15,690	517	2,769	2,769	572	313	0	0	0
V-L Flowrate (kg/hr)	452,775	452,775	14,911	79,902	79,902	16,500	9,028	0	0	3
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	52,317	1,114	282
Temperature (°C)	15	21	21	15	23	23	15	15	1,316	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	36.30	36.30	30.23	38.73	38.73	30.23	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-91.51	-91.51	-97.58	-89.08	-89.08	-97.58	-2,119.02	1,312.68	-13,402.95
Density (kg/m ³)	1.2	1.3	1.3	1.2	1.3	1.3	1.2	---	---	1,003.6
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015
V-L Flowrate (lb _{mol} /hr)	34,591	34,591	1,139	6,104	6,104	1,261	690	0	0	0
V-L Flowrate (lb/hr)	998,199	998,199	32,873	176,153	176,153	36,377	19,904	0	0	6
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	115,339	2,457	622
Temperature (°F)	59	70	70	59	74	74	59	59	2,400	59
Pressure (psia)	14.7	15.6	15.6	14.7	16.0	16.0	14.7	14.7	14.3	14.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	15.6	15.6	13.0	16.7	16.7	13.0	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-39.3	-39.3	-42.0	-38.3	-38.3	-42.0	-911.0	564.3	-5,762.2
Density (lb/ft ³)	0.076	0.079	0.079	0.076	0.080	0.080	0.076	---	---	62.650

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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Exhibit 5-44. Case B11A-F1 stream table, subcritical unit with Tier 1 flexibility options, cont'd

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction										
Ar	0.0087	0.0088	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081
CO ₂	0.1463	0.1379	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0889	0.0844	0.0000	0.0918	0.0000	0.0918	0.0918	0.9967	0.0099	0.1512
HCl	0.0001	0.0001	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
N ₂	0.7312	0.7336	0.0000	0.7277	0.0000	0.7277	0.7277	0.0000	0.7732	0.6801
O ₂	0.0226	0.0332	0.0000	0.0325	0.0000	0.0325	0.0325	0.0000	0.2074	0.0360
SO ₂	0.0021	0.0020	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.1148	0.0000	0.0000	0.0006	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0001	0.8852	0.0000	0.0000	0.0028	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	943	18,875	0	19,978	1	19,976	19,976	2,783	844	22,336
V-L Flowrate (kg/hr)	28,056	560,343	0	591,341	129	591,209	591,209	50,913	24,365	641,810
Solids Flowrate (kg/hr)	242	4,553	11	4,851	4,854	0	0	457	0	0
Temperature (°C)	384	143	15	143	143	143	156	27	15	57
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	---	---	289.08	302.74	---	30.23	297.86
AspenPlus Enthalpy (kJ/kg) ^B	-2,278.03	-2,399.41	-6.79	-2,459.22	-1,001.46	-2,471.50	-2,457.84	-15,764.00	-97.58	-2,944.15
Density (kg/m ³)	0.5	0.8	---	0.8	2,150.2	0.8	0.9	1,002.4	1.2	1.1
V-L Molecular Weight	29.738	29.687	---	29.600	104.953	29.596	29.596	18.297	28.857	28.735
V-L Flowrate (lb _{mol} /hr)	2,080	41,612	0	44,043	3	44,040	44,040	6,135	1,861	49,241
V-L Flowrate (lb/hr)	61,853	1,235,344	0	1,303,683	285	1,303,392	1,303,392	112,244	53,715	1,414,948
Solids Flowrate (lb/hr)	532	10,038	25	10,694	10,701	0	0	1,008	0	0
Temperature (°F)	724	289	59	289	289	289	312	80	59	135
Pressure (psia)	14.3	14.0	14.7	14.0	14.0	13.8	15.1	14.7	14.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	---	---	124.3	130.2	---	13.0	128.1
AspenPlus Enthalpy (Btu/lb) ^B	-979.4	-1,031.6	-2.9	-1,057.3	-430.5	-1,062.6	-1,056.7	-6,777.3	-42.0	-1,265.8
Density (lb/ft ³)	0.033	0.052	---	0.051	134.232	0.051	0.054	62.580	0.076	0.067

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-44. Case B11A-F1 stream table, subcritical unit with Tier 1 flexibility options, cont'd

	21	22	23	24	25	26	27	28	29
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	47	159	656	23,122	21,512	21,512	19,488	16,963	19,769
V-L Flowrate (kg/hr)	855	2,942	11,825	416,551	387,541	387,541	351,090	305,597	356,152
Solids Flowrate (kg/hr)	7,695	45	5,062	0	0	0	0	0	0
Temperature (°C)	15	57	15	538	311	538	336	46	46
Pressure (MPa, abs)	0.10	0.10	0.10	12.41	2.48	2.36	0.59	0.01	1.40
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	3,444.19	3,034.74	3,547.75	3,135.60	2,463.74	194.88
AspenPlus Enthalpy (kJ/kg) ^B	-12,513.34	-15,495.46	-14,994.25	-12,536.10	-12,945.55	-12,432.55	-12,844.70	-13,516.56	-15,785.42
Density (kg/m ³)	880.9	979.4	1,003.7	36.2	9.8	6.4	2.1	0.1	990.2
V-L Molecular Weight	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	105	351	1,447	50,976	47,425	47,425	42,965	37,397	43,584
V-L Flowrate (lb/hr)	1,886	6,487	26,070	918,338	854,382	854,382	774,022	673,726	785,180
Solids Flowrate (lb/hr)	16,964	99	11,160	0	0	0	0	0	0
Temperature (°F)	59	135	59	1,000	592	1,000	636	115	115
Pressure (psia)	14.7	14.7	14.7	1,800.0	360.0	342.9	85.7	1.5	202.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	1,480.7	1,304.7	1,525.3	1,348.1	1,059.2	83.8
AspenPlus Enthalpy (Btu/lb) ^B	-5,379.8	-6,661.8	-6,446.4	-5,389.6	-5,565.6	-5,345.0	-5,522.2	-5,811.1	-6,786.5
Density (lb/ft ³)	54.996	61.143	62.658	2.258	0.611	0.400	0.133	0.005	61.819

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

At full load, the plant produces a net output of 138 MWe at a net plant efficiency of 34.9% (HHV basis). Full load performance for Case B11A-F1 is summarized in Exhibit 5-45. Exhibit 5-46 presents a detailed breakdown of auxiliary power requirements at full load.

Exhibit 5-45. Case B11A-F1 plant performance summary

Performance Summary	
Percent Load	100%
Total Gross Power, MWe	150
Nameplate Capacity, MWe	150
Total Auxiliaries, MWe	12
Total Auxiliaries, % of Gross Power	8.3%
Net Power, MWe	138
HHV Net Plant Efficiency, %	34.9%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,322 (9,784)
LHV Net Plant Efficiency, %	36.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,956 (9,436)
HHV Boiler Efficiency, %	87.5%
LHV Boiler Efficiency, %	90.7%
Steam Turbine Cycle Efficiency, %	43.5%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,278 (7,846)
Condenser Duty, GJ/hr (MMBtu/hr)	694 (658)
As-Received Coal Feed, kg/hr (lb/hr)	52,317 (115,339)
Limestone Sorbent Feed, kg/hr (lb/hr)	5,062 (11,160)
HHV Thermal Input, kWt	394,341
LHV Thermal Input, kWt	380,346
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)
Excess Air, %	20.0%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-46. Case B11A-F1 plant power summary

Power Summary	
Percent Load	100%
Steam Turbine Power, MWe	150
Total Gross Power, MWe	150
Nameplate Capacity	150
Auxiliary Load Summary	
Activated Carbon Injection, kWe	8
Air Cooled Condenser Fans	1,790
Ancillary Glycol Cooling Loops	250
Ash Handling, kWe	176
Baghouse, kWe	24
Boiler Feedwater Pump, kWe	2,790
Coal Handling and Conveying, kWe	110
Condensate Pumps, kWe	184
Dry Sorbent Injection, kWe	14
Flue Gas Desulfurizer, kWe	810
Forced Draft Fans, kWe	800
Ground Water Pumps, kWe	13
Induced Draft Fans, kWe	2,330
Miscellaneous Balance of Plant, ^A kWe	1,250
Primary Air Fans, kWe	199
Pulverizers, kWe	580
SCR, kWe	9
Sorbent Handling & Reagent Preparation, kWe	244
Spray Dryer Evaporator, kWe	58
Steam Turbine Auxiliaries, kWe	350
Transformer Losses, kWe	480
Total Auxiliaries, MWe	12
Net Power, MWe	138

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

5.4.5.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B11A-F1 is presented in Exhibit 5-47. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-47. Case B11A-F1 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	367 (404)	0.328 (0.724)
NO _x	0.034 (0.078)	355 (391)	0.318 (0.700)
Particulate	0.004 (0.010)	46 (50)	0.041 (0.090)
Hg	1.44E-7 (3.34E-7)	0.002 (0.002)	1.36E-6 (3.00E-6)
CO ₂	86 (201)	911,306 (1,004,543)	816 (1,799)
CO ₂ ^C	-	-	890 (1,962)
mg/Nm ³			
Particulate Concentration ^{D,E}	13.68		

^A Calculations based on an 85% capacity factor

^B Emissions based on gross power, except where otherwise noted

^C CO₂ emissions based on net power instead of gross power

^D Concentration of particles in the flue gas after the baghouse

^E Normal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.35 lb/MMBtu using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 77.7 percent to about 0.08 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and FGD system) is 95.1 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 5-48. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-48. Case B11A-F1 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	33,349 (73,523)	Stack Gas	33,402 (73,639)
Air (CO ₂)	77 (170)	FGD Product	40 (87)
PAC	11 (25)	Baghouse	410 (905)
FGD Reagent	514 (1,132)	Bottom Ash	100 (220)
Total	33,951 (74,850)	Total	33,951 (74,850)

Exhibit 5-49 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-49. Case B11A-F1 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	1,311 (2,891)	FGD Product	1,233 (2,719)
		Stack Gas	26 (56)
		Baghouse	52 (116)
Total	1,311 (2,891)	Total	1,311 (2,891)

Exhibit 5-50 shows the water balance for Case B11A-F1.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is reused as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from ground water. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-50. Case B11A-F1 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Desulfurizer Makeup	0.5 (144)	0.1 (19)	0.5 (126)	–	0.5 (126)
Deaerator Vent	–	–	–	0.0 (3.7)	0.0 (-3.7)
Condenser Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
BFW Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
Cooling Tower	–	–	–	–	–
BFW Blowdown	–	–	–	–	–
Total	0.6 (167)	0.1 (19)	0.6 (148)	0.0 (3.7)	0.5 (144)

5.4.5.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B11A-F1 PC boiler, the FGD unit, and steam cycle as shown in Exhibit 5-51 and Exhibit 5-52.

An overall plant energy balance is provided in tabular form in Exhibit 5-53. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-45) is calculated by multiplying the power out by the full load generator efficiency of 98.5 percent.

Exhibit 5-51. Case B11A-F1 energy and mass balance, subcritical PC boiler

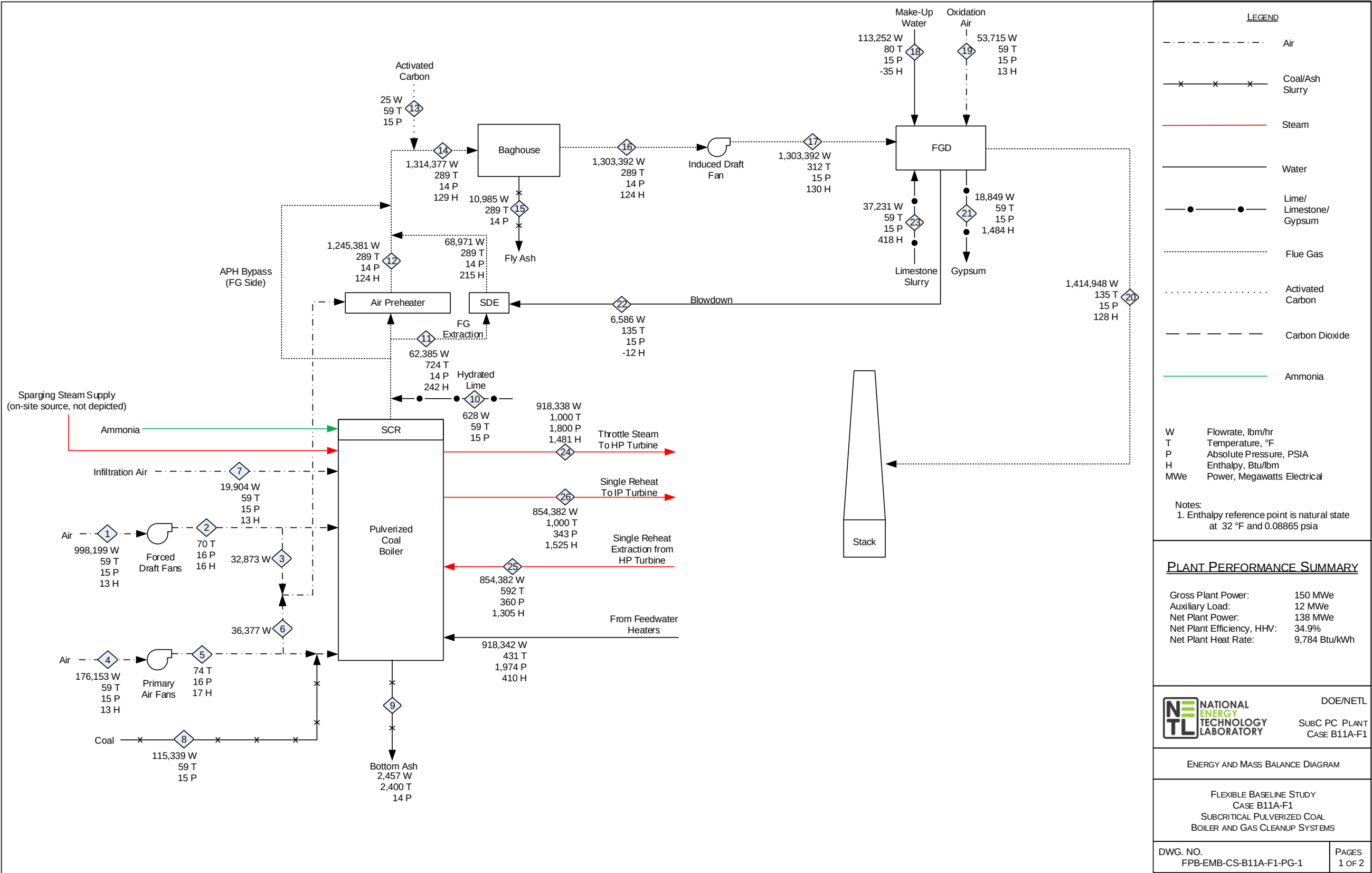
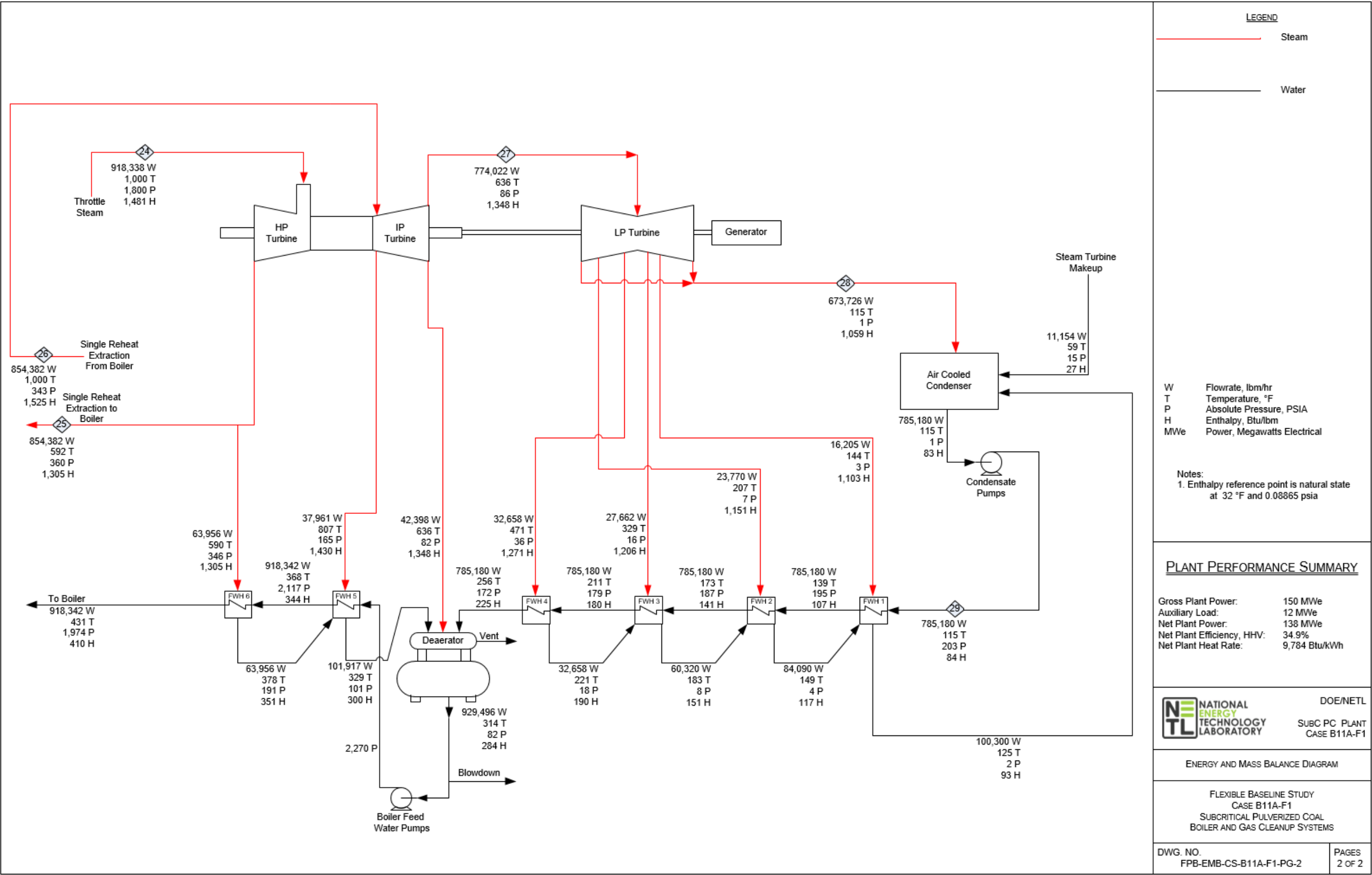


Exhibit 5-52. Case B11A-F1 energy and mass balance, subcritical steam cycle



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-53. Case B11A-F1 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	1,420 (1,346)	1.2 (1.1)	–	1,421 (1,347)
Air	–	16 (16)	–	16 (16)
Raw Water Makeup	–	2.1 (2.0)	–	2.1 (2.0)
Limestone	–	0.1 (0.1)	–	0.1 (0.1)
Auxiliary Power	–	–	45 (43)	45 (43)
Total	1,420 (1,346)	20 (19)	45 (43)	1,484 (1,407)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	1.5 (1.4)	–	1.5 (1.4)
Fly Ash	–	0.5 (0.5)	–	0.5 (0.5)
Stack Gas	–	191 (181)	–	191 (181)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Gypsum	–	0.5 (0.5)	–	0.5 (0.5)
Motor Losses and Design Allowances	–	–	8.7 (8.3)	8.7 (8.3)
Air Cooled Condenser Load ^A	–	694 (658)	–	694 (658)
Blowdown Streams and Deaerator Vent	–	3.3 (3.1)	–	3.3 (3.1)
<i>Ambient Losses^B</i>	–	39 (37)	–	39 (37)
Power	–	–	540 (512)	540 (512)
Total	0.0 (0.0)	930 (882)	549 (520)	1,479 (1,402)
<i>Unaccounted Energy^C</i>	–	–	–	5.3 (5.0)

^A Includes condenser load only

^B Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^C By difference

5.4.6 Case B11A-F1 – Part Load Performance Results

Plant performance results are summarized at each discrete load point in Exhibit 5-54. Exhibit 5-55 displays a detailed breakdown of the auxiliary power requirement at each discrete load point. Air emissions at each discrete load point are summarized in Exhibit 5-56.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-54. Case B11A-F1 part load plant performance summary

Performance Summary					
Percent Load	100%	75%	50%	30%	20%
Total Gross Power, MWe	150	113	75	45	30
Nameplate Capacity, MWe	150	150	150	150	150
Total Auxiliaries, MWe	12	10	8	5	4
Total Auxiliaries, % of Gross Power	8.3%	9.0%	10.1%	12.1%	14.1%
Net Power, MWe	138	102	67	40	26
HHV Net Plant Efficiency, %	34.9%	34.0%	32.6%	30.6%	28.8%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,322 (9,784)	10,589 (10,037)	11,040 (10,464)	11,764 (11,150)	12,485 (11,833)
LHV Net Plant Efficiency, %	36.2%	35.2%	33.8%	31.7%	29.9%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,956 (9,436)	10,213 (9,680)	10,648 (10,093)	11,347 (10,755)	12,042 (11,413)
HHV Boiler Efficiency, %	87.5%	87.5%	87.6%	87.6%	87.7%
LHV Boiler Efficiency, %	90.7%	90.7%	90.8%	90.9%	90.9%
Steam Turbine Cycle Efficiency, %	43.5%	42.7%	41.4%	39.7%	38.3%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,278 (7,846)	8,433 (7,993)	8,689 (8,235)	9,064 (8,591)	9,402 (8,911)
Condenser Duty, GJ/hr (MMBtu/hr)	694 (658)	536 (508)	376 (356)	242 (229)	171 (162)
As-Received Coal Feed, kg/hr (lb/hr)	52,317 (115,339)	39,953 (88,080)	27,424 (60,459)	17,153 (37,817)	11,857 (26,140)
Limestone Sorbent Feed, kg/hr (lb/hr)	5,062 (11,160)	3,874 (8,540)	2,670 (5,886)	1,678 (3,699)	1,163 (2,564)
HHV Thermal Input, kWt	394,341	301,144	206,707	129,294	89,373
LHV Thermal Input, kWt	380,346	290,457	199,372	124,705	86,201
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)	0.004 (1.1)	0.004 (1.2)	0.004 (1.1)	0.005 (1.2)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)	0.004 (1.1)	0.004 (1.1)	0.004 (1.1)	0.005 (1.2)
Excess Air, %	20.0%	22.1%	26.9%	33.0%	37.0%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-55. Case B11A-F1 part load plant power summary

Power Summary					
Percent Load	100%	75%	50%	30%	20%
Steam Turbine Power, MWe	150	113	75	45	30
Total Gross Power, MWe	150	113	75	45	30
Nameplate Capacity, MWe	150	150	150	150	150
Auxiliary Load Summary					
Activated Carbon Injection, kWe	8	6	4	3	2
Air Cooled Condenser Fans, kWe	1,790	1,780	1,250	750	470
Ancillary Glycol Cooling Loops, kWe	250	250	250	250	250
Ash Handling, kWe	176	133	90	55	37
Baghouse, kWe	24	18	12	7	5
Boiler Feedwater Pump, kWe	2,790	1,680	950	500	300
Coal Handling and Conveying, kWe	110	90	60	40	30
Condensate Pumps, kWe	184	119	77	50	37
Dry Sorbent Injection, kWe	14	10	6	3	1
Flue Gas Desulfurizer, kWe	810	730	720	620	500
Forced Draft Fans, kWe	800	660	460	260	140
Ground Water Pumps, kWe	13	10	8	5	4
Induced Draft Fans, kWe	2,330	1,830	1,270	790	520
Miscellaneous Balance of Plant, ^A kWe	1,250	1,250	1,250	1,250	1,250
Primary Air Fans, kWe	199	165	123	57	31
Pulverizers, kWe	580	440	300	190	130
SCR, kWe	9	8	6	4	3
Sorbent Handling and Reagent Preparation, kWe	244	187	129	81	56
Spray Dryer Evaporator, kWe	58	44	30	19	13
Steam Turbine Auxiliaries, kWe	350	350	350	350	350
Transformer Losses, kWe	480	360	250	150	100
Total Auxiliaries, MWe	12	10	8	5	4
Net Power, MWe	138	102	67	40	26

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-56. Case B11A-F1 part load air emissions summary

Emissions Summary					
Percent Load	100%	75%	50%	30%	20%
SO ₂ , kg/MWhgross (lb/MWhgross)	0.328 (0.724)	0.335 (0.738)	0.346 (0.763)	0.363 (0.799)	0.377 (0.831)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	816 (1,799)	831 (1,833)	858 (1,891)	896 (1,976)	931 (2,052)
CO ₂ , kg/MWhnet (lb/MWhnet)	890 (1,962)	914 (2,014)	954 (2,104)	1,020 (2,248)	1,084 (2,389)
Particulate Concentration, ^{A,B} mg/Nm ³	13.68	13.21	12.35	11.31	10.60

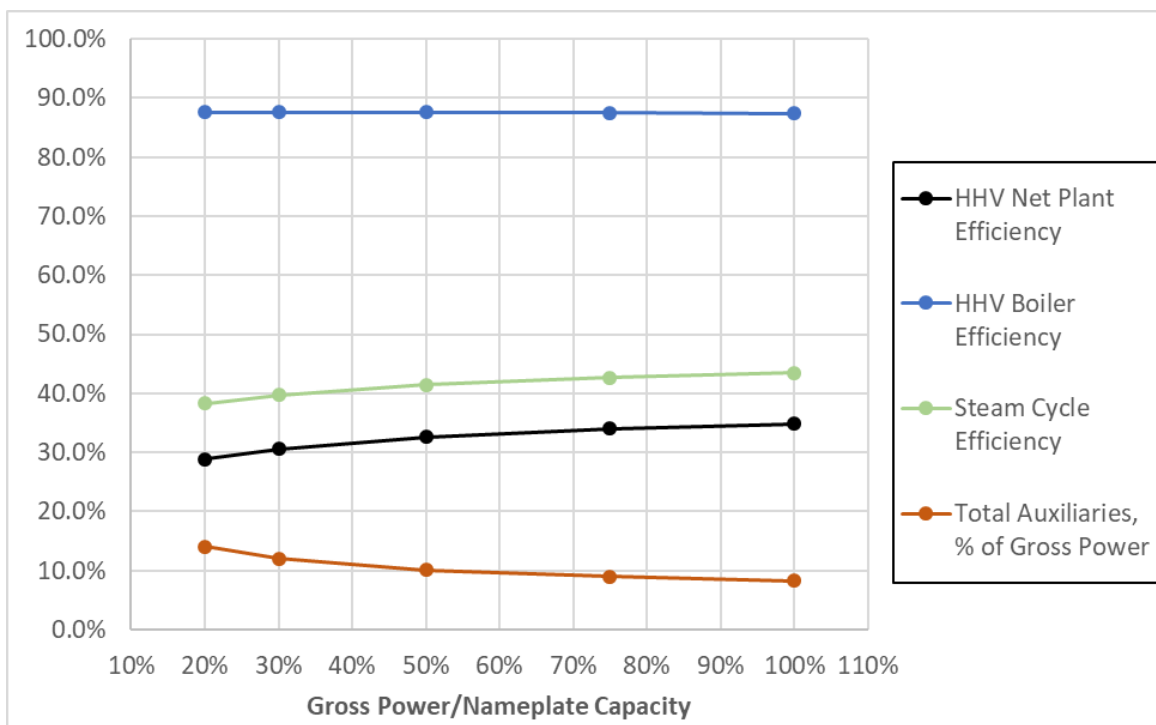
^A Concentration of particles in the flue gas after the baghouse

^B Normal conditions given at 32°F and 14.696 psia

Case B11A-F1 air emissions remained below the environmental target emission limits across the entire load range. Hg, NO_x, and PM emissions are maintained at constant levels across the load. SO₂ emissions increase as load is reduced but are kept below the environmental target emission limit.

Exhibit 5-57 displays the Case B11A-F1 itemized efficiencies (HHV net plant efficiency, HHV boiler efficiency, and steam cycle efficiency) and normalized auxiliary power consumption across the load range.

Exhibit 5-57. Case B11A-F1 part load itemized efficiencies



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Itemized efficiencies exhibit trends similar to those of Case B11A-F0. HHV net plant efficiency and steam cycle efficiency decrease as load is reduced, while HHV boiler efficiency improves slightly. However, compared to Case B11A-F0, the HHV net plant efficiency and steam cycle efficiency experience a much smaller penalty as load is reduced.

No flexibility options were implemented that impacted the modeled boiler efficiency, and it remains consistent with Case B11A-F0.

The improvement in the part load steam cycle efficiency is due to both sliding pressure operation and the implementation of an electric driven BFW pump. As described previously, sliding pressure reduces throttling losses at reduced loads, resulting in a lower steam cycle efficiency penalty. Furthermore, utilizing an electric driven BFW pump rather than a steam driven BFW pump eliminates the steam extraction required for the BFW pump steam turbine. Instead, the BFW pump power requirement is considered an auxiliary load and consequently no longer impacts the steam cycle efficiency.

5.4.7 Case B11A-F1 – Major Equipment List

Case B11A-F1 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	10 tonne (10 ton)	2	1
9	Feeder	Vibratory	40 tonne/hr (50 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	90 tonne/hr (100 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	40 tonne (50 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Transfer Tower No. 2	Enclosed	N/A	1	0
16	Coal Silo w/ Vent Filter and Slide Gates	Field erected	190 tonne (200 ton)	3	0
17	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 2 tonne (2 ton) Feeder - 10 kg/hr (30 lb/hr)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
18	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 50 tonne (60 ton) Feeder - 310 kg/hr (690 lb/hr)	1	0
19	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	21 tonne/hr (23 tph)	1	0
21	Limestone Conveyor No. 1	Belt	21 tonne/hr (23 tph)	1	0
22	Limestone Reclaim Hopper	N/A	4 tonne (5 ton)	1	0
23	Limestone Reclaim Feeder	Belt	16 tonne/hr (18 tph)	1	0
24	Limestone Conveyor No. 2	Belt	16 tonne/hr (18 tph)	1	0
25	Limestone Day Bin	w/ actuator	67 tonne (74 ton)	2	0

Case B11A-F1 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	10 tonne/hr (11 tph)	6	0
2	Coal Pulverizer	Rotary (Vertical)	10 tonne/hr (11 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	6 tonne/hr (6 tph)	1	1
4	Limestone Ball Mill	Rotary	6 tonne/hr (6 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	22,700 liters (6,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	380 lpm @ 10m H ₂ O (100 gpm @ 40 ft H ₂ O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	90 lpm (30 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	120,000 liters (32,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	250 lpm @ 9m H ₂ O (70 gpm @ 30 ft H ₂ O)	1	1

Case B11A-F1 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	334,000 liters (88,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,600 lpm @ 200 m H ₂ O (1,700 gpm @ 600 ft H ₂ O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	464,000 kg/hr (1,022,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump	Barrel type, multi-stage, centrifugal	7,700 lpm @ 1,900 m H ₂ O (2,000 gpm @ 6,100 ft H ₂ O)	1	1
5	N/A				

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	460,000 kg/hr (1,010,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	460,000 kg/hr (1,010,000 lb/hr)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	37 GJ/hr (35 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	14,600 lpm @ 30 m H ₂ O (3,900 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	150 lpm @ 20 m H ₂ O (40 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	150 lpm @ 270 m H ₂ O (40 gpm @ 880 ft H ₂ O)	2	1
22	Filtered Water Pumps	Stainless steel, single suction	350 lpm @ 50 m H ₂ O (90 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	340,000 liter (90,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 480 m ³ /min (17,120 acfm) @ 384°C (724°F) & 0.1 MPa (14 psia) Blowdown - 30 lpm (10 gpm) @ 20,018 ppmw Cl ⁻	2	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case B11A-F1 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	460,000 kg/hr steam @ 12.3 MPa/538°C/538°C (1,010,000 lb/hr steam @ 1,785 psig/1,000°F/1,000°F)	1	0
2	Primary Air Fan	Centrifugal	44,000 kg/hr, 600 m ³ /min @ 107 cm WG (97,000 lb/hr, 21,200 acfm @ 42 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	249,000 kg/hr, 3,400 m ³ /min @ 76 cm WG (549,000 lb/hr, 120,000 acfm @ 30 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	325,000 kg/hr, 6,700 m ³ /min @ 116 cm WG (717,000 lb/hr, 235,600 acfm @ 46 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	610,000 kg/hr (1,350,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	20 m ³ /min @ 108 cm WG (800 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	26,000 liter (7,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	5 lpm @ 90 m H ₂ O (1 gpm @ 300 ft H ₂ O)	2	1

Case B11A-F1 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	325,000 kg/hr (717,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	11,000 m ³ /min (389,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	64,000 lpm @ 65 m H ₂ O (17,000 gpm @ 210 ft H ₂ O)	3	1
4	Bleed Pumps	Horizontal centrifugal	1,070 lpm (280 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	180 m ³ /min @ 0.3 MPa (6,460 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	260 lpm (70 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	8 tonne/hr (9 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	160 lpm @ 13 m H ₂ O (40 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	110,000 lpm (30,000 gal)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
11	Process Makeup Water Pumps	Horizontal centrifugal	380 lpm @ 21 m H ₂ O (100 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	10 kg/hr (30 lb/hr)	1	0
13	Hydrated Lime Injectors	---	310 kg/hr (690 lb/hr)	1	0

Case B11A-F1 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	122 m (400 ft) high x 3.1 m (10 ft) diameter	1	0

Case B11A-F1 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	156 MW 12.3 MPa/538°C/538°C (1785 psig/ 1000°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	170 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Air-cooled Condenser	Forced draft, direct, A-frame air-cooled condenser	760 GJ/hr (720 MMBtu/hr), Condensing temperature 46°C (115°F), Ambient temperature 15°C (59°F)	1	0

Case B11A-F1 – Account 9: Auxiliary Cooling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Glycol Cooling Loops	Industrial grade, air to glycol, closed loop heat exchanger	10 GJ/hr (14 MMBtu/hr) heat duty	5	0

Case B11A-F1 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	1.2 tonne/hr (1.4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	12	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	5 m ³ /min @ 0.2 MPa (174 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	320 tonne (360 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	30 tonne/hr (30 tph)	1	0

Case B11A-F1 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 160 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 11 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 2 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Generator	Sized for black start capability	5000 kW, 480 V, 3-ph, 60 Hz	1	0

Case B11A-F1 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers, alarm management, HMIs, data historian, hard-wired control interface panels, and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor cabinets with redundant input/output, I/O cabinets, various I/C buses	Spare 25% I/O and processor bandwidth	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant	1	0

The following items represent the modifications to the major equipment categories for the Case B11A-F1 design basis, along with narrative regarding process description modifications. The Case B11A-F1 plant design includes the design features of Case B11A-F0 with the following modifications:

- **Account 2 — Coal and Sorbent Preparation and Feed**
 - Mill quantity estimated to increase from four for the baseload plant to approximately six for the Case B11A-F1 flexible plant
 - Increased (vertical roller) mill quantity will operate in a similar manner/philosophy compared to the baseload plant from a startup, shutdown and load change perspective; as outlined in the literature summary, there is a significant accumulation of mill operation best practices from existing coal-fired EGUs that include the operation of the mill shutdown scheme on SCR inlet temperatures, flame stability, radiant section coal ash slagging and steam temperatures. [24] [40]
 - Increased number of mills will allow for lower burner-level heat release (BLHR) (MBtu/hr/ft²), which allows for more granular low-load heat release control; based on Black & Veatch experience with evaluating boiler design parameters, lowering the BLHR allows for more even dispersion of the burner heat release, which leads to improvement heat absorption patterns in the radiant section of the boiler and is viewed as a means of proactively reducing the ash slagging buildup severity.
- **Account 3 — Feedwater and Miscellaneous System and Equipment**
 - Steam-driven BFW pump replaced with medium-voltage electric-driven BFW pump
 - Steam extraction for previous BFP turbine is eliminated.
 - The BFP electric motor operates at a constant speed with the shaft speed of the BFP modulated mechanical through use of a hydraulic coupling and/or planetary gear set.
 - This mechanical speed modulation provides pump efficiency improvements by eliminating throttling as a means of pressure control in exchange for speed control; the hydraulic coupling will exhibit reduced mechanical efficiency at significantly reduced loads (leading to the implementation of the VFD components in Tier 3).
 - Varying the shaft speed of the BFP modulates the pressure to the desired operating point during the sliding pressure operation.
 - Additional equipment added to natural gas auxiliary boiler and balance of plant to provide sparging steam.
- **Account 4 — Boiler and Accessories**

- Boiler design modified from “constant” pressure to “sliding” pressure (as necessary)
 - This design modification typically does not result in a significant step-change in unit size or extrinsic features.
- The economizer, SCR, and air heater gas-side bypasses can be implemented via small/moderate duct runs and control damper(s); no significant major equipment added; air heater air-side bypass achieved in a similar manner; economizer water-side bypass similarly can be equipped with small/moderate piping and control valve additions (no significant major equipment necessary).
 - All bypass functionality is operated in order to maintain water/flue gas temperature set points established within the control system; these bypass systems will likely be utilized predominantly during startup/shutdown and reduced (<50%) load conditions.
- **Account 8 — Steam Turbine Generator and Auxiliaries**
 - Steam turbine design changed from constant pressure to sliding pressure
 - No significant equipment modifications/changes for the steam turbine when converting from constant pressure to sliding pressure.
 - Throttling valve limitation for constant pressure units is one of the leading causes of minimum load limitations and operational issues; literature summary references confirm that extended periods of high throttling steam system (e.g., during reduced load periods) correlates to reduced lifetime of the turbine control valve by at least 20 percent. [30]
 - All major steam turbine OEMs will have models that can operate in both regimes; no significant commercial risk/operational risk with the sliding pressure units.
- **Account 11 — Accessory Electric Plant**
 - Emergency diesel (or optionally natural gas) generator would likely be increased in size (from current rating of 750 kW) to allow for plant black start capability.
 - Operation of the emergency reciprocating engine generator will largely be consistent with the functionality outlined in the baseload plant design; the notable change will be that the reciprocating engine generator outlined by Case B11A-F1 will be upsized for an increased nameplate capacity, equipped with larger battery storage units, and equipped with suitable switchgear to allow for full black start capabilities.
 - EGUs equipping these reciprocating engine generator units in the past 10-15 years has advanced the operational maturity of the technology and has developed a broad OEM base for these units across various fuel (diesel and/or natural gas) and operational demand (continuous or standby) bases, based on Black & Veatch experience with this technology.

5.4.8 Case B11A-F1 – Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-58 shows a detailed breakdown of the capital costs; Exhibit 5-59 shows the owner's costs, along with the TOC; and Exhibit 5-60 shows the initial and annual O&M costs.

The estimated TPC of the Case B11A-F1 plant is \$416 million. The project contingency is 13.3 percent of the TPC.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-58. Case B11A-F1 total plant cost summary

Case:		B11A-F1	Subcritical PC Flexible Plant (Tier 1)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
1 Coal & Sorbent Handling										
1.1	Coal Receive & Unload	\$267	\$0	\$120	\$0	\$387	\$68	\$0	\$68	\$523
1.2	Coal Stackout & Reclaim	\$876	\$0	\$196	\$0	\$1,072	\$188	\$0	\$189	\$1,448
1.3	Coal Conveyors	\$9,304	\$0	\$2,214	\$0	\$11,518	\$2,016	\$0	\$2,030	\$15,564
1.4	Other Coal Handling	\$1,036	\$0	\$218	\$0	\$1,254	\$219	\$0	\$221	\$1,694
1.5	Sorbent Receive & Unload	\$61	\$0	\$18	\$0	\$79	\$14	\$0	\$14	\$107
1.6	Sorbent Stackout & Reclaim	\$331	\$0	\$60	\$0	\$391	\$68	\$0	\$69	\$528
1.7	Sorbent Conveyors	\$588	\$128	\$142	\$0	\$858	\$150	\$0	\$151	\$1,159
1.8	Other Sorbent Handling	\$35	\$8	\$18	\$0	\$61	\$11	\$0	\$11	\$82
1.9	Coal & Sorbent Handling Foundations	\$0	\$430	\$567	\$0	\$997	\$175	\$0	\$176	\$1,348
	Subtotal	\$12,497	\$566	\$3,553	\$0	\$16,616	\$2,908	\$0	\$2,929	\$22,452
2 Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	\$569	\$0	\$109	\$0	\$678	\$119	\$0	\$120	\$916
2.2	Prepared Coal Storage & Feed	\$2,000	\$0	\$431	\$0	\$2,430	\$425	\$0	\$428	\$3,284
2.5	Sorbent Preparation Equipment	\$251	\$11	\$51	\$0	\$313	\$55	\$0	\$55	\$423
2.6	Sorbent Storage & Feed	\$405	\$0	\$153	\$0	\$557	\$98	\$0	\$98	\$753
2.9	Coal & Sorbent Feed Foundation	\$0	\$165	\$145	\$0	\$311	\$54	\$0	\$55	\$420
	Subtotal	\$3,224	\$176	\$889	\$0	\$4,289	\$751	\$0	\$756	\$5,796
3 Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	\$872	\$1,495	\$747	\$0	\$3,114	\$545	\$0	\$549	\$4,208
3.2	Water Makeup & Pretreating	\$1,460	\$146	\$827	\$0	\$2,433	\$426	\$0	\$572	\$3,431
3.3	Other Feedwater Subsystems	\$560	\$184	\$174	\$0	\$918	\$161	\$0	\$162	\$1,241
3.4	Service Water Systems	\$416	\$795	\$2,574	\$0	\$3,785	\$662	\$0	\$890	\$5,338
3.5	Other Boiler Plant Systems	\$170	\$62	\$155	\$0	\$387	\$68	\$0	\$68	\$523
3.6	Natural Gas Pipeline and Start-Up System	\$892	\$38	\$29	\$0	\$959	\$168	\$0	\$169	\$1,296
3.7	Waste Water Treatment Equipment	\$2,305	\$0	\$1,413	\$0	\$3,717	\$651	\$0	\$874	\$5,242
3.8	Spray Dryer Evaporator	\$4,228	\$0	\$2,448	\$0	\$6,676	\$1,168	\$0	\$1,569	\$9,413
3.9	Miscellaneous Plant Equipment	\$51	\$7	\$26	\$0	\$84	\$15	\$0	\$20	\$119
	Subtotal	\$10,955	\$2,727	\$8,394	\$0	\$22,075	\$3,863	\$0	\$4,872	\$30,810
4 Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	\$70,627	\$0	\$46,123	\$0	\$116,750	\$20,431	\$0	\$20,577	\$157,759
4.10	Selective Catalytic Reduction System	\$5,359	\$0	\$3,500	\$0	\$8,859	\$1,550	\$0	\$1,561	\$11,970
4.11	Boiler Balance of Plant	\$288	\$0	\$188	\$0	\$476	\$83	\$0	\$84	\$643
4.12	Primary Air System	\$341	\$0	\$223	\$0	\$563	\$99	\$0	\$99	\$761
4.13	Secondary Air System	\$692	\$0	\$452	\$0	\$1,144	\$200	\$0	\$202	\$1,546
4.14	Induced Draft Fans	\$1,297	\$0	\$847	\$0	\$2,145	\$375	\$0	\$378	\$2,898

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B11A-F1	Subcritical PC Flexible Plant (Tier 1)				Estimate Type: Cost Base:			Conceptual Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
4.15	Major Component Rigging	\$22	\$0	\$15	\$0	\$37	\$6	\$0	\$7	\$50
4.16	Boiler Foundations	\$0	\$96	\$85	\$0	\$181	\$32	\$0	\$32	\$244
	Subtotal	\$78,626	\$96	\$51,432	\$0	\$130,155	\$22,777	\$0	\$22,940	\$175,871
5		Flue Gas Cleanup								
5.2	WFGD Absorber Vessels & Accessories	\$20,989	\$0	\$4,488	\$0	\$25,477	\$4,458	\$0	\$4,490	\$34,426
5.3	Other FGD	\$73	\$0	\$82	\$0	\$155	\$27	\$0	\$27	\$210
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$595	\$131	\$585	\$0	\$1,311	\$229	\$0	\$231	\$1,772
5.9	Particulate Removal (Bag House & Accessories)	\$627	\$0	\$395	\$0	\$1,023	\$179	\$0	\$180	\$1,382
5.12	Gas Cleanup Foundations	\$0	\$42	\$37	\$0	\$78	\$14	\$0	\$14	\$106
5.13	Gypsum Dewatering System	\$187	\$0	\$32	\$0	\$219	\$38	\$0	\$39	\$296
	Subtotal	\$22,472	\$173	\$5,619	\$0	\$28,263	\$4,946	\$0	\$4,981	\$38,191
7		Ductwork & Stack								
7.3	Ductwork	\$0	\$209	\$145	\$0	\$354	\$62	\$0	\$62	\$478
7.4	Stack	\$2,526	\$0	\$1,468	\$0	\$3,993	\$699	\$0	\$704	\$5,396
7.5	Duct & Stack Foundations	\$0	\$51	\$61	\$0	\$112	\$20	\$0	\$26	\$158
	Subtotal	\$2,526	\$260	\$1,673	\$0	\$4,459	\$780	\$0	\$792	\$6,031
8		Steam Turbine & Accessories								
8.1	Steam Turbine Generator & Accessories	\$23,620	\$0	\$2,655	\$0	\$26,275	\$4,598	\$0	\$4,631	\$35,504
8.2	Steam Turbine Plant Auxiliaries	\$471	\$0	\$1,002	\$0	\$1,473	\$258	\$0	\$260	\$1,990
8.3	Condenser & Auxiliaries ^A	\$11,566	\$0	\$3,924	\$0	\$15,490	\$2,711	\$0	\$2,730	\$20,930
8.4	Steam Piping	\$10,602	\$0	\$4,297	\$0	\$14,899	\$2,607	\$0	\$2,626	\$20,132
8.5	Turbine Generator Foundations	\$0	\$57	\$94	\$0	\$151	\$26	\$0	\$35	\$213
	Subtotal	\$46,259	\$57	\$11,972	\$0	\$58,287	\$10,200	\$0	\$10,282	\$78,770
9		Cooling Water System								
9.6	Component Cooling Water System ^B	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
	Subtotal	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
10		Ash & Spent Sorbent Handling Systems								
10.6	Ash Storage Silos	\$300	\$0	\$917	\$0	\$1,217	\$213	\$0	\$214	\$1,644
10.7	Ash Transport & Feed Equipment	\$1,125	\$0	\$1,115	\$0	\$2,240	\$392	\$0	\$395	\$3,027
10.9	Ash/Spent Sorbent Foundation	\$0	\$202	\$248	\$0	\$449	\$79	\$0	\$106	\$633
	Subtotal	\$1,425	\$202	\$2,280	\$0	\$3,906	\$684	\$0	\$715	\$5,304
11		Accessory Electric Plant								
11.1	Generator Equipment	\$791	\$0	\$596	\$0	\$1,387	\$243	\$0	\$244	\$1,874
11.2	Station Service Equipment	\$1,433	\$0	\$123	\$0	\$1,556	\$272	\$0	\$274	\$2,103
11.3	Switchgear & Motor Control	\$2,384	\$0	\$414	\$0	\$2,798	\$490	\$0	\$493	\$3,781
11.4	Conduit & Cable Tray	\$0	\$323	\$931	\$0	\$1,254	\$219	\$0	\$221	\$1,695
11.5	Wire & Cable	\$0	\$635	\$1,136	\$0	\$1,771	\$310	\$0	\$312	\$2,393
11.6	Protective Equipment	\$17	\$0	\$60	\$0	\$77	\$13	\$0	\$14	\$104

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B11A-F1	Subcritical PC Flexible Plant (Tier 1)				Estimate Type: Cost Base:			Conceptual Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
11.7	Standby Equipment	\$224	\$0	\$206	\$0	\$430	\$75	\$0	\$76	\$581
11.8	Main Power Transformers	\$2,109	\$0	\$43	\$0	\$2,152	\$377	\$0	\$379	\$2,908
11.9	Electrical Foundations	\$0	\$57	\$146	\$0	\$203	\$36	\$0	\$48	\$286
	Subtotal	\$6,958	\$1,016	\$3,655	\$0	\$11,628	\$2,035	\$0	\$2,061	\$15,725
12 Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	\$185	\$0	\$33	\$0	\$217	\$38	\$0	\$38	\$294
12.3	Steam Turbine Control Equipment	\$182	\$0	\$20	\$0	\$203	\$35	\$0	\$36	\$274
12.5	Signal Processing Equipment	\$177	\$0	\$31	\$0	\$208	\$36	\$0	\$37	\$281
12.6	Control Boards, Panels & Racks	\$55	\$0	\$34	\$0	\$89	\$16	\$0	\$16	\$120
12.7	Distributed Control System Equipment	\$1,842	\$0	\$328	\$0	\$2,170	\$380	\$0	\$383	\$2,933
12.8	Instrument Wiring & Tubing	\$165	\$132	\$527	\$0	\$824	\$144	\$0	\$145	\$1,113
12.9	Other Instrumentation & Controls Equipment	\$196	\$0	\$454	\$0	\$650	\$114	\$0	\$114	\$878
	Subtotal	\$2,801	\$132	\$1,428	\$0	\$4,361	\$763	\$0	\$769	\$5,893
13 Improvements to Site										
13.1	Site Preparation	\$0	\$120	\$2,556	\$0	\$2,675	\$468	\$0	\$629	\$3,772
13.2	Site Improvements	\$0	\$656	\$867	\$0	\$1,523	\$266	\$0	\$358	\$2,147
13.3	Site Facilities	\$541	\$0	\$567	\$0	\$1,108	\$194	\$0	\$260	\$1,563
	Subtotal	\$541	\$776	\$3,990	\$0	\$5,306	\$929	\$0	\$1,247	\$7,482
14 Buildings & Structures										
14.2	Boiler Building	\$0	\$3,767	\$3,311	\$0	\$7,078	\$1,239	\$0	\$1,247	\$9,564
14.3	Steam Turbine Building	\$0	\$3,808	\$3,547	\$0	\$7,355	\$1,287	\$0	\$1,296	\$9,938
14.4	Administration Building	\$0	\$340	\$360	\$0	\$700	\$122	\$0	\$123	\$946
14.6	Water Treatment Buildings	\$0	\$97	\$88	\$0	\$184	\$32	\$0	\$33	\$249
14.7	Machine Shop	\$0	\$153	\$102	\$0	\$254	\$45	\$0	\$0	\$299
14.8	Warehouse	\$0	\$119	\$119	\$0	\$237	\$42	\$0	\$42	\$321
14.9	Other Buildings & Structures	\$0	\$86	\$73	\$0	\$159	\$28	\$0	\$28	\$214
14.10	Waste Treating Building & Structures	\$0	\$137	\$414	\$0	\$551	\$96	\$0	\$97	\$744
	Subtotal	\$0	\$8,506	\$8,012	\$0	\$16,518	\$2,891	\$0	\$2,866	\$22,275
	Total	\$188,669	\$14,685	\$103,192	\$0	\$306,546	\$53,646	\$0	\$55,330	\$415,522

^AACC; ^B Component cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
FLEXIBLE OPERATION

Exhibit 5-59. Case B11A-F1 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$4,255
1-Month Maintenance Materials	\$550
1-Month Non-Fuel Consumables	\$304
1-Month Waste Disposal	\$187
25% of 1-Month Fuel Cost at 100% CF	\$547
2% of TPC	\$8,310
Total	\$14,154
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$4,971
0.5% of TPC (spare parts)	\$2,078
Total	\$7,049
Other Costs	
Initial Cost for Catalyst and Chemicals	\$493
Land	\$117
Other Owner's Costs	\$62,328
Financing Costs	\$11,219
Total Overnight Costs (TOC)	\$510,881

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-60. Case B11A-F1 initial and annual operating and maintenance costs

Case:	B11A-F1	– Subcritical PC Flexible Plant (Tier 1)			Cost Base:	Dec 2018
Plant Size (MW, gross):	150	Heat Rate-net (Btu/kWh):			9,784	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$ /hour		Skilled Operator:	2.0	
Operating Labor Burden:	30.0	% of base		Operator:	3.0	
Labor O-H Charge Rate:	25.0	% of labor		Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	7.0	
Fixed Operating Costs						
					Annual Cost (\$)	
Annual Operating Labor:					\$3,069,066	
Maintenance Labor:					\$3,739,694	
Administrative & Support Labor:					\$1,702,190	
Property Taxes and Insurance:					\$8,310,431	
Total:					\$16,821,381	
Variable Operating Costs						
					Annual Cost (\$)	
Maintenance Material:					\$6,599,460 x CF	
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)	
Water (/1000 gallons):	0	107	\$1.90	\$0	\$73,873 x CF	
Makeup and Waste Water Treatment Chemicals (ton):	0	0.317	\$550.00	\$0	\$63,701 x CF	
Brominated Activated Carbon (ton):	0	0.304	\$1,600.00	\$0	\$177,431 x CF	
Enhanced Hydrated Lime (ton):	0	7.54	\$240.00	\$0	\$660,175 x CF	
Limestone (ton):	0	134	\$22.00	\$0	\$1,075,410 x CF	
Ammonia (19 wt%, ton):	0	13.1	\$300.00	\$0	\$1,436,390 x CF	
SCR Catalyst (ft³):	3,286	3.00	\$150.00	\$492,829	\$164,276 x CF	
Subtotal:				\$492,829	\$3,651,256 x CF	
Waste Disposal						
Fly Ash (ton):	0	132	\$38.00	\$0	\$1,828,422 x CF	
Bottom Ash (ton):	0	29.5	\$38.00	\$0	\$408,884 x CF	
SCR Catalyst (ft³):	0	3.00	\$2.50	\$0	\$2,738 x CF	
Subtotal:				\$0	\$2,240,044 x CF	
By-Products						
Gypsum (ton):	0	204	\$0.00	\$0	\$0	
Subtotal:				\$0	\$0	
Variable Operating Costs Total:				\$492,829	\$12,490,760 x CF	
Fuel Cost						
Illinois Number 6 (ton):	0	1,384	\$51.96	\$0	\$26,248,431 x CF	
Fuel Costs Total:				\$0	\$26,248,431 x CF	

5.4.8.1 Cost Differential Justifications

The primary contributors to the capital cost differential when comparing Case B11A-F1 to Case B11A-F0 are outlined below:

- Flexibility Option 52 — Online performance monitoring
- Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives
- Flexibility Option 7 — Economizer and feedwater heater bypass streams
- Flexibility Option 30 — Air heater bypass stream(s)
- Flexibility Option 31 — SCR reactor bypass stream
- Flexibility Option 41 — Application of 'continuous coupled' last stage blades to reduce flutter and dynamic stresses during low load operation
- Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Flexibility Option 81 — Investment in redundant/higher accuracy steam turbine casing metal temperature instruments
- Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation

The justifications for the capital cost differentials when comparing Case B11A-F1 to Case B11A-F0 are outlined below:

- Accounts 2.2 and 2.9 costs increase due to the coal system design modifications and equipment additions. The following flexibility options impacted the cost of accounts 2.2 and 2.9:
 - Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, and burner level
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
- Account 3.1 cost increases due to the increase in equipment and sub-system design for feedwater system engineering and installation. The following flexibility options impacted the cost of Account 3.1:
 - Flexibility Option 4 — Steam sparging
 - Flexibility Option 22 — Enhanced water chemistry monitoring and system response to cycling
- Account 3.2 cost increases due to an increase in engineering design, equipment, and material required for implementing additional testing and pretreating equipment (including the FFA and FFP equipment). The following flexibility options impacted the cost of Account 3.2:
 - Flexibility Option 22 — Enhanced water chemistry monitoring and system response to cycling
 - Flexibility Option 43 — Use of film forming amines or products to protect equipment from corrosion during layup and operation

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Account 3.4 cost increases due to service water required for the reciprocating engine, and the upgrades to the water chemistry monitoring system are expected to include additional equipment for the service water system. The following flexibility options impacted the cost of Account 3.4:
 - Flexibility Option 9 — Equipping the EGU with black start capability (e.g., reciprocating engine units)
 - Flexibility Option 22 — Enhanced water chemistry monitoring and system response to cycling
- Account 3.5 cost increases due to an increase in cost of the miscellaneous balance of plant systems that serve feedwater, steam, water treatment and service water systems such as engineered pipe supports, instrument routing, instrument installation, cooling water lines, instrument air lines, actuation air lines, damper seal air (if needed), etc. Replacement of all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives results in a 'price deduct' of Account 3; this deduct was counteracted by the increases in cost due to the other flexibility options impacting Account 3, and these competing factors ultimately resulted in a net increase of Account 3 cost. The following flexibility options impacted the cost of Account 3.5:
 - Flexibility Option 4 — Steam sparging
 - Flexibility Option 11 — Draft system isolation modifications to retain boiler heat as long as possible during shutdown periods
 - Flexibility Option 43 — Use of film forming amines or products to protect equipment from corrosion during layup and operation
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
 - Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives
- Account 3.9 cost increases due to an increased number of components (valves, drains, actuators) and engineering design and installation labor required for miscellaneous feedwater or steam-system-related areas. The following flexibility options impacted the cost of Account 3.9:
 - Flexibility Option 4 — Steam sparging
 - Flexibility Option 7 — Economizer and feedwater heater bypass streams
 - Flexibility Option 15 — Main steam warmup line to accelerate pipe wall temperature rise during startup
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Account 4.9 (PC Boiler and Accessories) for the PC Boiler and Account 8.1 (Steam Turbine Generator & Auxiliaries) for the STG; switching to a unit designed for sliding

pressure operation is not expected to increase or decrease the cost of the steam cycle and would not be expected to significantly modify the engineering design or system configuration for the boiler and steam turbine; the OEM offerings for these components do not vary considerably with respect to cost or design complexity between the constant pressure and sliding pressure operating schemes due to both systems being designed for the same top-end operating pressure and code-required design pressures (e.g., 1,800 psig); it is for these reasons that no cost increase or decrease was applied to the Case B11A-F1 for the implementation of Flexibility Option 59 (steam turbine sliding pressure operation). Overall, the Account 4.9 cost demonstrates a net increase as a result of the Tier 1 flexibility options due to the addition of new standalone equipment, sub-system features within the boiler island components, and additional engineering and installation labor required for these options. The following flexibility options impacted the cost of Account 4.9:

- Flexibility Option 4 — Steam sparging
 - Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, and burner level
 - Flexibility Option 7 — Economizer and feedwater heater bypass streams
 - Flexibility Option 11 — Draft system isolation modifications to retain boiler heat as long as possible during shutdown periods
 - Flexibility Option 30 — Air heater bypass stream(s)
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
 - Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Account 4.10 (Selective Catalytic Reduction System) cost increases due to the SCR OEM equipment design and fabrication differences (e.g., additional reactor penetrations) for the SCR reactor module knowing that an SCR bypass will be equipped in addition to the new build SCR bypass duct cost. The following flexibility options impacted the cost of Account 4.10:
 - Flexibility Option 32 — SCR reactor bypass stream
- Account 4.11 cost increases due to the additional equipment requiring boiler balance of plant sub-system engineering design (e.g., instrument air lines, electrical routing, more intricate pipe routing for clash avoidance, additional maintenance access points) and material installation. The following flexibility options impacted the cost of Account 4.11:
 - Flexibility Option 4 — Steam sparging

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
 - Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation
- Account 4.12 cost increases due to modifications to the coal system, which have a related impact on primary air system (e.g., number of PA ducts and headers, number of PA control dampers, safety instrumentation). The following flexibility options impacted the cost of Account 4.12:
 - Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, and burner level
 - Flexibility Option 11 — Draft system isolation modifications to retain boiler heat as long as possible during shutdown periods
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
- Account 4.15 cost increases due to the additional material supply and installation labor required for the major component rigging with the addition of new equipment, specifically the equipment that is erected at height above grade. The following flexibility options impacted the cost of Account 4.15:
 - Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, burner level
 - Flexibility Option 15 — Main steam warmup line to accelerate pipe wall temperature rise during startup
 - Flexibility Option 29 — Economizer gas-side bypass stream
 - Flexibility Option 30 — Air heater bypass stream(s)
 - Flexibility Option 31 — SCR bypass stream
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
- Account 7.3 increased due to the cost for the air heater (flue gas) bypass duct; when comparing the SCR bypass duct to the air heater bypass duct, the relative costs of these ductwork additions appropriately align with each other due to the higher duct cost being appropriate for the higher-temperature and longer-distance SCR gas bypass; the air heater bypass duct would be expected to be much shorter than the SCR bypass duct; additionally, the air heater bypass would be designed to a lower design temperature (i.e., lower grade carbon steel) due to its location in the gas path (thereby further reducing costs) The following flexibility options impacted the cost of Account 7.3:
 - Flexibility Option 30 — Air heater bypass stream(s)

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Account 8.1 cost increases due to the addition of equipment to the steam turbine island and scope of supply; this additional equipment would require additional engineering and installation hours. The following flexibility options impacted the cost of Account 8.1:
 - Flexibility Option 18 — Electric-resistance heating blankets for the steam turbine casing sections to pre-heat the casing
 - Flexibility Option 41 — Application of ‘continuous coupled’ last stage blades to reduce flutter and dynamic stresses during low load operation
- Account 8.2 cost increases due to the addition of ancillary components, such as instruments or instrument connection features to the steam turbine auxiliaries that would require additional engineering design and material supply. The following flexibility options impacted the cost of Account 8.2:
 - Flexibility Option 7 — Economizer and feedwater heater bypass streams
 - Flexibility Option 17 — Additional thermocouples to measure the steam-metal temperature differentials
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
 - Flexibility Option 81 — Investment in redundant and higher accuracy steam turbine casing metal temperature instruments
- Account 8.3 cost increases due to additional sub-system design engineering activities and equipment components added. The following flexibility options impacted the cost of Account 8.3:
 - Flexibility Option 57 — Self-cleaning condenser design with stable backpressure target
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Account 8.4 cost increases due to an increase in engineering design, material, and installation labor required for implementing the modifications to the steam piping; the additional steam cycle instruments would be expected to increase the cost of the steam piping due to the need for additional instrument penetrations, supports and drip legs. The following flexibility options impacted the cost of Account 8.4:
 - Flexibility Option 4/15 — Steam sparging/main steam warmup line
 - Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives (cost decrease associated with implementing this Option since a steam line would be removed from the plant design)
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions (cost increase to 8.4 due to increases in number of instrument locations, drip legs and supports)

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Accounts 11.3–11.6 costs increase due to the addition of equipment or additional sub-systems within the plant design. Adding equipment has compulsory impacts to the plant's electrical system design (e.g., MCCs, switchgear, protective relays, cable trays, cable wiring, etc.) resulting from the addition of new equipment (even when considering the NOAK plant estimate methodology). The following flexibility options impacted the cost of accounts 11.3–11.6:
 - Flexibility Option 18 — Electric-resistance heating blankets for the steam turbine casing sections to pre-heat the casing
 - Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
 - Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
 - Flexibility Option 81 — Investment in redundant and higher accuracy steam turbine casing metal temperature instruments
- Account 11.7 cost increased due to the increase to the size of the reciprocating engine generator; this cost increase was applied to Account 11.7 'Standby Equipment' due to its title of 'Emergency Generator' in the Account 11 Equipment List.
 - Flexibility Option 9 — Equipping the EGU with black start capability (e.g., reciprocating engine units)
- Account 11.9 cost increased due to the additional electrical equipment requiring additional foundation engineering design, material supply, and installation cost. The following flexibility options impacted the cost of Account 11.9:
 - Flexibility Option 18 — Electric-resistance heating blankets for the steam turbine casing sections to pre-heat the casing
 - Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives
- Account 12 cost increased due to the increase in hardware and software components associated with the Case B11A-F1 flexibility options; the implementation of these options requires additional equipment (hardware) supply, material supply (e.g., wiring, conduit, raceway), installation hours for physically installing the components and commissioning hours where specialists program and tune the system prior to commercial operation. The following flexibility options impacted the cost of Account 12:
 - Flexibility Option 4/15 — Steam sparging/main steam warmup line

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, burner level
- Flexibility Option 9 — Equipping the EGU with black start capability (e.g., reciprocating engine units)
- Flexibility Option 11 — Draft system isolation modifications to retain boiler heat as long as possible during shutdown periods
- Flexibility Option 17 — Additional thermocouples to measure the steam-metal temperature differentials
- Flexibility Option 22 — Enhanced water chemistry monitoring and system response to cycling
- Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives
- Flexibility Option 29 — Economizer gas-side bypass stream
- Flexibility Option 30 — Air heater bypass stream(s)
- Flexibility Option 31 — SCR bypass stream
- Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
- Flexibility Option 43 — Use of film forming amines or products to protect equipment from corrosion during layup and operation
- Flexibility Option 52 — Online performance monitoring
- Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation
- Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Flexibility Option 81 — Investment in redundant/higher accuracy steam turbine casing metal temperature instruments; closer monitoring of these temperatures allows for more accurate tracking of design life/maintenance overhaul projections

The justifications for the O&M cost differentials when comparing Case B11A-F1 to Case B11A-F0 are outlined below:

- Maintenance Material and Labor costs are increased from 1.6 percent of TPC in Case B11A-F0 to 2.3 percent of TPC in Case B11A-F1, which is considered a reasonable average increase in proactive maintenance and standardized maintenance programs for high cycling PC EGUs. However, the actual cost of maintenance material and labor would be dependent upon the specific operational profile of the plant.

5.4.9 Case B11A-F2 – PC Subcritical Flexible Plant with Tier 1 and 2 Flexibility Options

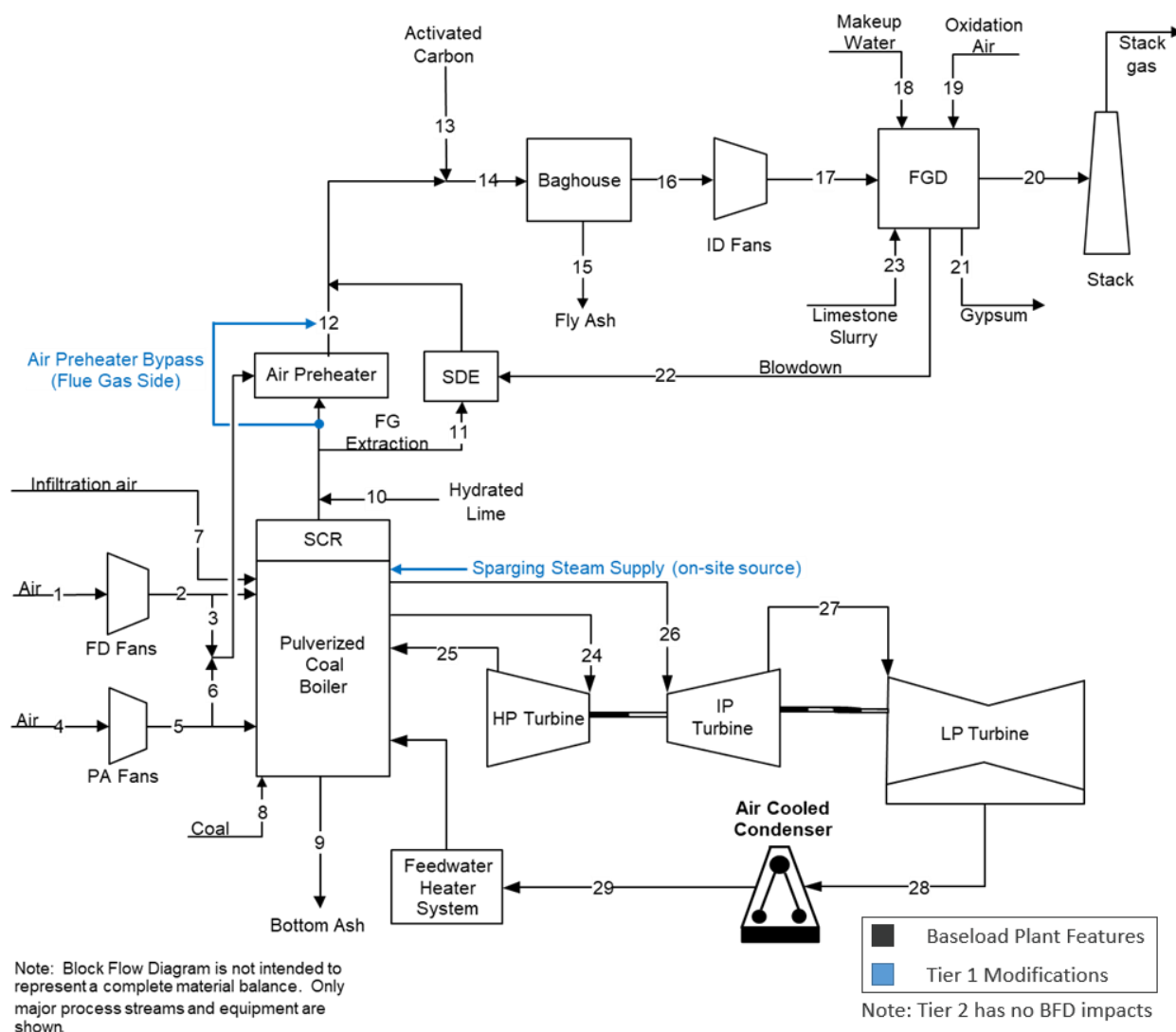
The following subsections outline the Case B11A-F2 BFD modifications, full and part load performance results, and cost estimates.

The plant configuration for Case B11A-F2, subcritical flexible plant with Tier 1 and 2 flexibility options, is identical to Case B11A-F1. The full list of Tier 2 flexibility options was presented in Exhibit 4-15. The nominal gross plant output was maintained at 150 MW.

5.4.10 Case B11A-F2 – Full Load Performance Results

The BFD for Case B11A-F2 is shown in Exhibit 5-61. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 5-62. Full stream tables are only provided for the 100 percent load point.

Exhibit 5-61. Case B11A-F2 block flow diagram



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-62. Case B11A-F2 stream table, subcritical unit with tiers 1–2 flexibility options

	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	15,690	15,690	517	2,769	2,769	572	313	0	0	0
V-L Flowrate (kg/hr)	452,775	452,775	14,911	79,902	79,902	16,500	9,028	0	0	3
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	52,317	1,114	282
Temperature (°C)	15	21	21	15	23	23	15	15	1,316	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	36.30	36.30	30.23	38.73	38.73	30.23	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-91.51	-91.51	-97.58	-89.08	-89.08	-97.58	-2,119.02	1,312.68	-13,402.95
Density (kg/m ³)	1.2	1.3	1.3	1.2	1.3	1.3	1.2	---	---	1,003.6
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015
V-L Flowrate (lb _{mol} /hr)	34,591	34,591	1,139	6,104	6,104	1,261	690	0	0	0
V-L Flowrate (lb/hr)	998,199	998,199	32,873	176,153	176,153	36,377	19,904	0	0	6
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	115,339	2,457	622
Temperature (°F)	59	70	70	59	74	74	59	59	2,400	59
Pressure (psia)	14.7	15.6	15.6	14.7	16.0	16.0	14.7	14.7	14.3	14.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	15.6	15.6	13.0	16.7	16.7	13.0	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-39.3	-39.3	-42.0	-38.3	-38.3	-42.0	-911.0	564.3	-5,762.2
Density (lb/ft ³)	0.076	0.079	0.079	0.076	0.080	0.080	0.076	---	---	62.650

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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Exhibit 5-62. Case B11A-F2 stream table, subcritical unit with tiers 1–2 flexibility options, cont'd

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction										
Ar	0.0087	0.0088	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081
CO ₂	0.1463	0.1379	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0889	0.0844	0.0000	0.0918	0.0000	0.0918	0.0918	0.9967	0.0099	0.1512
HCl	0.0001	0.0001	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
N ₂	0.7312	0.7336	0.0000	0.7277	0.0000	0.7277	0.7277	0.0000	0.7732	0.6801
O ₂	0.0226	0.0332	0.0000	0.0325	0.0000	0.0325	0.0325	0.0000	0.2074	0.0360
SO ₂	0.0021	0.0020	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.1148	0.0000	0.0000	0.0006	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0001	0.8852	0.0000	0.0000	0.0028	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	943	18,875	0	19,978	1	19,976	19,976	2,783	844	22,336
V-L Flowrate (kg/hr)	28,056	560,343	0	591,341	129	591,209	591,209	50,913	24,365	641,810
Solids Flowrate (kg/hr)	242	4,553	11	4,851	4,854	0	0	457	0	0
Temperature (°C)	384	143	15	143	143	143	156	27	15	57
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	---	---	289.08	302.74	---	30.23	297.86
AspenPlus Enthalpy (kJ/kg) ^B	-2,278.03	-2,399.41	-6.79	-2,459.22	-1,001.46	-2,471.50	-2,457.84	-15,764.00	-97.58	-2,944.15
Density (kg/m ³)	0.5	0.8	---	0.8	2,150.2	0.8	0.9	1,002.4	1.2	1.1
V-L Molecular Weight	29.738	29.687	---	29.600	104.953	29.596	29.596	18.297	28.857	28.735
V-L Flowrate (lb _{mol} /hr)	2,080	41,612	0	44,043	3	44,040	44,040	6,135	1,861	49,241
V-L Flowrate (lb/hr)	61,853	1,235,344	0	1,303,683	285	1,303,392	1,303,392	112,244	53,715	1,414,948
Solids Flowrate (lb/hr)	532	10,038	25	10,694	10,701	0	0	1,008	0	0
Temperature (°F)	724	289	59	289	289	289	312	80	59	135
Pressure (psia)	14.3	14.0	14.7	14.0	14.0	13.8	15.1	14.7	14.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	---	---	124.3	130.2	---	13.0	128.1
AspenPlus Enthalpy (Btu/lb) ^B	-979.4	-1,031.6	-2.9	-1,057.3	-430.5	-1,062.6	-1,056.7	-6,777.3	-42.0	-1,265.8
Density (lb/ft ³)	0.033	0.052	---	0.051	134.232	0.051	0.054	62.580	0.076	0.067

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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Exhibit 5-62. Case B11A-F2 stream table, subcritical unit with tiers 1–2 flexibility options, cont'd

	21	22	23	24	25	26	27	28	29
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	47	159	656	23,122	21,512	21,512	19,488	16,963	19,769
V-L Flowrate (kg/hr)	855	2,942	11,825	416,551	387,541	387,541	351,090	305,597	356,152
Solids Flowrate (kg/hr)	7,695	45	5,062	0	0	0	0	0	0
Temperature (°C)	15	57	15	538	311	538	336	46	46
Pressure (MPa, abs)	0.10	0.10	0.10	12.41	2.48	2.36	0.59	0.01	1.40
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	3,444.19	3,034.74	3,547.75	3,135.60	2,463.74	194.88
AspenPlus Enthalpy (kJ/kg) ^B	-12,513.34	-15,495.46	-14,994.25	-12,536.10	-12,945.55	-12,432.55	-12,844.70	-13,516.56	-15,785.42
Density (kg/m ³)	880.9	979.4	1,003.7	36.2	9.8	6.4	2.1	0.1	990.2
V-L Molecular Weight	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	105	351	1,447	50,976	47,425	47,425	42,965	37,397	43,584
V-L Flowrate (lb/hr)	1,886	6,487	26,070	918,338	854,382	854,382	774,022	673,726	785,180
Solids Flowrate (lb/hr)	16,964	99	11,160	0	0	0	0	0	0
Temperature (°F)	59	135	59	1,000	592	1,000	636	115	115
Pressure (psia)	14.7	14.7	14.7	1,800.0	360.0	342.9	85.7	1.5	202.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	1,480.7	1,304.7	1,525.3	1,348.1	1,059.2	83.8
AspenPlus Enthalpy (Btu/lb) ^B	-5,379.8	-6,661.8	-6,446.4	-5,389.6	-5,565.6	-5,345.0	-5,522.2	-5,811.1	-6,786.5
Density (lb/ft ³)	54.996	61.143	62.658	2.258	0.611	0.400	0.133	0.005	61.819

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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At full load, the plant produces a net output of 138 MWe at a net plant efficiency of 34.9 percent (HHV basis). Full load performance for Case B11A-F2 is summarized in Exhibit 5-63. Exhibit 5-64 presents a detailed breakdown of auxiliary power requirements at full load.

Exhibit 5-63. Case B11A-F2 plant performance summary

Performance Summary	
Percent Load	100%
Total Gross Power, MWe	150
Nameplate Capacity, MWe	150
Total Auxiliaries, MWe	12
Total Auxiliaries, % of Gross Power	8.3%
Net Power, MWe	138
HHV Net Plant Efficiency, %	34.9%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,322 (9,784)
LHV Net Plant Efficiency, %	36.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,956 (9,436)
HHV Boiler Efficiency, %	87.5%
LHV Boiler Efficiency, %	90.7%
Steam Turbine Cycle Efficiency, %	43.5%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,278 (7,846)
Condenser Duty, GJ/hr (MMBtu/hr)	694 (658)
As-Received Coal Feed, kg/hr (lb/hr)	52,317 (115,339)
Limestone Sorbent Feed, kg/hr (lb/hr)	5,062 (11,160)
HHV Thermal Input, kWt	394,341
LHV Thermal Input, kWt	380,346
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)
Excess Air, %	20.0%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-64. Case B11A-F2 plant power summary

Power Summary	
Percent Load	100%
Steam Turbine Power, MWe	150
Total Gross Power, MWe	150
Nameplate Capacity	150
Auxiliary Load Summary	
Activated Carbon Injection, kWe	8
Air Cooled Condenser Fans	1,790
Ancillary Glycol Cooling Loops	250
Ash Handling, kWe	176
Baghouse, kWe	24
Boiler Feedwater Pump, kWe	2,790
Coal Handling and Conveying, kWe	110
Condensate Pumps, kWe	184
Dry Sorbent Injection, kWe	14
Flue Gas Desulfurizer, kWe	810
Forced Draft Fans, kWe	800
Ground Water Pumps, kWe	13
Induced Draft Fans, kWe	2,330
Miscellaneous Balance of Plant, ^A kWe	1,250
Primary Air Fans, kWe	199
Pulverizers, kWe	580
SCR, kWe	9
Sorbent Handling & Reagent Preparation, kWe	244
Spray Dryer Evaporator, kWe	58
Steam Turbine Auxiliaries, kWe	350
Transformer Losses, kWe	480
Total Auxiliaries, MWe	12
Net Power, MWe	138

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

5.4.10.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B11A-F2 is presented in Exhibit 5-65. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-65. Case B11A-F2 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	367 (404)	0.328 (0.724)
NO _x	0.034 (0.078)	355 (391)	0.318 (0.700)
Particulate	0.004 (0.010)	46 (50)	0.041 (0.090)
Hg	1.44E-7 (3.34E-7)	0.002 (0.002)	1.36E-6 (3.00E-6)
CO ₂	86 (201)	911,306 (1,004,543)	816 (1,799)
CO ₂ ^C	-	-	890 (1,962)
mg/Nm ³			
Particulate Concentration ^{D,E}	13.68		

^A Calculations based on an 85% capacity factor

^B Emissions based on gross power, except where otherwise noted

^C CO₂ emissions based on net power instead of gross power

^D Concentration of particles in the flue gas after the baghouse

^E Normal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.35 lb/MMBtu using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 77.7 percent to about 0.08 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and FGD system) is 95.1 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 5-66. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

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Exhibit 5-66. Case B11A-F2 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	33,349 (73,523)	Stack Gas	33,402 (73,639)
Air (CO ₂)	77 (170)	FGD Product	40 (87)
PAC	11 (25)	Baghouse	410 (905)
FGD Reagent	514 (1,132)	Bottom Ash	100 (220)
Total	33,951 (74,850)	Total	33,951 (74,850)

Exhibit 5-67 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-67. Case B11A-F2 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	1,311 (2,891)	FGD Product	1,233 (2,719)
		Stack Gas	26 (56)
		Baghouse	52 (116)
Total	1,311 (2,891)	Total	1,311 (2,891)

Exhibit 5-68 shows the water balance for Case B11A-F2.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is reused as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from ground water. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-68. Case B11A-F2 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Desulfurizer Makeup	0.5 (144)	0.1 (19)	0.5 (126)	–	0.5 (126)
Deaerator Vent	–	–	–	0.0 (3.7)	0.0 (–3.7)
Condenser Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
BFW Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
Cooling Tower	–	–	–	–	–
BFW Blowdown	–	–	–	–	–
Total	0.6 (167)	0.1 (19)	0.6 (148)	0.0 (3.7)	0.5 (144)

5.4.10.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B11A-F2 PC boiler, the FGD unit, and steam cycle as shown in Exhibit 5-69 and Exhibit 5-70.

An overall plant energy balance is provided in tabular form in Exhibit 5-71. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-63) is calculated by multiplying the power out by the full load generator efficiency of 98.5 percent.

Exhibit 5-69. Case B11A-F2 energy and mass balance, subcritical PC boiler

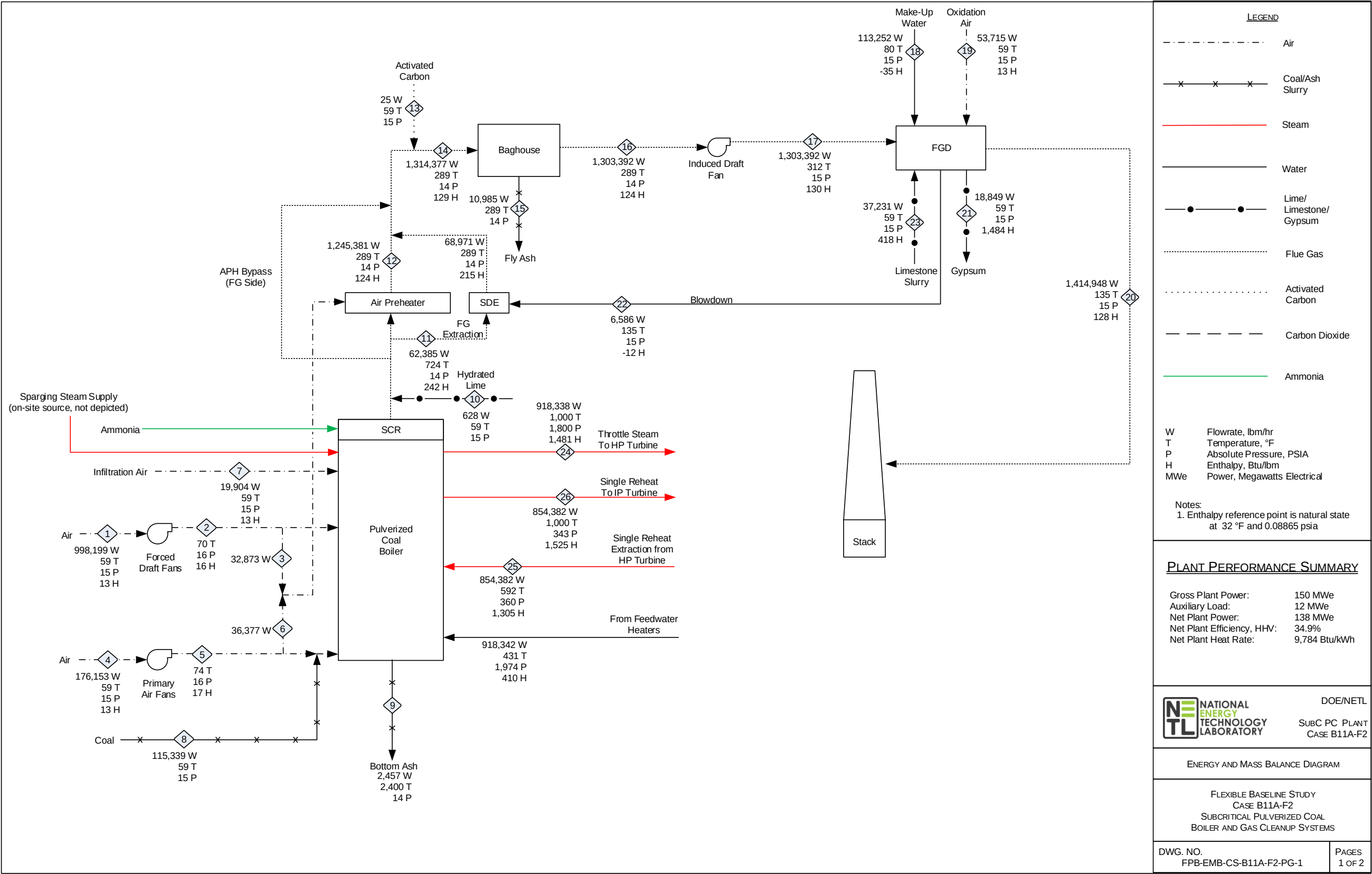
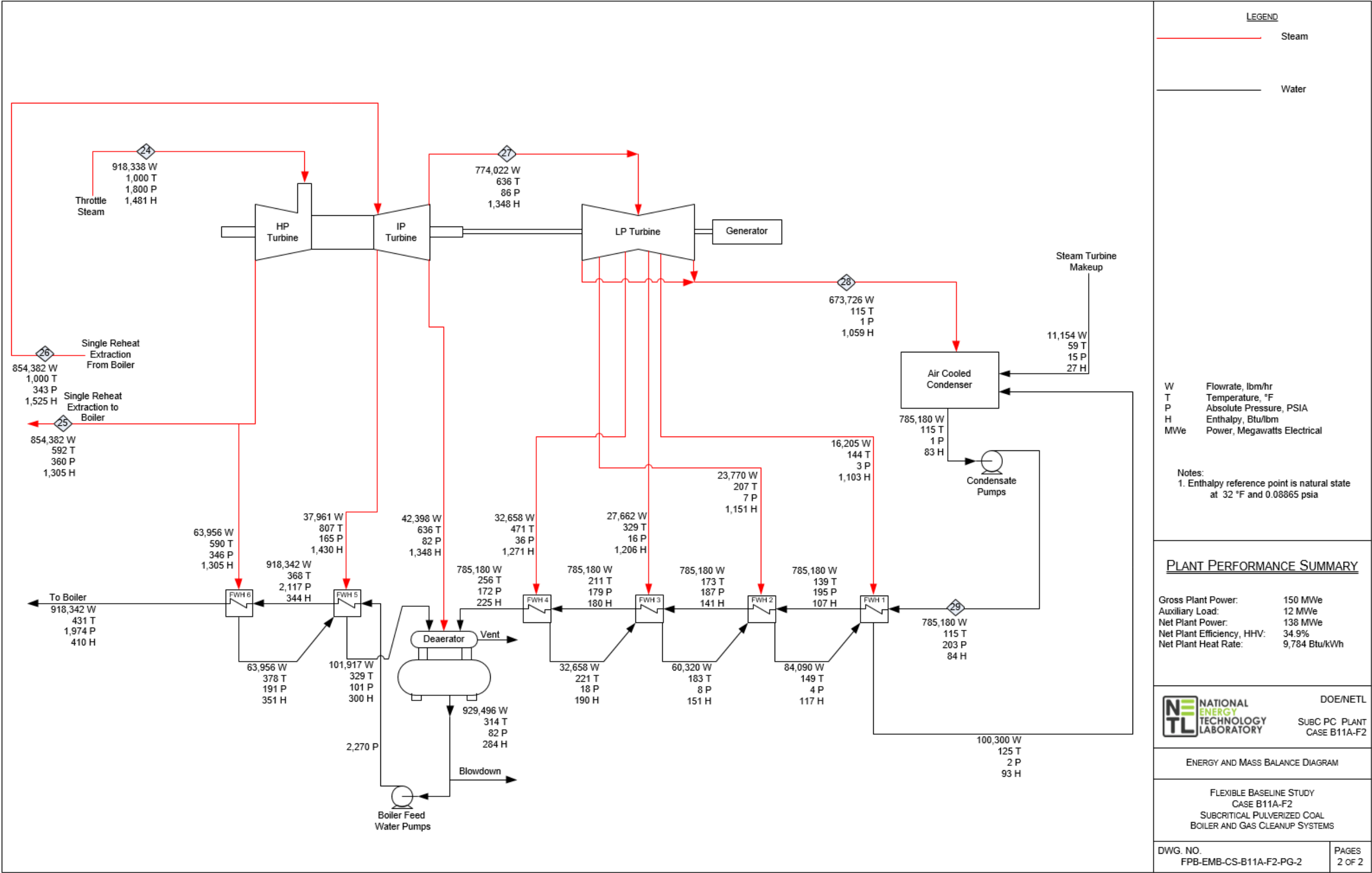


Exhibit 5-70. Case B11A-F2 energy and mass balance, subcritical steam cycle



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Exhibit 5-71. Case B11A-F2 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	1,420 (1,346)	1.2 (1.1)	–	1,421 (1,347)
Air	–	16 (16)	–	16 (16)
Raw Water Makeup	–	2.1 (2.0)	–	2.1 (2.0)
Limestone	–	0.1 (0.1)	–	0.1 (0.1)
Auxiliary Power	–	–	45 (43)	45 (43)
Total	1,420 (1,346)	20 (19)	45 (43)	1,484 (1,407)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	1.5 (1.4)	–	1.5 (1.4)
Fly Ash	–	0.5 (0.5)	–	0.5 (0.5)
Stack Gas	–	191 (181)	–	191 (181)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Gypsum	–	0.5 (0.5)	–	0.5 (0.5)
Motor Losses and Design Allowances	–	–	8.7 (8.3)	8.7 (8.3)
Air Cooled Condenser Load ^A	–	694 (658)	–	694 (658)
Blowdown Streams and Deaerator Vent	–	3.3 (3.1)	–	3.3 (3.1)
<i>Ambient Losses^B</i>	–	39 (37)	–	39 (37)
Power	–	–	540 (512)	540 (512)
Total	0.0 (0.0)	930 (882)	549 (520)	1,479 (1,402)
<i>Unaccounted Energy^C</i>	–	–	–	5.3 (5.0)

^A Includes condenser load only

^B Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^C By difference

5.4.11 Case B11A-F2 – Part Load Performance Results

Plant performance results are summarized at each discrete load point in Exhibit 5-72. Exhibit 5-73 displays a detailed breakdown of the auxiliary power consumption at each discrete load point. Air emissions at each discrete load point are summarized in Exhibit 5-74.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-72. Case B11A-F2 part load plant performance summary

Performance Summary					
Percent Load	100%	75%	50%	30%	20%
Total Gross Power, MWe	150	113	75	45	30
Nameplate Capacity, MWe	150	150	150	150	150
Total Auxiliaries, MWe	12	10	8	5	4
Total Auxiliaries, % of Gross Power	8.3%	9.0%	10.1%	11.9%	13.7%
Net Power, MWe	138	102	67	40	26
HHV Net Plant Efficiency, %	34.9%	34.0%	32.6%	30.7%	29.0%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,322 (9,784)	10,589 (10,037)	11,040 (10,464)	11,743 (11,131)	12,427 (11,778)
LHV Net Plant Efficiency, %	36.2%	35.2%	33.8%	31.8%	30.0%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,956 (9,436)	10,213 (9,680)	10,648 (10,093)	11,327 (10,736)	11,986 (11,360)
HHV Boiler Efficiency, %	87.5%	87.5%	87.6%	87.6%	87.7%
LHV Boiler Efficiency, %	90.7%	90.7%	90.8%	90.9%	90.9%
Steam Turbine Cycle Efficiency, %	43.5%	42.7%	41.4%	39.7%	38.3%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,278 (7,846)	8,433 (7,993)	8,689 (8,235)	9,064 (8,591)	9,402 (8,911)
Condenser Duty, GJ/hr (MMBtu/hr)	694 (658)	536 (508)	376 (356)	242 (229)	171 (162)
As-Received Coal Feed, kg/hr (lb/hr)	52,317 (115,339)	39,953 (88,080)	27,424 (60,459)	17,153 (37,817)	11,857 (26,140)
Limestone Sorbent Feed, kg/hr (lb/hr)	5,062 (11,160)	3,874 (8,540)	2,670 (5,886)	1,678 (3,699)	1,163 (2,564)
HHV Thermal Input, kWt	394,341	301,144	206,707	129,294	89,373
LHV Thermal Input, kWt	380,346	290,457	199,372	124,705	86,201
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)	0.004 (1.1)	0.004 (1.2)	0.004 (1.1)	0.005 (1.2)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)	0.004 (1.1)	0.004 (1.1)	0.004 (1.1)	0.005 (1.2)
Excess Air, %	20.0%	22.1%	26.9%	33.0%	37.0%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-73. Case B11A-F2 part load plant power summary

Power Summary					
Percent Load	100%	75%	50%	30%	20%
Steam Turbine Power, MWe	150	113	75	45	30
Total Gross Power, MWe	150	113	75	45	30
Nameplate Capacity, MWe	150	150	150	150	150
Auxiliary Load Summary					
Activated Carbon Injection, kWe	8	6	4	3	2
Air Cooled Condenser Fans, kWe	1,790	1,780	1,250	750	470
Ancillary Glycol Cooling Loops, kWe	250	250	250	250	250
Ash Handling, kWe	176	133	90	55	37
Baghouse, kWe	24	18	12	7	5
Boiler Feedwater Pump, kWe	2,790	1,680	950	500	300
Coal Handling and Conveying, kWe	110	90	60	40	30
Condensate Pumps, kWe	184	119	77	50	37
Dry Sorbent Injection, kWe	14	10	6	3	1
Flue Gas Desulfurizer, kWe	810	730	720	550	380
Forced Draft Fans, kWe	800	660	460	260	140
Ground Water Pumps, kWe	13	10	8	5	4
Induced Draft Fans, kWe	2,330	1,830	1,270	790	520
Miscellaneous Balance of Plant, ^A kWe	1,250	1,250	1,250	1,250	1,250
Primary Air Fans, kWe	199	165	123	57	31
Pulverizers, kWe	580	440	300	190	130
SCR, kWe	9	8	6	4	3
Sorbent Handling and Reagent Preparation, kWe	244	187	129	81	56
Spray Dryer Evaporator, kWe	58	44	30	19	13
Steam Turbine Auxiliaries, kWe	350	350	350	350	350
Transformer Losses, kWe	480	360	250	150	100
Total Auxiliaries, MWe	12	10	8	5	4
Net Power, MWe	138	102	67	40	26

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-74. Case B11A-F2 part load air emissions summary

Emissions Summary					
Percent Load	100%	75%	50%	30%	20%
SO ₂ , kg/MWhgross (lb/MWhgross)	0.328 (0.724)	0.335 (0.738)	0.346 (0.763)	0.363 (0.799)	0.377 (0.831)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	816 (1,799)	831 (1,833)	858 (1,891)	896 (1,976)	931 (2,052)
CO ₂ ^B , kg/MWhnet (lb/MWhnet)	890 (1,962)	914 (2,014)	954 (2,104)	1,018 (2,244)	1,079 (2,378)
Particulate Concentration ^{AB} , mg/Nm ³	13.68	13.21	12.35	11.31	10.60

^A Concentration of particles in the flue gas after the baghouse

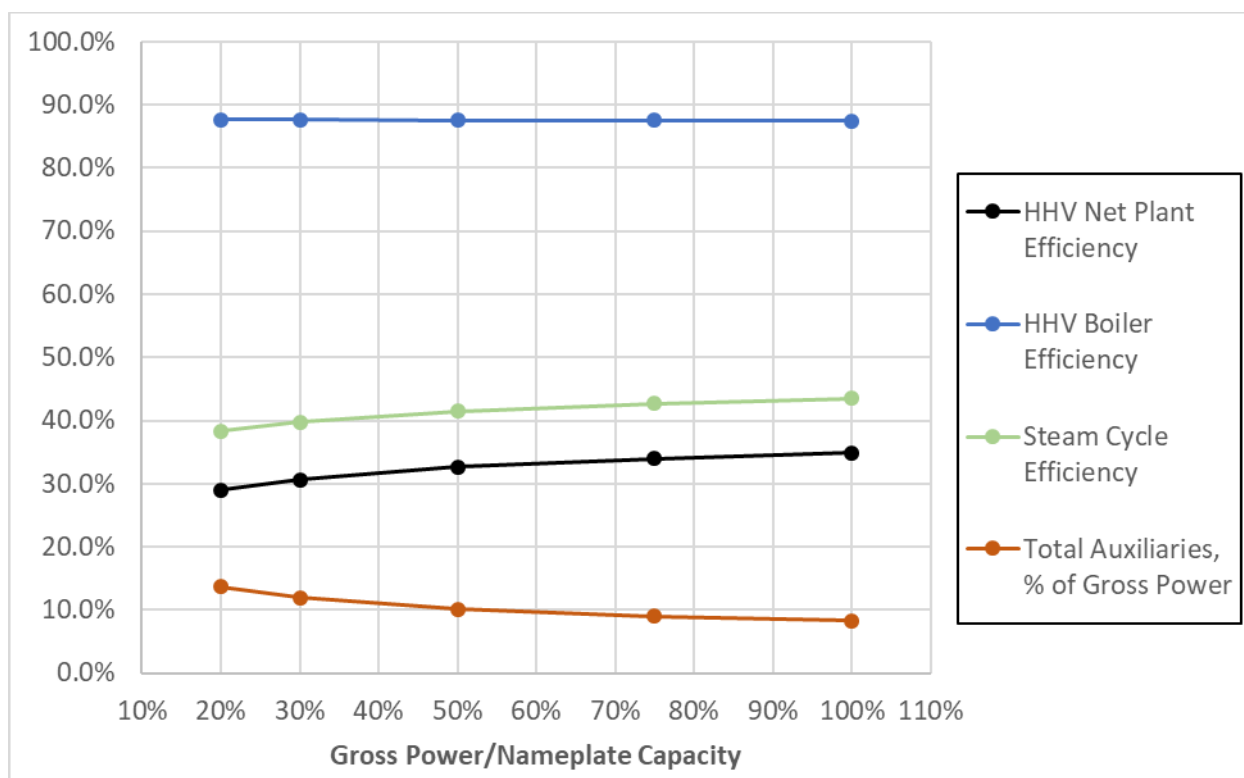
^B Normal conditions given at 32°F and 14.696 psia

Case B11A-F2 NO_x, SO₂, PM and Hg emissions remained below the environmental target emission limits across the entire load range. Hg, NO_x, and PM emissions are maintained at constant levels across the load. SO₂ emissions increase as load is reduced but are kept below the environmental target emission limit.

Exhibit 5-75 displays the Case B11A-F2 itemized efficiencies (HHV net plant efficiency, HHV boiler efficiency, and steam cycle efficiency) and normalized auxiliary power consumption across the load range.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-75. Case B11A-F2 part load itemized efficiencies



Compared to Case B11A-F1, Case B11A-F2 has a slightly improved HHV net plant heat rate at loads below 50 percent due to the decrease in WFGD power consumption from auxiliary load optimization. The HHV boiler efficiency and steam cycle efficiency remain consistent with Case B11A-F1.

5.4.12 Case B11A-F2 – Major Equipment List

Case B11A-F2 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	10 tonne (10 ton)	2	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
9	Feeder	Vibratory	40 tonne/hr (50 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	90 tonne/hr (100 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	40 tonne (50 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Transfer Tower No. 2	Enclosed	N/A	1	0
16	Coal Silo w/ Vent Filter and Slide Gates	Field erected	190 tonne (200 ton)	3	0
17	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 2 tonne (2 ton) Feeder - 10 kg/hr (30 lb/hr)	1	0
18	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 50 tonne (60 ton) Feeder - 310 kg/hr (690 lb/hr)	1	0
19	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	21 tonne/hr (23 tph)	1	0
21	Limestone Conveyor No. 1	Belt	21 tonne/hr (23 tph)	1	0
22	Limestone Reclaim Hopper	N/A	4 tonne (5 ton)	1	0
23	Limestone Reclaim Feeder	Belt	16 tonne/hr (18 tph)	1	0
24	Limestone Conveyor No. 2	Belt	16 tonne/hr (18 tph)	1	0
25	Limestone Day Bin	w/ actuator	67 tonne (74 ton)	2	0

Case B11A-F2 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	10 tonne/hr (11 tph)	6	0
2	Coal Pulverizer	Rotary (Vertical)	10 tonne/hr (11 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	6 tonne/hr (6 tph)	1	1
4	Limestone Ball Mill	Rotary	6 tonne/hr (6 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	22,700 liters (6,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	380 lpm @ 10m H ₂ O (100 gpm @ 40 ft H ₂ O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	90 lpm (30 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	120,000 liters (32,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	250 lpm @ 9m H ₂ O (70 gpm @ 30 ft H ₂ O)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case B11A-F2 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	334,000 liters (88,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,600 lpm @ 200 m H ₂ O (1,700 gpm @ 600 ft H ₂ O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	464,000 kg/hr (1,022,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump	Barrel type, multi-stage, centrifugal	7,700 lpm @ 1,900 m H ₂ O (2,000 gpm @ 6,100 ft H ₂ O)	1	1
5	N/A				
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	460,000 kg/hr (1,010,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	460,000 kg/hr (1,010,000 lb/hr)	1	0
12	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	37 GJ/hr (35 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	14,600 lpm @ 30 m H ₂ O (3,900 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	150 lpm @ 20 m H ₂ O (40 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	150 lpm @ 270 m H ₂ O (40 gpm @ 880 ft H ₂ O)	2	1
22	Filtered Water Pumps	Stainless steel, single suction	350 lpm @ 50 m H ₂ O (90 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	340,000 liter (90,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO	330 lpm (90 gpm)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
		membrane assembly, electrodeionization unit			
25	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 480 m ³ /min (17,120 acfm) @ 384°C (724°F) & 0.1 MPa (14 psia) Blowdown - 30 lpm (10 gpm) @ 20,018 ppmw Cl ⁻	2	1

Case B11A-F2 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	460,000 kg/hr steam @ 12.3 MPa/538°C/538°C (1,010,000 lb/hr steam @ 1,785 psig/1,000°F/1,000°F)	1	0
2	Primary Air Fan	Centrifugal	44,000 kg/hr, 600 m ³ /min @ 107 cm WG (97,000 lb/hr, 21,200 acfm @ 42 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	249,000 kg/hr, 3,400 m ³ /min @ 76 cm WG (549,000 lb/hr, 120,000 acfm @ 30 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	325,000 kg/hr, 6,700 m ³ /min @ 116 cm WG (717,000 lb/hr, 235,600 acfm @ 46 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	610,000 kg/hr (1,350,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	20 m ³ /min @ 108 cm WG (800 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	26,000 liter (7,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	5 lpm @ 90 m H ₂ O (1 gpm @ 300 ft H ₂ O)	2	1

Case B11A-F2 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	325,000 kg/hr (717,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	11,000 m ³ /min (389,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	64,000 lpm @ 65 m H ₂ O (17,000 gpm @ 210 ft H ₂ O)	3	1
4	Bleed Pumps	Horizontal centrifugal	1,070 lpm (280 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	180 m ³ /min @ 0.3 MPa (6,460 acfm @ 37 psia)	2	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	260 lpm (70 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	8 tonne/hr (9 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	160 lpm @ 13 m H ₂ O (40 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	110,000 lpm (30,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	380 lpm @ 21 m H ₂ O (100 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	10 kg/hr (30 lb/hr)	1	0
13	Hydrated Lime Injectors	---	310 kg/hr (690 lb/hr)	1	0

Case B11A-F2 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	122 m (400 ft) high x 3.1 m (10 ft) diameter	1	0

Case B11A-F2 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	156 MW 12.3 MPa/538°C/538°C (1785 psig/1000°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	170 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Air-cooled Condenser	Forced draft, direct, A-frame air-cooled condenser	760 GJ/hr (720 MMBtu/hr), Condensing temperature 46°C (115°F), Ambient temperature 15°C (59°F)	1	0

Case B11A-F2 – Account 9: Auxiliary Cooling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Glycol Cooling Loops	Industrial grade, air to glycol, closed loop heat exchanger	10 GJ/hr (14 MMBtu/hr) heat duty	5	0

Case B11A-F2 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	—	—	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	—	—	2	0
3	Clinker Grinder	—	1.2 tonne/hr (1.4 tph)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	12	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	5 m ³ /min @ 0.2 MPa (174 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	320 tonne (360 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	30 tonne/hr (30 tph)	1	0

Case B11A-F2 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 160 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 11 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 2 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Generator	Sized for black start capability	5000 kW, 480 V, 3-ph, 60 Hz	1	0

Case B11A-F2 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers, alarm management, HMIs, data historian, hard-wired control interface panels, and engineering stations/printers	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	DCS - Processor	Microprocessor cabinets with redundant input/output, I/O cabinets, various I/C buses	Spare 25% I/O and processor bandwidth	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant	1	0

The following items represent the modifications to the major equipment categories for the Case B11A-F2 design basis, along with narrative regarding process description modifications. Case B11A-F2 flexible plant design includes the design features of the Case B11A-F1 plant with the following modifications:

- **Account 4 — Boiler and Accessories**

- The modifications/changes to the boiler's burner arrangement to include an even lower BLHR burner row is typically outlined during detailed design with the boiler OEM; smaller burner rows (or their integration within the existing rows) will likely not impact the overall unit cost significantly due to their incorporation during original design of the plant; additional/supplemental coal burners will operate according to standard operating principles for coal-fired burners.

- **Account 5 — Flue Gas Cleanup**

- Auxiliary load optimization was assumed to reduce the normalized WFGD power requirement at low loads; normalized WFGD power consumption will increase at low loads; prudent operation of recycle pumps allows for reduction of the low-load power consumption penalty; specific achievement/degrees of auxiliary load optimization/reduction at low load will depend on operator training and system tuning at reduced loads.

- **General**

- No other significant major equipment category updates as a result of the Case B11A-F2 flexibility options; the additional condensate drains and thermocouples are considered small-scale capital cost components with no significant impact on the plant performance other than improved automation and control of the plant by the operators.
 - Additional (automated) condensate drains and blowdown lines will operate automatically based on predetermined set points within the control system.
 - Additional thermocouples/flame scanners installed in the boiler will operate within the control system to provide further granularity of monitoring furnace temperatures, as well as flame health (particularly important during low load); the upgrades to flame detection sensors and software have also been linked to increased regularity and reproducibility

of startups, which contributes to lowering equipment fatigue during startups and overall cost of startups. [24] [40] [18]

5.4.13 Case B11A-F2– Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-76 shows a detailed breakdown of the capital costs; Exhibit 5-77 shows the owner's costs, along with the TOC; and Exhibit 5-78 shows the initial and annual O&M costs.

The estimated TPC of the Case B11A-F2 plant is \$423 million. The project contingency is 13.3 percent of the TPC.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-76. Case B11A-F2 total plant cost details

Case:		B11A-F2	Subcritical PC Flexible Plant (Tiers 1–2)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
1 Coal & Sorbent Handling										
1.1	Coal Receive & Unload	\$267	\$0	\$120	\$0	\$387	\$68	\$0	\$68	\$523
1.2	Coal Stackout & Reclaim	\$876	\$0	\$196	\$0	\$1,072	\$188	\$0	\$189	\$1,448
1.3	Coal Conveyors	\$9,304	\$0	\$2,214	\$0	\$11,518	\$2,016	\$0	\$2,030	\$15,564
1.4	Other Coal Handling	\$1,036	\$0	\$218	\$0	\$1,254	\$219	\$0	\$221	\$1,694
1.5	Sorbent Receive & Unload	\$61	\$0	\$18	\$0	\$79	\$14	\$0	\$14	\$107
1.6	Sorbent Stackout & Reclaim	\$331	\$0	\$60	\$0	\$391	\$68	\$0	\$69	\$528
1.7	Sorbent Conveyors	\$588	\$128	\$142	\$0	\$858	\$150	\$0	\$151	\$1,159
1.8	Other Sorbent Handling	\$35	\$8	\$18	\$0	\$61	\$11	\$0	\$11	\$82
1.9	Coal & Sorbent Handling Foundations	\$0	\$430	\$567	\$0	\$997	\$175	\$0	\$176	\$1,348
	Subtotal	\$12,497	\$566	\$3,553	\$0	\$16,616	\$2,908	\$0	\$2,929	\$22,452
2 Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	\$569	\$0	\$109	\$0	\$678	\$119	\$0	\$120	\$916
2.2	Prepared Coal Storage & Feed	\$2,037	\$0	\$439	\$0	\$2,476	\$433	\$0	\$436	\$3,346
2.5	Sorbent Preparation Equipment	\$251	\$11	\$51	\$0	\$313	\$55	\$0	\$55	\$423
2.6	Sorbent Storage & Feed	\$405	\$0	\$153	\$0	\$557	\$98	\$0	\$98	\$753
2.9	Coal & Sorbent Feed Foundation	\$0	\$165	\$145	\$0	\$311	\$54	\$0	\$55	\$420
	Subtotal	\$3,262	\$176	\$897	\$0	\$4,335	\$759	\$0	\$764	\$5,858
3 Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	\$872	\$1,495	\$747	\$0	\$3,114	\$545	\$0	\$549	\$4,208
3.2	Water Makeup & Pretreating	\$1,460	\$146	\$827	\$0	\$2,433	\$426	\$0	\$572	\$3,431
3.3	Other Feedwater Subsystems	\$563	\$185	\$175	\$0	\$923	\$161	\$0	\$163	\$1,247
3.4	Service Water Systems	\$416	\$795	\$2,574	\$0	\$3,785	\$662	\$0	\$890	\$5,338
3.5	Other Boiler Plant Systems	\$171	\$62	\$155	\$0	\$388	\$68	\$0	\$68	\$524
3.6	Natural Gas Pipeline and Start-Up System	\$892	\$38	\$29	\$0	\$959	\$168	\$0	\$169	\$1,296
3.7	Waste Water Treatment Equipment	\$2,305	\$0	\$1,413	\$0	\$3,717	\$651	\$0	\$874	\$5,242
3.8	Spray Dryer Evaporator	\$4,228	\$0	\$2,448	\$0	\$6,676	\$1,168	\$0	\$1,569	\$9,413
3.9	Miscellaneous Plant Equipment	\$52	\$7	\$27	\$0	\$86	\$15	\$0	\$20	\$121
	Subtotal	\$10,959	\$2,728	\$8,395	\$0	\$22,082	\$3,864	\$0	\$4,873	\$30,819
4 Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	\$74,034	\$0	\$48,348	\$0	\$122,382	\$21,417	\$0	\$21,570	\$165,369
4.10	Selective Catalytic Reduction System	\$5,359	\$0	\$3,500	\$0	\$8,859	\$1,550	\$0	\$1,561	\$11,970
4.11	Boiler Balance of Plant	\$294	\$0	\$192	\$0	\$486	\$85	\$0	\$86	\$657

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B11A-F2	Subcritical PC Flexible Plant (Tiers 1–2)				Estimate Type: Cost Base:			Conceptual Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
4.12	Primary Air System	\$341	\$0	\$223	\$0	\$563	\$99	\$0	\$99	\$761
4.13	Secondary Air System	\$692	\$0	\$452	\$0	\$1,144	\$200	\$0	\$202	\$1,546
4.14	Induced Draft Fans	\$1,297	\$0	\$847	\$0	\$2,145	\$375	\$0	\$378	\$2,898
4.15	Major Component Rigging	\$22	\$0	\$15	\$0	\$37	\$6	\$0	\$7	\$50
4.16	Boiler Foundations	\$0	\$96	\$85	\$0	\$181	\$32	\$0	\$32	\$244
	Subtotal	\$82,040	\$96	\$53,661	\$0	\$135,797	\$23,764	\$0	\$23,934	\$183,495
5		Flue Gas Cleanup								
5.2	WFGD Absorber Vessels & Accessories	\$20,989	\$0	\$4,488	\$0	\$25,477	\$4,458	\$0	\$4,490	\$34,426
5.3	Other FGD	\$73	\$0	\$82	\$0	\$155	\$27	\$0	\$27	\$210
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$595	\$131	\$585	\$0	\$1,311	\$229	\$0	\$231	\$1,772
5.9	Particulate Removal (Bag House & Accessories)	\$627	\$0	\$395	\$0	\$1,023	\$179	\$0	\$180	\$1,382
5.12	Gas Cleanup Foundations	\$0	\$42	\$37	\$0	\$78	\$14	\$0	\$14	\$106
5.13	Gypsum Dewatering System	\$187	\$0	\$32	\$0	\$219	\$38	\$0	\$39	\$296
	Subtotal	\$22,472	\$173	\$5,619	\$0	\$28,263	\$4,946	\$0	\$4,981	\$38,191
7		Ductwork & Stack								
7.3	Ductwork	\$0	\$209	\$145	\$0	\$354	\$62	\$0	\$62	\$478
7.4	Stack	\$2,526	\$0	\$1,468	\$0	\$3,993	\$699	\$0	\$704	\$5,396
7.5	Duct & Stack Foundations	\$0	\$51	\$61	\$0	\$112	\$20	\$0	\$26	\$158
	Subtotal	\$2,526	\$260	\$1,673	\$0	\$4,459	\$780	\$0	\$792	\$6,031
8		Steam Turbine & Accessories								
8.1	Steam Turbine Generator & Accessories	\$23,620	\$0	\$2,655	\$0	\$26,275	\$4,598	\$0	\$4,631	\$35,504
8.2	Steam Turbine Plant Auxiliaries	\$471	\$0	\$1,002	\$0	\$1,473	\$258	\$0	\$260	\$1,990
8.3	Condenser & Auxiliaries ^A	\$11,566	\$0	\$3,924	\$0	\$15,490	\$2,711	\$0	\$2,730	\$20,930
8.4	Steam Piping	\$10,602	\$0	\$4,297	\$0	\$14,899	\$2,607	\$0	\$2,626	\$20,132
8.5	Turbine Generator Foundations	\$0	\$57	\$94	\$0	\$151	\$26	\$0	\$35	\$213
	Subtotal	\$46,259	\$57	\$11,972	\$0	\$58,287	\$10,200	\$0	\$10,282	\$78,770
9		Cooling Water System								
9.6	Component Cooling Water System ^B	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
	Subtotal	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
10		Ash & Spent Sorbent Handling Systems								
10.6	Ash Storage Silos	\$300	\$0	\$917	\$0	\$1,217	\$213	\$0	\$214	\$1,644
10.7	Ash Transport & Feed Equipment	\$1,125	\$0	\$1,115	\$0	\$2,240	\$392	\$0	\$395	\$3,027
10.9	Ash/Spent Sorbent Foundation	\$0	\$202	\$248	\$0	\$449	\$79	\$0	\$106	\$633
	Subtotal	\$1,425	\$202	\$2,280	\$0	\$3,906	\$684	\$0	\$715	\$5,304
11		Accessory Electric Plant								
11.1	Generator Equipment	\$791	\$0	\$596	\$0	\$1,387	\$243	\$0	\$244	\$1,874

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B11A-F2	Subcritical PC Flexible Plant (Tiers 1–2)				Estimate Type: Cost Base:			Conceptual Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
11.2	Station Service Equipment	\$1,440	\$0	\$124	\$0	\$1,563	\$274	\$0	\$276	\$2,112
11.3	Switchgear & Motor Control	\$2,406	\$0	\$418	\$0	\$2,824	\$494	\$0	\$498	\$3,816
11.4	Conduit & Cable Tray	\$0	\$327	\$943	\$0	\$1,270	\$222	\$0	\$224	\$1,716
11.5	Wire & Cable	\$0	\$643	\$1,150	\$0	\$1,794	\$314	\$0	\$316	\$2,424
11.6	Protective Equipment	\$17	\$0	\$60	\$0	\$78	\$14	\$0	\$14	\$105
11.7	Standby Equipment	\$224	\$0	\$206	\$0	\$430	\$75	\$0	\$76	\$581
11.8	Main Power Transformers	\$2,109	\$0	\$43	\$0	\$2,152	\$377	\$0	\$379	\$2,908
11.9	Electrical Foundations	\$0	\$57	\$146	\$0	\$203	\$36	\$0	\$48	\$286
	Subtotal	\$6,986	\$1,028	\$3,686	\$0	\$11,700	\$2,048	\$0	\$2,074	\$15,822
12		Instrumentation & Control								
12.1	Pulverized Coal Boiler Control Equipment	\$188	\$0	\$34	\$0	\$222	\$39	\$0	\$39	\$300
12.3	Steam Turbine Control Equipment	\$185	\$0	\$21	\$0	\$205	\$36	\$0	\$36	\$278
12.5	Signal Processing Equipment	\$179	\$0	\$32	\$0	\$210	\$37	\$0	\$37	\$284
12.6	Control Boards, Panels & Racks	\$56	\$0	\$34	\$0	\$90	\$16	\$0	\$16	\$121
12.7	Distributed Control System Equipment	\$1,869	\$0	\$333	\$0	\$2,202	\$385	\$0	\$388	\$2,976
12.8	Instrument Wiring & Tubing	\$167	\$134	\$535	\$0	\$836	\$146	\$0	\$147	\$1,130
12.9	Other Instrumentation & Controls Equipment	\$199	\$0	\$460	\$0	\$659	\$115	\$0	\$116	\$891
	Subtotal	\$2,842	\$134	\$1,449	\$0	\$4,425	\$774	\$0	\$780	\$5,979
13		Improvements to Site								
13.1	Site Preparation	\$0	\$120	\$2,556	\$0	\$2,675	\$468	\$0	\$629	\$3,772
13.2	Site Improvements	\$0	\$656	\$867	\$0	\$1,523	\$266	\$0	\$358	\$2,147
13.3	Site Facilities	\$541	\$0	\$567	\$0	\$1,108	\$194	\$0	\$260	\$1,563
	Subtotal	\$541	\$776	\$3,990	\$0	\$5,306	\$929	\$0	\$1,247	\$7,482
14		Buildings & Structures								
14.2	Boiler Building	\$0	\$3,767	\$3,311	\$0	\$7,078	\$1,239	\$0	\$1,247	\$9,564
14.3	Steam Turbine Building	\$0	\$3,808	\$3,547	\$0	\$7,355	\$1,287	\$0	\$1,296	\$9,938
14.4	Administration Building	\$0	\$340	\$360	\$0	\$700	\$122	\$0	\$123	\$946
14.6	Water Treatment Buildings	\$0	\$97	\$88	\$0	\$184	\$32	\$0	\$33	\$249
14.7	Machine Shop	\$0	\$153	\$102	\$0	\$254	\$45	\$0	\$0	\$299
14.8	Warehouse	\$0	\$119	\$119	\$0	\$237	\$42	\$0	\$42	\$321
14.9	Other Buildings & Structures	\$0	\$86	\$73	\$0	\$159	\$28	\$0	\$28	\$214
14.10	Waste Treating Building & Structures	\$0	\$137	\$414	\$0	\$551	\$96	\$0	\$97	\$744
	Subtotal	\$0	\$8,506	\$8,012	\$0	\$16,518	\$2,891	\$0	\$2,866	\$22,275
	Total	\$192,193	\$14,700	\$105,483	\$0	\$312,376	\$54,666	\$0	\$56,358	\$423,400

^AACC; ^B Component cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
FLEXIBLE OPERATION

Exhibit 5-77. Case B11A-F2 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$4,300
1-Month Maintenance Materials	\$560
1-Month Non-Fuel Consumables	\$304
1-Month Waste Disposal	\$187
25% of 1-Month Fuel Cost at 100% CF	\$547
2% of TPC	\$8,468
Total	\$14,366
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$4,971
0.5% of TPC (spare parts)	\$2,117
Total	\$7,088
Other Costs	
Initial Cost for Catalyst and Chemicals	\$493
Land	\$117
Other Owner's Costs	\$63,510
Financing Costs	\$11,432
Total Overnight Costs (TOC)	\$520,405

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-78. Case B11A-F2 initial and annual operating and maintenance costs

Case:	B11A-F2	– Subcritical PC Flexible Plant (Tiers 1–2)			Cost Base:	Dec 2018
Plant Size (MW, gross):	150	Heat Rate-net (Btu/kWh):			9,784	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$ /hour		Skilled Operator:	2.0	
Operating Labor Burden:	30.0	% of base		Operator:	3.0	
Labor O-H Charge Rate:	25.0.	% of labor		Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	7.0	
Fixed Operating Costs						
					Annual Cost (\$)	
Annual Operating Labor:					\$3,069,066	
Maintenance Labor:					\$3,810,596	
Administrative & Support Labor:					\$1,719,916	
Property Taxes and Insurance:					\$8,467,992	
Total:					\$17,067,570	
Variable Operating Costs						
					Annual Cost (\$)	
Maintenance Material:					\$6,724,582 x CF	
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)	
Water (/1000 gallons):	0	107	\$1.90	\$0	\$73,873 x CF	
Makeup and Waste Water Treatment Chemicals (ton):	0	0.317	\$550.00	\$0	\$63,701 x CF	
Brominated Activated Carbon (ton):	0	0.304	\$1,600.00	\$0	\$177,431 x CF	
Enhanced Hydrated Lime (ton):	0	7.54	\$240.00	\$0	\$660,175 x CF	
Limestone (ton):	0	134	\$22.00	\$0	\$1,075,410 x CF	
Ammonia (19 wt%, ton):	0	13.1	\$300.00	\$0	\$1,436,390 x CF	
SCR Catalyst (ft³):	3,286	3.00	\$150.00	\$492,829	\$164,276 x CF	
Subtotal:				\$492,829	\$3,651,256 x CF	
Waste Disposal						
Fly Ash (ton):	0	132	\$38.00	\$0	\$1,828,422 x CF	
Bottom Ash (ton):	0	29.5	\$38.00	\$0	\$408,884 x CF	
SCR Catalyst (ft³):	0	3.00	\$2.50	\$0	\$2,738 x CF	
Subtotal:				\$0	\$2,240,044 x CF	
By-Products						
Gypsum (ton):	0	204	\$0.00	\$0	\$0	
Subtotal:				\$0	\$0	
Variable Operating Costs Total:				\$492,829	\$12,615,881 x CF	
Fuel Cost						
Illinois Number 6 (ton):	0	1,384	\$51.96	\$0	\$26,248,431 x CF	
Fuel Costs Total:				\$0	\$26,248,431 x CF	

5.4.13.1 Cost Differential Justifications

The primary contributors to the capital cost differential when comparing Case B11A-F2 to Case B11A-F1 are outlined below:

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
- Flexibility Option 34 — Installation of more robust direct flame detection sensors and more thermocouples to monitor temperatures within the boiler
- Flexibility Option 10 — Installation of additional condensate drains and instrumentation for condensate detection in all boiler headers and piping systems

The justifications for the capital cost differentials when comparing Case B11A-F2 to Case B11A-F1 are outlined below:

- Account 2.2 cost increases due to modifications to the coal system. The following flexibility option impacted the cost of Account 2.2:
 - Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
- Account 2.9 is not expected to increase because the modifications to the burner design (Flexibility Option 27) would not be expected to impact the foundations.
- Accounts 3.3, 3.5, and 3.9 increase due to an increase in engineering design, equipment, and material required for additional components installed within the boiler drum, boiler steam headers, and steam piping. The following flexibility options impacted the cost of accounts 3.3, 3.5, and 3.9:
 - Flexibility Option 10 — Installation of condensate drains and instrumentation for condensate detection in all boiler headers and piping systems
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)
- Account 4.9 cost increases due to the additional equipment provided by the boiler OEM, additional sub-system features within the boiler island components (e.g., header and piping drain taps), additional engineering and installation labor required for these options. The following flexibility options impacted the cost of Account 4.9:
 - Flexibility Option 10 — Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems
 - Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
 - Flexibility Option 34 — Installation of direct flame detection sensors and more thermocouples to monitor temperatures within the boiler
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)
- Account 4.11 cost increases due to the additional equipment requiring boiler balance of plant sub-system engineering design (e.g., instrument air lines, electrical routing, more intricate pipe routing for clash avoidance, and additional maintenance access points)

and material installation. The following flexibility options impacted the cost of Account 4.11:

- Flexibility Option 10 — Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems
 - Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)
- Account 11 (sub-accounts 11.2, 11.4–11.6) cost increases due to the installation of additional instrumentation and auxiliary power wiring, controls wiring, and communications wiring to operate the additional components. The following flexibility options impacted the cost of Account 11:
 - Flexibility Option 10 — Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems
 - Flexibility Option 34 — Installation of direct flame detection sensors and more thermocouples to monitor temperatures within the boiler
 - Flexibility Option 49 — Auxiliary load optimization
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)
- Account 11.3 cost increases due to the expected relay/MCC modifications required for greater optimization of auxiliary load demand at reduced plant loads; these expected upgrades would not be expected to have foundation cost increase impacts. The following flexibility option impacted the cost of Account 11.3:
 - Flexibility Option 49 — Auxiliary load optimization
- Account 12 cost increased due to the additional equipment (hardware) supply, material supply (e.g., wiring, conduit, raceway), installation hours for physically installing the components and commissioning hours where specialists program and tune the system prior to commercial operation. The following flexibility options impacted the cost of Account 12:
 - Flexibility Option 10 — Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems
 - Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
 - Flexibility Option 34 — Installation of direct flame detection sensors and more thermocouples to monitor temperatures within the boiler
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)

- Flexibility Option 65 — Automated prioritization of plant alarm signals to allow for simplified triage of plant information received in the control room

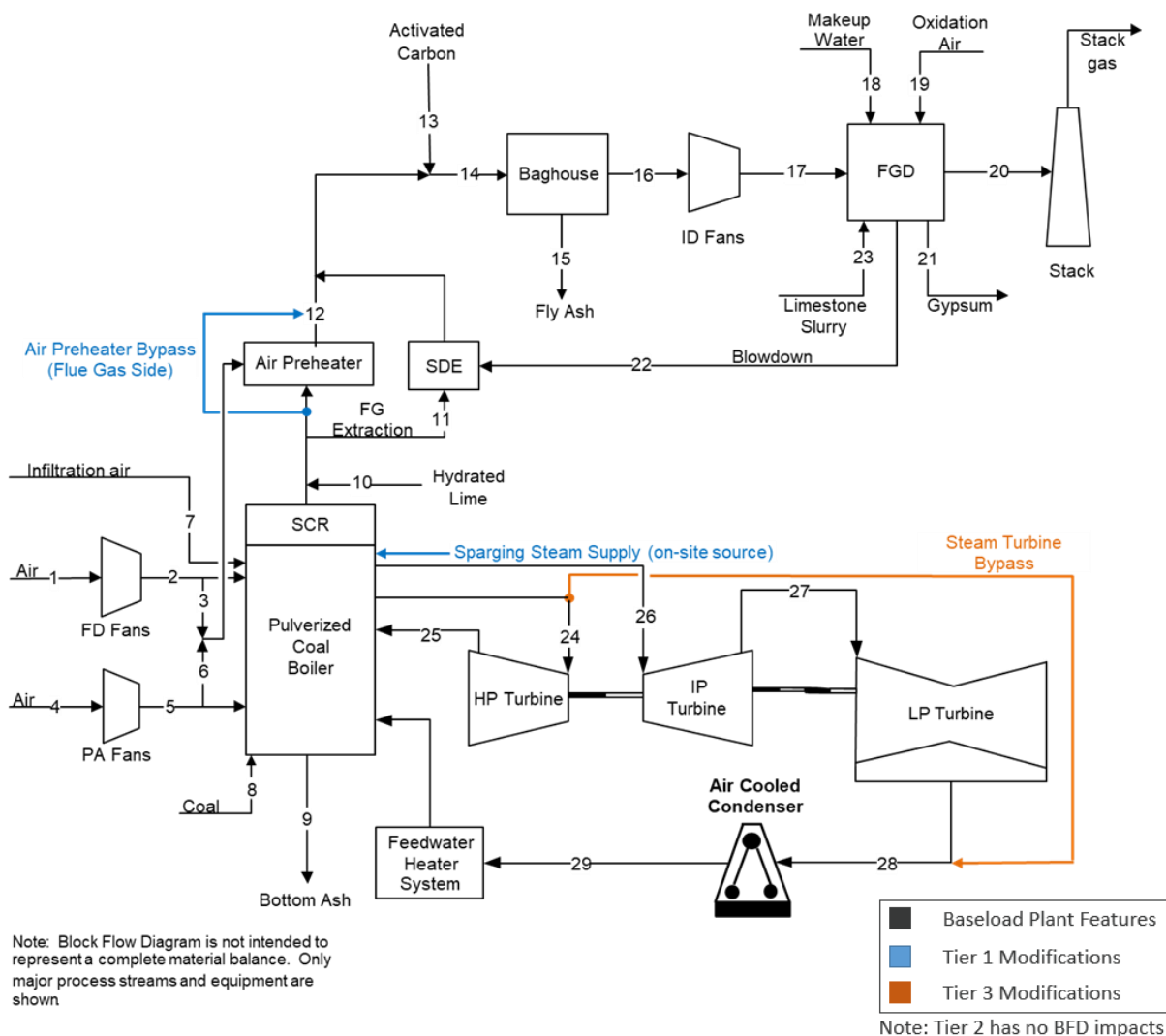
5.4.14 Case B11A-F3– PC Subcritical Flexible Plant with Tier 1, 2, and 3 Flexibility Options

The plant configuration for Case B11A-F3, subcritical flexible plant with Tier 1, 2, and 3 flexibility options, is similar to Case B11A-F2. Major modifications to the plant include the installation of a steam turbine bypass line. The full list of Tier 3 flexibility options was presented in Exhibit 4-16. The nominal gross plant output was maintained at 150 MW.

5.4.15 Case B11A-F3– Full Load Performance Results

The BFD for Case B11A-F3 is shown in Exhibit 5-79. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 5-80. Full stream tables are only provided for the 100 percent load point.

Exhibit 5-79. Case B11A-F3 block flow diagram



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-80. Case B11A-F3 stream table, subcritical unit with tiers 1–3 flexibility options

	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	15,690	15,690	517	2,769	2,769	572	313	0	0	0
V-L Flowrate (kg/hr)	452,777	452,777	14,911	79,902	79,902	16,500	9,029	0	0	3
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	52,317	1,114	282
Temperature (°C)	15	21	21	15	23	23	15	15	1,316	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	36.30	36.30	30.23	38.69	38.69	30.23	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-91.51	-91.51	-97.58	-89.12	-89.12	-97.58	-2,119.02	1,312.68	-13,402.95
Density (kg/m ³)	1.2	1.3	1.3	1.2	1.3	1.3	1.2	---	---	1,003.6
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015
V-L Flowrate (lb _{mol} /hr)	34,591	34,591	1,139	6,104	6,104	1,261	690	0	0	0
V-L Flowrate (lb/hr)	998,203	998,203	32,874	176,153	176,153	36,377	19,904	0	0	6
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	115,340	2,457	622
Temperature (°F)	59	70	70	59	74	74	59	59	2,400	59
Pressure (psia)	14.7	15.6	15.6	14.7	16.0	16.0	14.7	14.7	14.3	14.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	15.6	15.6	13.0	16.6	16.6	13.0	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-39.3	-39.3	-42.0	-38.3	-38.3	-42.0	-911.0	564.3	-5,762.2
Density (lb/ft ³)	0.076	0.079	0.079	0.076	0.080	0.080	0.076	---	---	62.650

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-80. Case B11A-F3 stream table, subcritical unit with tiers 1–3 flexibility options, cont'd

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction										
Ar	0.0087	0.0088	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081
CO ₂	0.1463	0.1379	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0889	0.0844	0.0000	0.0918	0.0000	0.0918	0.0918	0.9967	0.0099	0.1512
HCl	0.0001	0.0001	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
N ₂	0.7312	0.7336	0.0000	0.7277	0.0000	0.7277	0.7277	0.0000	0.7732	0.6801
O ₂	0.0226	0.0332	0.0000	0.0325	0.0000	0.0325	0.0325	0.0000	0.2074	0.0360
SO ₂	0.0021	0.0020	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.1148	0.0000	0.0000	0.0006	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0001	0.8852	0.0000	0.0000	0.0028	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	943	18,875	0	19,978	1	19,976	19,976	2,783	844	22,336
V-L Flowrate (kg/hr)	28,056	560,345	0	591,343	129	591,211	591,211	50,912	24,365	641,810
Solids Flowrate (kg/hr)	242	4,553	11	4,851	4,854	0	0	457	0	0
Temperature (°C)	384	143	15	143	143	143	156	27	15	57
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	---	---	289.08	302.74	---	30.23	297.86
AspenPlus Enthalpy (kJ/kg) ^B	-2,278.03	-2,399.41	-6.79	-2,459.22	-1,001.45	-2,471.50	-2,457.85	-15,764.00	-97.58	-2,944.12
Density (kg/m ³)	0.5	0.8	---	0.8	2,150.2	0.8	0.9	1,002.4	1.2	1.1
V-L Molecular Weight	29.738	29.687	---	29.600	104.953	29.596	29.596	18.297	28.857	28.735
V-L Flowrate (lb _{mol} /hr)	2,080	41,612	0	44,043	3	44,040	44,040	6,134	1,861	49,241
V-L Flowrate (lb/hr)	61,853	1,235,349	0	1,303,688	285	1,303,397	1,303,397	112,241	53,715	1,414,950
Solids Flowrate (lb/hr)	532	10,038	25	10,694	10,701	0	0	1,008	0	0
Temperature (°F)	724	289	59	289	289	289	312	80	59	135
Pressure (psia)	14.3	14.0	14.7	14.0	14.0	13.8	15.1	14.7	14.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	---	---	124.3	130.2	---	13.0	128.1
AspenPlus Enthalpy (Btu/lb) ^B	-979.4	-1,031.6	-2.9	-1,057.3	-430.5	-1,062.6	-1,056.7	-6,777.3	-42.0	-1,265.7
Density (lb/ft ³)	0.033	0.052	---	0.051	134.232	0.051	0.054	62.580	0.076	0.067

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-80. Case B11A-F3 stream table, subcritical unit with tiers 1–3 flexibility options, cont'd

	21	22	23	24	25	26	27	28	29
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	47	159	656	23,122	21,512	21,512	19,488	16,963	19,769
V-L Flowrate (kg/hr)	855	2,942	11,825	416,551	387,541	387,541	351,091	305,597	356,152
Solids Flowrate (kg/hr)	7,695	45	5,062	0	0	0	0	0	0
Temperature (°C)	15	57	15	538	311	538	336	46	46
Pressure (MPa, abs)	0.10	0.10	0.10	12.41	2.48	2.36	0.59	0.01	1.40
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	3,444.19	3,034.74	3,547.75	3,135.60	2,463.74	194.88
AspenPlus Enthalpy (kJ/kg) ^B	-12,513.34	-15,495.46	-14,994.25	-12,536.10	-12,945.55	-12,432.55	-12,844.70	-13,516.56	-15,785.42
Density (kg/m ³)	880.9	979.4	1,003.7	36.2	9.8	6.4	2.1	0.1	990.2
V-L Molecular Weight	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	105	351	1,447	50,976	47,425	47,425	42,965	37,397	43,584
V-L Flowrate (lb/hr)	1,886	6,487	26,071	918,338	854,382	854,382	774,022	673,726	785,180
Solids Flowrate (lb/hr)	16,964	99	11,160	0	0	0	0	0	0
Temperature (°F)	59	135	59	1,000	592	1,000	636	115	115
Pressure (psia)	14.7	14.7	14.7	1,800.0	360.0	342.9	85.7	1.5	202.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	1,480.7	1,304.7	1,525.3	1,348.1	1,059.2	83.8
AspenPlus Enthalpy (Btu/lb) ^B	-5,379.8	-6,661.8	-6,446.4	-5,389.6	-5,565.6	-5,345.0	-5,522.2	-5,811.1	-6,786.5
Density (lb/ft ³)	54.996	61.143	62.658	2.258	0.611	0.400	0.133	0.005	61.819

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

At full load, the plant produces a net output of 138 MWe at a net plant efficiency of 34.9 percent (HHV basis). Full load performance for Case B11A-F3 is summarized in Exhibit 5-81. Exhibit 5-82 presents a detailed breakdown of auxiliary power requirements at full load.

Exhibit 5-81. Case B11A-F3 plant performance summary

Performance Summary	
Percent Load	100%
Total Gross Power, MWe	150
Nameplate Capacity, MWe	150
Total Auxiliaries, MWe	12
Total Auxiliaries, % of Gross Power	8.2%
Net Power, MWe	138
HHV Net Plant Efficiency, %	34.9%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,313 (9,775)
LHV Net Plant Efficiency, %	36.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,947 (9,428)
HHV Boiler Efficiency, %	87.5%
LHV Boiler Efficiency, %	90.7%
Steam Turbine Cycle Efficiency, %	43.5%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,278 (7,846)
Condenser Duty, GJ/hr (MMBtu/hr)	694 (658)
As-Received Coal Feed, kg/hr (lb/hr)	52,317 (115,340)
Limestone Sorbent Feed, kg/hr (lb/hr)	5,062 (11,160)
HHV Thermal Input, kWt	394,342
LHV Thermal Input, kWt	380,348
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)
Excess Air, %	20.0%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-82. Case B11A-F3 plant power summary

Power Summary	
Percent Load	100%
Steam Turbine Power, MWe	150
Total Gross Power, MWe	150
Nameplate Capacity	150
Auxiliary Load Summary	
Activated Carbon Injection, kWe	8
Air Cooled Condenser Fans	1,790
Ancillary Glycol Cooling Loops	250
Ash Handling, kWe	176
Baghouse, kWe	24
Boiler Feedwater Pump, kWe	2,560
Coal Handling and Conveying, kWe	110
Condensate Pumps, kWe	184
Dry Sorbent Injection, kWe	14
Flue Gas Desulfurizer, kWe	810
Forced Draft Fans, kWe	830
Ground Water Pumps, kWe	13
Induced Draft Fans, kWe	2,400
Miscellaneous Balance of Plant, ^A kWe	1,250
Primary Air Fans, kWe	204
Pulverizers, kWe	580
SCR, kWe	9
Sorbent Handling & Reagent Preparation, kWe	244
Spray Dryer Evaporator, kWe	58
Steam Turbine Auxiliaries, kWe	350
Transformer Losses, kWe	480
Total Auxiliaries, MWe	12
Net Power, MWe	138

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

5.4.15.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B11A-F3 is presented in Exhibit 5-83. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-83. Case B11A-F3 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	367 (404)	0.328 (0.724)
NO _x	0.034 (0.078)	355 (391)	0.318 (0.700)
Particulate	0.004 (0.010)	46 (50)	0.041 (0.090)
Hg	1.44E-7 (3.34E-7)	0.002 (0.002)	1.36E-6 (3.00E-6)
CO ₂	86 (201)	911,309 (1,004,547)	816 (1,799)
CO ₂ ^C	-	-	889 (1,960)
mg/Nm ³			
Particulate Concentration ^{D,E}	13.68		

^A Calculations based on an 85% capacity factor

^B Emissions based on gross power, except where otherwise noted

^C CO₂ emissions based on net power instead of gross power

^D Concentration of particles in the flue gas after the baghouse

^E Normal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.35 lb/MMBtu using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 77.7 percent to about 0.08 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and FGD system) is 95.1 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 5-84. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-84. Case B11A-F3 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	33,349 (73,523)	Stack Gas	33,402 (73,639)
Air (CO ₂)	77 (170)	FGD Product	40 (87)
PAC	11 (25)	Baghouse	410 (905)
FGD Reagent	514 (1,132)	Bottom Ash	100 (220)
Total	33,952 (74,850)	Total	33,952 (74,850)

Exhibit 5-85 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-85. Case B11A-F3 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	1,311 (2,891)	FGD Product	1,233 (2,719)
		Stack Gas	26 (56)
		Baghouse	52 (116)
Total	1,311 (2,891)	Total	1,311 (2,891)

Exhibit 5-86 shows the water balance for Case B11A-F3.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is reused as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from ground water. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-86. Case B11A-F3 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Desulfurizer Makeup	0.5 (144)	0.1 (19)	0.5 (126)	–	0.5 (126)
Deaerator Vent	–	–	–	0.0 (3.7)	0.0 (-3.7)
Condenser Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
BFW Makeup	0.1 (22)	–	0.1 (22)	–	0.1 (22)
Cooling Tower	–	–	–	–	–
BFW Blowdown	–	–	–	–	–
Total	0.6 (167)	0.1 (19)	0.6 (148)	0.0 (3.7)	0.5 (144)

5.4.15.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B11A-F3 PC boiler, the FGD unit, and steam cycle as shown in Exhibit 5-87 and Exhibit 5-88.

An overall plant energy balance is provided in tabular form in Exhibit 5-89. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-81) is calculated by multiplying the power out by the full load generator efficiency of 98.5 percent.

Exhibit 5-87. Case B11A-F3 energy and mass balance, subcritical PC boiler

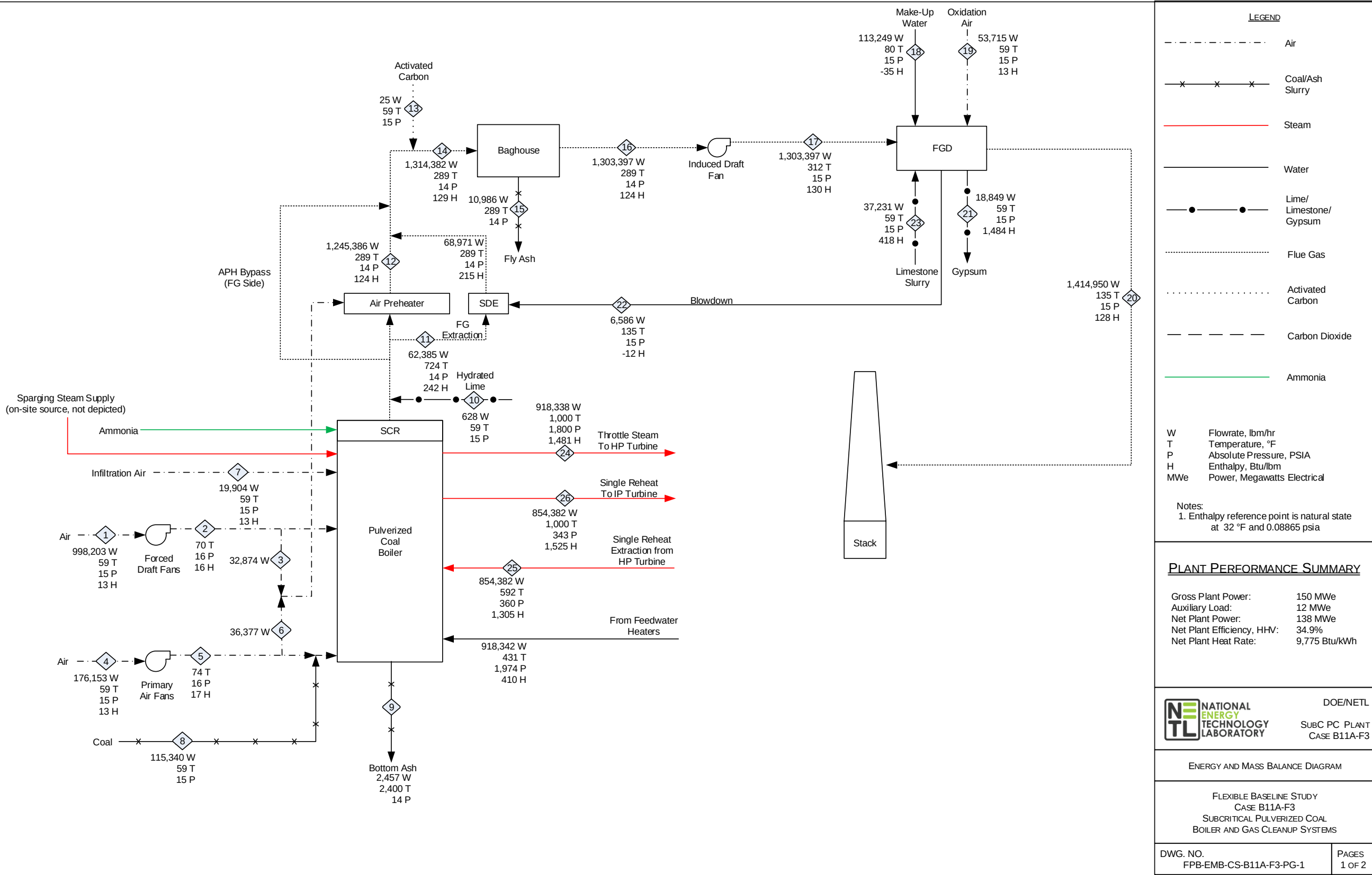
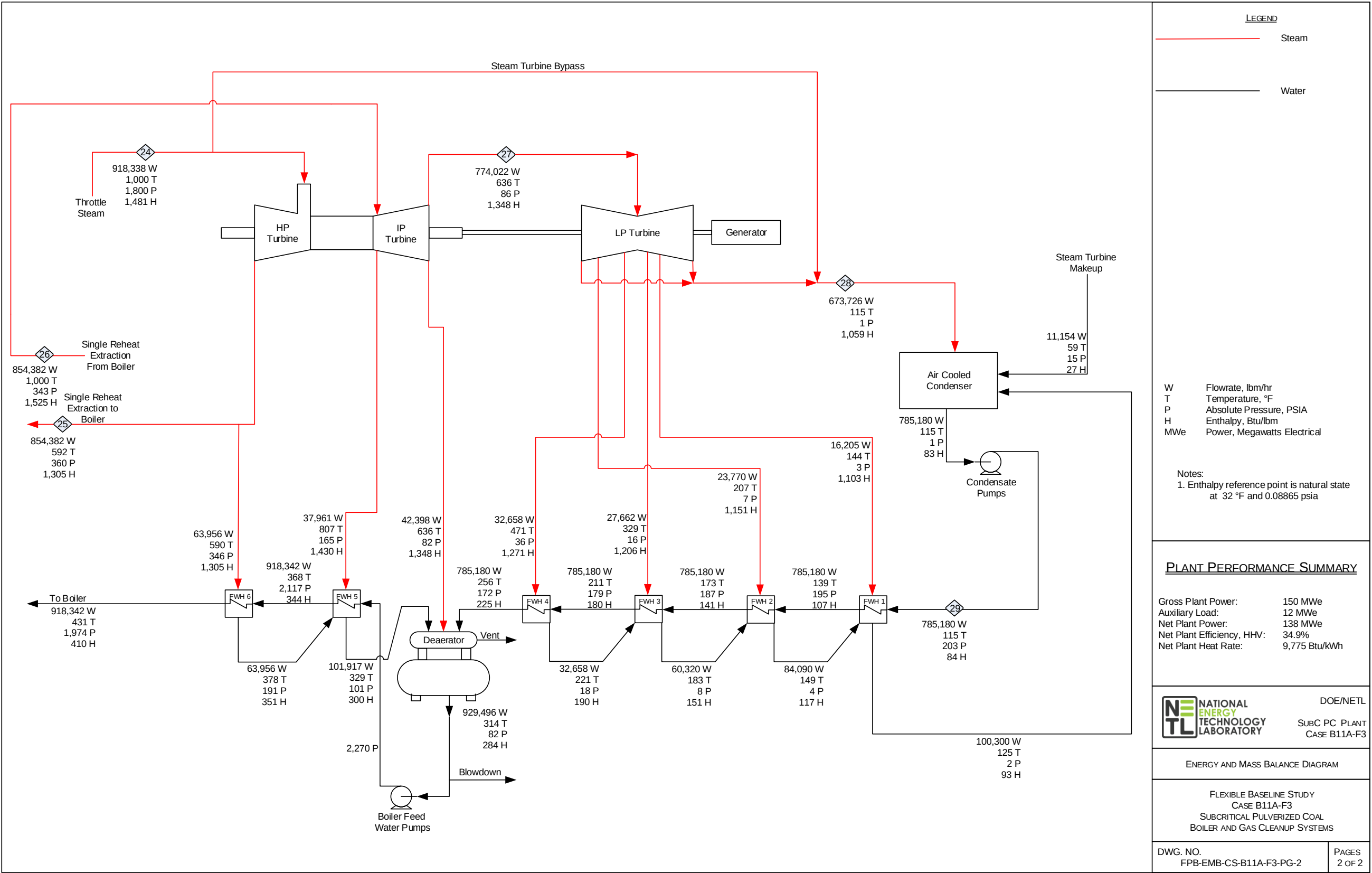


Exhibit 5-88. Case B11A-F3 energy and mass balance, subcritical steam cycle



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-89. Case B11A-F3 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	1,420 (1,346)	1.2 (1.1)	–	1,421 (1,347)
Air	–	16 (16)	–	16 (16)
Raw Water Makeup	–	2.1 (2.0)	–	2.1 (2.0)
Limestone	–	0.1 (0.1)	–	0.1 (0.1)
Auxiliary Power	–	–	44 (42)	44 (42)
Total	1,420 (1,346)	20 (19)	44 (42)	1,484 (1,406)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	1.5 (1.4)	–	1.5 (1.4)
Fly Ash	–	0.5 (0.5)	–	0.5 (0.5)
Stack Gas	–	191 (181)	–	191 (181)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Gypsum	–	0.5 (0.5)	–	0.5 (0.5)
Motor Losses and Design Allowances	–	–	8.8 (8.3)	8.8 (8.3)
Air Cooled Condenser Load ^A	–	694 (658)	–	694 (658)
Blowdown Streams and Deaerator Vent	–	3.3 (3.1)	–	3.3 (3.1)
<i>Ambient Losses^B</i>	–	39 (37)	–	39 (37)
Power	–	–	540 (512)	540 (512)
Total	0.0 (0.0)	930 (882)	549 (520)	1,479 (1,402)
<i>Unaccounted Energy^C</i>	–	–	–	4.8 (4.6)

^A Includes condenser load only

^B Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^C By difference

5.4.16 Case B11A-F3 – Part Load Performance Results

Plant performance results are summarized at each discrete load point in Exhibit 5-90. Exhibit 5-91 displays a detailed breakdown of the auxiliary power consumption at each discrete load point. Air emissions at each discrete load point are summarized in Exhibit 5-92.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
FLEXIBLE OPERATION

Exhibit 5-90. Case B11A-F3 part load plant performance summary

Performance Summary					
Percent Load	100%	75%	50%	30%	20%
Total Gross Power, MWe	150	113	75	45	30
Nameplate Capacity, MWe	150	150	150	150	150
Total Auxiliaries, MWe	12	10	7	5	4
Total Auxiliaries, % of Gross Power	8.2%	8.5%	9.0%	10.1%	11.7%
Net Power, MWe	138	103	68	40	26
HHV Net Plant Efficiency, %	34.9%	34.2%	33.0%	31.2%	29.6%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	10,313 (9,775)	10,534 (9,984)	10,908 (10,339)	11,522 (10,921)	12,161 (11,526)
LHV Net Plant Efficiency, %	36.2%	35.4%	34.2%	32.4%	30.7%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,947 (9,428)	10,160 (9,630)	10,521 (9,972)	11,113 (10,533)	11,729 (11,117)
HHV Boiler Efficiency, %	87.5%	87.5%	87.5%	87.5%	87.6%
LHV Boiler Efficiency, %	90.7%	90.7%	90.7%	90.7%	90.8%
Steam Turbine Cycle Efficiency, %	43.5%	42.7%	41.4%	39.7%	38.3%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	8,278 (7,846)	8,433 (7,993)	8,689 (8,236)	9,065 (8,592)	9,402 (8,912)
Condenser Duty, GJ/hr (MMBtu/hr)	694 (658)	536 (508)	376 (356)	242 (229)	171 (162)
As-Received Coal Feed, kg/hr (lb/hr)	52,317 (115,340)	39,968 (88,114)	27,450 (60,516)	17,176 (37,866)	11,872 (26,173)
Limestone Sorbent Feed, kg/hr (lb/hr)	5,062 (11,160)	3,875 (8,544)	2,672 (5,891)	1,680 (3,704)	1,165 (2,568)
HHV Thermal Input, kWt	394,342	301,257	206,902	129,462	89,483
LHV Thermal Input, kWt	380,348	290,566	199,559	124,867	86,308
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.1)	0.004 (1.1)	0.004 (1.1)	0.004 (1.1)	0.005 (1.2)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)	0.004 (1.1)	0.004 (1.1)	0.004 (1.1)	0.004 (1.2)
Excess Air, %	20.0%	22.1%	26.9%	33.0%	37.0%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-91. Case B11A-F3 part load plant power summary

Power Summary					
Percent Load	100%	75%	50%	30%	20%
Steam Turbine Power, MWe	150	113	75	45	30
Total Gross Power, MWe	150	113	75	45	30
Nameplate Capacity, MWe	150	150	150	150	150
Auxiliary Load Summary					
Activated Carbon Injection, kWe	8	6	4	3	2
Air Cooled Condenser Fans, kWe	1,790	1,780	1,250	750	470
Ancillary Glycol Cooling Loops, kWe	250	250	250	250	250
Ash Handling, kWe	176	133	90	55	37
Baghouse, kWe	24	18	12	7	5
Boiler Feedwater Pump, kWe	2,560	1,410	630	220	100
Coal Handling and Conveying, kWe	110	90	60	40	30
Condensate Pumps, kWe	184	119	77	50	37
Dry Sorbent Injection, kWe	14	10	6	3	1
Flue Gas Desulfurizer, kWe	810	730	720	560	380
Forced Draft Fans, kWe	830	580	310	130	60
Ground Water Pumps, kWe	13	10	7	5	4
Induced Draft Fans, kWe	2,400	1,610	890	390	210
Miscellaneous Balance of Plant, ^A kWe	1,250	1,250	1,250	1,250	1,250
Primary Air Fans, kWe	204	159	106	43	22
Pulverizers, kWe	580	440	300	190	130
SCR, kWe	9	8	6	4	3
Sorbent Handling and Reagent Preparation, kWe	244	187	129	81	56
Spray Dryer Evaporator, kWe	58	44	30	19	13
Steam Turbine Auxiliaries, kWe	350	350	350	350	350
Transformer Losses, kWe	480	360	240	150	100
Total Auxiliaries, MWe	12	10	7	5	4
Net Power, MWe	138	103	68	40	26

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-92. Case B11A-F3 part load air emissions summary

Emissions Summary					
Percent Load	100%	75%	50%	30%	20%
SO ₂ , kg/MWhgross (lb/MWhgross)	0.328 (0.724)	0.335 (0.739)	0.347 (0.764)	0.363 (0.800)	0.378 (0.832)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	816 (1,799)	832 (1,834)	859 (1,893)	898 (1,979)	932 (2,055)
CO ₂ , kg/MWhnet (lb/MWhnet)	889 (1,960)	909 (2,004)	943 (2,079)	999 (2,201)	1,055 (2,327)
Particulate Concentration, ^{A,B} mg/Nm ³	13.68	13.21	12.34	11.30	10.59

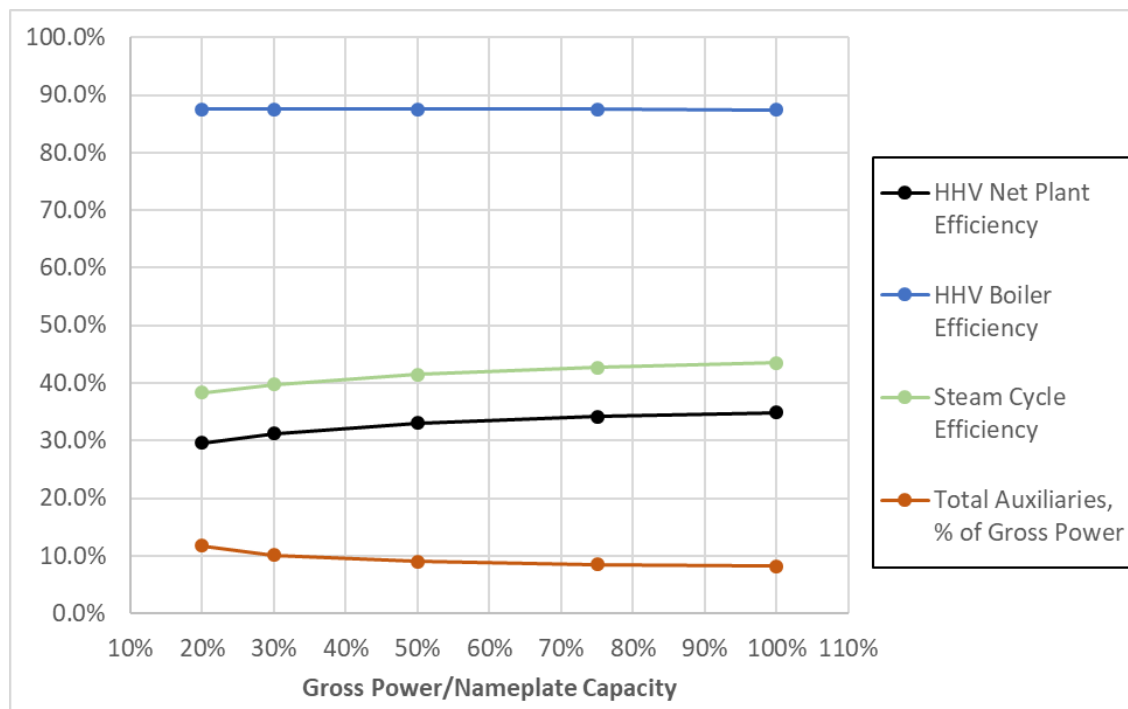
^A Concentration of particles in the flue gas after the baghouse

^B Normal conditions given at 32°F and 14.696 psia

Case B11A-F3 air emissions remained below the environmental target emission limits across the entire load range. Hg, NO_x, and PM emissions are maintained at constant levels across the load. SO₂ emissions increase as load is reduced but are kept below the environmental target emission limit.

Exhibit 5-93 displays the Case B11A-F3 itemized efficiencies (HHV net plant efficiency, HHV boiler efficiency, and steam cycle efficiency) and normalized auxiliary power consumption across the load range.

Exhibit 5-93. Case B11A-F3 part load itemized efficiencies



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

The Case B11A-F3 itemized heat rates are similar to those presented in Case B11A-F2. VFDs lead to a reduced auxiliary power consumption for the BFW pump and the PA, FD, and ID fans, which leads to a moderate reduction in the HHV NPHR compared to Case B11A-F2. Additionally, VFDs have a small impact on the modeled boiler heat rate due to their impact on PA and FD fan isentropic efficiency, but the impact is small, and has little effect on the overall NPHR.

5.4.17 Case B11A-F3 – Major Equipment List

Case B11A-F3 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	10 tonne (10 ton)	2	1
9	Feeder	Vibratory	40 tonne/hr (50 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	90 tonne/hr (100 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	40 tonne (50 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Transfer Tower No. 2	Enclosed	N/A	1	0
16	Coal Silo w/ Vent Filter and Slide Gates	Field erected	190 tonne (200 ton)	3	0
17	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 2 tonne (2 ton) Feeder - 10 kg/hr (30 lb/hr)	1	0
18	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 50 tonne (60 ton) Feeder - 310 kg/hr (690 lb/hr)	1	0
19	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
20	Limestone Feeder	Belt	21 tonne/hr (23 tph)	1	0
21	Limestone Conveyor No. 1	Belt	21 tonne/hr (23 tph)	1	0
22	Limestone Reclaim Hopper	N/A	4 tonne (5 ton)	1	0
23	Limestone Reclaim Feeder	Belt	16 tonne/hr (18 tph)	1	0
24	Limestone Conveyor No. 2	Belt	16 tonne/hr (18 tph)	1	0
25	Limestone Day Bin	w/ actuator	67 tonne (74 ton)	2	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case B11A-F3 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	10 tonne/hr (11 tph)	6	0
2	Coal Pulverizer	Rotary (Vertical)	10 tonne/hr (11 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	6 tonne/hr (6 tph)	1	1
4	Limestone Ball Mill	Rotary	6 tonne/hr (6 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	22,700 liters (6,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	380 lpm @ 10m H ₂ O (100 gpm @ 40 ft H ₂ O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	90 lpm (30 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	120,000 liters (32,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	250 lpm @ 9m H ₂ O (70 gpm @ 30 ft H ₂ O)	1	1

Case B11A-F3 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	334,000 liters (88,000 gal)	2	0
2	Condensate Pumps	Vertical canned	6,600 lpm @ 200 m H ₂ O (1,700 gpm @ 600 ft H ₂ O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	464,000 kg/hr (1,022,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump	Barrel type, multi-stage, centrifugal	7,700 lpm @ 1,900 m H ₂ O (2,000 gpm @ 6,100 ft H ₂ O)	1	1
5	N/A				
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	200,000 kg/hr (430,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	460,000 kg/hr (1,010,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	460,000 kg/hr (1,010,000 lb/hr)	1	0
12	Auxiliary Boiler	Shop fabricated, electrode boiler	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
13	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
14	Service Air Compressors	Flooded screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
15	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
16	Closed Cycle Cooling Heat Exchangers	Shell and tube	37 GJ/hr (35 MMBtu/hr) each	2	0
17	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	14,600 lpm @ 30 m H ₂ O (3,900 gpm @ 100 ft H ₂ O)	2	1
18	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
19	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
20	Raw Water Pumps	Stainless steel, single suction	150 lpm @ 20 m H ₂ O (40 gpm @ 60 ft H ₂ O)	2	1
21	Ground Water Pumps	Stainless steel, single suction	150 lpm @ 270 m H ₂ O (40 gpm @ 880 ft H ₂ O)	2	1
22	Filtered Water Pumps	Stainless steel, single suction	350 lpm @ 50 m H ₂ O (90 gpm @ 160 ft H ₂ O)	2	1
23	Filtered Water Tank	Vertical, cylindrical	340,000 liter (90,000 gal)	1	0
24	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
25	Liquid Waste Treatment System	—	10 years, 24-hour storm	1	0
26	Process Water Treatment	Spray dryer evaporator	Flue Gas - 480 m ³ /min (17,120 acfm) @ 384°C (724°F) & 0.1 MPa (14 psia) Blowdown - 30 lpm (10 gpm) @ 20,018 ppmw Cl ⁻	2	1

Case B11A-F3 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Subcritical, drum wall-fired, low NOx burners, overfire air	460,000 kg/hr steam @ 12.3 MPa/538°C/538°F (1,010,000 lb/hr steam @ 1,785 psig/1,000°F/1,000°F)	1	0
2	Primary Air Fan	Centrifugal	44,000 kg/hr, 600 m ³ /min @ 107 cm WG (97,000 lb/hr, 21,200 acfm @ 42 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	249,000 kg/hr, 3,400 m ³ /min @ 76 cm WG (549,000 lb/hr, 120,000 acfm @ 30 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	325,000 kg/hr, 6,700 m ³ /min @ 116 cm WG (717,000 lb/hr, 235,600 acfm @ 46 in. WG)	2	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
5	SCR Reactor Vessel	Space for spare layer	610,000 kg/hr (1,350,000 lb/hr)	2	0
6	SCR Catalyst	—	—	3	0
7	Dilution Air Blower	Centrifugal	20 m ³ /min @ 108 cm WG (800 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	26,000 liter (7,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	5 lpm @ 90 m H ₂ O (1 gpm @ 300 ft H ₂ O)	2	1

Case B11A-F3 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	325,000 kg/hr (717,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	11,000 m ³ /min (389,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	64,000 lpm @ 65 m H ₂ O (17,000 gpm @ 210 ft H ₂ O)	3	1
4	Bleed Pumps	Horizontal centrifugal	1,070 lpm (280 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	180 m ³ /min @ 0.3 MPa (6,460 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	260 lpm (70 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	8 tonne/hr (9 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	160 lpm @ 13 m H ₂ O (40 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	110,000 lpm (30,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	380 lpm @ 21 m H ₂ O (100 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	10 kg/hr (30 lb/hr)	1	0
13	Hydrated Lime Injectors	---	310 kg/hr (690 lb/hr)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case B11A-F3 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	122 m (400 ft) high x 3.1 m (10 ft) diameter	1	0

Case B11A-F3 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	156 MW 12.3 MPa/538°C/538°C (1785 psig/ 1000°F/1000°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	170 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Air-cooled Condenser	Forced draft, direct, A-frame air-cooled condenser	760 GJ/hr (720 MMBtu/hr), Condensing temperature 46°C (115°F), Ambient temperature 15°C (59°F)	1	0

Case B11A-F3 – Account 9: Auxiliary Cooling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Glycol Cooling Loops	Industrial grade, air to glycol, closed loop heat exchanger	10 GJ/hr (14 MMBtu/hr) heat duty	5	0

Case B11A-F3 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	1.2 tonne/hr (1.4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	12	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	5 m ³ /min @ 0.2 MPa (174 scfm @ 24 psi)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Fly Ash Silo	Reinforced concrete	320 tonne (360 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	30 tonne/hr (30 tph)	1	0

Case B11A-F3 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 160 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 11 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 2 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Generator	Sized for black start capability	5000 kW, 480 V, 3-ph, 60 Hz	1	0
9	Boiler Feed Pump Motor VFD	Medium voltage, air-cooled	2610 kW, 4160 V, 3-ph, 60 Hz	1	0
10	ID Fan Motor VFD	Medium voltage, air-cooled	1300 kW, 4160 V, 3-ph, 60 Hz	1	0
11	FD Fan Motor VFD	Medium voltage, air-cooled	450 kW, 4160 V, 3-ph, 60 Hz	1	0
12	PA Fan Motor VFD	Medium voltage, air-cooled	120 kW, 4160 V, 3-ph, 60 Hz	1	0

Case B11A-F3 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers, alarm management, HMI's, data historian, hard-wired control interface panels, and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor cabinets with redundant input/output, I/O cabinets, various I/C buses	Spare 25% I/O and processor bandwidth	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant	1	0

The Case B11A-F3 plant design includes the design features of the Case B11A-F2 plant with the following modifications:

- **Account 3 — Feedwater and Miscellaneous Systems and Equipment**
 - Medium-voltage electric-driven BFW pump outfitted with VFD
 - VFD equipment varies the frequency and voltage fed to the BFW pump medium-voltage electric motor to control flow/pressure via speed control.
 - Speed control allows for the pump to (largely) operate within a region of “constant efficiency” at its maximum capability curve for a specific flow rate; this constant efficiency is the predominant benefit of utilizing “speed control” in lieu of “throttling” when establishing means of flow control.
 - Typically, speed control pumps will still be equipped with a standard outlet throttling valve to serve as a secondary means of flow control (if needed).
 - Based on Black & Veatch experience with the equipment, a frequently noted operational advantage to the VFD equipment is that it can be remotely located from the BFW pump medium voltage electric motor; based on estimates from established VFD OEMs, the VFD enclosure can be remotely located hundreds of feet away from the motor it serves (when equipped with the appropriate cabling material).
 - Rollout of the VFD equipment was limited to only the largest electrical consumers within the plant (i.e., BFW pump, ID fan, FD fan, PA fan) in order to control electrical equipment costs of the VFD units.
 - Auxiliary boiler removed and replaced with an “electrode boiler”
 - Electrode boiler(s) produces saturated steam at the design pressure and will predominantly serve as the onsite sparging steam supply.
 - A pump that is internal to the vessel pumps feedwater into the electrode boiler vessel (typically operated on 4.16–13.8 kV); the water contacts the electrodes and steam is produced.
 - The electrode boiler would be served by the plant’s auxiliary power system when the plant is operating; when the plant is not operating, the electrode boiler could be fed from the site’s substation (requiring consumption of grid back-feed power for a short period of time during startup) or from the emergency generator. This operational decision is typically made by plant operations personnel based on seasonal energy prices, emergency generator operating hours, and fuel availability.
 - As with any sparging steam supply, feedwater-level water quality is preferred by the OEMs to reduce the mineral deposits within the electrode boiler internals.
 - Addition of a steam turbine bypass line
 - Steam turbine bypass line likely only utilized during startup, shutdown, or plant “trip” conditions to allow the decoupling of the boiler/steam turbine, thereby improving equipment protection and plant control.

- The use of the steam turbine bypass during startup has been linked to improved steam/material temperature matching during startups and shutdowns. [15] [38]
- **Account 4 — Boiler and Accessories**
 - Converting a burner row to “indirect firing”
 - This supplemental coal-firing is predominantly used at reduced loads (likely less than 30% load); additionally, application of indirect firing has been linked to reducing the “inertia” in the firing system, which provides additional benefits to ramp rate. [25]
 - Primary air is decoupled from the coal supply; multiple channels/lines are used to compartmentalize the air/coal streams.
 - This firing technique allows for lower primary air flow rates and lower NO_x production levels at reduced loads; this burner row outfitted for indirect firing can also be used to reduce startup times. [18]
 - BFW pump, PA, FD, and ID fans outfitted with VFDs to the existing electric motors
 - VFD equipment varies the frequency and voltage fed to the fans’ medium-voltage electric motors to control flow/pressure via speed control; as mentioned in the Tier 1 discussion, these VFD units can be remotely located up to hundreds of feet from the motor(s) served.
 - Speed control allows for the fan to (largely) operate within a region of constant efficiency at its maximum capability curve for a specific flow rate; this constant efficiency is the predominant benefit of utilizing speed control in lieu of throttling when establishing means of flow control.
 - As mentioned above, rollout of the VFD equipment was limited to only the largest electrical consumers within the plant (i.e., BFP, ID Fan, FD Fan, PA Fan) in order to control electrical equipment costs of the VFD units.
 - Typically, speed control (centrifugal) fans will still be outfitted with standard inlet guide vanes to allow for fast-response flow control (if needed).
- **Account 11 — Accessory Electric Plant**
 - Application of VFDs on large electric motors; no significant cost impacts to the plant electrical distribution or auxiliary system design as a result of the VFD components

5.4.18 Case B11A-F3– Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-94 shows a detailed breakdown of the capital costs; Exhibit 5-95 shows the owner’s costs, along with the TOC; and Exhibit 5-96 shows the initial and annual O&M costs.

The estimated TPC of the Case B11A-F3 plant is \$491 million. The project contingency is 13.3 percent of the TPC.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-94. Case B11A-F3 total plant cost details

Case:		B11A-F3	Subcritical PC Flexible Plant (Tiers 1–3)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
1		Coal & Sorbent Handling								
1.1	Coal Receive & Unload	\$267	\$0	\$120	\$0	\$387	\$68	\$0	\$68	\$523
1.2	Coal Stackout & Reclaim	\$876	\$0	\$196	\$0	\$1,072	\$188	\$0	\$189	\$1,448
1.3	Coal Conveyors	\$9,304	\$0	\$2,214	\$0	\$11,518	\$2,016	\$0	\$2,030	\$15,564
1.4	Other Coal Handling	\$1,036	\$0	\$218	\$0	\$1,254	\$219	\$0	\$221	\$1,694
1.5	Sorbent Receive & Unload	\$61	\$0	\$18	\$0	\$79	\$14	\$0	\$14	\$107
1.6	Sorbent Stackout & Reclaim	\$331	\$0	\$60	\$0	\$391	\$68	\$0	\$69	\$528
1.7	Sorbent Conveyors	\$588	\$128	\$142	\$0	\$858	\$150	\$0	\$151	\$1,159
1.8	Other Sorbent Handling	\$35	\$8	\$18	\$0	\$61	\$11	\$0	\$11	\$82
1.9	Coal & Sorbent Handling Foundations	\$0	\$430	\$567	\$0	\$997	\$175	\$0	\$176	\$1,348
	Subtotal	\$12,497	\$566	\$3,553	\$0	\$16,616	\$2,908	\$0	\$2,929	\$22,452
2		Coal & Sorbent Preparation & Feed								
2.1	Coal Crushing & Drying	\$569	\$0	\$109	\$0	\$678	\$119	\$0	\$120	\$916
2.2	Prepared Coal Storage & Feed	\$2,264	\$0	\$487	\$0	\$2,752	\$482	\$0	\$485	\$3,718
2.5	Sorbent Preparation Equipment	\$251	\$11	\$51	\$0	\$313	\$55	\$0	\$55	\$423
2.6	Sorbent Storage & Feed	\$405	\$0	\$153	\$0	\$557	\$98	\$0	\$98	\$753
2.9	Coal & Sorbent Feed Foundation	\$0	\$172	\$151	\$0	\$324	\$57	\$0	\$57	\$438
	Subtotal	\$3,488	\$183	\$952	\$0	\$4,624	\$809	\$0	\$815	\$6,248
3		Feedwater & Miscellaneous BOP Systems								
3.1	Feedwater System	\$894	\$1,533	\$766	\$0	\$3,193	\$559	\$0	\$563	\$4,314
3.2	Water Makeup & Pretreating	\$1,540	\$154	\$873	\$0	\$2,567	\$449	\$0	\$603	\$3,620
3.3	Other Feedwater Subsystems	\$574	\$188	\$179	\$0	\$940	\$165	\$0	\$166	\$1,271
3.4	Service Water Systems	\$416	\$795	\$2,574	\$0	\$3,785	\$662	\$0	\$890	\$5,338
3.5	Other Boiler Plant Systems	\$171	\$62	\$155	\$0	\$388	\$68	\$0	\$68	\$524
3.6	Natural Gas Pipeline and Start-Up System	\$892	\$38	\$29	\$0	\$959	\$168	\$0	\$169	\$1,296
3.7	Waste Water Treatment Equipment	\$2,305	\$0	\$1,413	\$0	\$3,717	\$651	\$0	\$874	\$5,242
3.8	Spray Dryer Evaporator	\$4,228	\$0	\$2,448	\$0	\$6,676	\$1,168	\$0	\$1,569	\$9,413
3.9	Miscellaneous Plant Equipment	\$734	\$96	\$373	\$0	\$1,204	\$211	\$0	\$283	\$1,698
	Subtotal	\$11,754	\$2,866	\$8,810	\$0	\$23,430	\$4,100	\$0	\$5,184	\$32,715
4		Pulverized Coal Boiler & Accessories								
4.9	Pulverized Coal Boiler & Accessories	\$96,498	\$0	\$63,019	\$0	\$159,516	\$27,915	\$0	\$28,115	\$215,547
4.10	Selective Catalytic Reduction System	\$5,359	\$0	\$3,500	\$0	\$8,859	\$1,550	\$0	\$1,561	\$11,970
4.11	Boiler Balance of Plant	\$300	\$0	\$196	\$0	\$496	\$87	\$0	\$87	\$670
4.12	Primary Air System	\$341	\$0	\$223	\$0	\$563	\$99	\$0	\$99	\$761
4.13	Secondary Air System	\$692	\$0	\$452	\$0	\$1,144	\$200	\$0	\$202	\$1,546
4.14	Induced Draft Fans	\$1,297	\$0	\$847	\$0	\$2,145	\$375	\$0	\$378	\$2,898
4.15	Major Component Rigging	\$22	\$0	\$15	\$0	\$37	\$6	\$0	\$7	\$50

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B11A-F3	Subcritical PC Flexible Plant (Tiers 1–3)				Estimate Type: Cost Base:			Conceptual Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
4.16	Boiler Foundations	\$0	\$97	\$86	\$0	\$183	\$32	\$0	\$32	\$247
	Subtotal	\$104,510	\$97	\$68,336	\$0	\$172,943	\$30,265	\$0	\$30,481	\$233,690
5		Flue Gas Cleanup								
5.2	WFGD Absorber Vessels & Accessories	\$20,989	\$0	\$4,488	\$0	\$25,477	\$4,458	\$0	\$4,490	\$34,426
5.3	Other FGD	\$73	\$0	\$82	\$0	\$155	\$27	\$0	\$27	\$210
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$595	\$131	\$585	\$0	\$1,311	\$229	\$0	\$231	\$1,772
5.9	Particulate Removal (Bag House & Accessories)	\$627	\$0	\$395	\$0	\$1,023	\$179	\$0	\$180	\$1,382
5.12	Gas Cleanup Foundations	\$0	\$42	\$37	\$0	\$78	\$14	\$0	\$14	\$106
5.13	Gypsum Dewatering System	\$187	\$0	\$32	\$0	\$219	\$38	\$0	\$39	\$296
	Subtotal	\$22,472	\$173	\$5,619	\$0	\$28,263	\$4,946	\$0	\$4,981	\$38,191
7		Ductwork & Stack								
7.3	Ductwork	\$0	\$209	\$145	\$0	\$354	\$62	\$0	\$62	\$478
7.4	Stack	\$2,526	\$0	\$1,468	\$0	\$3,993	\$699	\$0	\$704	\$5,396
7.5	Duct & Stack Foundations	\$0	\$51	\$61	\$0	\$112	\$20	\$0	\$26	\$158
	Subtotal	\$2,526	\$260	\$1,673	\$0	\$4,459	\$780	\$0	\$792	\$6,031
8		Steam Turbine & Accessories								
8.1	Steam Turbine Generator & Accessories	\$28,198	\$0	\$3,170	\$0	\$31,368	\$5,489	\$0	\$5,529	\$42,387
8.2	Steam Turbine Plant Auxiliaries	\$489	\$0	\$1,039	\$0	\$1,528	\$267	\$0	\$269	\$2,065
8.3	Condenser & Auxiliaries ^A	\$12,094	\$0	\$4,103	\$0	\$16,197	\$2,834	\$0	\$2,855	\$21,886
8.4	Steam Piping	\$12,345	\$0	\$5,003	\$0	\$17,348	\$3,036	\$0	\$3,058	\$23,442
8.5	Turbine Generator Foundations	\$0	\$57	\$94	\$0	\$151	\$26	\$0	\$35	\$213
	Subtotal	\$53,126	\$57	\$13,410	\$0	\$66,592	\$11,654	\$0	\$11,746	\$89,992
9		Cooling Water System								
9.6	Component Cooling Water System ^B	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
	Subtotal	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
10		Ash & Spent Sorbent Handling Systems								
10.6	Ash Storage Silos	\$300	\$0	\$917	\$0	\$1,217	\$213	\$0	\$214	\$1,644
10.7	Ash Transport & Feed Equipment	\$1,125	\$0	\$1,115	\$0	\$2,240	\$392	\$0	\$395	\$3,027
10.9	Ash/Spent Sorbent Foundation	\$0	\$202	\$248	\$0	\$449	\$79	\$0	\$106	\$633
	Subtotal	\$1,425	\$202	\$2,280	\$0	\$3,906	\$684	\$0	\$715	\$5,304
11		Accessory Electric Plant								
11.1	Generator Equipment	\$791	\$0	\$596	\$0	\$1,387	\$243	\$0	\$244	\$1,874
11.2	Station Service Equipment	\$1,466	\$0	\$126	\$0	\$1,592	\$279	\$0	\$281	\$2,151
11.3	Switchgear & Motor Control	\$4,787	\$0	\$831	\$0	\$5,618	\$983	\$0	\$990	\$7,591
11.4	Conduit & Cable Tray	\$0	\$336	\$969	\$0	\$1,305	\$228	\$0	\$230	\$1,764
11.5	Wire & Cable	\$0	\$661	\$1,182	\$0	\$1,843	\$323	\$0	\$325	\$2,491
11.6	Protective Equipment	\$17	\$0	\$60	\$0	\$78	\$14	\$0	\$14	\$105
11.7	Standby Equipment	\$224	\$0	\$206	\$0	\$430	\$75	\$0	\$76	\$581

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Case:		B11A-F3	Subcritical PC Flexible Plant (Tiers 1–3)				Estimate Type: Cost Base:			Conceptual Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
11.8	Main Power Transformers	\$2,109	\$0	\$43	\$0	\$2,152	\$377	\$0	\$379	\$2,908
11.9	Electrical Foundations	\$0	\$61	\$156	\$0	\$217	\$38	\$0	\$51	\$306
	Subtotal	\$9,394	\$1,059	\$4,169	\$0	\$14,622	\$2,559	\$0	\$2,590	\$19,770
12		Instrumentation & Control								
12.1	Pulverized Coal Boiler Control Equipment	\$200	\$0	\$36	\$0	\$236	\$41	\$0	\$42	\$319
12.3	Steam Turbine Control Equipment	\$192	\$0	\$22	\$0	\$213	\$37	\$0	\$38	\$288
12.5	Signal Processing Equipment	\$185	\$0	\$33	\$0	\$218	\$38	\$0	\$39	\$295
12.6	Control Boards, Panels & Racks	\$58	\$0	\$35	\$0	\$93	\$16	\$0	\$16	\$126
12.7	Distributed Control System Equipment	\$1,937	\$0	\$345	\$0	\$2,282	\$399	\$0	\$402	\$3,084
12.8	Instrument Wiring & Tubing	\$173	\$139	\$554	\$0	\$866	\$152	\$0	\$153	\$1,171
12.9	Other Instrumentation & Controls Equipment	\$206	\$0	\$477	\$0	\$683	\$120	\$0	\$120	\$923
	Subtotal	\$2,951	\$139	\$1,502	\$0	\$4,592	\$804	\$0	\$809	\$6,205
13		Improvements to Site								
13.1	Site Preparation	\$0	\$120	\$2,556	\$0	\$2,675	\$468	\$0	\$629	\$3,772
13.2	Site Improvements	\$0	\$656	\$867	\$0	\$1,523	\$266	\$0	\$358	\$2,147
13.3	Site Facilities	\$541	\$0	\$567	\$0	\$1,108	\$194	\$0	\$260	\$1,563
	Subtotal	\$541	\$776	\$3,990	\$0	\$5,306	\$929	\$0	\$1,247	\$7,482
14		Buildings & Structures								
14.2	Boiler Building	\$0	\$3,767	\$3,311	\$0	\$7,078	\$1,239	\$0	\$1,247	\$9,564
14.3	Steam Turbine Building	\$0	\$3,808	\$3,547	\$0	\$7,355	\$1,287	\$0	\$1,296	\$9,938
14.4	Administration Building	\$0	\$340	\$360	\$0	\$700	\$122	\$0	\$123	\$946
14.6	Water Treatment Buildings	\$0	\$97	\$88	\$0	\$184	\$32	\$0	\$33	\$249
14.7	Machine Shop	\$0	\$153	\$102	\$0	\$254	\$45	\$0	\$0	\$299
14.8	Warehouse	\$0	\$119	\$119	\$0	\$237	\$42	\$0	\$42	\$321
14.9	Other Buildings & Structures	\$0	\$86	\$73	\$0	\$159	\$28	\$0	\$28	\$214
14.10	Waste Treating Building & Structures	\$0	\$137	\$414	\$0	\$551	\$96	\$0	\$97	\$744
	Subtotal	\$0	\$8,506	\$8,012	\$0	\$16,518	\$2,891	\$0	\$2,866	\$22,275
	Total	\$225,069	\$14,883	\$122,602	\$0	\$362,554	\$63,447	\$0	\$65,276	\$491,277

^AACC; ^B Component cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

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FLEXIBLE OPERATION

Exhibit 5-95. Case B11A-F3 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$4,682
1-Month Maintenance Materials	\$650
1-Month Non-Fuel Consumables	\$342
1-Month Waste Disposal	\$187
25% of 1-Month Fuel Cost at 100% CF	\$547
2% of TPC	\$9,826
Total	\$16,233
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$5,047
0.5% of TPC (spare parts)	\$2,456
Total	\$7,503
Other Costs	
Initial Cost for Catalyst and Chemicals	\$518
Land	\$117
Other Owner's Costs	\$73,692
Financing Costs	\$13,264
Total Overnight Costs (TOC)	\$602,604

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Exhibit 5-96. Case B11A-F3 initial and annual operating and maintenance costs

Case:	B11A-F3	– Subcritical PC Flexible Plant (Tiers 1–3)			Cost Base:	Dec 2018
Plant Size (MW, gross):	150	Heat Rate-net (Btu/kWh):			9,775	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$/hour		Skilled Operator:	2.0	
Operating Labor Burden:	30.0	% of base		Operator:	3.0	
Labor O-H Charge Rate:	25.0	% of labor		Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	7.0	
Fixed Operating Costs						
					Annual Cost (\$)	
Annual Operating Labor:					\$3,069,066	
Maintenance Labor:					\$4,421,491	
Administrative & Support Labor:					\$1,872,639	
Property Taxes and Insurance:					\$9,825,535	
Total:					\$19,188,732	
Variable Operating Costs						
					Annual Cost (\$)	
Maintenance Material:					\$7,802,631 x CF	
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)	
Water (/1000 gallons):	0	107	\$1.90	\$0	\$73,870 x CF	
Makeup and Waste Water Treatment Chemicals (ton):	0	0.317	\$550.00	\$0	\$63,698 x CF	
Brominated Activated Carbon (ton):	0	0.30	\$1,600.00	\$0	\$177,432 x CF	
Enhanced Hydrated Lime (ton):	0	7.54	\$240.00	\$0	\$660,177 x CF	
Limestone (ton):	0	134	\$22.00	\$0	\$1,075,415 x CF	
Ammonia (19 wt%, ton):	0	13.1	\$300.00	\$0	\$1,436,397 x CF	
SCR Catalyst (ft³):	3,286	3.00	\$150.00	\$492,831	\$164,277 x CF	
Fuel additive for boiler slagging/fouling mitigation (gal)	1,000	50.0	\$25.00	\$25,000	\$456,250 x CF	
Subtotal:				\$517,831	\$4,107,515 x CF	
Waste Disposal						
Fly Ash (ton):	0	132	\$38.00	\$0	\$1,828,429 x CF	
Bottom Ash (ton):	0	29.5	\$38.00	\$0	\$408,885 x CF	
SCR Catalyst (ft³):	0	3.00	\$2.50	\$0	\$2,738 x CF	
Subtotal:				\$0	\$2,240,052 x CF	
By-Products						
Gypsum (ton):	0	204	\$0.00	\$0	\$0	
Subtotal:				\$0	\$0	
Variable Operating Costs Total:				\$517,831	\$14,150,198 x CF	
Fuel Cost						
Illinois Number 6 (ton):	0	1,384	\$51.96	\$0	\$26,248,532 x CF	
Fuel Costs Total:				\$0	\$26,248,532 x CF	

5.4.18.1 Cost Differential Justifications

The primary contributors to the capital cost differential when comparing Case B11A-F3 to Case B11A-F2 are outlined below:

- Flexibility Option 60 — Application of variable speed drives on large electric motors

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- Flexibility Option 1 — Use of advanced materials to reduce tube and pressure wall thickness requirements to improve rate of warm-up
- Flexibility Option 13 — Use of advanced materials to reduce turbine casing thickness and reduce STG warm-up times
- Flexibility Option 14 — Turbine blade coatings for improved resistance to water impingement
- Flexibility Option 37 — STG steam turbine bypass to condenser
- Flexibility Option 3 — Increase the number of headers to decrease header size and warm-up time
- Flexibility Option 2 — Decrease drum holding time to reduce drum diameter and drum wall thickness
- Flexibility Option 32 — Converting a burner row to indirect firing
- Flexibility Option 80 — Utilization of electrode boiler for fast saturated steam production for supporting plant systems

The justifications for the capital cost differentials when comparing Case B11A-F3 to Case B11A-F2 are outlined below:

- Account 2.2 cost increases due to changes to the silos, feeders, and mills. Account 2.1 cost does not increase since it would not be impacted by changing the number of coal silos; all upstream conveyors, transfer stations, and belts would likely remain consistent regardless of the downstream changes to the coal system. The following flexibility options impacted the cost of Account 2.2:
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 47 — Fuel additive for slagging, fouling and erosion
- Account 2.9 cost increases due to additional equipment foundations required for supplement silos/blowers for the indirect firing system, and for the modularized pump skids and drip feed piping for the fuel additive system (which drips a low flow of additive onto the coal conveyors upstream of the coal silos). The following flexibility options impacted the cost of Account 2.9:
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 47 — Fuel additives for slagging/fouling mitigation
- Accounts 3.1, 3.2, and 3.3 increased in cost due to the additional equipment supplied, sub-system engineering design, and installation man-hours resulting from the condensate polishing system. The following flexibility option impacted the cost of accounts 3.1–3.3:
 - Flexibility Option 12 — Use of condensate polishing system to maintain cycle chemistry parameters during shutdown/layup periods and reduce startup times

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- Account 3.9 cost increases due to additional equipment added for faster sparging steam supply. The following flexibility option impacted the cost of Account 3.9:
 - Flexibility Option 80 — Utilization of electrode boiler for fast saturated steam production for supporting plant systems
- Account 4.9 cost increases due to the additional equipment provided by the boiler OEM, additional sub-system features within the boiler island components (e.g., header and drum interconnection modifications and implementation of advanced materials), additional engineering and installation labor required for these options. The following flexibility options impacted the cost of Account 4.9:
 - Flexibility Option 1 — Use of advanced materials to reduce tube and pressure wall thickness requirements to improve rate of warm-up
 - Flexibility Option 2 — Decrease drum holding time to reduce drum diameter and drum wall thickness
 - Flexibility Option 3 — Increase the number of headers to decrease header size and warm-up time
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 45 — Neural networks and online combustion optimizer
- Account 4.11 cost increases due to the additional equipment requiring boiler balance of plant sub-system engineering design (e.g., instrument air lines, electrical routing, more intricate pipe routing for clash avoidance, additional maintenance access points) and material installation. The following flexibility options impacted the cost of Account 4.11:
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 33 — Intelligent soot blowing for managing heat transfer within the boiler
- Account 4.16 cost increases due to the additional foundation requirements to accommodate the installation of the electrode boiler. The following flexibility option impacted the cost of Account 4.16:
 - Flexibility Option 80 — Utilization of electrode boiler for fast saturated steam production for supporting plant systems
- Account 8.1 cost increases due to the addition of equipment features within the steam turbine island OEM's scope of supply; this additional equipment would result in additional equipment cost, additional engineering man-hours and installation hours. The following flexibility options impacted the cost of Account 8.1:
 - Flexibility Option 13 — Use of advanced materials to reduce turbine casing thickness and reduce STG warm-up times
 - Flexibility Option 14 — Turbine blade coatings for improved resistance to water impingement

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- Flexibility Option 19 — Use of a steam-cooled turbine outer casing to reduce casing thickness
- Account 8.2 cost increases due to the addition of ancillary components, such as bypass lines, additional instruments and instrument connection features to the steam turbine auxiliaries; these additional features would require additional engineering design and material supply. The following flexibility options impacted the cost of Account 8.2:
 - Flexibility Option 19 — Use of a steam-cooled turbine outer casing to reduce casing thickness
 - Flexibility Option 37 — STG steam bypass to condenser
- Account 8.3 cost increases due to the additional engineering, material supply and OEM equipment modifications necessary to accommodate the steam turbine bypass to the existing ACC. This additional sub-system feature would also require additional installation man-hours. The following flexibility option impacted the cost of Account 8.3:
 - Flexibility Option 37 — STG steam bypass to condenser
- Account 8.4 cost increases due to an increase in engineering design, material, and installation labor required for implementing the modifications to the steam piping required to accommodate the turbine casing modifications and the additional steam line to the ACC for bypass functionality. The following flexibility options impacted the cost of Account 8.4:
 - Flexibility Option 19 — Use of a steam-cooled turbine outer casing to reduce casing thickness
 - Flexibility Option 37 — STG steam bypass to condenser
- Account 11.3 cost increases due to installation of VFDs for the BFW pump and fans (PA, FD, and ID). VFDs were incorporated into Account 11.3 because of their alignment with the 'Switchgear and Motor Control' category of equipment; assigning the VFD equipment to this electrical-related category is common for plant design and procurement practices.
- Account 11 (sub-accounts 11.2–11.5 and 11.9) cost increases due to the additional control wiring and cabling for communications and/or power supply to ancillary components and the compulsory cable tray and conduit required to route the wiring and cabling. The following flexibility options impacted the cost of Account 11:
 - Flexibility Option 12 — Use of condensate polishing system
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 33 — Intelligent soot blowing for managing heat transfer within the boiler
 - Flexibility Option 45 — Neural networks and online combustion optimizer
 - Flexibility Option 47 — Fuel additives for slagging/fouling mitigation

- Account 11.9 cost increases due to the foundation requirements of the VFD cabinets/enclosures; the enclosures that house the VFDs typically require poured foundations for support due to their size and weight. It would be expected that these VFD foundations would be separate from main building foundations. No other modifications to accounts 11.2, 11.4, 11.5, 11.6, or 11.7 were expected to have a cost increase impact on Account 11.9; the reason for this is that the majority of the electrical components are direct wall-mounted or “anchor-in-place” to the existing foundation within the boiler and steam turbine buildings.
- Account 12 cost increases significantly due to the additional equipment added to the plant design; it is not only the complexity of the controls system that impacts Account 12 costs, but also the number of components that must be integrated (e.g., electrode boiler, VFD units, additional process steam piping, combustion analyzer(s), indirect firing, intelligent sootblowing). The addition of these components to the plant DCS would be expected to increase the cost of the controls system.

The justifications for the O&M cost differentials when comparing Case B11A-F3 to Case B11A-F2 are outlined below:

- An additional variable O&M cost is introduced due to Flexibility Option 47 — Fuel additive for slagging/fouling mitigation. This highly modularized fuel additive system applies a slurry compound drip-feed to the coal as it is transported on the coal conveyors to the tripper level directly above the coal silos. The application of this option adds an additional consumable stream, which is reflected in the Case B11A-F3 O&M costs.
 - This additional consumable stream accounts for an 11.5 percent increase in (non-fuel) variable operating costs from Case B11A-F2 to Case B11A-F3.

5.4.19 Case B11A-F4 – PC Subcritical Flexible Plant with Tier 1, 2, 3, and 4 Flexibility Options

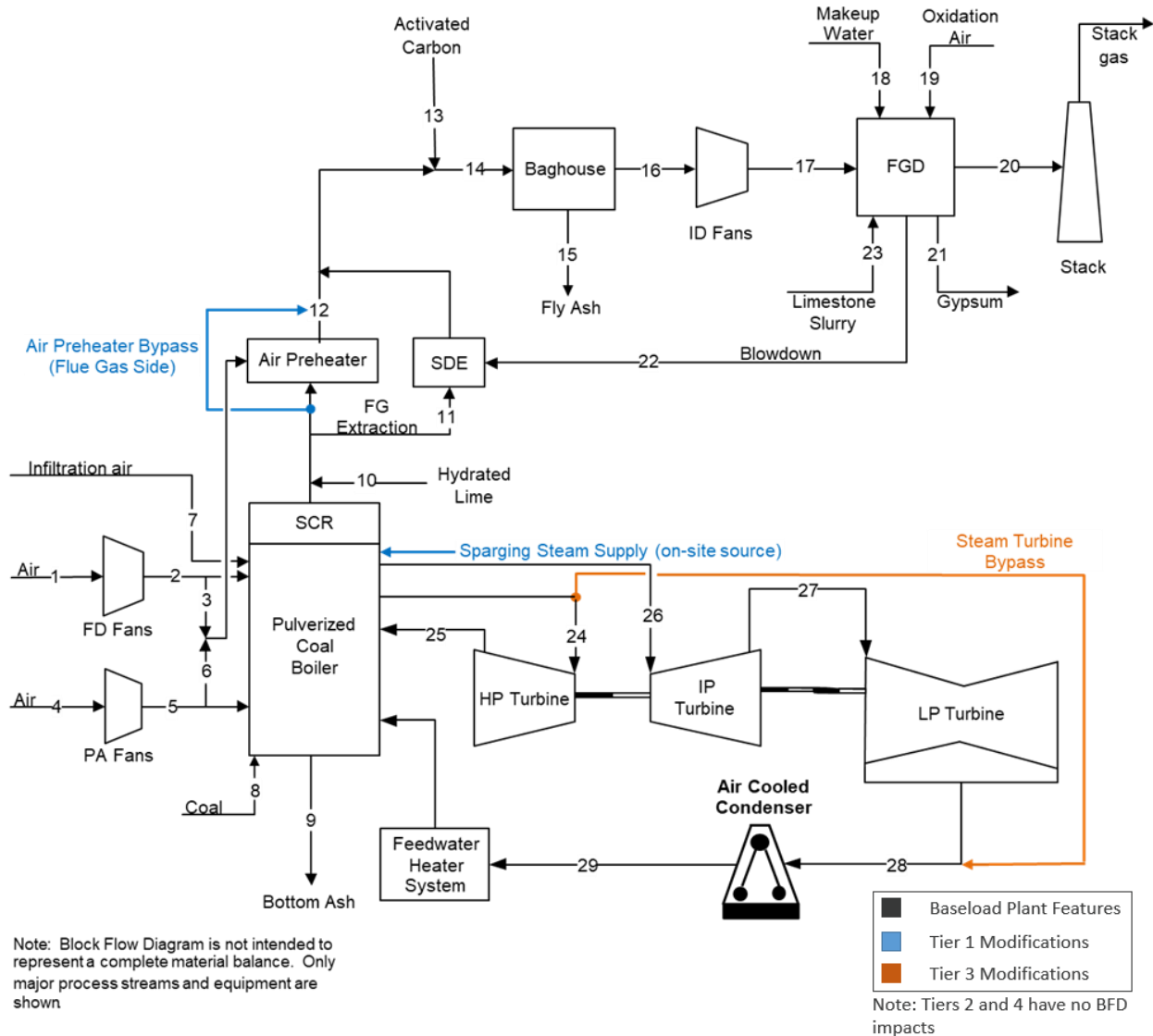
The plant configuration for Case B11A-F4, subcritical flexible plant with tiers 1–4 flexibility options, is identical to Case B11A-F3. The full list of Tier 3 flexibility options was presented in Exhibit 4-17. The nominal gross plant output was maintained at 150 MW.

5.4.20 Case B11A-F4 – Full Load Performance Results

The BFD for Case B11A-F2 is shown in Exhibit 5-97. Case B11A-F4 stream tables and full load performance results are identical to Case B11A-F3 (see Section 5.4.15) so they are not repeated here.

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Exhibit 5-97. Case B11A-F4 block flow diagram



5.4.21 Case B11A-F4 – Part Load Performance Results

Case B11A-F4 Part load performance results are identical to Case B11A-F3 (see Section 5.4.16) so they are not repeated here.

5.4.22 Case B11A-F4 – Major Equipment List

The Case B11A-F4 equipment list is identical to the Case B11A-F3 equipment list (see Section 5.4.17), so it is not repeated here.

The Case B11A-F4 flexible plant design basis includes the design features of the Case B11A-F3 flexible plant with the following modifications:

- **Account 4 – Boiler and Accessories**

- Equipping water cannons in lieu of other distributed soot blowing devices; this equipment changeout was not anticipated to significantly impact overall capital cost/design of the boiler; no anticipated impacts to the major boiler/feedwater equipment categories.
 - No significant operational/process changes due to deployment of water cannons; water cannons will be equipped in the upper radiant section of the boiler and managed by the soot blower management system.
- **Account 8 — Steam Turbine Generator and Auxiliaries**
 - Enhanced turbine seals considered to be an “internal” steam turbine design feature; not anticipated to significantly impact overall capital cost/design of the steam turbine; no anticipated impacts to the major equipment categories.
 - Enhanced turbine seals not anticipated to impact standard steam turbine operation/procedures.

5.4.23 Case B11A-F4 – Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-98 shows a detailed breakdown of the capital costs; Exhibit 5-99 shows the owner’s costs, along with the TOC; Exhibit 5-100 shows the initial and annual O&M costs; and Exhibit 5-101 shows startup and shutdown costs. The estimated TPC of the Case B11A-F4 plant is \$496 million. The project contingency is 13.3 percent of the TPC.

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Exhibit 5-98. Case B11A-F4 total plant cost details

Case:		B11A-F4	Subcritical PC Flexible Plant (Tiers 1–4)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
1		Coal & Sorbent Handling								
1.1	Coal Receive & Unload	\$267	\$0	\$120	\$0	\$387	\$68	\$0	\$68	\$523
1.2	Coal Stackout & Reclaim	\$876	\$0	\$196	\$0	\$1,072	\$188	\$0	\$189	\$1,448
1.3	Coal Conveyors	\$9,304	\$0	\$2,214	\$0	\$11,518	\$2,016	\$0	\$2,030	\$15,564
1.4	Other Coal Handling	\$1,036	\$0	\$218	\$0	\$1,254	\$219	\$0	\$221	\$1,694
1.5	Sorbent Receive & Unload	\$61	\$0	\$18	\$0	\$79	\$14	\$0	\$14	\$107
1.6	Sorbent Stackout & Reclaim	\$331	\$0	\$60	\$0	\$391	\$68	\$0	\$69	\$528
1.7	Sorbent Conveyors	\$588	\$128	\$142	\$0	\$858	\$150	\$0	\$151	\$1,159
1.8	Other Sorbent Handling	\$35	\$8	\$18	\$0	\$61	\$11	\$0	\$11	\$82
1.9	Coal & Sorbent Handling Foundations	\$0	\$430	\$567	\$0	\$997	\$175	\$0	\$176	\$1,348
	Subtotal	\$12,497	\$566	\$3,553	\$0	\$16,616	\$2,908	\$0	\$2,929	\$22,452
2		Coal & Sorbent Preparation & Feed								
2.1	Coal Crushing & Drying	\$569	\$0	\$109	\$0	\$678	\$119	\$0	\$120	\$916
2.2	Prepared Coal Storage & Feed	\$2,264	\$0	\$487	\$0	\$2,752	\$482	\$0	\$485	\$3,718
2.5	Sorbent Preparation Equipment	\$251	\$11	\$51	\$0	\$313	\$55	\$0	\$55	\$423
2.6	Sorbent Storage & Feed	\$405	\$0	\$153	\$0	\$557	\$98	\$0	\$98	\$753
2.9	Coal & Sorbent Feed Foundation	\$0	\$172	\$151	\$0	\$324	\$57	\$0	\$57	\$438
	Subtotal	\$3,488	\$183	\$952	\$0	\$4,624	\$809	\$0	\$815	\$6,248
3		Feedwater & Miscellaneous BOP Systems								
3.1	Feedwater System	\$894	\$1,533	\$766	\$0	\$3,193	\$559	\$0	\$563	\$4,314
3.2	Water Makeup & Pretreating	\$1,540	\$154	\$873	\$0	\$2,567	\$449	\$0	\$603	\$3,620
3.3	Other Feedwater Subsystems	\$574	\$188	\$179	\$0	\$940	\$165	\$0	\$166	\$1,271
3.4	Service Water Systems	\$416	\$795	\$2,574	\$0	\$3,785	\$662	\$0	\$890	\$5,338
3.5	Other Boiler Plant Systems	\$171	\$62	\$155	\$0	\$388	\$68	\$0	\$68	\$524
3.6	Natural Gas Pipeline and Start-Up System	\$892	\$38	\$29	\$0	\$959	\$168	\$0	\$169	\$1,296
3.7	Waste Water Treatment Equipment	\$2,305	\$0	\$1,413	\$0	\$3,717	\$651	\$0	\$874	\$5,242
3.8	Spray Dryer Evaporator	\$4,228	\$0	\$2,448	\$0	\$6,676	\$1,168	\$0	\$1,569	\$9,413
3.9	Miscellaneous Plant Equipment	\$734	\$96	\$373	\$0	\$1,204	\$211	\$0	\$283	\$1,698
	Subtotal	\$11,754	\$2,866	\$8,810	\$0	\$23,430	\$4,100	\$0	\$5,184	\$32,715
4		Pulverized Coal Boiler & Accessories								
4.9	Pulverized Coal Boiler & Accessories	\$98,257	\$0	\$64,167	\$0	\$162,425	\$28,424	\$0	\$28,627	\$219,476
4.10	Selective Catalytic Reduction System	\$5,359	\$0	\$3,500	\$0	\$8,859	\$1,550	\$0	\$1,561	\$11,970
4.11	Boiler Balance of Plant	\$302	\$0	\$197	\$0	\$499	\$87	\$0	\$88	\$675
4.12	Primary Air System	\$341	\$0	\$223	\$0	\$563	\$99	\$0	\$99	\$761
4.13	Secondary Air System	\$692	\$0	\$452	\$0	\$1,144	\$200	\$0	\$202	\$1,546
4.14	Induced Draft Fans	\$1,297	\$0	\$847	\$0	\$2,145	\$375	\$0	\$378	\$2,898

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Case:		B11A-F4	Subcritical PC Flexible Plant (Tiers 1–4)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	
4.15	Major Component Rigging	\$22	\$0	\$15	\$0	\$37	\$6	\$0	\$7	\$50
4.16	Boiler Foundations	\$0	\$97	\$86	\$0	\$183	\$32	\$0	\$32	\$247
	Subtotal	\$106,271	\$97	\$69,487	\$0	\$175,855	\$30,775	\$0	\$30,994	\$237,624
5							Flue Gas Cleanup			
5.2	WFGD Absorber Vessels & Accessories	\$20,989	\$0	\$4,488	\$0	\$25,477	\$4,458	\$0	\$4,490	\$34,426
5.3	Other FGD	\$73	\$0	\$82	\$0	\$155	\$27	\$0	\$27	\$210
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$595	\$131	\$585	\$0	\$1,311	\$229	\$0	\$231	\$1,772
5.9	Particulate Removal (Bag House & Accessories)	\$627	\$0	\$395	\$0	\$1,023	\$179	\$0	\$180	\$1,382
5.12	Gas Cleanup Foundations	\$0	\$42	\$37	\$0	\$78	\$14	\$0	\$14	\$106
5.13	Gypsum Dewatering System	\$187	\$0	\$32	\$0	\$219	\$38	\$0	\$39	\$296
	Subtotal	\$22,472	\$173	\$5,619	\$0	\$28,263	\$4,946	\$0	\$4,981	\$38,191
7							Ductwork & Stack			
7.3	Ductwork	\$0	\$209	\$145	\$0	\$354	\$62	\$0	\$62	\$478
7.4	Stack	\$2,526	\$0	\$1,468	\$0	\$3,993	\$699	\$0	\$704	\$5,396
7.5	Duct & Stack Foundations	\$0	\$51	\$61	\$0	\$112	\$20	\$0	\$26	\$158
	Subtotal	\$2,526	\$260	\$1,673	\$0	\$4,459	\$780	\$0	\$792	\$6,031
8							Steam Turbine & Accessories			
8.1	Steam Turbine Generator & Accessories	\$28,457	\$0	\$3,199	\$0	\$31,656	\$5,540	\$0	\$5,579	\$42,775
8.2	Steam Turbine Plant Auxiliaries	\$491	\$0	\$1,045	\$0	\$1,536	\$269	\$0	\$271	\$2,076
8.3	Condenser & Auxiliaries^A	\$12,094	\$0	\$4,103	\$0	\$16,197	\$2,834	\$0	\$2,855	\$21,886
8.4	Steam Piping	\$12,345	\$0	\$5,003	\$0	\$17,348	\$3,036	\$0	\$3,058	\$23,442
8.5	Turbine Generator Foundations	\$0	\$57	\$94	\$0	\$151	\$26	\$0	\$35	\$213
	Subtotal	\$53,387	\$57	\$13,444	\$0	\$66,888	\$11,705	\$0	\$11,798	\$90,391
9							Cooling Water System			
9.6	Component Cooling Water System^B	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
	Subtotal	\$385	\$0	\$296	\$0	\$681	\$119	\$0	\$120	\$920
10							Ash & Spent Sorbent Handling Systems			
10.6	Ash Storage Silos	\$300	\$0	\$917	\$0	\$1,217	\$213	\$0	\$214	\$1,644
10.7	Ash Transport & Feed Equipment	\$1,125	\$0	\$1,115	\$0	\$2,240	\$392	\$0	\$395	\$3,027
10.9	Ash/Spent Sorbent Foundation	\$0	\$202	\$248	\$0	\$449	\$79	\$0	\$106	\$633
	Subtotal	\$1,425	\$202	\$2,280	\$0	\$3,906	\$684	\$0	\$715	\$5,304
11							Accessory Electric Plant			
11.1	Generator Equipment	\$791	\$0	\$596	\$0	\$1,387	\$243	\$0	\$244	\$1,874
11.2	Station Service Equipment	\$1,466	\$0	\$126	\$0	\$1,592	\$279	\$0	\$281	\$2,151
11.3	Switchgear & Motor Control	\$4,787	\$0	\$831	\$0	\$5,618	\$983	\$0	\$990	\$7,591
11.4	Conduit & Cable Tray	\$0	\$336	\$969	\$0	\$1,305	\$228	\$0	\$230	\$1,764
11.5	Wire & Cable	\$0	\$661	\$1,182	\$0	\$1,843	\$323	\$0	\$325	\$2,491
11.6	Protective Equipment	\$17	\$0	\$60	\$0	\$78	\$14	\$0	\$14	\$105

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B11A-F4	Subcritical PC Flexible Plant (Tiers 1–4)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
11.7	Standby Equipment	\$224	\$0	\$206	\$0	\$430	\$75	\$0	\$76	\$581
11.8	Main Power Transformers	\$2,109	\$0	\$43	\$0	\$2,152	\$377	\$0	\$379	\$2,908
11.9	Electrical Foundations	\$0	\$61	\$156	\$0	\$217	\$38	\$0	\$51	\$306
	Subtotal	\$9,394	\$1,059	\$4,169	\$0	\$14,622	\$2,559	\$0	\$2,590	\$19,770
12 Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	\$200	\$0	\$36	\$0	\$236	\$41	\$0	\$42	\$319
12.3	Steam Turbine Control Equipment	\$192	\$0	\$22	\$0	\$213	\$37	\$0	\$38	\$288
12.5	Signal Processing Equipment	\$185	\$0	\$33	\$0	\$218	\$38	\$0	\$39	\$295
12.6	Control Boards, Panels & Racks	\$58	\$0	\$35	\$0	\$93	\$16	\$0	\$16	\$126
12.7	Distributed Control System Equipment	\$1,937	\$0	\$345	\$0	\$2,282	\$399	\$0	\$402	\$3,084
12.8	Instrument Wiring & Tubing	\$173	\$139	\$554	\$0	\$866	\$152	\$0	\$153	\$1,171
12.9	Other Instrumentation & Controls Equipment	\$206	\$0	\$477	\$0	\$683	\$120	\$0	\$120	\$923
	Subtotal	\$2,951	\$139	\$1,502	\$0	\$4,592	\$804	\$0	\$809	\$6,205
13 Improvements to Site										
13.1	Site Preparation	\$0	\$120	\$2,556	\$0	\$2,675	\$468	\$0	\$629	\$3,772
13.2	Site Improvements	\$0	\$656	\$867	\$0	\$1,523	\$266	\$0	\$358	\$2,147
13.3	Site Facilities	\$541	\$0	\$567	\$0	\$1,108	\$194	\$0	\$260	\$1,563
	Subtotal	\$541	\$776	\$3,990	\$0	\$5,306	\$929	\$0	\$1,247	\$7,482
14 Buildings & Structures										
14.2	Boiler Building	\$0	\$3,767	\$3,311	\$0	\$7,078	\$1,239	\$0	\$1,247	\$9,564
14.3	Steam Turbine Building	\$0	\$3,808	\$3,547	\$0	\$7,355	\$1,287	\$0	\$1,296	\$9,938
14.4	Administration Building	\$0	\$340	\$360	\$0	\$700	\$122	\$0	\$123	\$946
14.6	Water Treatment Buildings	\$0	\$97	\$88	\$0	\$184	\$32	\$0	\$33	\$249
14.7	Machine Shop	\$0	\$153	\$102	\$0	\$254	\$45	\$0	\$0	\$299
14.8	Warehouse	\$0	\$119	\$119	\$0	\$237	\$42	\$0	\$42	\$321
14.9	Other Buildings & Structures	\$0	\$86	\$73	\$0	\$159	\$28	\$0	\$28	\$214
14.10	Waste Treating Building & Structures	\$0	\$137	\$414	\$0	\$551	\$96	\$0	\$97	\$744
	Subtotal	\$0	\$8,506	\$8,012	\$0	\$16,518	\$2,891	\$0	\$2,866	\$22,275
	Total	\$227,091	\$14,883	\$123,787	\$0	\$365,761	\$64,008	\$0	\$65,841	\$495,611

^AACC; ^B Component cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
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Exhibit 5-99. Case B11A-F4 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$4,706
1-Month Maintenance Materials	\$656
1-Month Non-Fuel Consumables	\$342
1-Month Waste Disposal	\$187
25% of 1-Month Fuel Cost at 100% CF	\$547
2% of TPC	\$9,912
Total	\$16,350
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$5,047
0.5% of TPC (spare parts)	\$2,478
Total	\$7,525
Other Costs	
Initial Cost for Catalyst and Chemicals	\$518
Land	\$117
Other Owner's Costs	\$74,342
Financing Costs	\$13,381
Total Overnight Costs (TOC)	\$607,843

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Exhibit 5-100. Case B11A-F4 initial and annual operating and maintenance costs

Case:	B11A-F4 – Subcritical PC Flexible Plant (Tiers 1–4)			Cost Base:	Dec 2018
Plant Size (MW, gross):	150	Heat Rate-net (Btu/kWh):			9,775
Operating & Maintenance Labor					
Operating Labor			Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:	30.0	% of base	Operator:	3.0	
Labor O-H Charge Rate:	25.0	% of labor	Foreman:	1.0	
			Lab Techs, etc.:	1.0	
			Total:	7.0	
Fixed Operating Costs					
				Annual Cost (\$)	
Annual Operating Labor:				\$3,069,066	
Maintenance Labor:				\$4,460,495	
Administrative & Support Labor:				\$1,882,390	
Property Taxes and Insurance:				\$9,912,210	
Total:				\$19,324,161	
Variable Operating Costs					
				Annual Cost (\$)	
Maintenance Material:				\$7,871,461 x CF	
Consumables					
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)
Water (/1000 gallons):	0	107	\$1.90	\$0	\$73,870 x CF
Makeup and Waste Water Treatment Chemicals (ton):	0	0.317	\$550.00	\$0	\$63,698 x CF
Brominated Activated Carbon (ton):	0	0.304	\$1,600.00	\$0	\$177,432 x CF
Enhanced Hydrated Lime (ton):	0	7.54	\$240.00	\$0	\$660,177 x CF
Limestone (ton):	0	134	\$22.00	\$0	\$1,075,415 x CF
Ammonia (19 wt%, ton):	0	13.1	\$300.00	\$0	\$1,436,397 x CF
SCR Catalyst (ft³):	3,286	3.00	\$150.00	\$492,831	\$164,277 x CF
Fuel additive for boiler slagging/fouling mitigation (gal)	1,000	50.0	\$25.00	\$25,000	\$456,250 x CF
Subtotal:				\$517,831	\$4,107,515 x CF
Waste Disposal					
Fly Ash (ton):	0	132	\$38.00	\$0	\$1,828,429 x CF
Bottom Ash (ton):	0	29.5	\$38.00	\$0	\$408,885 x CF
SCR Catalyst (ft³):	0	3.00	\$2.50	\$0	\$2,738 x CF
Subtotal:				\$0	\$2,240,052 x CF
By-Products					
Gypsum (ton):	0	204	\$0.00	\$0	\$0
Subtotal:				\$0	\$0
Variable Operating Costs Total:				\$517,831	\$14,219,028 x CF
Fuel Cost					
Illinois Number 6 (ton):	0	1,384	\$51.96	\$0	\$26,248,532 x CF
Fuel Costs Total:				\$0	\$26,248,532 x CF

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-101. Case B11A-F4 Synchronization startup and shutdown costs

Event to Synchronization		Hot Start	Warm Start	Cold Start	Shutdown
Energy and Duration					
Energy Produced	MWh	-	-	-	-
Duration	hr	0.3	0.8	2.1	0.1
NG Heat Input (HHV)	MMBtu	94	231	598	17
Coal Heat Input (HHV)	MMBtu	-	-	-	-
House Energy Consumed	MWh	0.6	1.4	3.6	0.1
Aux Boiler Energy	MWh	5.8	11.5	23.0	-
Costs					
Variable O&M Cost	\$	100	200	400	-
Natural Gas Cost	\$	400	1,000	2,600	100
Coal Cost	\$	-	-	-	-
House Energy Cost	\$	400	800	1,600	-
Total Cost for Event	\$	900	2,000	4,600	100

Exhibit 5-102. Case B11A-F4 full load startup and shutdown costs

Event to Full Load		Hot Start	Warm Start	Cold Start	Shutdown
Energy and Duration					
Energy Produced	MWh	37.8	63.5	161.1	53.8
Duration	hr	1.0	2.0	5.0	1.0
NG Heat Input (HHV)	MMBtu	198	422	835	2,367
Coal Heat Input (HHV)	MMBtu	469	796	2,195	579
House Energy Consumed	MWh	4.1	7.5	18.6	5.0
Aux Boiler Energy	MWh	11.5	23	46	-
Costs					
Variable O&M Cost	\$	500	900	2,200	600
Natural Gas Cost	\$	900	1,900	3,700	1,000
Coal Cost	\$	1,000	1,800	4,900	1,300
House Energy Cost	\$	900	1,800	3,900	300
Total Cost for Event	\$	3,300	6,400	14,700	3,200

5.4.23.1.1 Cost Differential Justifications

The contributors to the capital cost differential when comparing Case B11A-F4 to Case B11A-F3 are outlined below:

- Flexibility Option 16 — Advanced turbine seals to improve clearances during startup
- Flexibility Option 46 — Water cannons for sootblowing within the boiler radiant section

The Tier 4 flexibility options did not result in impacts to the performance or operational metrics of the plant (e.g., heat rate, auxiliary power usage, water usage). Therefore, there are no changes to the plant O&M costs when compared to Case B11A-F3. The O&M costs for the Case B11A-F4 plant increased slightly due to the shift in TPC.

The justifications for the capital cost differentials when comparing Case B11A-F4 to Case B11A-F3 are outlined below:

- Account 4.9 (Pulverized Coal Boiler & Accessories) and Account 4.11 (Boiler Balance of Plant) costs increase due to the increase in engineering design and additional equipment within the boiler island scope of supply. The following flexibility option impacted the cost of Account 4.9 and Account 4.11:
 - Flexibility Option 46 — Water cannons for sootblowing within the boiler radiant section
- Account 8.1 (Steam Turbine Generator & Accessories) and Account 8.2 (Steam Turbine Plant Auxiliaries) costs increase due to the increase in additional equipment within the steam turbine scope of supply. The following flexibility option impacted the cost of Account 8.1 and Account 8.2:
 - Flexibility Option 16 — Advanced turbine seals to improve clearances during startup

Tier 4 only includes two flexibility options (improved turbine seals and water cannons), the implementation of which do not result in a significant cost increase (BEC increased by approximately \$3,207,000, relative to Case B11A-F3) due to the new-build methodology used for the cost estimation.

While the magnitude of the cost impact of these options is not significant, relative to the other tiers of flexibility options presented, they remain in the 'High Cost/Low Performance' impact tier because they add cost without an appreciable return on performance improvement.

5.5 SUBCRITICAL PC CASE SUMMARY

5.5.1 Performance Results

Exhibit 5-103 shows the performance and environmental profile summary for all subcritical cases at full and minimum sustainable load.^g As shown, the normalized raw water consumption (gpm/MW-gross) at full load is 2.5 percent lower in the flexible plants (cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4) than in the baseload plant (Case B11A-F0). At the minimum loads, the normalized raw water consumption is 16.7 percent lower in the flexible plants (cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4) than in the baseload plant (Case B11A-F0).^h

^g As discussed in Section 4.8.1, sustainable load is an operating point that is tenable for an indefinite period of time between outages, whereas, achievable load is an operating point that is tenable for a shorter period of time (<12 hours) in order to withstand atypical operating conditions (e.g., overnight operation, equipment malfunction, and weather events affecting grid dispatch).

^h The minimum load for Case B11A-F0 is 40 percent, whereas the minimum load for cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4 is 20 percent.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-103. Performance summary and environmental profile for subcritical cases

Case Name	Baseload		Flexible							
	Case B11A-F0		Case B11A-F1		Case B11A-F2		Case B11A-F3		Case B11A-F4	
Load	Full Load (100%)	Min. Stable Load ^A (40%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)
PERFORMANCE										
Nameplate Capacity	150	150	150	150	150	150	150	150	150	150
Gross Power Output (MWe)	150	60	150	30	150	30	150	30	150	30
Auxiliary Power Requirement (MWe)	10	6	12	4	12	4	12	4	12	4
Total Auxiliaries (% of Gross Power)	6.6%	10.7%	8.3%	14.1%	8.3%	13.7%	8.2%	11.7%	8.2%	11.7%
Net Power Output (MWe)	140	54	138	26	138	26	138	26	138	26
Coal Flow Rate (lb/hr)	118,337	59,729	115,339	26,140	115,339	26,140	115,340	26,173	115,340	26,173
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	404,592	204,210	394,341	89,373	394,341	89,373	394,342	89,483	394,342	89,483
Net Plant HHV Efficiency (%)	34.6%	26.2%	34.9%	28.8%	34.9%	29.0%	34.9%	29.6%	34.9%	29.6%
Net Plant HHV Heat Rate (Btu/kWh)	9,851	13,002	9,784	11,833	9,784	11,778	9,775	11,526	9,775	11,526
Raw Water Withdrawal (gpm)	152	76	148	32	148	32	148	32	148	32
Process Water Discharge (gpm)	4	2	4	1	4	1	4	1	4	1
Raw Water Consumption (gpm)	148	75	144	31	144	31	144	31	144	31
CO ₂ Emissions (lb/MMBtu)	201	201	201	202	201	202	201	202	201	202
CO ₂ Emissions (lb/MWh-gross)	1,846	2,338	1,799	2,052	1,799	2,052	1,799	2,055	1,799	2,055
CO ₂ Emissions (lb/MWh-net)	1,975	2,618	1,962	2,389	1,962	2,378	1,960	2,327	1,960	2,327
SO ₂ Emissions (lb/MMBtu)	0.081	0.081	0.081	0.082	0.081	0.082	0.081	0.082	0.081	0.082
SO ₂ Emissions (lb/MWh-gross)	0.742	0.945	0.724	0.831	0.724	0.831	0.724	0.832	0.724	0.832
NO _x Emissions (lb/MMBtu)	0.076	0.060	0.078	0.069	0.078	0.069	0.078	0.069	0.078	0.069
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.010	0.008	0.010	0.009	0.010	0.009	0.010	0.009	0.010	0.009
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.326	0.258	0.334	0.295	0.334	0.295	0.334	0.295	0.334	0.295
Hg Emissions (lb/MWh-gross) ^B	3.00E-06	3.00E-6	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06

^A Minimum stable load is the operating point that is tenable for an indefinite period of time between outages

^B As discussed in Section 4.4.1, the mercury capture units were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

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EPA promulgated a New Source Performance Standard on October 23, 2015, for emissions of CO₂ for new fossil fuel-fired electric utility generating units; the limit for new steam generating units was set as 1,400 lb-CO₂/MWh-gross. [11] A December 2018 proposed update to 111(b) set the limit for new steam generating units based on size. For small-scale ($\leq 2,000$ MMBtu/hr heat input) PC plants, the limit is 2,000 lb-CO₂/MWh-gross, while that of larger ($>2,000$ MMBtu/hr heat input) PC plants is 1,900 lb-CO₂/MWh-gross. [12]

As all subcritical cases within this study are classified as small-scale EGUs, they would be required to maintain their emissions below 2,000 lb-CO₂/MWh-gross on a 12-operating-month average. This regulation is always applicable—even during startup and shutdown periods.

While the CO₂ emissions for all cases are below the established limit at full load, the CO₂ emissions increase as the load decreases. Exhibit 5-104 shows that the CO₂ emissions exceed the established limit at their minimum load, with Case B11A-F0 exceeding by 16.9 percent, cases B11A-F1 and B11A-F2 exceeding by 2.6 percent, and cases B11A-F3 and B11A-F4 exceeding by 2.8 percent.ⁱ While no CO₂ capture systems are included in this study, if the plants were expected to regularly operate at or near their minimum loads, a capture system would need to be included to ensure compliance with applicable regulations. The maximum amount of time each plant could run at minimum load could be calculated for the plant to remain within CO₂ emissions compliance on a 12-month average basis. This would involve forecasting a plant operating profile including emissions associated with startups and shutdowns and reacting to actual plant emissions. Alternatively, natural gas co-firing could be utilized at low load to reduce CO₂ emissions.

Accordingly, for each case/load point that exceeded the CO₂ emission limit of 2,000 lb/MWh gross, the amount of natural gas cofiring that was required to meet this emission limit exactly was determined. Case B11A-F0 exceeded this emission limit at 50 and 40 percent load, and cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4 only exceeded this emission limit at 20 percent load.

Exhibit 5-104. Natural gas cofire required to meet CO₂ emission limit of December 2018 update to 111(b)

Case	Percent Load	Original CO ₂ Emissions (lb/MWhgross)	NG Cofire Required to Meet 111(b) Emission Limit (Percent of HHV Thermal Input) ^A	CO ₂ Emissions with NG Cofire (lb/MWhgross)
B11A-F0	50%	2,180	22%	2,000
B11A-F0	40%	2,338	39%	2,000
B11A-F1	20%	2,052	7%	2,000
B11A-F2	20%	2,052	7%	2,000
B11A-F3	20%	2,055	7%	2,000
B11A-F4	20%	2,055	7%	2,000

^A Cofire rates were determined with no modifications to plant performance or equipment design

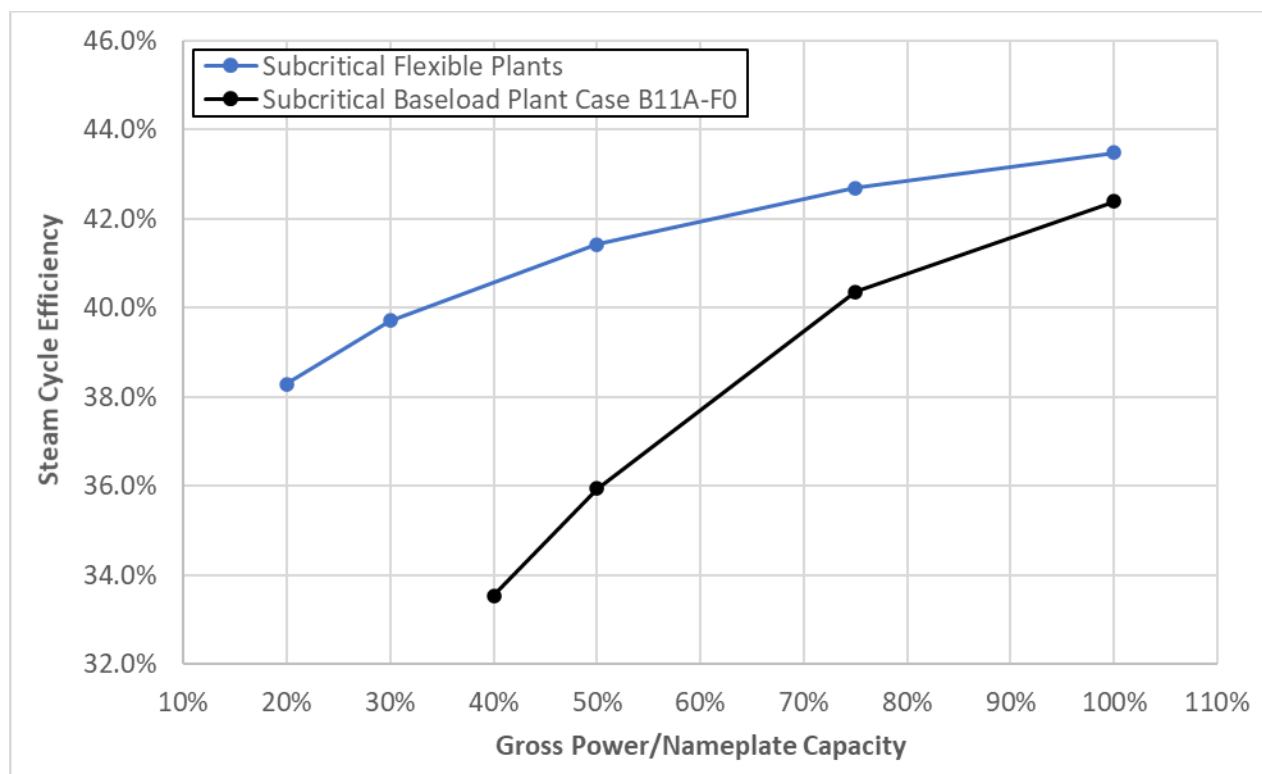
ⁱ The minimum load for Case B11A-F0 is 40 percent, whereas the minimum load for cases B11A-F1, B11A-F2, B11A-F3, and B11A-F4 is 20 percent.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

All other emissions remain at or below the current applicable regulatory limits across all loads.

Exhibit 5-105 presents a comparison of the baseload and flexible plant part load steam cycle efficiencies. Only Case B11A-F0 and Case B11A-F1 are shown, since all four flexible plant cases have the same steam cycle efficiency.

Exhibit 5-105. Steam cycle efficiency cross case comparison for subcritical cases



At full load, the subcritical baseload and flexible plant steam cycle efficiencies are similar; however, the flexible plant case has a slightly improved (1.1 percentage points) steam cycle efficiency due to the use of an electric driven BFW pump. Switching to an electric driven BFW pump eliminates the steam extraction required for a steam driven BFW pump, improving the steam cycle efficiency. However, the electric power required for driving the electric driven BFW pump is noted as an increase in the plant auxiliary power requirements.

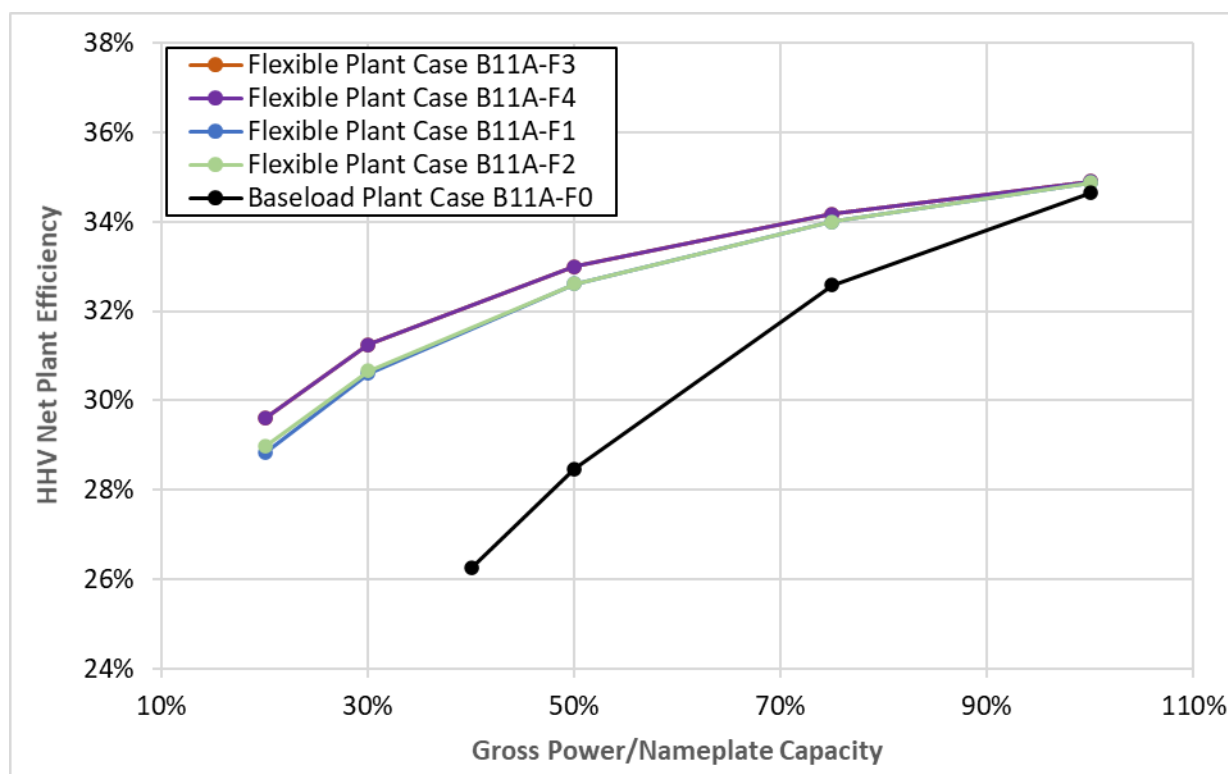
The subcritical baseload plant suffers a much higher steam cycle efficiency penalty at low loads, compared to subcritical flexible plant cases, due to throttle losses that occur from expanding main steam through the control valve. This efficiency penalty becomes more drastic as load is further reduced, and it is a result of constant pressure operation. The improvement in the flexible plant steam cycle efficiency is due to the implementation of sliding pressure operation, along with the installation of an electric driven BFW pump.

Sliding pressure operation eliminates throttling losses by allowing the main steam pressure to vary with load. This means that main steam is already at the appropriate throttle pressure and does not need to be expanded before entering the HP turbine. Additionally, switching to an

electric driven BFW pump eliminates the steam extraction required for a steam driven BFW pump. This effectively improves the steam cycle efficiency, but the electric power required for driving the electric driven BFW pump is noted as an increase in the plant auxiliary power requirements.

A graph of the net plant efficiency (HHV basis) across the load range for each subcritical case is provided in Exhibit 5-106; note that Case B11A-F0 performance is reported at 100, 75, 50, and 40 percent load, while flexible case performance is reported at 100, 75, 50, 30, and 20 percent load—the discrete load points used for modeling were modified for the flexible plant cases to reflect its reduced minimum load.

Exhibit 5-106. HHV Net plant efficiency for all subcritical cases



Note: The HHV net plant efficiency curves for cases B11A-F3 and B11A-F4 are overlapping

As shown in Exhibit 5-106, the installation of flexibility options has an increasing impact on plant performance as the load of the plant is reduced.

The flexibility options introduced in Case B11A-F1 (Tier 1) result in the greatest improvement to net plant efficiency, followed by those introduced in Case B11A-F3 (Tier 3) and Case B11A-F2 (Tier 2). The flexibility options introduced in Case B11A-F4 (Tier 4) did not result in a noticeable improvement in plant performance. The following flexibility options were the primary contributor to the net plant efficiency improvement in each case:

- Case B11A-F1: Sliding pressure operation
- Case B11A-F2: Auxiliary load optimization

- Case B11A-F3: Outfitting large electric motors with VFD units

A consequence of the large decrease in part load steam cycle efficiency seen in Case B11A-F0 is a substantial minimum load efficiency penalty. The Case B11A-F0 HHV net plant efficiency decreases from 34.6 percent at full load to 26.2 percent at minimum load, which corresponds to an efficiency penalty of approximately 24.0 percent.

Compared to Case B11A-F0, Case B11A-F1 has a similar HHV net plant efficiency at full load but suffers a much smaller efficiency penalty as load is reduced. Sliding pressure was incorporated as part of the Tier 1 plant flexibility options, which allows the boiler pressure to reduce (“slide”) along with the unit load during turndown, reducing BFW pump power consumption and reducing losses from control valve throttling. Additionally, the BFW pump was switched to an electric driven pump to eliminate flexibility limits imposed by a steam driven pump. Sliding pressure operation leads to a much more efficient steam cycle at low loads and reduces the part load efficiency penalty. The Case B11A-F1 HHV net plant efficiency decreases from 34.9 percent at full load to 28.8 percent at minimum load, which corresponds to an efficiency penalty of approximately 17.5 percent. Compared to Case B11A-F0, the Case B11A-F1 minimum load HHV net plant efficiency is improved by 2.5 percentage points, or approximately 9.5 percent. The improvement in minimum efficiency is especially notable considering the concurrent reduction in minimum load (from 40 to 20 percent) compared to Case B11A-F0.

Case B11A-F2 has identical performance to Case B11A-F1 at loads above 50 percent. Below 50 percent load, Case B11A-F2 has a slightly improved net plant efficiency due to the reduced FGD normalized power requirement. The Case B11A-F2 HHV net plant efficiency decreases from 34.9 percent at full load to 29.0 percent at minimum load, which corresponds to an efficiency penalty of approximately 16.9 percent. Compared to Case B11A-F1, the Case B11A-F2 minimum load HHV net plant efficiency is improved by 0.2 percentage points, or approximately 0.7 percent.

Case B11A-F3 has a similar full load efficiency compared to Case B11A-F2 but achieves an improved efficiency as load is reduced. Installation of VFDs improves the part load efficiency of major rotating equipment, and the efficiency improvement is more noticeable as load is further reduced. The Case B11A-F3 HHV net plant efficiency decreases from 34.9 percent at full load to 29.6 percent at minimum load, which corresponds to a minimum load efficiency penalty of approximately 15.2 percent. Compared to Case B11A-F2, the minimum load HHV net plant efficiency is improved by 0.6 percentage points, or approximately 2.1 percent.

Compared to the baseload plant, all flexible plant cases achieve higher efficiencies across the entire load range. The improvement in efficiency for each flexible plant case becomes greater as load is reduced, indicating that the more often a plant operates at low loads, the more benefit they will see from installation of the flexibility options. Exhibit 5-107 presents an efficiency comparison at the lowest common load point of 50 percent.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

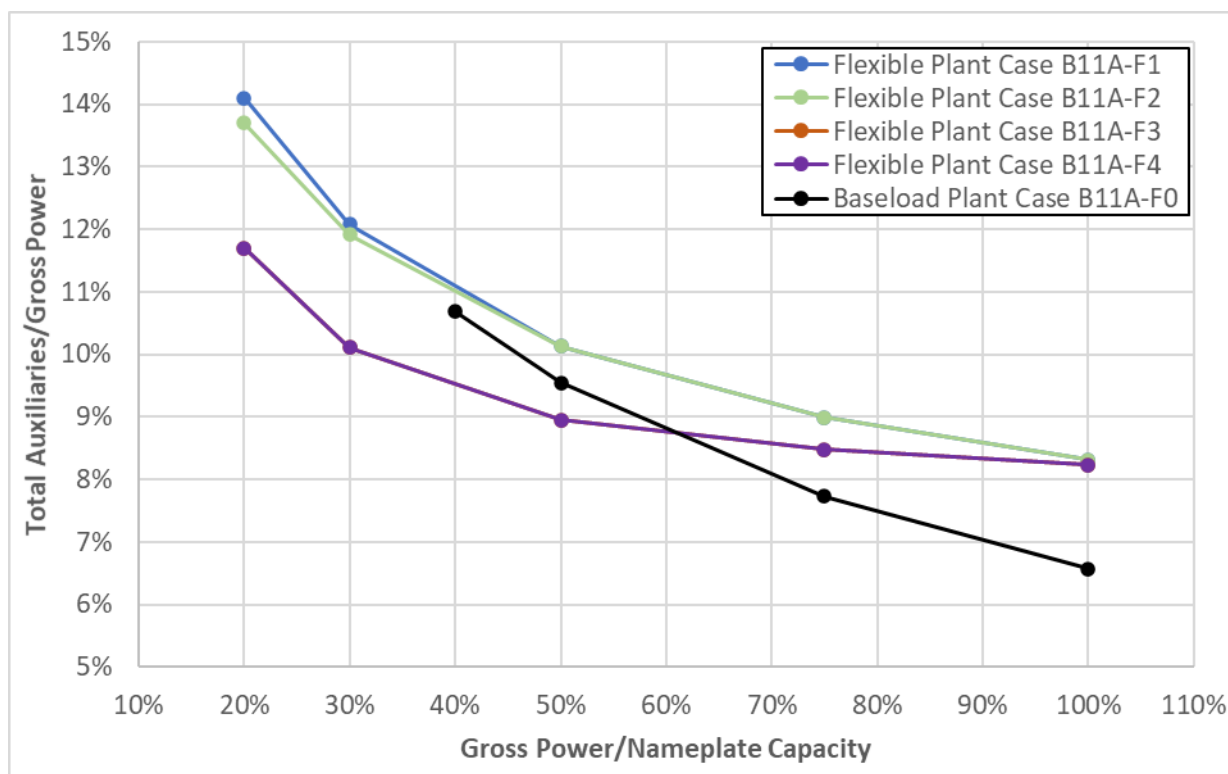
Exhibit 5-107. HHV Net plant efficiency comparison at 50 percent load for subcritical cases

Case	HHV Net Plant Efficiency at 50% Load	Incremental Improvement	Total Improvement
Baseload (Case B11A-F0)	28.5%	--	--
Case B11A-F1	32.6%	14.4%	14.4%
Case B11A-F2	32.6%	0.0%	14.4%
Case B11A-F3	33.0%	1.2%	15.8%
Case B11A-F4	33.0%	0.0%	15.8%

Case B11A-F1 offers the most substantial improvement in efficiency. Case B11A-F2 shows no efficiency improvement at 50 percent load; however, the Tier 2 flexibility options only impact performance at loads below 50 percent. Case B11A-F3 shows a notable improvement in efficiency, with VFDs offering a reduction in the auxiliary load.

Exhibit 5-108 presents a cumulative case comparison of total normalized auxiliary load (as a percent of gross output) across the load range.

Exhibit 5-108. Normalized auxiliary power consumption cross-case comparison for subcritical cases



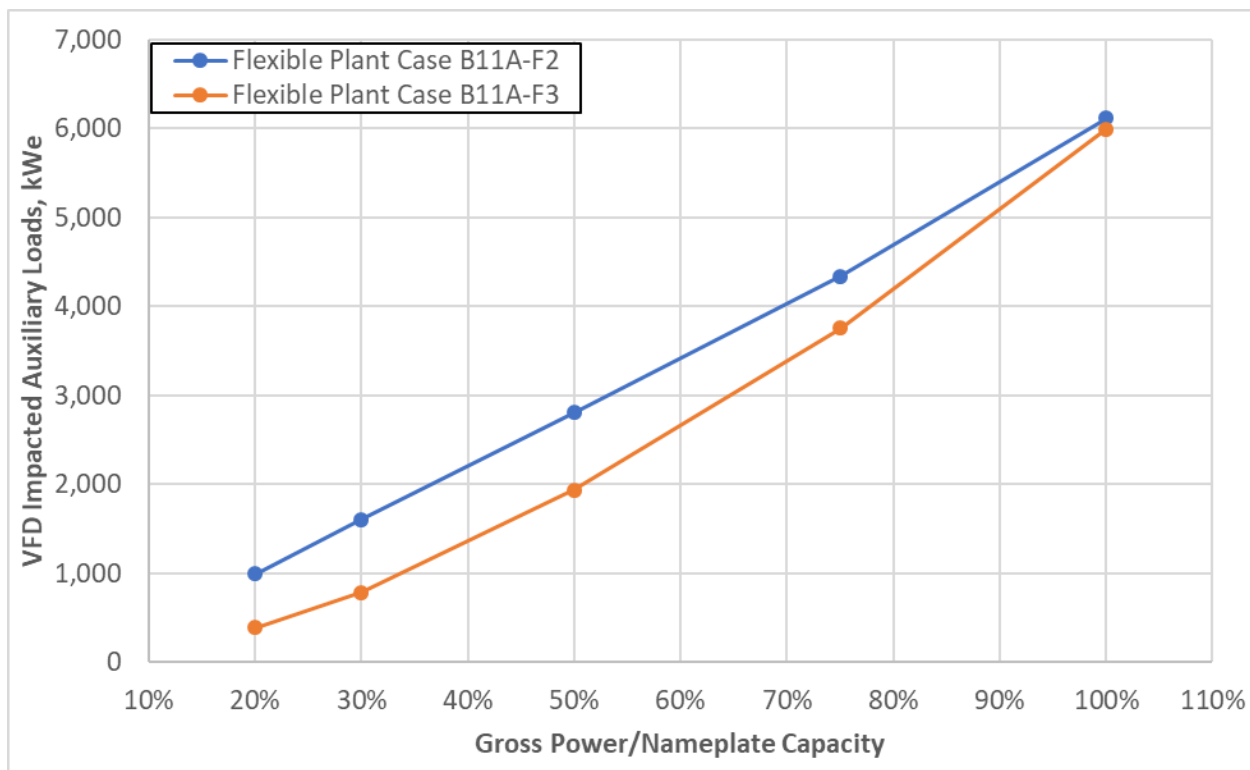
Case B11A-F1 has a higher auxiliary power requirement compared to Case B11A-F0, which is a consequence of utilizing an electric driven BFW pump that extracts power as an auxiliary power requirement rather than utilizing a steam driven BFW pump. In addition, the hydraulic coupling

that is required for modulating the BFW pump outlet pressure is a source of inefficiency that leads to a higher power consumption. Despite this, Case B11A-F1 still approaches the Case B11A-F0 normalized auxiliary loads at very low loads. The slower increase in normalized auxiliary power requirement seen in Case B11A-F1 is due to the implementation of sliding pressure operation. The normalized auxiliary power consumption of the electric driven BFW pump does not increase as rapidly as load is reduced, since the BFW pump outlet pressure is allowed to decrease with plant load. Additionally, the improved part load steam cycle efficiency reduces the required steam flow and coal input, causing a plant-wide reduction in auxiliary power requirements.

Case B11A-F2 normalized auxiliary power consumption is very similar to Case B11A-F1, with a slight reduction at loads below 50 percent. This is due to the auxiliary load optimization that reduces the FGD system normalized power requirement at low loads.

The Case B11A-F3 normalized auxiliary load is notably reduced compared to Case B11A-F2. Installation of VFDs increases the efficiency of the BFW pump and the PA, FD, and ID fans. In addition, it eliminates the need for a hydraulic coupling since the VFD allows for modulation of the BFW pump outlet pressure. This results in decreased normalized auxiliary power consumption as load is reduced. The total auxiliary load for the components that are impacted by VFDs is shown for Case B11A-F2 and Case B11A-F3 in Exhibit 5-109.

Exhibit 5-109. VFD impacted auxiliary loads



5.5.2 Flexibility Metric Results Comparison

For each flexibility metric, performance comparisons of the discrete breakpoints have been prepared based on the grouping and cumulative implementation of the flexibility options. The tabulated summary of the quantitative breakpoints between the various flexibility metrics is presented in Exhibit 5-110. The flexibility metrics total plant cost and O&M cost were omitted from the quantitative breakpoint table as they are covered in a separate section.

While not quantified in this study, there are competing influences of the implemented flexibility options for each of the flexibility metrics. For example, the addition of variable frequency drives, an electrode boiler, a condensate polishing system, a steam turbine bypass, and a fuel additive system in Case B11A-F3 improves several flexibility metrics; however, the addition of equipment accumulates single-points of failure within the plant design, which begins to effectively reduce availability. Additional examples of trade-offs associated with several flexibility options are provided in Section. 4.7.2.

Exhibit 5-110. Quantitative breakpoints for flexibility metrics

Flexibility Metric Quantitative Breakpoint Estimates	Case B11A-F0 (Baseload)	Case B11A-F1 (Tier 1)	Case B11A-F2 (Tiers 1–2)	Case B11A-F3 (Tiers 1–3)	Case B11A-F4 (Tiers 1–4)
Startup Time to Full Load					
Cold Start ^A to Full Load, Hours	7–15	5–6	5–6	4–5	4–5
Warm Start ^B to Full Load, Hours	3–6	1–2	1–2	1–2	1–2
Hot Start ^C to Full Load, Hours	1–3	0.5–1.0	0.5–1.0	0.5–1.0	0.5–1.0
Ramp Rate, % Load ^D per Minute	3–5	5–7	7–8	8–9	8–9
Minimum Stable Load (Emissions-Compliant, No Supplemental Firing), % Load ^D	40	20	20	20	20
Minimum Achievable Load (Emissions-Compliant, No Supplemental Firing), % Load ^D	30	15	15	12.5	12.5
Design Life, Years	30	30+	30+	30+	30+
Availability/Reliability (New Construction)					
Equivalent Availability Factor, %	88–90	90–92	92–94	92–94	92–94
Equivalent Forced Outage Rate, %	5–8	4–6	4–5	4–5	4–5
Planned Outages					
Plant Maintenance Outage (Spring/Fall)					
Frequency, Outage/Year	1–2	2–4	2–4	2–4	2–4
Duration, Days	1–7	1–4	1–4	1–4	1–4

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Flexibility Metric Quantitative Breakpoint Estimates	Case B11A-F0 (Baseload)	Case B11A-F1 (Tier 1)	Case B11A-F2 (Tiers 1–2)	Case B11A-F3 (Tiers 1–3)	Case B11A-F4 (Tiers 1–4)
Plant/Boiler Outage(s)					
Frequency, Years/Outage	1–2	2	2	2	2
Duration, Weeks	2–4	2	2	2	2
Steam Turbine Generator Outage(s)					
Frequency, Years/Outage	6–9	9–11	9–11	9–11	9–11
Duration, Weeks	6	4–6	4–6	4–6	4–6
Number of Starts, Per Year	10–20	30–60	30–60	30–60	30–60

^A Cold Start – Offline greater than 48 hours

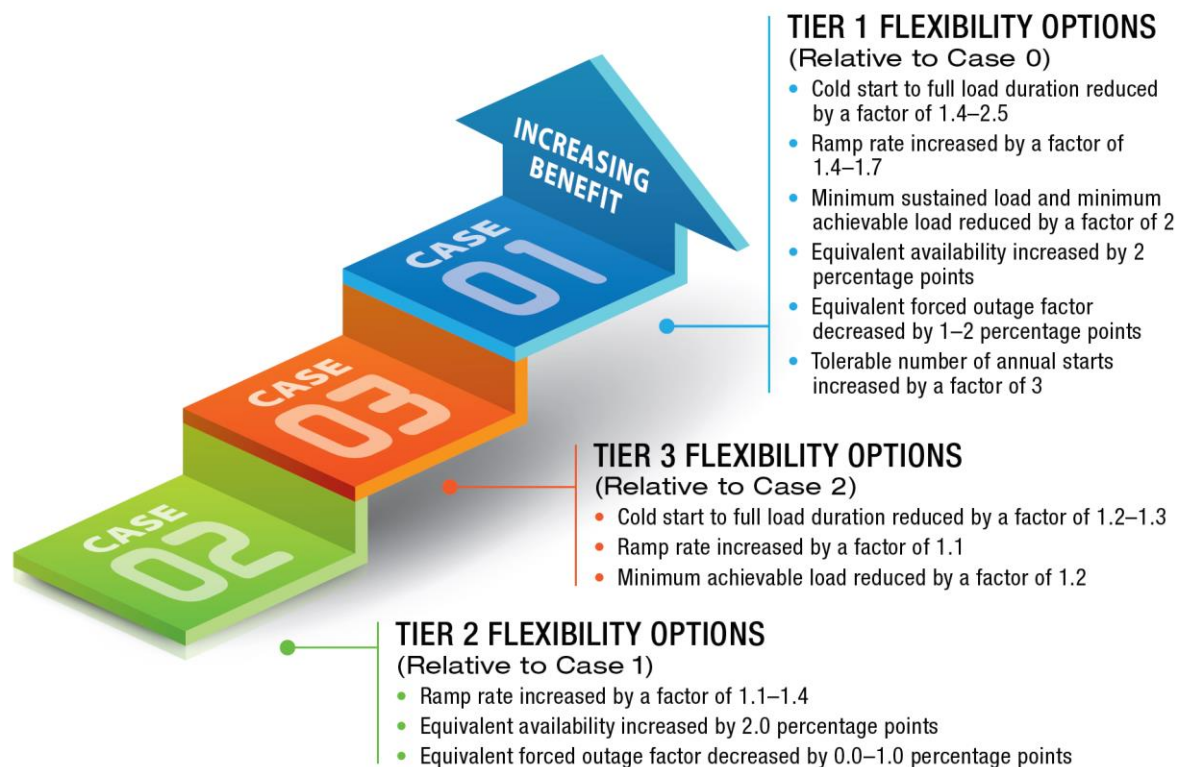
^B Warm Start – Offline between 8 and 48 hours

^C Hot Start – Offline less than eight hours

^D Ramp rate is often communicated as the ability to change load in percent full-load per minute

As illustrated in Exhibit 5-111, the flexibility options introduced in Case B11A-F1 (Tier 1) are perceived to provide the greatest value-added improvement to the flexibility metrics, followed by those introduced in Case B11A-F3 (Tier 3) and Case B11A-F2 (Tier 2). The flexibility options introduced in Case B11A-F4 (Tier 4) did not result in a noticeable improvement in flexibility metrics.

Exhibit 5-111. Primary observations on the impact of flexibility options on flexibility metrics



The following narrative describes the major contributing factors to the flexibility metric breakpoints shown in Exhibit 5-110.

- **Startup Time: Cold Start to Full Load:** The most significant breakpoint is established following the implementation of the Tier 1 flexibility options (e.g., steam sparging, EGU with black start capability, main steam warmup line, and electric-resistance blankets for pre-heating the turbine casing shell); implementing the Tier 2 flexibility options is not anticipated to create a significant shift/break in the cold start time already achieved through the Tier 1 flexibility options; the next (and final) breakpoint for cold start time is achieved through implementation of the Tier 3 flexibility options, including installation of advanced materials to reduce tube thicknesses, decreasing the drum diameter, increasing the number of feedwater/steam headers to improve furnace heat absorption patterns, and installation of a condensate polishing system to further mitigate feedwater chemistry excursions during startup. The methodology for developing these startup time breakpoints for the 'Cold Start to Full Load' operating scenario was based on industry references [24] [40] in addition to in-house Black & Veatch data from existing coal-fired EGUs studying and/or implementing design features to improve cold startup time.
- **Startup Time: Warm Start to Full Load:** Similar to the previous startup time flexibility metric, improvement of the warm start time diminishes after implementation of the Tier 1 flexibility options; this flexibility metric is estimated to remain approximately constant for cases 2–4. The methodology for the 'Warm Start to Full Load' metric breakpoints was based on industry references [24] [40] that outlined startup times empirically achieved by coal-fired plants or results of modeled plant performance following design improvements; the values outlined in these references generally aligned with Black & Veatch in-house data for this specific metric.
- **Startup Time: Hot Start to Full Load:** Similar to the previous startup time flexibility metric, improvement of the warm start time diminishes after implementation of the Tier 1 flexibility options; the flexibility metric most benefitted by the Tier 1 flexibility options is the cold startup to full load timeframe; no significant hot start to full-load timeframe breakpoints are estimated for cases 2–4. The methodology for the 'Hot Start to Full Load' metric breakpoints was based on industry references [24] [40] that outlined empirically achieved startup times for various plants or results of modeled plant performance following design improvements; the values outlined in these references generally aligned with Black & Veatch in-house data for this specific metric.
- **Ramp Rate:** The improvement to ramp rate starts with the implementation of the advanced online performance monitoring, water chemistry monitoring, electric BFW pump, and various flue gas/water-side bypasses equipped as part of the Tier 1 flexibility options; a marginal ramp rate breakpoint is achieved in Tier 2 due to enhanced operator training and additional flame detection/stabilization means; the final breakpoint for ramp rate is after implementation of the Tier 3 flexibility options due to installation of advanced creep-strength materials, online combustion optimizer, and the drum/header modifications that allow for more evenly dispersed heat absorption patterns in the furnace under high ramp rate conditions; the ramp rate of the plant will be closely

coordinated with the boiler and steam turbine OEM to ensure that recommended thermal gradient rates are monitored closely. The methodology for developing the ramp rate values and breakpoint changes associated with application of the flexibility options (e.g., indirect firing, smaller headers) was based on literature summary sources [25] [13] and Black & Veatch in-house references for the capabilities of existing coal-fired EGUs built for baseload operation (including recent OEM/EGU feedback during user-group conferences and industry meetings); the ramp rates characterized in the quantitative breakpoint table were estimated to be approximately constant across the load range for the 150 MW (gross) subcritical plant; for larger EGUs it has been observed that load shedding ramp rate (the rate of decreasing load) tends to be greater than the increasing-load ramp rate (the rate of increasing load) in addition to subcritical plants tending to exhibit a higher average ramp rate across their load range than a suitably equivalent supercritical [24] [40] plant.

- **Minimum Stable Load (Emissions-Compliant, No Supplemental Firing):** The differentiation between minimum “stable” load and minimum “achievable” load is outlined in Section 4.8.1; the primary contributors to the breakpoint following the implementation of the Tier 1 flexibility options are the sliding pressure operation, increased number of smaller-sized mills, various flue gas/water-side bypasses available, the detailed boiler and steam cycle tuning at reduced loads, and the application of the “continuous-coupled” last-stage blades in the steam turbine; the minimum stable load is expected to hold approximately constant for the further plant cases. The methodology for developing the minimum load values and breakpoint shifts associated with application of the flexibility options (e.g., operational tuning, smaller mills) was based on literature summary sources [24] [40] [25] outlining case studies of empirical and modeled minimum load improvements following implementation of specific flexibility options; these references and the values outlined for minimum stable load aligned with Black & Veatch experience and in-house data; the minimum stable load was intended to characterize a tenable load point for the flexible plant performance modeling.
- **Minimum Achievable Load (Emissions-Compliant, No Supplemental Firing):** The differentiation between minimum stable load and minimum achievable load is outlined in Section 4.8.1; the minimum achievable load scenario is characterized by remaining emissions compliant while also targeting shorter overall timeframe of operation in the achievable range; the flexibility options that equipped the plant for the minimum stable load breakpoints above are what also establish the breakpoint for this flexibility metric; however, the addition of the Tier 3 flexibility options, including indirect firing, VFD units, the steam turbine bypass, and intelligent soot blowing system, all contribute to the estimated breakpoint shown for minimum achievable load shown; these estimated values were sourced from the literature summary as well as other plants that have set a precedence for aggressive turndown/load reduction capabilities (for short periods of time). The methodology for developing the quantitative values and breakpoints for the minimum achievable load values was (similar to the other minimum load metric) based on literature summary sources [24] [40] [25] outlining case studies of empirical and modeled minimum load improvements following implementation of specific flexibility

options; these references and the values outlined for minimum stable load aligned with Black & Veatch experience and in-house data; the minimum achievable load is an extension of the minimum stable load, intended to characterize a more aggressive (offset by shorter duration) load point that has been empirically demonstrated by existing (retrofitted) EGUs or modeled performance results.

- **Design Life:** The flexible plant cases exhibit a marginally improved forecast on the expected operating life of the plant; utilization of the advanced online performance monitoring and diagnostics, enhanced operator training, and strict adherence to inspection programs (e.g., HEP/FAC) and layup procedures are the contributing factors to this marginal expected improvement in expected operating life of the plant design(s); however, there is no significant breakpoint established by any flexibility options proposed that would appreciably increase the design life of the plant. The values and breakpoints outlined in the quantitative breakpoint table are based on Black & Veatch experience with equipment manufacturers regarding the expected operating life for components from reputable and proven equipment suppliers.
- **Availability/Reliability–EAF:** The marginal shift in EAF following the implementation of the Tier 1 flexibility options is generally attributed to implementation of analysis/targeted maintenance based on the NERC-GADS data analysis, implementation of advanced online performance monitoring, and the ability for operators to diagnose and mitigate plant heat rate issues in real time; the next marginal breakpoint is associated with the continuation of the advanced training of operators to improve situation awareness; following the implementation of the Tier 2 flexibility options, the EAF was expected to level off due to additional equipment added to site (e.g., VFDs, electrode boiler(s)) as part of Tier 3, which tends to have the effect of leveling off the top-end availability thresholds deemed achievable. These EAF values and breakpoints align with Black & Veatch in-house data for industry-leading coal-fired plants aligned to the size and design features of the flexible plant cases. The values and increases of the EAF value reflect a general trend of plants that implement the more advanced inspection and testing methods outlined in the cumulative tiers; this data is based on in-house Black & Veatch information for existing plants.
- **Availability/Reliability–EFOR:** In a similar manner as EAF, the plant's EFOR is expected to exhibit a breakpoint following the Tier 1 flexibility options, followed by another marginal breakpoint resulting from the Tier 2 flexibility options; the flexibility options that contribute to improved EAF also contribute to reducing EFOR. The EFOR values and breakpoints align with Black & Veatch in-house data for industry-leading coal-fired units conceptually aligned with the size and design features of the flexible plant cases; the values and breakpoints of the EFOR values reflect a general trend of units that implement the more advanced inspection and testing methods outlined in the cumulative tiers, offset in certain cases by the increase in cycling [49] operation; this data is aligned with in-house Black & Veatch information for existing units.
- **Plant, Boiler, and Steam Turbine Generator Maintenance Outages:** The plant designs utilize established and proven technology that would fit into a traditional outage

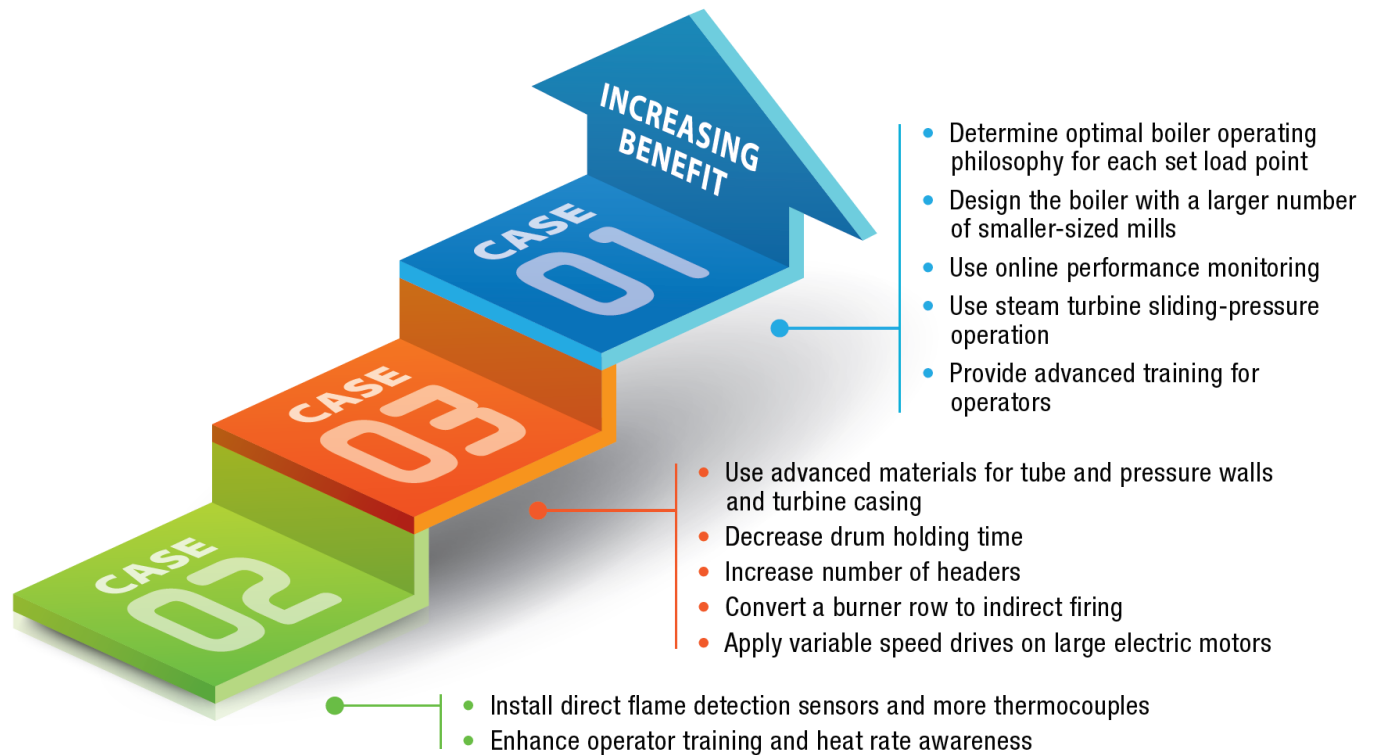
program/pattern for a coal-fired plant of the size outlined in this study (150 MW_{gross}); the trend reflected in the quantitative breakpoint table is intended to reflect that while the baseload plant would be expected to operate based on fewer annual outages that are longer in duration, the plant outage and maintenance philosophy is likely to cumulatively result in approximately the same number of outage days, but reaching that goal through a greater number of shorter duration outages; this trend is reflected in existing coal and gas-fired EGUs that are transitioning to a higher cycling duty. The number of outages and duration of these outages was developed based on Black & Veatch in-house information for typical plant maintenance programs and practices of industry-leading coal-fired EGUs.

- **Number of Starts:** The flexible plant cases have the ability to accept a higher number of starts as compared to the baseload plant design due predominantly to the higher redundancy in steam turbine casing thermocouples for thermal gradient tracking, the electric-resistance blankets for the steam turbine casing, the implementation of advanced online performance monitoring, and the targeted modification/tuning of startup/shutdown protocols to specifically lower component fatigue stresses; these components (in addition to others) are what equip the plant to significantly increase the acceptable/design number of starts per year without creating significant negative impacts on the overall plant health; following the breakpoint established from the Tier 1 flexibility options, there are no further expected breakpoints in the acceptable or design number of starts per year based on tiers 2–4 flexibility options. The increase in perceived number of starts reflects a range that existing coal plants have experienced in the past due to changing dispatch characteristics and challenges of achieving suitable (e.g., overnight) minimum load. The benefits of the flexibility options associated with improving the number of starts was primarily sourced from Black & Veatch in-house data regarding typical number of starts for coal plants that are looking to implement cycling and load flexibility improvements in response to changing dispatch market conditions.

It can be noted that there are no flexibility metric breakpoints or performance advantages associated with the implementation of the Case B11A-F4 flexibility options (high-cost/low-performance impact). Following the qualitative and quantitative comparison of the application of the flexibility options and various flexible plant cases, the flexibility options illustrated in Exhibit 5-112 are those that were perceived to provide the greatest contribution to the improvement of plant flexibility.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-112. The relative impact of flexibility options on flexibility metrics



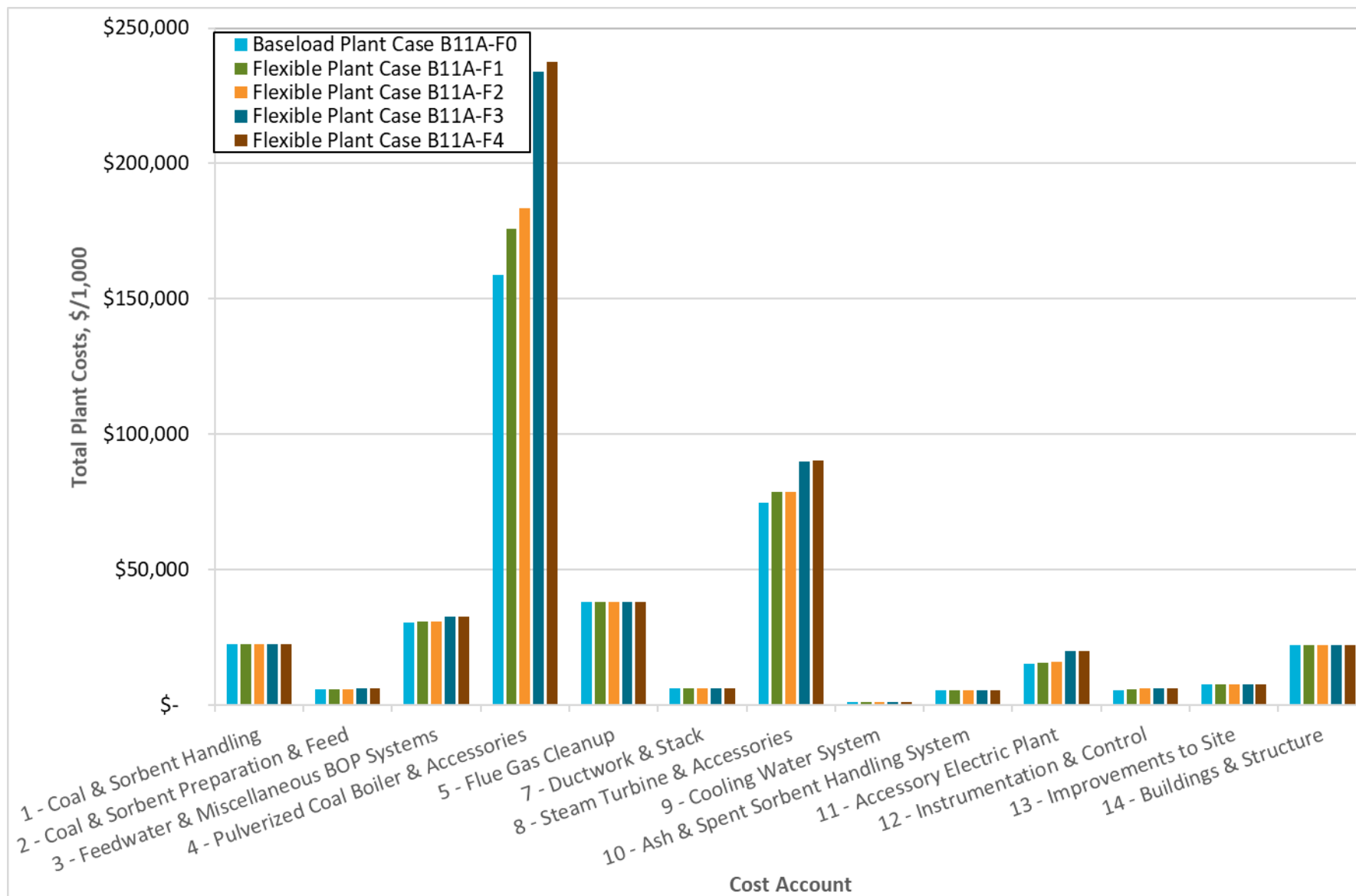
5.5.3 Cost Results

Exhibit 5-113 presents the capital cost summary by cost account for each case. The following observations can be made:

- None of the flexibility options implemented in this study impact the capital costs of the coal and sorbent handling system (Account 1), flue gas cleanup systems (Account 5), cooling water system (Account 9), ash and spent sorbent handling system (Account 10), improvements to site (Account 13), or buildings and structures (Account 14).
- The boiler (Account 4) and steam turbine (Account 8) accounts represent the greatest portions of the TPC and the two accounts together make up at least 90 percent of the cost increases that result from implementation of the flexibility options in all cases. As these accounts are frequently cited as the primary limiters for flexible operation, it is reasonable that the majority of the costs for improving plant flexibility are associated with these accounts.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-113. Total plant cost summary by cost account for subcritical cases

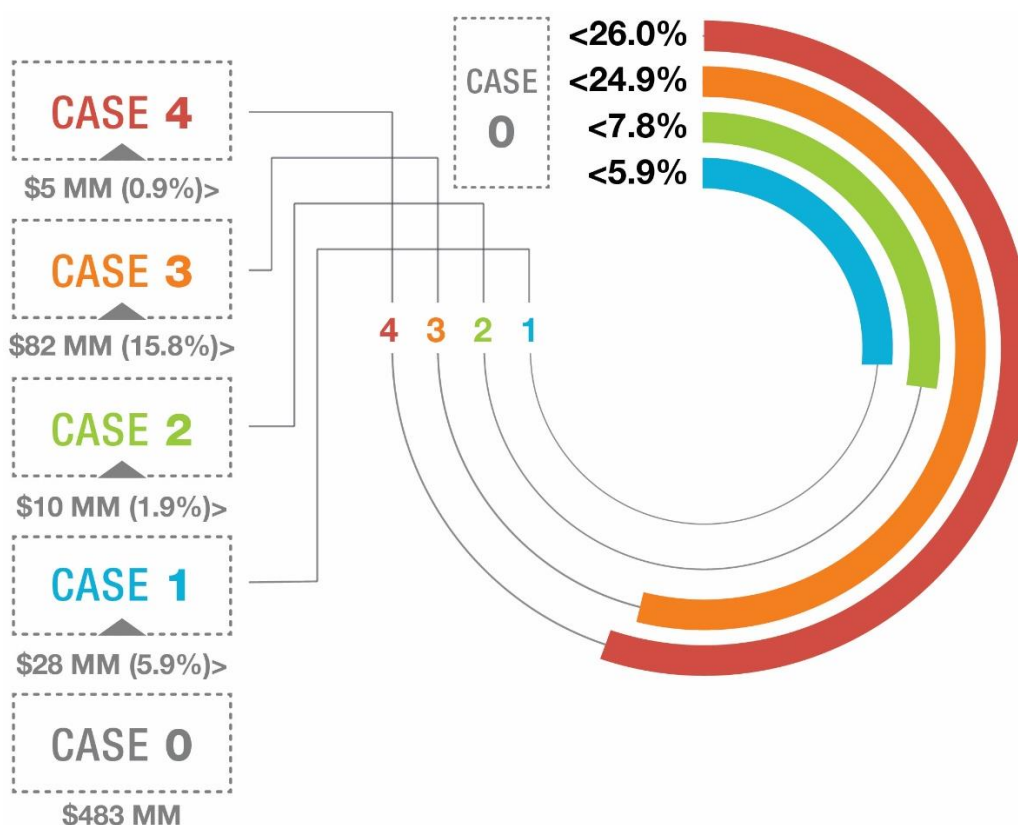


CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

The relative impact of each case on total overnight cost (TOC) is illustrated in Exhibit 5-114. As shown, each subsequent addition of a tier of design options for improving the flexibility of a plant results in a corresponding increase in costs. While the flexibility options included in Case B11A-F1 (Tier 1) are individually considered to be “low-cost” options, the large number (38) of flexibility options included in Case B11A-F1 resulted in a TOC increase of \$28 million (5.9 percent), relative to Case B11A-F0. This relative increase in TPC is only exceeded by the flexibility options introduced in Case B11A-F3 (Tier 3), which resulted in a \$82 million (15.8 percent) increase in TOC, relative to Case B11A-F2.

Further study is needed to determine the cost of individual options and which options would offer the greatest improvement to flexibility and plant performance.

Exhibit 5-114. Relative total overnight cost impact for subcritical cases



The TOC cost components of each case are presented in Exhibit 5-115 and summarized in Exhibit 5-116.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-115. Total overnight cost, by component, for subcritical cases

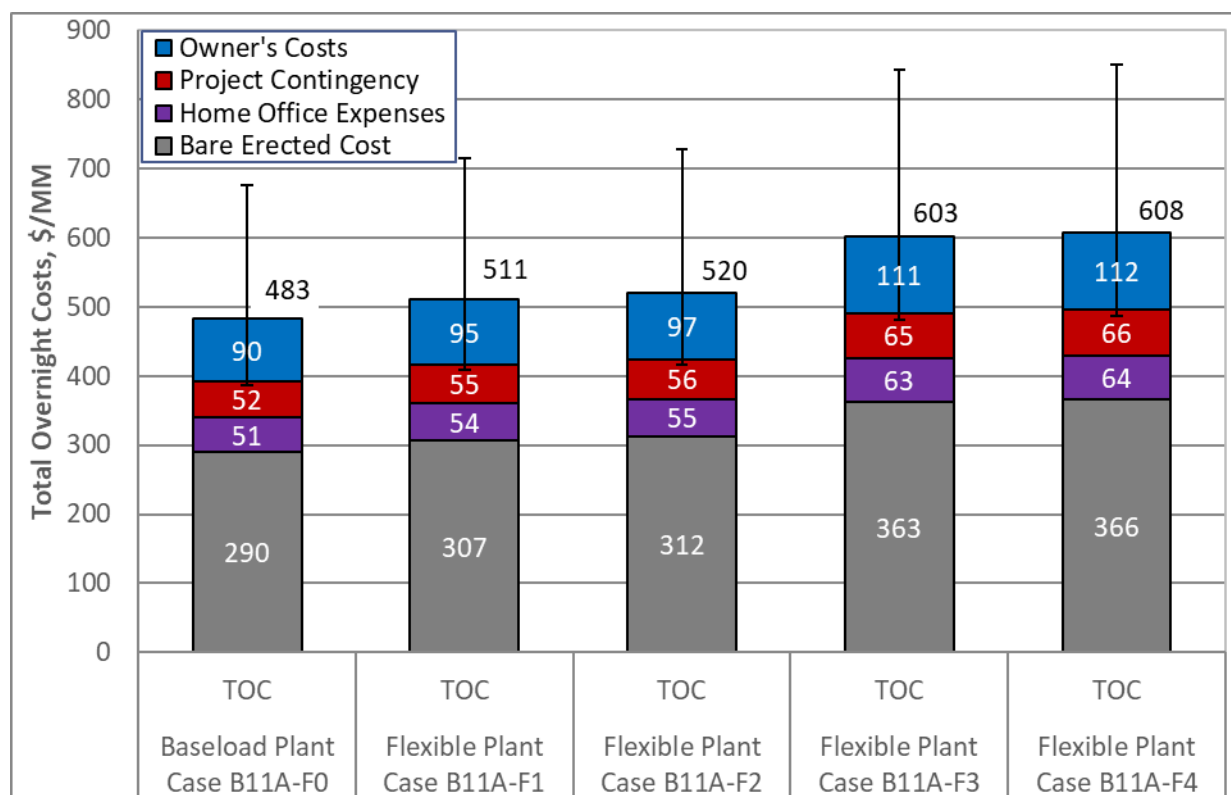


Exhibit 5-116. Summary of cost components for subcritical cases

	Pulverized Coal Boiler				
	PC Subcritical Baseload	PC Subcritical Flexible			
	Case B11A-F0	Case B11A-F1	Case B11A-F2	Case B11A-F3	Case B11A-F4
CAPITAL COST					
Total Plant Cost (2018\$/MM)	393	416	423	491	496
Bare Erected Cost	290	307	312	363	366
Home Office Expenses	51	54	55	63	64
Project Contingency	52	55	56	65	66
Process Contingency	0	0	0	0	0
Total Overnight Cost (2018\$/MM)	483	511	520	603	608
Owner's Costs	90	95	97	111	112
O&M COST					
Fixed Costs (2018\$/MM)	14	17	17	19	19
Variable Costs (2018\$/MM)	10 x CF	12 x CF	13 x CF	14 x CF	14 x CF
Fuel Costs (2018\$/MM)	27 x CF	26 x CF	26 x CF	26 x CF	26 x CF

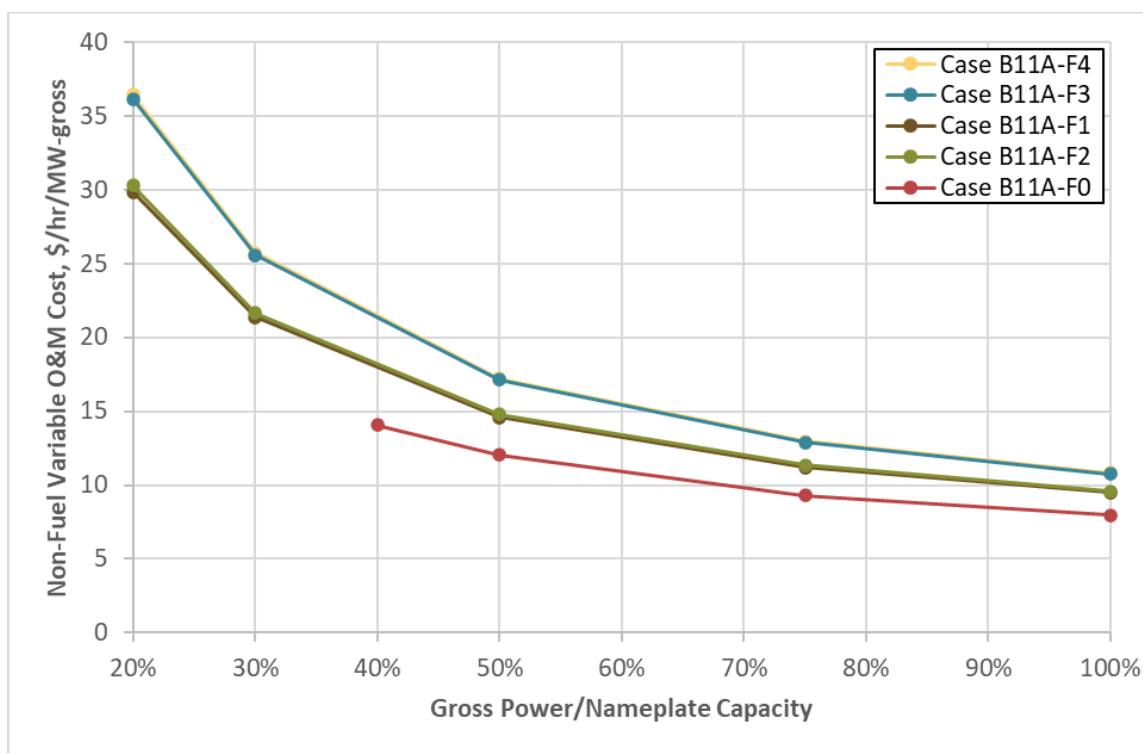
The following observations about O&M costs can be made:

- The fixed O&M costs of the flexible plant cases as a percentage of TPC range from 3.9 percent (Case B11A-F4) to 4.0 percent (Case B11A-F1), with the largest increases in fixed O&M costs occurring from Case B11A-F0 to Case B11A-F1, and Case B11A-F2 to Case B11A-F3.
 - The increase in fixed O&M costs between the baseload (Case B11A-F0) plant and Case B11A-F1 can be attributed to the increase in maintenance labor cost as a percentage of TPC (0.92 percent of TPC for cases 1–4; 0.64 percent for Case B11A-F0), which is due to the proactive maintenance programs implemented by high cycling plants, and to the increase in staff headcount (one additional skilled operator per shift).
 - The increase in fixed O&M costs between Case B11A-F2 and Case B11A-F3 can be attributed to the relatively large increase in TPC.
- The variable O&M costs experience the largest increase between Case B11A-F0 to Case B11A-F1, and Case B11A-F2 to Case B11A-F3.
 - The slight reduction in Case B11A-F1 consumables cost (due to an improvement in plant efficiency compared to Case B11A-F0) is outweighed by the increase in maintenance material costs as a percentage of TPC (1.38 percent of TPC for cases 1–4; 0.96 percent for Case B11A-F0), which is due to the proactive maintenance programs implemented by high cycling plants.
 - The increase in variable O&M costs between Case B11A-F2 and B11A-F3 is attributed to the additional consumable stream added as part of the Tier 3 group of flexibility options (Option 47 – Fuel additives for slagging/fouling mitigation); these additives are typically magnesium hydroxide and other related minerals; the additive can be shipped in either liquid form or solid reagent form, which would then be mixed with plant water to form the final slurry solution.
- Fuel costs are similar between all cases. A slight reduction is seen between Case B11A-F0 and Case B11A-F1 due to the improved plant efficiency.

The non-fuel variable O&M and fuel costs are presented as a function of plant load on an hourly basis in Exhibit 5-117 and Exhibit 5-118, respectively. These charts assume that the plant is operating at reduced loads 100 percent of the year (service factor of 1). If the service factor is reduced, the maintenance materials costs would be reduced.

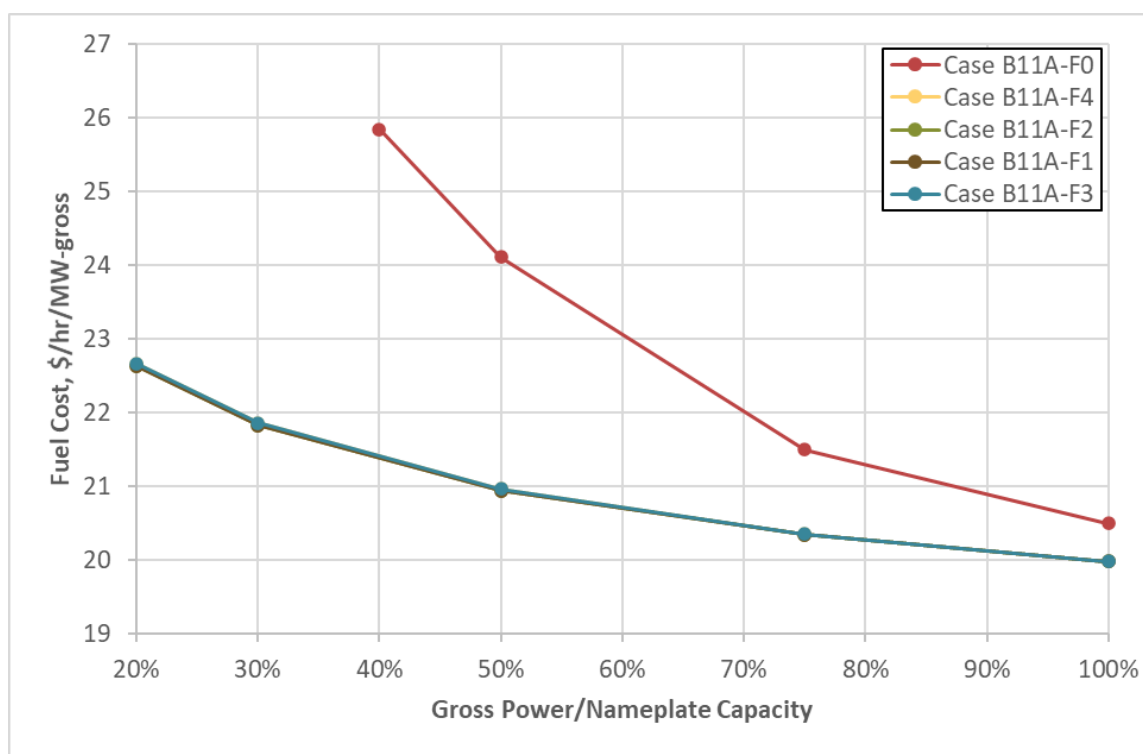
CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-117. Non-fuel variable O&M costs as a function of plant load



Note: The cost curves for Cases B11A-F3-F4 are overlapping

Exhibit 5-118. Fuel costs as a function of plant load



Note: The cost curves for Cases B11A-F1-F4 are overlapping

5.6 SUPERCRITICAL BASELOAD PLANT CASE

This section contains an evaluation of plant design for Case B12A-F0, which is based on a supercritical baseload PC plant with a nominal gross output of 300 MWe. The plant uses a single reheat 24.1 MPa/593°C/593°C (3,500 psia/1,100°F/1,100°F) cycle.

The balance of this section is organized as follows:

- Key Assumptions is a summary of study and modeling assumptions relevant to Case B12A-F0.
- Sparing Philosophy is provided for Case B12A-F0.
- Process Description provides an overview of the technology operation as applied to Case B12A-F0. The systems that are common to all PC cases were covered in Section 5.2 and only features that are unique to Case B12A-F0 are discussed further in this section.
- Performance Results provides the main modeling results from Case B12A-F0, including the full load performance summary, part load performance summary, environmental performance, carbon/sulfur balances, water balance, energy and mass balance diagrams and energy balance table.
- Major Equipment List provides an itemized list of major equipment for Case B12A-F0 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case B12A-F0.
- Impact of Plant Capacity on Configuration, Performance, and Cost provides a comparison between Case B12A-F0 (300 MWgross) and Case B12A (685 MWgross) from the Bituminous Baseline. [63]

5.6.1 Key System Assumptions

System assumptions for Case B12A-F0 compiled in Exhibit 5-119. Some of these parameters vary as the plant reduces load. For the values of process parameters that vary with load, refer to the Case B12A-F0 performance curves in Appendix A.6.

Exhibit 5-119. Supercritical baseload PC plant study configuration matrix

	Case B12A-F0
Steam Cycle, MPa/°C/°C (psig/°F/°F)	24.1/593/593 (3,500/1,100/1,100)
Steam Turbine	Sliding Pressure Main Steam, Triple-Pressure (HP/IP/LP), Single-Reheat, Single-Shaft, Condensing
Coal	Illinois No. 6
Condenser Type	Air-Cooled
Condenser Pressure, mm Hg (in. Hg)	76.2 (3)
Auxiliary Cooling	Ancillary Air-to-Glycol Cooling Loops
Feedwater Pump	Turbine-Driven

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	Case B12A-F0
Fan Drives	Static Frequency
Boiler Efficiency, HHV %	87.5
Stack Temperature, °C (°F)	57 (135)
SO ₂ Control	Wet FGD
FGD Efficiency, % ^A	98
FGD Blowdown Treatment (Effluent Limitation Guidelines)	Spray dryer evaporator
NO _x Control	LNB w/OFA, SCR
SCR Efficiency, % ^A	76.0
Ammonia Slip (end of catalyst life), ppmv	2
Particulate Control	Fabric Filter
Fabric Filter Efficiency, % ^A	99.9
Ash Distribution, Fly/Bottom	80%/20%
SO ₃ Control	DSI
Mercury Control	Co-benefit Capture and ACI

^ARemoval efficiencies are based on the flue gas content

5.6.1.1 Balance of Plant – Case B12A-F0

The balance of plant assumptions for Case B12A-F0 are presented in Exhibit 5-120.

Exhibit 5-120. Case B12A-F0 balance of plant assumptions

Parameter	Value
<u>Cooling System</u>	Air-Cooled Condenser
<u>Fuel and Other Storage</u>	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	30 days
Hydrated lime	7 days
Activated carbon	7 days
<u>Plant Distribution Voltage</u>	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V

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Parameter	Value
Steam and CT generators	24,000 V
Grid Interconnection voltage	345 kV
<u>Water and Waste Water</u>	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and deionized water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day).
Water Discharge	Blowdown will be treated for chloride and metals and discharged to the spray dryer evaporator.

5.6.2 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC supercritical boiler (1 x 100%)
- Two SCR reactors (2 x 50%)
- One DSI system (1 x 100%)
- One ACI system (1 x 100%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)

5.6.3 Process Description

In this section the supercritical baseload PC process is described. The system description follows the block flow diagram (BFD) in Exhibit 5-121 and stream numbers reference the same exhibit. Exhibit 5-122 provides process data for the numbered streams in the BFD. Full stream tables are only provided for the 100 percent load point.

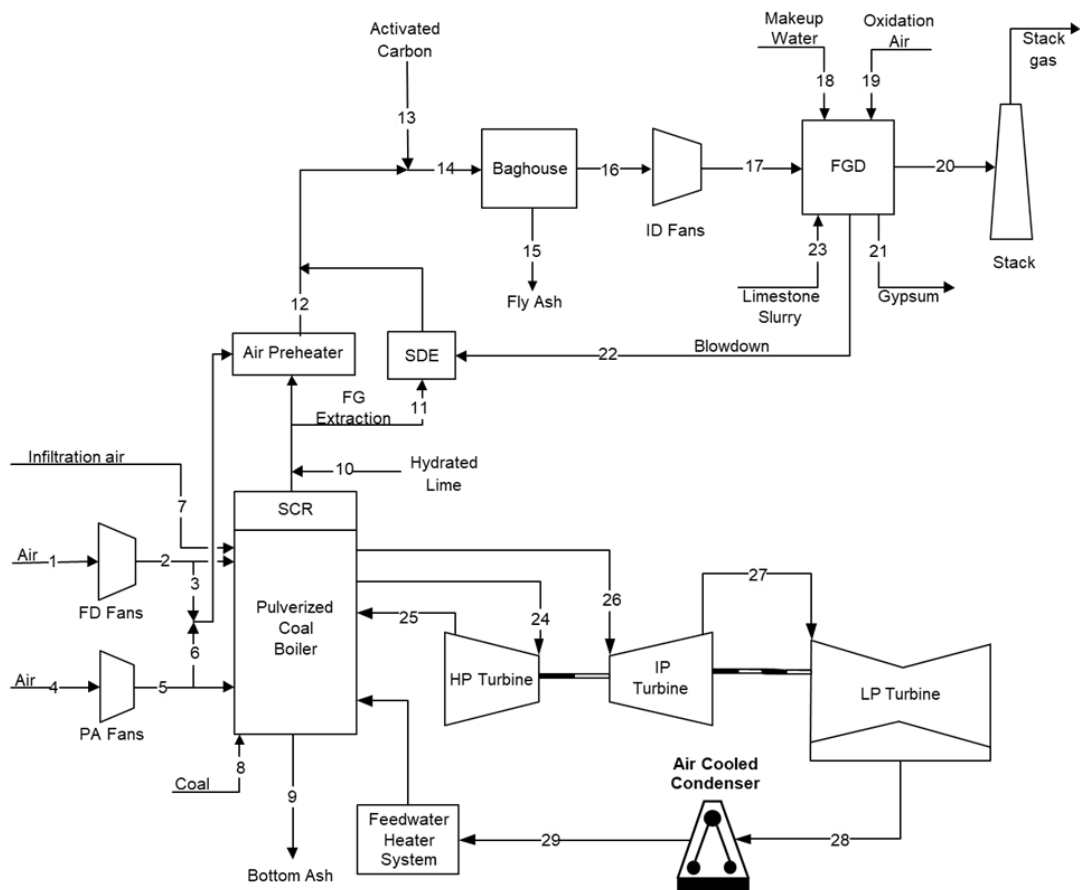
Coal (stream 8) and PA (stream 4) are introduced into the boiler through the wall-fired burners. Additional combustion air, including the OFA, is provided by the FD fans (stream 1). The boiler operates at a slight negative pressure; therefore, air leakage is into the boiler, and the

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infiltration air is accounted for in stream 7. Streams 3 and 6 show Ljungstrom air preheater leakages from the FD and PA fan outlet streams to the boiler exhaust.

Flue gas exits the boiler through the SCR reactor where ammonia is injected to reduce NO_x compounds, followed by hydrated lime injection (stream 10) for the reduction of SO₃. A small flue gas stream is extracted for use in the spray dryer evaporator (stream 11). The flue gas then passes through the combustion air preheater (where the air preheater leakages are introduced) and, at full load, is cooled to 143°C (289°F) (stream 12) before PAC is injected (stream 13) for mercury reduction. The flue gas then passes through a fabric filter for particulate removal (stream 16). At full load, an ID fan increases the flue gas temperature to 156°C (312°F) and provides the motive force for the flue gas (stream 17) to pass through the FGD unit. FGD inputs and outputs include makeup water (stream 18), oxidation air (stream 19), limestone slurry (stream 23) and product gypsum (stream 21). The clean, saturated flue gas exiting the FGD unit (stream 20) passes to the plant stack and is discharged to the atmosphere. The FGD blowdown (stream 22) is sent to the spray dryer evaporator where extracted flue gas (stream 11) is used to evaporate the FGD blowdown stream. The spray dryer evaporator outlet gas stream is recombined into the flue gas path after the air preheater, and before PAC injection.

Exhibit 5-121. Case B12A-FD block flow diagram, supercritical baseload unit



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

■ Baseload Plant Features

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Exhibit 5-122. Case B12A-F0 stream table, supercritical baseload unit

	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flowrate (kgmol/hr)	29,113	29,113	959	5,138	5,138	1,061	581	0	0	0
V-L Flowrate (kg/hr)	840,106	840,106	27,667	148,254	148,254	30,616	16,752	0	0	5
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	97,072	2,068	523
Temperature (°C)	15	21	21	15	23	23	15	15	1,316	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	36.30	36.30	30.23	38.73	38.73	30.23	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-91.51	-91.51	-97.58	-89.08	-89.08	-97.58	-2,119.02	1,312.68	-13,402.95
Density (kg/m ³)	1.2	1.3	1.3	1.2	1.3	1.3	1.2	---	---	1,003.6
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015
V-L Flowrate (lbmol/hr)	64,183	64,183	2,114	11,326	11,326	2,339	1,280	0	0	1
V-L Flowrate (lb/hr)	1,852,116	1,852,116	60,995	326,844	326,844	67,496	36,932	0	0	12
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	214,007	4,558	1,154
Temperature (°F)	59	70	70	59	74	74	59	59	2,400	59
Pressure (psia)	14.7	15.6	15.6	14.7	16.0	16.0	14.7	14.7	14.3	14.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	15.6	15.6	13.0	16.7	16.7	13.0	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-39.3	-39.3	-42.0	-38.3	-38.3	-42.0	-911.0	564.3	-5,762.2
Density (lb/ft ³)	0.076	0.079	0.079	0.076	0.080	0.080	0.076	---	---	62.650

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-122. Case B12A-F0 stream table, supercritical baseload unit, cont'd

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction										
Ar	0.0087	0.0088	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081
CO ₂	0.1463	0.1379	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0889	0.0844	0.0000	0.0918	0.0000	0.0918	0.0918	0.9967	0.0099	0.1512
HCl	0.0001	0.0001	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
N ₂	0.7312	0.7336	0.0000	0.7277	0.0000	0.7277	0.7277	0.0000	0.7732	0.6801
O ₂	0.0226	0.0332	0.0000	0.0325	0.0000	0.0325	0.0325	0.0000	0.2074	0.0360
SO ₂	0.0021	0.0020	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.1148	0.0000	0.0000	0.0006	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0001	0.8852	0.0000	0.0000	0.0028	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	1,750	35,022	0	37,067	2	37,065	37,065	5,163	1,567	41,443
V-L Flowrate (kg/hr)	52,056	1,039,693	0	1,097,208	240	1,096,963	1,096,963	94,467	45,208	1,190,851
Solids Flowrate (kg/hr)	448	8,448	21	9,000	9,006	0	0	849	0	0
Temperature (°C)	384	143	15	143	143	143	156	27	15	57
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	---	---	289.08	302.74	---	30.23	297.86
AspenPlus Enthalpy (kJ/kg) ^B	-2,278.03	-2,399.41	-6.79	-2,459.22	-1,001.45	-2,471.50	-2,457.84	-15,764.00	-97.58	-2,944.15
Density (kg/m ³)	0.5	0.8	---	0.8	2,150.2	0.8	0.9	1,002.4	1.2	1.1
V-L Molecular Weight	29.738	29.687	---	29.600	104.953	29.596	29.596	18.297	28.857	28.735
V-L Flowrate (lb _{mol} /hr)	3,859	77,210	0	81,720	5	81,715	81,715	11,383	3,454	91,365
V-L Flowrate (lb/hr)	114,764	2,292,130	0	2,418,930	528	2,418,389	2,418,389	208,264	99,666	2,625,377
Solids Flowrate (lb/hr)	988	18,624	47	19,842	19,855	0	0	1,871	0	0
Temperature (°F)	724	289	59	289	289	289	312	80	59	135
Pressure (psia)	14.3	14.0	14.7	14.0	14.0	13.8	15.1	14.7	14.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	---	---	124.3	130.2	---	13.0	128.1
AspenPlus Enthalpy (Btu/lb) ^B	-979.4	-1,031.6	-2.9	-1,057.3	-430.5	-1,062.6	-1,056.7	-6,777.3	-42.0	-1,265.8
Density (lb/ft ³)	0.033	0.052	---	0.051	134.232	0.051	0.054	62.580	0.076	0.067

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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Exhibit 5-122. Case B12A-F0 stream table, supercritical baseload unit, cont'd

	21	22	23	24	25	26	27	28	29
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	88	295	1,218	50,383	38,045	38,045	34,032	25,883	34,133
V-L Flowrate (kg/hr)	1,587	5,460	21,941	907,668	685,387	685,387	613,093	466,293	614,911
Solids Flowrate (kg/hr)	14,277	83	9,393	0	0	0	0	0	0
Temperature (°C)	15	57	15	593	343	593	288	45	45
Pressure (MPa, abs)	0.10	0.10	0.10	24.23	4.85	4.11	0.51	0.01	1.31
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	3,477.96	3,052.30	3,658.08	3,037.83	2,403.96	191.45
AspenPlus Enthalpy (kJ/kg) ^B	-12,513.34	-15,495.45	-14,994.25	-12,502.33	-12,928.00	-12,322.21	-12,942.47	-13,576.33	-15,788.84
Density (kg/m ³)	880.9	979.4	1,003.7	69.2	18.9	10.5	2.0	0.1	990.5
V-L Molecular Weight	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	194	651	2,685	111,076	83,874	83,874	75,027	57,063	75,250
V-L Flowrate (lb/hr)	3,499	12,036	48,373	2,001,066	1,511,021	1,511,021	1,351,639	1,027,999	1,355,647
Solids Flowrate (lb/hr)	31,475	183	20,708	0	0	0	0	0	0
Temperature (°F)	59	135	59	1,100	649	1,100	550	114	114
Pressure (psia)	14.7	14.7	14.7	3,514.7	702.9	595.9	74.5	1.4	190.2
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	1,495.3	1,312.3	1,572.7	1,306.0	1,033.5	82.3
AspenPlus Enthalpy (Btu/lb) ^B	-5,379.8	-6,661.8	-6,446.4	-5,375.0	-5,558.0	-5,297.6	-5,564.3	-5,836.8	-6,788.0
Density (lb/ft ³)	54.996	61.143	62.658	4.319	1.181	0.655	0.126	0.004	61.838

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

5.6.4 Case B12A-F0 – Full Load Performance Results

At full load, the plant produces a net output of 283 MWe at a net plant efficiency of 38.7 percent (HHV basis). Full load performance for Case B12A-F0 is summarized in Exhibit 5-123. Exhibit 5-124 presents a detailed breakdown of auxiliary power requirements at full load.

Exhibit 5-123. Case B12A-F0 plant performance summary

Performance Summary	
Percent Load	100%
Total Gross Power, MWe	300
Nameplate Capacity, MWe	300
Total Auxiliaries, MWe	17
Total Auxiliaries, % of Gross Power	5.5%
Net Power, MWe	283
HHV Net Plant Efficiency, %	38.7%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,295 (8,810)
LHV Net Plant Efficiency, %	40.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,965 (8,497)
HHV Boiler Efficiency, %	87.5%
LHV Boiler Efficiency, %	90.7%
Steam Turbine Cycle Efficiency, %	46.9%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,680 (7,279)
Condenser Duty, GJ/hr (MMBtu/hr)	1,196 (1,133)
As-Received Coal Feed, kg/hr (lb/hr)	97,072 (214,007)
Limestone Sorbent Feed, kg/hr (lb/hr)	9,393 (20,708)
HHV Thermal Input, kWt	731,682
LHV Thermal Input, kWt	705,717
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (0.9)
Excess Air, %	20.0%

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Exhibit 5-124. Case B12A-F0 plant power summary

Power Summary	
Percent Load	100%
Steam Turbine Power, MWe	300
Total Gross Power, MWe	300
Nameplate Capacity	300
Auxiliary Load Summary	
Activated Carbon Injection, kWe	14
Air Cooled Condenser Fans	3,580
Ancillary Glycol Cooling Loops	250
Ash Handling, kWe	327
Baghouse, kWe	44
Boiler Circulation Pump, kWe	0
Boiler Feedwater Pump, ^A kWe	0
Coal Handling and Conveying, kWe	210
Condensate Pumps, kWe	297
Dry Sorbent Injection, kWe	26
Flue Gas Desulfurizer, kWe	1,500
Forced Draft Fans, kWe	1,470
Ground Water Pumps, kWe	25
Induced Draft Fans, kWe	4,310
Miscellaneous Balance of Plant, ^{A,B} kWe	1,250
Primary Air Fans, kWe	369
Pulverizers, kWe	1,070
SCR, kWe	16
Sorbent Handling & Reagent Preparation, kWe	452
Spray Dryer Evaporator, kWe	107
Steam Turbine Auxiliaries, kWe	350
Transformer Losses, kWe	940
Total Auxiliaries, MWe	17
Net Power, MWe	283

^A Boiler feed pumps are turbine-driven

^B Includes plant control systems; lighting; heating, ventilation, and air conditioning (HVAC); and miscellaneous low-voltage loads

5.6.4.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B12A-F0 is presented in Exhibit 5-125. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-125. Case B12A-F0 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	680 (750)	0.305 (0.671)
NO _x	0.036 (0.084)	709 (782)	0.318 (0.700)
Particulate	0.005 (0.011)	91 (101)	0.041 (0.090)
Hg	1.55E-7 (3.60E-7)	0.003 (0.003)	1.36E-6 (3.00E-6)
CO ₂	86 (201)	1,690,890 (1,863,887)	757 (1,669)
CO ₂ ^C	-	-	801 (1,767)
mg/Nm³			
Particulate Concentration ^{D,E}	14.75		

^A Calculations based on an 85% capacity factor

^B Emissions based on gross power, except where otherwise noted

^C CO₂ emissions based on net power instead of gross power

^D Concentration of particles in the flue gas after the baghouse

^E Normal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.35 lb/MMBtu using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 76.0 percent to about 0.08 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and FGD system) is 94.7 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 5-126. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-126. Case B12A-F0 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	61,878 (136,418)	Stack Gas	61,976 (136,633)
Air (CO ₂)	143 (315)	FGD Product	73 (162)
PAC	21 (47)	Baghouse	761 (1,678)
FGD Reagent	953 (2,101)	Bottom Ash	185 (408)
Total	62,995 (138,881)	Total	62,995 (138,881)

Exhibit 5-127 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-127. Case B12A-F0 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	2,433 (5,364)	FGD Product	2,288 (5,044)
		Stack Gas	48 (105)
		Baghouse	97 (215)
Total	2,433 (5,364)	Total	2,433 (5,364)

Exhibit 5-128 shows the water balance for Case B12A-F0.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is reused as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from ground water. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-128. Case B12A-F0 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Desulfurizer Makeup	1.0 (268)	–	1.0 (268)	–	1.0 (268)
Deaerator Vent	–	–	–	0.0 (8.0)	0.0 (-8.0)
Condenser Makeup	0.0 (8.0)	–	0.0 (8.0)	–	0.0 (8.0)
BFW Makeup	0.0 (8.0)	–	0.0 (8.0)	–	0.0 (8.0)
Cooling Tower	–	–	–	–	–
BFW Blowdown	–	–	–	–	–
Total	1.0 (276)	–	1.0 (276)	0.0 (8.0)	1.0 (268)

5.6.4.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B12A-F0 PC boiler, the FGD unit, and steam cycle as shown in Exhibit 5-129 and Exhibit 5-130.

An overall plant energy balance is provided in tabular form in Exhibit 5-131. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-123) is calculated by multiplying the power out by the full load generator efficiency of 98.5 percent.

Exhibit 5-129. Case B12A-F0 energy and mass balance, supercritical PC boiler

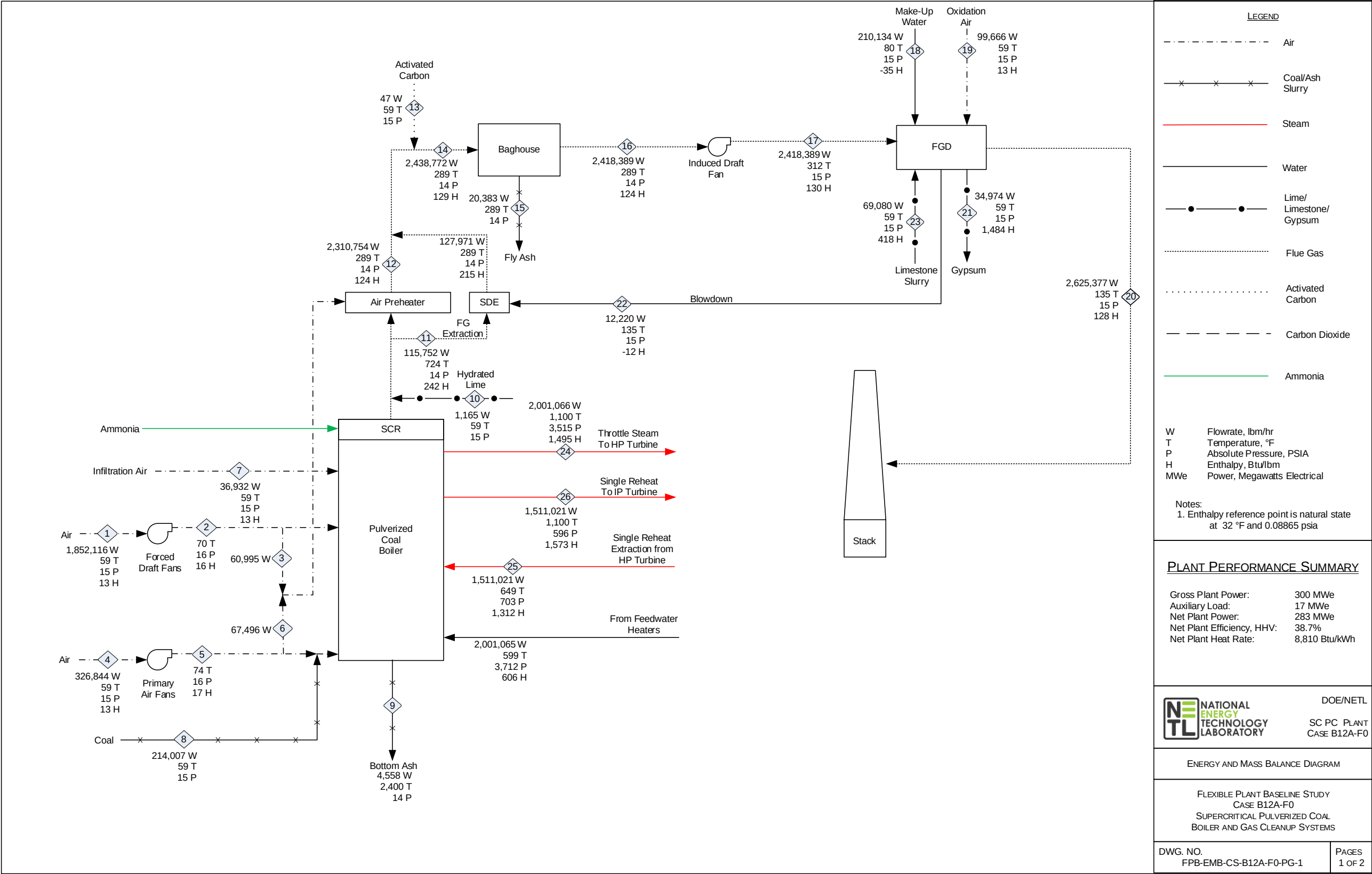
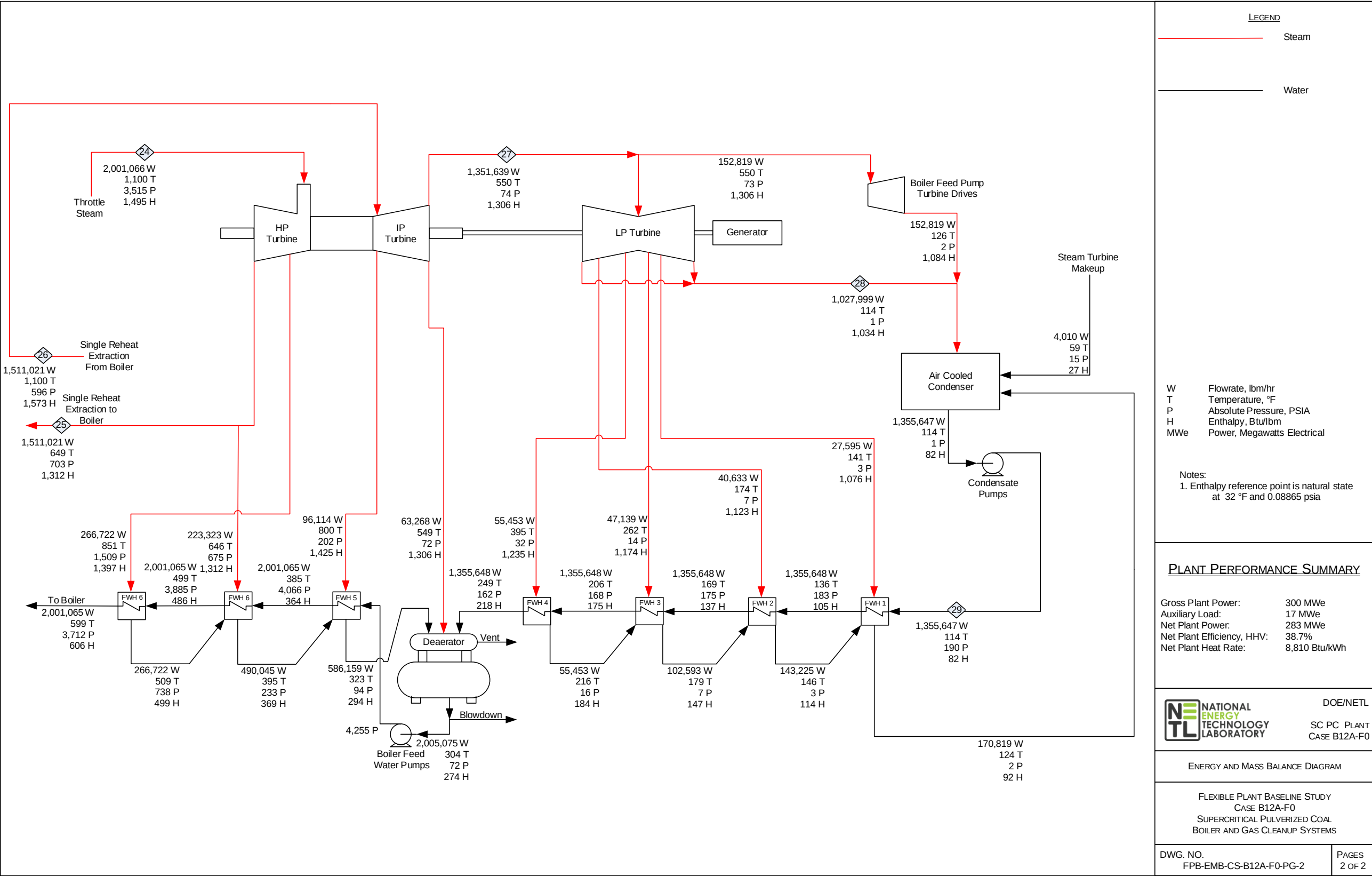


Exhibit 5-130. Case B12A-F0 energy and mass balance, supercritical steam cycle



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-131. Case B12A-F0 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	2,634 (2,497)	2.2 (2.1)	–	2,636 (2,499)
Air	–	30 (29)	–	30 (29)
Raw Water Makeup	–	3.9 (3.7)	–	3.9 (3.7)
Limestone	–	0.2 (0.2)	–	0.2 (0.2)
Auxiliary Power	–	–	60 (57)	60 (57)
Total	2,634 (2,497)	37 (35)	60 (57)	2,731 (2,588)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	2.7 (2.6)	–	2.7 (2.6)
Fly Ash	–	1.0 (0.9)	–	1.0 (0.9)
Stack Gas	–	355 (336)	–	355 (336)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Gypsum	–	0.9 (0.9)	–	0.9 (0.9)
Motor Losses and Design Allowances	–	–	17 (16)	17 (16)
Air Cooled Condenser Load ^A	–	1,196 (1,133)	–	1,196 (1,133)
Blowdown Streams and Deaerator Vent	–	1.2 (1.1)	–	1.2 (1.1)
<i>Ambient Losses^B</i>	–	70 (67)	–	70 (67)
Power	–	–	1,080 (1,024)	1,080 (1,024)
Total	0.0 (0.0)	1,626 (1,541)	1,097 (1,040)	2,724 (2,581)
<i>Unaccounted Energy^C</i>	–	–	–	6.9 (6.6)

^A Includes condenser load only

^B Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^C By difference

5.6.5 Case B12A-F0 – Part Load Performance Results

Plant performance results are summarized at each discrete load point in Exhibit 5-132. Exhibit 5-133 displays a detailed breakdown of the auxiliary power requirement at each discrete load point. Air emissions at each discrete load point are summarized in Exhibit 5-134.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-132. Case B12A-F0 part load plant performance summary

Performance Summary				
Percent Load	100%	75%	50%	40%
Total Gross Power, MWe	300	225	150	120
Nameplate Capacity, MWe	300	300	300	300
Total Auxiliaries, MWe	17	14	11	9
Total Auxiliaries, % of Gross Power	5.5%	6.3%	7.2%	7.7%
Net Power, MWe	283	211	139	111
HHV Net Plant Efficiency, %	38.7%	38.1%	36.9%	36.2%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,295 (8,810)	9,455 (8,962)	9,756 (9,246)	9,944 (9,425)
LHV Net Plant Efficiency, %	40.2%	39.5%	38.3%	37.5%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,965 (8,497)	9,120 (8,644)	9,409 (8,918)	9,591 (9,091)
HHV Boiler Efficiency, %	87.5%	87.5%	87.6%	87.6%
LHV Boiler Efficiency, %	90.7%	90.7%	90.8%	90.8%
Steam Turbine Cycle Efficiency, %	46.9%	46.5%	45.4%	44.8%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,680 (7,279)	7,750 (7,346)	7,926 (7,513)	8,040 (7,621)
Condenser Duty, GJ/hr (MMBtu/hr)	1,196 (1,133)	913 (865)	634 (601)	521 (494)
As-Received Coal Feed, kg/hr (lb/hr)	97,072 (214,007)	73,435 (161,896)	50,035 (110,308)	40,590 (89,486)
Limestone Sorbent Feed, kg/hr (lb/hr)	9,393 (20,708)	7,120 (15,698)	4,871 (10,739)	3,960 (8,731)
HHV Thermal Input, kWt	731,682	553,518	377,138	305,949
LHV Thermal Input, kWt	705,717	533,875	363,754	295,091
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)	0.004 (1.0)	0.004 (1.0)	0.004 (1.0)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (0.9)	0.004 (1.0)	0.004 (1.0)	0.004 (1.0)
Excess Air, %	20.0%	22.1%	26.9%	29.7%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-133. Case B12A-F0 part load plant power summary

Power Summary				
Percent Load	100%	75%	50%	40%
Steam Turbine Power, MWe	300	225	150	120
Total Gross Power, MWe	300	225	150	120
Nameplate Capacity	300	300	300	300
Auxiliary Load Summary				
Activated Carbon Injection, kWe	14	11	7	6
Air Cooled Condenser Fans, kWe	3,580	3,570	2,510	2,020
Ancillary Glycol Cooling Loops, kWe	250	250	250	250
Ash Handling, kWe	327	245	164	131
Baghouse, kWe	44	33	22	17
Boiler Circulation Pump kWe	0	0	0	0
Boiler Feedwater Pump ^A kWe	0	0	0	0
Circulating Water Pumps, kWe	0	0	0	0
Coal Handling and Conveying, kWe	210	160	110	90
Condensate Pumps, kWe	297	193	126	104
Cooling Tower Fans, kWe	0	0	0	0
Dry Sorbent Injection, kWe	26	18	10	7
Flue Gas Desulfurizer, kWe	1,500	1,340	1,310	1,240
Forced Draft Fans, kWe	1,470	1,190	830	660
Ground Water Pumps, kWe	25	19	14	12
Induced Draft Fans, kWe	4,310	3,360	2,320	1,870
Miscellaneous Balance of Plant, ^B kWe	1,250	1,250	1,250	1,250
Primary Air Fans, kWe	369	304	225	159
Pulverizers, kWe	1,070	810	550	450
SCR, kWe	16	14	10	9
Sorbent Handling and Reagent Preparation, kWe	452	343	235	191
Spray Dryer Evaporator, kWe	107	81	55	45
Steam Turbine Auxiliaries, kWe	350	350	350	350
Transformer Losses, kWe	940	710	480	380
Total Auxiliaries, MWe	17	14	11	9
Net Power, MWe	283	211	139	111

^A BFW pumps are turbine-driven

^B Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-134. Case B12A-F0 part load air emissions summary

Emissions Summary				
Percent Load	100%	75%	50%	40%
SO ₂ , kg/MWhgross (lb/MWhgross)	0.305 (0.671)	0.308 (0.679)	0.316 (0.696)	0.321 (0.708)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	757 (1,669)	764 (1,685)	783 (1,725)	794 (1,751)
CO ₂ , kg/MWhnet (lb/MWhnet)	801 (1,767)	816 (1,799)	843 (1,859)	861 (1,898)
Particulate Concentration, ^{A,B} mg/Nm ³	14.75	14.38	13.54	13.07

^A Concentration of particles in the flue gas after the baghouse

^B Normal conditions given at 32°F and 14.696 psia

Case B12A-F0 air emissions remained below the environmental target emission limits across the entire load range. Hg, NO_x, and PM emissions are maintained at constant levels across the load. SO₂ emissions increase as load is reduced but are kept below the environmental target emission limit.

Exhibit 5-135 displays the Case B12A-F0 itemized efficiencies (HHV net plant efficiency, HHV boiler efficiency, and steam cycle efficiency) and normalized auxiliary power consumption across the load range.

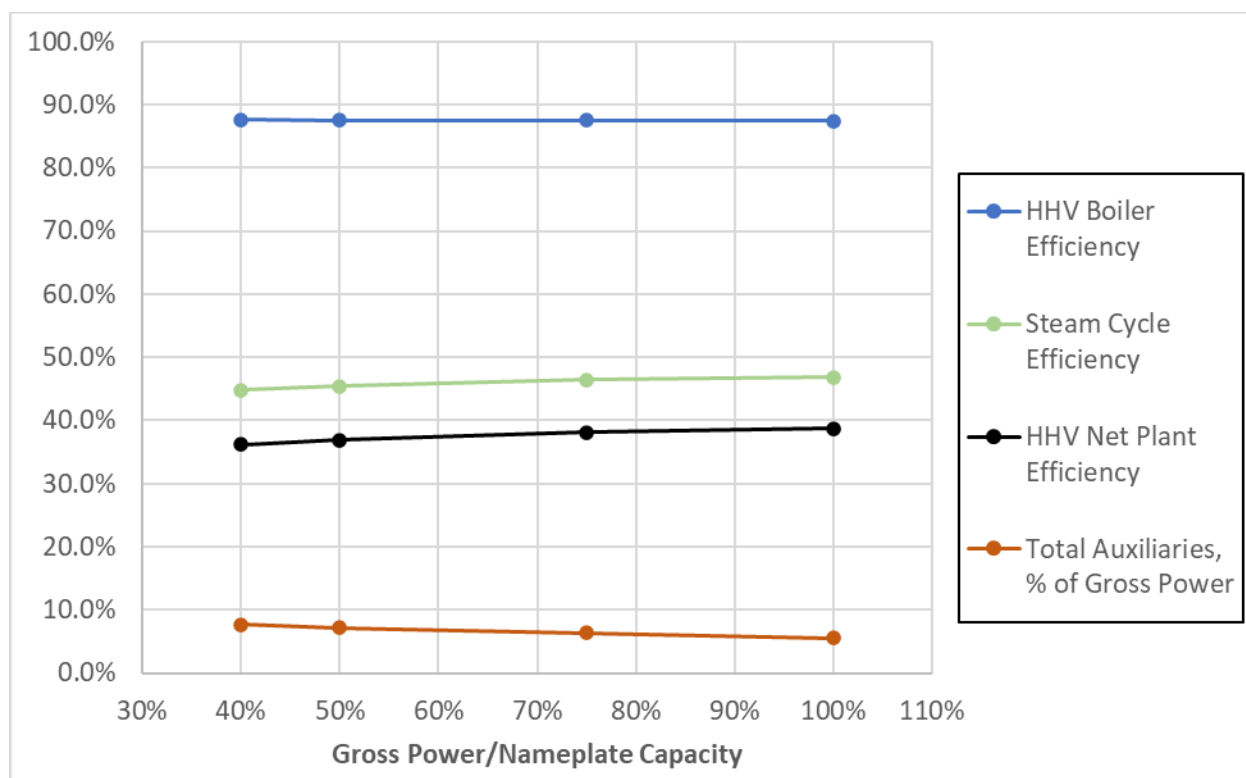
The decrease in part load net plant efficiency is primarily attributable to two key factors: 1) a decrease in the part load steam cycle efficiency, and 2) an increase in the normalized auxiliary power consumption. Conversely, boiler efficiency slightly improves as load is reduced.

Several competing effects impact boiler efficiency as the load is reduced. In general, reduced loads lead to lower flowrates through the boiler, thereby increasing residence time. The increased residence time lowers the unburned carbon rate, which contributes to the increase in reduced load boiler efficiency. Moreover, SO₃ formation rates tend to decrease as load is reduced, allowing for lower air preheater flue gas outlet temperatures while maintaining a constant acid gas condensation approach temperature.

Natural circulation boilers tend to absorb a constant rate of Btus even when load is reduced; this, along with the increased air to fuel ratio that results from increased excess air, leads to a drop in the radiant zone outlet temperature of the boiler, which negatively impacts the boiler efficiency. However, the net impact of these factors results in a slight increase in boiler efficiency as load is reduced.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-135. Case B12A-F0 part load itemized efficiencies



5.6.6 Case B12A-F0 – Major Equipment List

Case B12A-F0 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	20 tonne (20 ton)	2	1
9	Feeder	Vibratory	80 tonne/hr (90 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	160 tonne/hr (180 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	80 tonne (90 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
15	Conveyor No. 4	Belt w/tripper	160 tonne/hr (180 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Coal Silo w/ Vent Filter and Slide Gates	Field erected	360 tonne (400 ton)	3	0
18	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 4 tonne (4 ton) Feeder - 20 kg/hr (50 lb/hr)	1	0
19	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 100 tonne (110 ton) Feeder - 580 kg/hr (1,280 lb/hr)	1	0
20	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
21	Limestone Feeder	Belt	39 tonne/hr (43 tph)	1	0
22	Limestone Conveyor No. 1	Belt	39 tonne/hr (43 tph)	1	0
23	Limestone Reclaim Hopper	N/A	8 tonne (9 ton)	1	0
24	Limestone Reclaim Feeder	Belt	31 tonne/hr (34 tph)	1	0
25	Limestone Conveyor No. 2	Belt	31 tonne/hr (34 tph)	1	0
26	Limestone Day Bin	w/ actuator	124 tonne (137 ton)	2	0

Case B12A-F0 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	27 tonne/hr (29 tph)	4	0
2	Coal Pulverizer	Rotary (Vertical)	27 tonne/hr (29 tph)	4	0
3	Limestone Weigh Feeder	Gravimetric	10 tonne/hr (11 tph)	1	1
4	Limestone Ball Mill	Rotary	10 tonne/hr (11 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	38,600 liters (10,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	650 lpm @ 10m H ₂ O (170 gpm @ 40 ft H ₂ O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	160 lpm (40 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	223,000 liters (59,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	470 lpm @ 9m H ₂ O (120 gpm @ 30 ft H ₂ O)	1	1

Case B12A-F0 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	120,000 liters (32,000 gal)	2	0
2	Condensate Pumps	Vertical canned	11,400 lpm @ 200 m H ₂ O (3,000 gpm @ 500 ft H ₂ O)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
3	Deaerator and Storage Tank	Horizontal spray type	1,000,000 kg/hr (2,206,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump/Turbine	Barrel type, multi-stage, centrifugal	16,800 lpm @ 3,600 m H ₂ O (4,400 gpm @ 11,700 ft H ₂ O)	1	1
5	Startup Boiler Feed Pump, Electric Motor Driven	Barrel type, multi-stage, centrifugal	5,000 lpm @ 3,600 m H ₂ O (1,300 gpm @ 11,700 ft H ₂ O)	1	0
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	340,000 kg/hr (750,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	340,000 kg/hr (750,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	340,000 kg/hr (750,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	340,000 kg/hr (750,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	1,000,000 kg/hr (2,200,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	1,000,000 kg/hr (2,200,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	1,000,000 kg/hr (2,200,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	37 GJ/hr (35 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	14,600 lpm @ 30 m H ₂ O (3,900 gpm @ 100 ft H ₂ O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	250 lpm @ 20 m H ₂ O (70 gpm @ 60 ft H ₂ O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	250 lpm @ 270 m H ₂ O (70 gpm @ 880 ft H ₂ O)	2	1
23	Filtered Water Pumps	Stainless steel, single suction	520 lpm @ 50 m H ₂ O (140 gpm @ 160 ft H ₂ O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	500,000 liter (132,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO	330 lpm (90 gpm)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
		membrane assembly, electrodeionization unit			
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 900 m ³ /min (31,770 acfm) @ 384°C (724°F) & 0.1 MPa (14 psia) Blowdown - 50 lpm (10 gpm) @ 20,019 ppmw Cl ⁻	2	1

Case B12A-F0 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	1,000,000 kg/hr steam @ 24.1 MPa/593°C (2,200,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	82,000 kg/hr, 1,100 m ³ /min @ 107 cm WG (180,000 lb/hr, 39,300 acfm @ 42 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	462,000 kg/hr, 6,300 m ³ /min @ 76 cm WG (1,019,000 lb/hr, 222,700 acfm @ 30 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	603,000 kg/hr, 12,400 m ³ /min @ 116 cm WG (1,330,000 lb/hr, 437,200 acfm @ 46 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	1,140,000 kg/hr (2,510,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	40 m ³ /min @ 108 cm WG (1,500 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	47,000 liter (12,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	9 lpm @ 90 m H ₂ O (2 gpm @ 300 ft H ₂ O)	2	1

Case B12A-F0 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	603,000 kg/hr (1,330,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	20,000 m ³ /min (723,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	119,000 lpm @ 65 m H ₂ O (31,000 gpm @ 210 ft H ₂ O)	3	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
4	Bleed Pumps	Horizontal centrifugal	1,980 lpm (520 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	340 m ³ /min @ 0.3 MPa (11,980 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	490 lpm (130 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	16 tonne/hr (17 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	300 lpm @ 13 m H ₂ O (80 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	200,000 lpm (50,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	710 lpm @ 21 m H ₂ O (190 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	---	20 kg/hr (50 lb/hr)	1	0
13	Hydrated Lime Injectors	---	580 kg/hr (1,280 lb/hr)	1	0

Case B12A-F0 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	122 m (400 ft) high x 4.2 m (14 ft) diameter	1	0

Case B12A-F0 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	311 MW 24.0 MPa/593°C/593°C (3485 psig/ 1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Air-cooled Condenser	Forced draft, direct, A-frame air-cooled condenser	1,320 GJ/hr (1,250 MMBtu/hr), Condensing temperature 45°C (114°F), Ambient temperature 15°C (59°F)	1	0

Case B12A-F0 – Account 9: Auxiliary Cooling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Glycol Cooling Loops	Industrial grade, air to glycol, closed loop heat exchanger	10 GJ/hr (14 MMBtu/hr) heat duty	5	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case B12A-F0 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	2.3 tonne/hr (2.5 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	12	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	9 m ³ /min @ 0.2 MPa (323 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	600 tonne (660 ton)	2	0
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	60 tonne/hr (60 tph)	1	0

Case B12A-F0 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 330 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 15 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 3 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Diesel Generator	Sized for emergency shutdown	750 kW, 480 V, 3-ph, 60 Hz	1	0

Case B12A-F0 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers, alarm management, HMIs, data historian, hard-wired control interface panels, and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor cabinets with redundant input/output, I/O cabinets, various I/C buses	Spare 25% I/O and processor bandwidth	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant	1	0

5.6.7 Case B12A-F0 – Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-136 shows a detailed breakdown of the capital costs; Exhibit 5-137 shows the owner's costs, along with the TOC; and Exhibit 5-138 shows the initial and annual O&M costs.

The estimated TPC of the Case B12A-F0 plant is \$662 million. The project contingency is 13.3 percent of the TPC.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-136. Case B12A-F0 total plant cost summary

Case:		B12A-F0	Supercritical PC Baseload Plant				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
1 Coal & Sorbent Handling										
1.1	Coal Receive & Unload	\$422	\$0	\$190	\$0	\$613	\$107	\$0	\$108	\$828
1.2	Coal Stackout & Reclaim	\$1,387	\$0	\$310	\$0	\$1,697	\$297	\$0	\$299	\$2,293
1.3	Coal Conveyors	\$14,731	\$0	\$3,505	\$0	\$18,236	\$3,191	\$0	\$3,214	\$24,641
1.4	Other Coal Handling	\$1,640	\$0	\$345	\$0	\$1,985	\$347	\$0	\$350	\$2,682
1.5	Sorbent Receive & Unload	\$96	\$0	\$29	\$0	\$125	\$22	\$0	\$22	\$169
1.6	Sorbent Stackout & Reclaim	\$523	\$0	\$95	\$0	\$618	\$108	\$0	\$109	\$835
1.7	Sorbent Conveyors	\$929	\$202	\$225	\$0	\$1,356	\$237	\$0	\$239	\$1,832
1.8	Other Sorbent Handling	\$55	\$13	\$28	\$0	\$96	\$17	\$0	\$17	\$129
1.9	Coal & Sorbent Handling Foundations	\$0	\$681	\$898	\$0	\$1,579	\$276	\$0	\$278	\$2,134
	Subtotal	\$19,784	\$896	\$5,624	\$0	\$26,304	\$4,603	\$0	\$4,636	\$35,543
2 Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	\$899	\$0	\$173	\$0	\$1,072	\$188	\$0	\$189	\$1,448
2.2	Prepared Coal Storage & Feed	\$3,026	\$0	\$652	\$0	\$3,678	\$644	\$0	\$648	\$4,969
2.5	Sorbent Preparation Equipment	\$397	\$17	\$81	\$0	\$495	\$87	\$0	\$87	\$669
2.6	Sorbent Storage & Feed	\$640	\$0	\$241	\$0	\$881	\$154	\$0	\$155	\$1,190
2.9	Coal & Sorbent Feed Foundation	\$0	\$254	\$223	\$0	\$477	\$83	\$0	\$84	\$644
	Subtotal	\$4,962	\$271	\$1,370	\$0	\$6,602	\$1,155	\$0	\$1,164	\$8,921
3 Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	\$1,290	\$2,211	\$1,106	\$0	\$4,607	\$806	\$0	\$812	\$6,225
3.2	Water Makeup & Pretreating	\$2,044	\$204	\$1,158	\$0	\$3,406	\$596	\$0	\$800	\$4,803
3.3	Other Feedwater Subsystems	\$884	\$290	\$275	\$0	\$1,449	\$254	\$0	\$255	\$1,958
3.4	Service Water Systems	\$598	\$1,141	\$3,696	\$0	\$5,435	\$951	\$0	\$1,277	\$7,663
3.5	Other Boiler Plant Systems	\$265	\$96	\$241	\$0	\$602	\$105	\$0	\$106	\$814
3.6	Natural Gas Pipeline and Start-Up System	\$1,315	\$57	\$42	\$0	\$1,414	\$247	\$0	\$249	\$1,911
3.7	Waste Water Treatment Equipment	\$3,403	\$0	\$2,086	\$0	\$5,489	\$961	\$0	\$1,290	\$7,740
3.8	Spray Dryer Evaporator	\$6,399	\$0	\$3,705	\$0	\$10,105	\$1,768	\$0	\$2,375	\$14,248
3.9	Miscellaneous Plant Equipment	\$88	\$11	\$44	\$0	\$143	\$25	\$0	\$34	\$202
	Subtotal	\$16,285	\$4,011	\$12,354	\$0	\$32,650	\$5,714	\$0	\$7,199	\$45,563
4 Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	\$115,710	\$0	\$75,565	\$0	\$191,275	\$33,473	\$0	\$33,712	\$258,460
4.10	Selective Catalytic Reduction System	\$8,627	\$0	\$5,634	\$0	\$14,262	\$2,496	\$0	\$2,514	\$19,271
4.11	Boiler Balance of Plant	\$463	\$0	\$302	\$0	\$766	\$134	\$0	\$135	\$1,034
4.12	Primary Air System	\$511	\$0	\$334	\$0	\$845	\$148	\$0	\$149	\$1,142
4.13	Secondary Air System	\$1,063	\$0	\$694	\$0	\$1,757	\$307	\$0	\$310	\$2,374

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B12A-F0	Supercritical PC Baseload Plant				Estimate Type:		Conceptual	
				Labor			Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Direct	Indirect	Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
								Process	Project	\$/1,000
4.14	Induced Draft Fans	\$1,992	\$0	\$1,301	\$0	\$3,293	\$576	\$0	\$580	\$4,450
4.15	Major Component Rigging	\$34	\$0	\$22	\$0	\$56	\$10	\$0	\$10	\$75
4.16	Boiler Foundations	\$0	\$142	\$125	\$0	\$266	\$47	\$0	\$47	\$360
	Subtotal	\$128,400	\$142	\$83,977	\$0	\$212,518	\$37,191	\$0	\$37,456	\$287,165
5		Flue Gas Cleanup								
5.2	WFGD Absorber Vessels & Accessories	\$34,246	\$0	\$7,322	\$0	\$41,568	\$7,274	\$0	\$7,326	\$56,169
5.3	Other FGD	\$119	\$0	\$134	\$0	\$253	\$44	\$0	\$45	\$342
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$978	\$215	\$962	\$0	\$2,155	\$377	\$0	\$380	\$2,912
5.9	Particulate Removal (Bag House & Accessories)	\$1,133	\$0	\$714	\$0	\$1,847	\$323	\$0	\$326	\$2,496
5.12	Gas Cleanup Foundations	\$0	\$61	\$54	\$0	\$115	\$20	\$0	\$20	\$155
5.13	Gypsum Dewatering System	\$309	\$0	\$52	\$0	\$361	\$63	\$0	\$64	\$487
	Subtotal	\$36,785	\$276	\$9,238	\$0	\$46,299	\$8,102	\$0	\$8,160	\$62,562
7		Ductwork & Stack								
7.3	Ductwork	\$0	\$291	\$202	\$0	\$493	\$86	\$0	\$87	\$666
7.4	Stack	\$4,093	\$0	\$2,378	\$0	\$6,471	\$1,132	\$0	\$1,141	\$8,744
7.5	Duct & Stack Foundations	\$0	\$77	\$92	\$0	\$169	\$30	\$0	\$40	\$238
	Subtotal	\$4,093	\$368	\$2,672	\$0	\$7,133	\$1,248	\$0	\$1,267	\$9,648
8		Steam Turbine & Accessories								
8.1	Steam Turbine Generator & Accessories	\$38,325	\$0	\$4,309	\$0	\$42,634	\$7,461	\$0	\$7,514	\$57,609
8.2	Steam Turbine Plant Auxiliaries	\$792	\$0	\$1,684	\$0	\$2,477	\$433	\$0	\$436	\$3,346
8.3	Condenser & Auxiliaries ^A	\$15,198	\$0	\$5,157	\$0	\$20,355	\$3,562	\$0	\$3,588	\$27,505
8.4	Steam Piping	\$15,277	\$0	\$6,191	\$0	\$21,468	\$3,757	\$0	\$3,784	\$29,009
8.5	Turbine Generator Foundations	\$0	\$86	\$142	\$0	\$228	\$40	\$0	\$54	\$322
	Subtotal	\$69,592	\$86	\$17,483	\$0	\$87,162	\$15,253	\$0	\$15,376	\$117,790
9		Cooling Water System								
9.6	Component Cooling Water System ^B	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
	Subtotal	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
10		Ash & Spent Sorbent Handling Systems								
10.6	Ash Storage Silos	\$466	\$0	\$1,426	\$0	\$1,892	\$331	\$0	\$333	\$2,556
10.7	Ash Transport & Feed Equipment	\$1,749	\$0	\$1,733	\$0	\$3,482	\$609	\$0	\$614	\$4,705
10.9	Ash/Spent Sorbent Foundation	\$0	\$299	\$367	\$0	\$665	\$116	\$0	\$156	\$938
	Subtotal	\$2,215	\$299	\$3,526	\$0	\$6,039	\$1,057	\$0	\$1,103	\$8,199
11		Accessory Electric Plant								
11.1	Generator Equipment	\$1,473	\$0	\$1,111	\$0	\$2,585	\$452	\$0	\$456	\$3,493
11.2	Station Service Equipment	\$2,623	\$0	\$225	\$0	\$2,848	\$498	\$0	\$502	\$3,848
11.3	Switchgear & Motor Control	\$4,202	\$0	\$729	\$0	\$4,931	\$863	\$0	\$869	\$6,663
11.4	Conduit & Cable Tray	\$0	\$563	\$1,623	\$0	\$2,187	\$383	\$0	\$385	\$2,955

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B12A-F0	Supercritical PC Baseload Plant				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
11.5	Wire & Cable	\$0	\$1,090	\$1,948	\$0	\$3,038	\$532	\$0	\$535	\$4,105
11.6	Protective Equipment	\$31	\$0	\$109	\$0	\$140	\$24	\$0	\$25	\$189
11.7	Standby Equipment	\$361	\$0	\$333	\$0	\$694	\$121	\$0	\$122	\$937
11.8	Main Power Transformers	\$3,929	\$0	\$80	\$0	\$4,009	\$702	\$0	\$707	\$5,417
11.9	Electrical Foundations	\$0	\$83	\$211	\$0	\$294	\$52	\$0	\$69	\$415
	Subtotal	\$12,618	\$1,736	\$6,370	\$0	\$20,725	\$3,627	\$0	\$3,670	\$28,021
12 Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	\$308	\$0	\$55	\$0	\$363	\$63	\$0	\$64	\$490
12.3	Steam Turbine Control Equipment	\$320	\$0	\$36	\$0	\$355	\$62	\$0	\$63	\$480
12.5	Signal Processing Equipment	\$308	\$0	\$55	\$0	\$363	\$63	\$0	\$64	\$490
12.6	Control Boards, Panels & Racks	\$94	\$0	\$58	\$0	\$152	\$27	\$0	\$27	\$205
12.7	Distributed Control System Equipment	\$3,017	\$0	\$538	\$0	\$3,555	\$622	\$0	\$627	\$4,803
12.8	Instrument Wiring & Tubing	\$279	\$223	\$891	\$0	\$1,393	\$244	\$0	\$245	\$1,882
12.9	Other Instrumentation & Controls Equipment	\$332	\$0	\$769	\$0	\$1,101	\$193	\$0	\$194	\$1,488
	Subtotal	\$4,657	\$223	\$2,401	\$0	\$7,281	\$1,274	\$0	\$1,283	\$9,839
13 Improvements to Site										
13.1	Site Preparation	\$0	\$183	\$3,910	\$0	\$4,093	\$716	\$0	\$962	\$5,772
13.2	Site Improvements	\$0	\$1,004	\$1,326	\$0	\$2,330	\$408	\$0	\$547	\$3,285
13.3	Site Facilities	\$828	\$0	\$868	\$0	\$1,696	\$297	\$0	\$399	\$2,391
	Subtotal	\$828	\$1,187	\$6,104	\$0	\$8,119	\$1,421	\$0	\$1,908	\$11,448
14 Buildings & Structures										
14.2	Boiler Building	\$0	\$6,120	\$5,378	\$0	\$11,498	\$2,012	\$0	\$2,027	\$15,537
14.3	Steam Turbine Building	\$0	\$6,187	\$5,762	\$0	\$11,949	\$2,091	\$0	\$2,106	\$16,146
14.4	Administration Building	\$0	\$553	\$584	\$0	\$1,137	\$199	\$0	\$200	\$1,536
14.6	Water Treatment Buildings	\$0	\$150	\$137	\$0	\$287	\$50	\$0	\$51	\$387
14.7	Machine Shop	\$0	\$248	\$165	\$0	\$413	\$72	\$0	\$0	\$486
14.8	Warehouse	\$0	\$193	\$193	\$0	\$386	\$67	\$0	\$68	\$521
14.9	Other Buildings & Structures	\$0	\$139	\$118	\$0	\$258	\$45	\$0	\$45	\$348
14.10	Waste Treating Building & Structures	\$0	\$221	\$670	\$0	\$890	\$156	\$0	\$157	\$1,203
	Subtotal	\$0	\$13,810	\$13,007	\$0	\$26,818	\$4,693	\$0	\$4,654	\$36,165
	Total	\$300,817	\$23,305	\$164,586	\$0	\$488,708	\$85,524	\$0	\$88,063	\$662,294

^AACC; ^B Component cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
FLEXIBLE OPERATION

Exhibit 5-137. Case B12A-F0 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$4,837
1-Month Maintenance Materials	\$622
1-Month Non-Fuel Consumables	\$560
1-Month Waste Disposal	\$346
25% of 1-Month Fuel Cost at 100% CF	\$1,015
2% of TPC	\$13,246
Total	\$20,626
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$9,214
0.5% of TPC (spare parts)	\$3,311
Total	\$12,525
Other Costs	
Initial Cost for Catalyst and Chemicals	\$914
Land	\$117
Other Owner's Costs	\$99,344
Financing Costs	\$17,882
Total Overnight Costs (TOC)	\$813,702

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-138. Case B12A-F0 initial and annual operating and maintenance costs

Case:	B12A-F0	– Supercritical PC Baseload Plant			Cost Base:	Dec 2018
Plant Size (MW, gross):	300	Heat Rate-net (Btu/kWh):			8,810	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$/hour		Skilled Operator:	1.0	
Operating Labor Burden:	30.0	% of base		Operator:	5.0	
Labor O-H Charge Rate:	25.0.	% of labor		Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	8.0	
Fixed Operating Costs						
					Annual Cost (\$)	
Annual Operating Labor:					\$3,507,504	
Maintenance Labor:					\$4,231,793	
Administrative & Support Labor:					\$1,934,824	
Property Taxes and Insurance:					\$13,245,878	
Total:					\$22,920,000	
Variable Operating Costs						
					Annual Cost (\$)	
Maintenance Material:					\$7,467,870 x CF	
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)	
Water (/1000 gallons):	0	198	\$1.90	\$0	\$137,629 x CF	
Makeup and Waste Water Treatment Chemicals (ton):	0	0.591	\$550.00	\$0	\$118,678 x CF	
Brominated Activated Carbon (ton):	0	0.564	\$1,600.00	0	\$329,216 x CF	
Enhanced Hydrated Lime (ton):	0	13.98	\$240.00	0	\$1,224,926 x CF	
Limestone (ton):	0	248	\$22.0.00	\$0	\$1,995,379 x CF	
Ammonia (19 wt%, ton):	0	23.8	\$300.00	\$0	\$2,605,589 x CF	
SCR Catalyst (ft³):	6,096	5.57	\$150.00	\$914,424	\$304,808 x CF	
Subtotal:				\$914,424	\$6,716,225 x CF	
Waste Disposal						
Fly Ash (ton):	0	245	\$38.00	\$0	\$3,392,561 x CF	
Bottom Ash (ton):	0	54.7	\$38.00	\$0	\$758,666 x CF	
SCR Catalyst (ft³):	0	5.57	\$2.50	\$0	\$5,080 x CF	
Subtotal:				\$0	\$4,156,308 x CF	
By-Products						
Gypsum (ton):	0	378	\$0.00	\$0	\$0	
Subtotal:				\$0	\$0	
Variable Operating Costs Total:				\$914,424	\$18,340,403 x CF	
Fuel Cost						
Illinois Number 6 (ton):	0	2,568	\$51.96	\$0	\$48,702,865 x CF	
Fuel Costs Total:				\$0	\$48,702,865 x CF	

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
FLEXIBLE OPERATION

Exhibit 5-139. Case B12A-F0 Synchronization startup and shutdown costs

Event to Synchronization		Hot Start	Warm Start	Cold Start	Shutdown
Energy and Duration					
Energy Produced	MWh	-	-	-	-
Duration	hr	1.0	1.9	4.4	0.2
NG Heat Input (HHV)	MMBtu	439	894	1,946	66
Coal Heat Input (HHV)	MMBtu	-	-	-	-
House Energy Consumed	MWh	1.7	3.5	7.7	0.3
Aux Boiler Energy	MWh	25.9	51.8	103.6	-
Costs					
Variable O&M Cost	\$	300	500	1,200	-
Natural Gas Cost	\$	2,000	4,200	9,000	300
Coal Cost	\$	-	-	-	-
House Energy Cost	\$	100	200	500	-
Total Cost for Event	\$	2,400	4,900	10,700	300

Exhibit 5-140. Case B12A-F0 full load startup and shutdown costs

Event to Full Load		Hot Start	Warm Start	Cold Start	Shutdown
Energy and Duration					
Energy Produced	MWh	226.6	317.4	676.6	268.8
Duration	hr	3.0	5.0	10.5	2.5
NG Heat Input (HHV)	MMBtu	921	1,636	2,719	918
Coal Heat Input (HHV)	MMBtu	2,183	3,087	7,149	2,246
House Energy Consumed	MWh	12.6	19.1	40.0	12.8
Aux Boiler Energy	MWh	51.8	103.6	207.2	-
Costs					
Variable O&M Cost	\$	2,000	3,000	6,200	2,000
Natural Gas Cost	\$	4,300	7,600	12,800	4,000
Coal Cost	\$	4,900	6,900	15,900	5,000
House Energy Cost	\$	800	1,100	2,400	800
Total Cost for Event	\$	12,000	18,600	37,300	11,800

5.6.8 Impact of Plant Capacity on Configuration, Performance, and Cost

This section is intended to highlight the major configuration, performance, and cost differences that result from a change in plant capacity. Case B12A-F0 (300 MW gross) is compared to Case B12A (685 MW gross) from Revision 4 of the Bituminous Baseline study. Both cases are intended to reflect a state-of-the-art supercritical bituminous coal plant designed for baseload operation, with the main differing design criteria being the capacity of the plant. Therefore, they provide a valuable basis for understanding the effect of capacity on plant configuration, performance, and cost.

5.6.8.1 Supercritical Plant Configuration

The major Case B12A-F0 equipment modifications and summaries of the process description updates relative to Case B12A are outlined in the following items:

- **Broad-scale reduction of equipment sizes due to the reduced plant size (from 685 MW-gross to 300 MW-gross).**
- **Account 1 — Coal and Sorbent Handling**
 - Number of conveyors reduced from 5 to 4 to reflect what would be expected for a smaller capacity plant
- **Account 2 — Coal and Sorbent Preparation and Feed**
 - Mill type changing from “ball-type” to “vertical roller”; mill quantity is expected to reduce to 4
 - Bulk-stock coal fed into vertical roller mill directly from the gravimetric feeders; vertical-roller mills provide operational simplicity benefits as compared to ball-type mills, based on Black & Veatch experience
 - Horizontal “table” rotates with three stationary (spring-compressed) rollers used to grind coal to adequate size to be entrained in primary air flow and then transported to coal burners
 - Mills equipped with pyrites/rejects hopper
- **Account 3 — Feedwater and Miscellaneous Systems and Equipment**
 - Fuel oil system onsite would be eliminated on the basis of cost and unnecessary fuel redundancy; it is not typical for a plant this size to equip and maintain two supplemental fuel sources and systems
- **Account 5 — Flue Gas Cleanup**
 - Operating quantity of recirculation pumps reduced from 5 to 4
- **Account 7 — Ducting and Stack**
 - Stack size likely to be reduced to 400-ft height and 14-ft diameter (stack material type likely to remain consistent)

- Final stack characteristics (height/exit velocity) would be determined by permit and dispersion modeling
- **Account 8 — Steam Turbine Generator and Auxiliaries^j**
 - ACC replacing the B12A “surface condenser”
 - LP turbine outlet routes directly to the upper channel of the A-frame ACC
 - Cooling fan “cells” draw air through the A-frame tube channels to fully condense steam in the separate “leg channels” at the bottom of the ACC
 - Condensate pumps draw suction from the condensed liquid
 - Use of an ACC is not due to the reduced plant size. It was selected for this study to maintain “regional agnosticism”
- **Account 9 — Cooling Water System**
 - ACC replacing the Case B12A wet mechanical draft cooling tower
 - Utilization of an ACC requires air-to-glycol cooling loops to be installed for handling miscellaneous cooling loads
- **Account 10 — Ash and Spent Sorbent Handling System**
 - Operating quantity of baghouse hoppers reduced from 24 to 16

Additionally, a 300-MW plant would likely retain few (if any) major equipment spares (e.g., boiler waterwall panels, tube assemblies, spare steam turbine rotors, spare bearing liners). The baseload and flexible plant designs maintain similar number of PA, FD, and ID fans and BFW pump units. One major equipment category where the sparing philosophy is most notably modified from the Case B12A reference plant design is the type and number of coal mills utilized.

Unlike Case B12A, Case B12A-F0 does not include an economizer bypass in the plant design. Case B12A-F0 is designed with some consideration for daily or weekly cycling, whereas Case B12A is intended to reflect a plant designed purely for baseload operation. [63] While the economizer bypass can provide benefits during startup and shutdown processes, the baseload plant by definition would be experiencing very few startup or shutdown periods throughout the year. Therefore, the marginal benefit to flue gas temperature control upstream of the SCR afforded by the operation of an economizer gas-side bypass would not be able to demonstrate significant cost savings or operational improvements for the 300 MW gross baseload plant.

Apart from these areas where major equipment supply quantities were modified, no other equipment category was subject to a modification of the sparing (e.g., 2x100 percent) philosophy already established in the Case B12A design. [63]

^j B11A-F0 was designed as constant pressure while B12A-F0 is assumed to be sliding pressure. Sliding pressure steam turbine designs are considered standard for supercritical units. All major steam turbine OEMs will have models that can operate in both regimes; no significant commercial or operational risk is associated with the sliding pressure units.

5.6.8.2 Performance

Performance for Case B12A and Case B12A-F0 are summarized in Exhibit 5-141. Exhibit 5-142 presents a detailed breakdown of Case B12A and Case B12A-F0 auxiliary power requirements. Part load performance results are not provided for either case, since part load performance results have not been generated for Case B12A.

Exhibit 5-141. Baseload plant performance summary comparison: Case B12A and Case B12A-F0

Performance Summary		
Case	B12A	B12A-F0
Percent Load	100%	100%
Total Gross Power, MWe	685	300
Nameplate Capacity, MWe	685	300
Circulating Water Pumps, kWe	5,300	0
Cooling Tower Fans, kWe	2,740	0
ACC Fans, kWe	0	3,580
Balance of Plant, kWe	27,030	13,027
Total Auxiliaries, MWe	35	17
Total Auxiliaries, % of Gross Power	5.1%	5.5%
Net Power, MWe	650	283
HHV Net Plant Efficiency, %	40.3%	38.7%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,939 (8,473)	9,295 (8,810)
LHV Net Plant Efficiency, %	41.8%	40.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,622 (8,172)	8,965 (8,497)
HHV Boiler Efficiency, %	88.1%	87.5%
LHV Boiler Efficiency, %	91.3%	90.7%
Steam Turbine Cycle Efficiency, %	48.2%	46.9%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,471 (7,082)	7,680 (7,279)
Condenser Duty, GJ/hr (MMBtu/hr)	2,589 (2,454)	1,196 (1,133)
As-Received Coal Feed, kg/hr (lb/hr)	214,112 (472,037)	97,072 (214,007)
Limestone Sorbent Feed, kg/hr (lb/hr)	20,712 (45,662)	9,393 (20,708)
HHV Thermal Input, kWt	1,613,879	731,682
LHV Thermal Input, kWt	1,556,606	705,717
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.035 (9.3)	0.004 (1.0)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.028 (7.4)	0.004 (0.9)
Excess Air, %	20.3%	20.0%

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Exhibit 5-142. Baseload plant power summary comparison: Case B12A and Case B12A-F0

Power Summary		
Case	B12A	B12A-F0
Percent Load	100%	100%
Steam Turbine Power, MWe	685	300
Total Gross Power, MWe	685	300
Nameplate Capacity	685	300
Auxiliary Load Summary		
Activated Carbon Injection, kWe	30	14
Air Cooled Condenser Fans, kWe	0	3,580
Ancillary Glycol Cooling Loops, kWe	0	250
Ash Handling, kWe	690	327
Baghouse, kWe	90	44
Boiler Circulation Pump, kWe	0	0
Boiler Feedwater Pump, ^A kWe	0	0
Circulating Water Pumps, kWe	5,300	0
Coal Handling and Conveying, kWe	470	210
Condensate Pumps, kWe	660	297
Cooling Tower Fans, kWe	2,740	0
Dry Sorbent Injection, kWe	60	26
Flue Gas Desulfurizer, kWe	3,310	1,500
Forced Draft Fans, kWe	2,010	1,470
Ground Water Pumps, kWe	550	25
Induced Draft Fans, kWe	8,210	4,310
Miscellaneous Balance of Plant, ^B kWe	2,250	1,250
Primary Air Fans, kWe	1,570	369
Pulverizers, kWe	3,210	1,070
SCR, kWe	30	16
Sorbent Handling and Reagent Preparation, kWe	1,000	452
Spray Dryer Evaporator, kWe	240	107
Steam Turbine Auxiliaries, kWe	500	350
Transformer Losses, kWe	2,150	940
Total Auxiliaries, MWe	35	17
Net Power, MWe	650	283

^A BFW pumps are turbine-driven

^B Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

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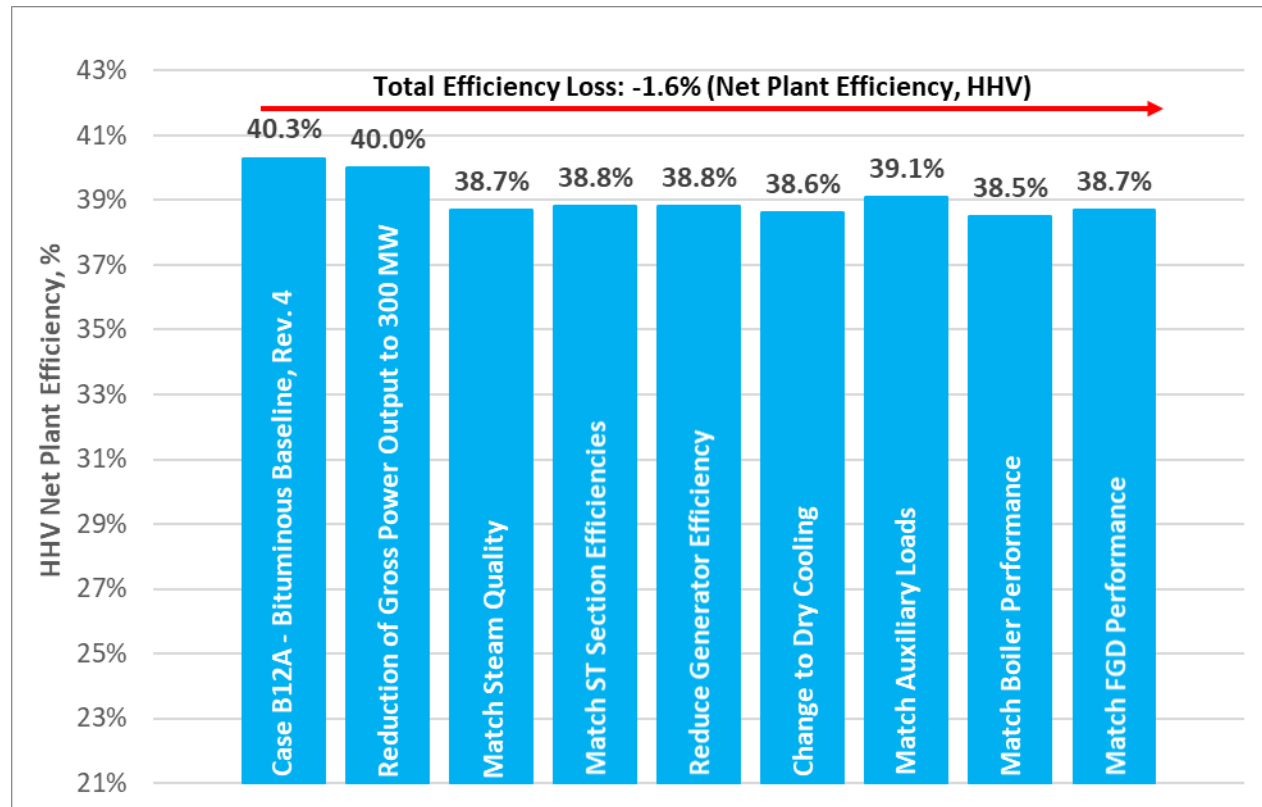
Normalized water consumption is substantially lower in Case B12A-F0 due to the use of an ACC. Case B12A utilizes a recirculating wet cooling tower rather than an ACC; this allows for an improvement in net plant efficiency by way of a reduced condenser operating pressure, but requires substantial water withdrawal. Furthermore, use of a recirculating wet cooling tower requires a circulating water system to deliver cooling water to the condenser and auxiliary cooling systems. This circulating water system can be eliminated if an ACC is used in lieu of a wet cooling system.

The auxiliary power requirement of the Case B12A cooling system is reflected in the power requirement of the circulating water system and cooling tower fans, while the auxiliary power requirement of the Case B12A-F0 cooling system is reflected in power requirement of the ACC fans. However, comparison of auxiliary power requirement alone does not give an adequate representation of their relative performance, since cooling type also has a notable impact on condenser operating pressure.

Case B12A-F0 has a notably lower net plant efficiency when compared to Case B12A. Several factors contribute to this, including the use of dry cooling and a higher normalized auxiliary power consumption. In addition, smaller rotating equipment (e.g., pumps, fans, turbines) tends to have lower efficiencies than their larger-scale counterparts.

A waterfall chart is provided in Exhibit 5-143, which illustrates the individual impacts various differences between Cases B11A and B11A-F0 have on the net plant efficiency.

Exhibit 5-143. Supercritical PC Comparison - Case B12A to Case B12A-F0



5.6.8.2.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B12A-F0 and Case B12A is presented in Exhibit 5-144. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

NO_x, particulate, and mercury emissions are reduced to exactly meet regulatory limits, and consequently are equivalent between Case B12A-F0 and Case B12A. Case B12A-F0 has higher SO₂ emissions due to the constant removal rate of the wet FGD system; the lower net plant efficiency leads to a higher normalized formation of SO₂ in the boiler, causing a higher rate of emission. Similarly, Case B12A-F0 CO₂ emissions are higher due to the lower net plant efficiency.

Exhibit 5-144. Baseload plant air emissions summary comparison: Case B12A and Case B12A-F0

Emissions Summary		
Case	B12A	B12A-F0
SO ₂ , kg/MWhgross (lb/MWhgross)	0.294 (0.648)	0.304 (0.671)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	738 (1,627)	757 (1,669)
CO ₂ , kg/MWhnet (lb/MWhnet)	778 (1,714)	801 (1,767)
Particulate Concentration ^{A,B} , mg/Nm ³	15.12	14.75

^A Concentration of particles in the flue gas after the baghouse

^B Normal conditions given at 32°F and 14.696 psia

5.6.8.3 Cost Results

Due to plant size changes and configuration differences (e.g., ACC instead of a water-cooled condenser), various cost account line items were omitted from the Case B12A-F0 capital cost estimates when compared to Case B12A. [63] Exhibit 5-145 presents a summary of the specific cost account categories that were omitted compared to Case B12A, and the justification for their omission.

Exhibit 5-145. Cost account deviations for small-scale plants, relative to 687 MW gross plants [63]

Cost Account Number	Cost Account Description	Justification for Omission
9.1	Cooling Towers	Use of cooling towers omitted from all capital cost cases (cases 0–4) due to the use of an ACC, which replaces the wet mechanical draft cooling tower utilized in the Bituminous Baseline [63] cost estimates.
9.2	Circulating Water Pumps	Circulating water pumps omitted due to the use of the ACC, which handles all cycle heat rejection. Smaller-duty component cooling throughout the

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Cost Account Number	Cost Account Description	Justification for Omission
		plant (previously served by the circulating water system) are served by individual closed loop glycol-based cooling systems.
9.3	Circulating Water System Auxiliaries	See Account 9.2
9.4	Circulating Water Piping	See Account 9.2
9.5	Circulating Water System Foundations	See Account 9.2
14.5	Circulation Water Pump house	See Account 9.2

The capital and O&M costs presented for Case B12A-F0 do not have reference cases for simple comparison or scaling within the Bituminous Baseline. [2] Furthermore, the Case B12A-F0 plant size is well outside the applicable range for scaling plant system costs via the methodologies and parameters outlined in the QGESS capital cost scaling methodologies report. [82] For this reason, a comparison between the flexible plant TPC figures and scaled Case B12A costs would not provide a suitable comparison basis to draw any relevant conclusions.

However, the analysis was performed to address any discrepancies when comparing Case B12A-F0 costs estimates with the cost estimates of Case B12A scaled per the QGESS methodology. Upon comparison, it was clear that several Case B12A-F0 cost accounts were lower than predicted. The reasons for these account variations are addressed below for the accounts where the differential is most prominent:

- Account 1 (Coal and Sorbent Handling) and Account 2 (Coal and Sorbent Preparation and Feed) — Material selection, standardized equipment designs (e.g., rollers and conveyor belts), and broader supplier base typically reduce costs for material handling systems applicable to PC plants in the 300 MW size range; additionally, the opportunity for prefabrication of silos allows for significant cost reduction of these Account 1 and 2 systems.
- Account 7 (Ductwork & Stack) — For PC plants in the 300 MW size range, higher degrees of modularization of major duct sections and the stack are possible; additionally, step changes in standard supplier offerings (e.g., being able to utilize pre-fabricated and pre-insulated duct sections) also contribute to more competitive sub-system costs; a concrete stack is utilized for the flexible plant configuration due to plant size (MW) and potential for stack height variations due to air permit dispersion modeling (taller stack requirements would likely require concrete).
- Account 10 (Ash & Spent Sorbent Handling Systems) — Similar to contributing factors to the cost competitiveness of Account 1 and Account 2 discussed above, the ash and spent storage system costs would be expected to be lower for a PC plant in the 300 MW size

range (compared to the scaled Case B12A costs) due to step-change improvements in pre-fabricated supplier offerings and more standardized designs.

- Account 11 (Accessory Electric Plant) — The step change in system design, number of available suppliers, and competitive supplier market for smaller sized motor control centers (MCCs), VFDs, switchgear panels, and other accessory electric plant components would be expected to contribute to a reduction of Account 11 costs for Case B12A-F0 when compared to a larger scale PC plant's costs.
- Account 12 (Instrumentation & Control) — The application of advanced control systems and instrumentation is included in the estimated cost for Account 12 within Case B12A-F0; the cost premium for these 'advanced control techniques' and equipment are not as severely impactful to Account 12 cost due to their commercial availability, competitive supplier market, increasing standardization of hardware and software components, and various OEM mergers and acquisitions leading to increasingly competitive and modularized offerings. Account 12 within Case B12A accounted for 1.5 percent of the TPC (\$20,356,000 of \$1,364,033,000) and the Account 12 cost for Case B12A-F0 is approximately 1.5 percent (\$9,839,000 of \$662,294,000), which is considered to be reasonable given the more highly modularized systems for the Case B12A-F0 plant size and the previously identified items regarding the competitive supplier market and technology maturity.
- Account 13 (Site Improvement) — The significant reduction of site size contributes to a step-change reduction in the cost for site improvement(s) for a PC plant in the 300 MW size range compared to a scaled cost from a larger scale plant.
- Account 14 (Buildings & Structures) — As reflected in the capital cost summary tables, the Circulation Water Pumphouse was omitted due to the ACC replacing the wet mechanical draft cooling tower.
- 'Maintenance Material and Labor' costs in Case B12A [2] are 1.6 percent of TPC, distributed 40 percent to labor and 60 percent to material; all flexible plant cases match the distribution; Case B12A-F0 matches the 1.6 percent of TPC total.
- The number of 'Per-Shift' staff was reduced to align with 'total head count' figures and general staffing rules-of-thumb for similar sized plants (300 MW) based on Black & Veatch experience; plants of this size range will not typically have multiple lab techs staffed per shift; fewer techs would be expected to handle the amount of lab/processing data necessary for plant operations; 'Skilled Operators' are typically differentiated from 'Operators' by years of experience and ability to manage complex operational scenarios (e.g., startup, heavy cycling, emergency shutdowns).
- The SCR catalyst make-up rate would be expected to be consistent with a larger plant size due to the similar operating conditions (i.e., temperatures and normalized gas velocity across the catalyst and the likely similarity in chemical composition of the catalyst regardless of plant size (e.g., 685 MW or 300 MW).

5.7 Supercritical Flexible Plant Cases

This section contains an evaluation of plant designs for cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4, which are based on a supercritical flexible PC plant with a nominal gross output of 300 MWe. The plant uses a single reheat 24.1 MPa/593°C/593°C (3,500 psig/1,100°F/1,100°F) cycle.

The balance of this section is organized as follows:

- Key Assumptions is a summary of study and modeling assumptions relevant to cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4.
- Sparing Philosophy is provided for cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4.
- Process Description provides an overview of the technology operation as applied to Case B12A-F1. The systems that are common to all PC cases were covered in Section 5.2 and only features that are unique to Case B12A-F1 are discussed further in this section.
- Performance Results provides the main modeling results from Case B12A-F1, including the full load performance summary, part load performance summary, environmental performance, carbon/sulfur balances, water balance, energy and mass balance diagrams and energy balance table.
- Major Equipment List provides an itemized list of major equipment for Case B12A-F1 with account codes that correspond to the cost accounts in the Cost Estimates section.
- Cost Estimates provides a summary of capital and operating costs for Case B12A-F1.
- Process Description, Performance Results, Major Equipment List and Cost Estimates are discussed for cases B12A-F2, B12A-F3, and B12A-F4.

5.7.1 Key System Assumptions

System assumptions for cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4, as well as supercritical flexible PC plant with tiers 1–4 flexibility options are compiled in Exhibit 5-146. Some of these parameters vary as the plant reduces load. For the values of process parameters that vary with load, refer to the flexible case performance curves in Section A.7 through Section A.10.

Exhibit 5-146. Supercritical flexible PC plant study configuration matrix

Case	B12A-F1	B12A-F2	B12A-F3	B12A-F4
Steam Cycle, MPa/°C/°C (psig/°F/°F)	24.1/593/593 (3,500/1,100/1,100)			
Steam Turbine	Sliding-Pressure Main Steam, Triple-Pressure (HP/IP/LP), Single-Reheat, Single-Shaft, Condensing			
Coal	Illinois No. 6			
Condenser Type	Air Cooled			
Condenser Pressure, mm Hg (in. Hg)	76.2 (3)			
Auxiliary Cooling	Ancillary Air-to-Glycol Cooling Loops			
Feedwater Pump	Motor-Driven, Hydraulic Coupling		Motor-Driven, VFD	

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Case	B12A-F1	B12A-F2	B12A-F3	B12A-F4
Fan Drives	Static Frequency		VFD	
Boiler Efficiency, HHV %	87.5			
Stack Temperature, °C (°F)	57 (135)			
SO ₂ Control	Wet Limestone Forced Oxidation			
FGD Efficiency, % ^A	98			
FGD Blowdown Treatment (Effluent Limitation Guidelines)	Spray dryer evaporator			
NO _x Control	LNB w/OFA, SCR			
SCR Efficiency, % ^A	75.0			
Ammonia Slip (end of catalyst life), ppmv	2			
Particulate Control	Fabric Filter			
Fabric Filter Efficiency, % ^A	99.9			
Ash Distribution, Fly/Bottom	80%/20%			
SO ₃ Control	DSI			
Mercury Control	Co-benefit Capture and ACI			

^ARemoval efficiencies are based on the flue gas content

5.7.1.1 Balance of Plant – Cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4

The balance of plant assumptions are common for cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4 and are presented in Exhibit 5-147.

Exhibit 5-147. Cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4 balance of plant assumptions

Parameter	Value
Cooling System	Air-Cooled Condenser
Fuel and Other Storage	
Coal	30 days
Ash	30 days
Gypsum	30 days
Limestone	30 days
Hydrated lime	7 days
Activated carbon	7 days
Plant Distribution Voltage	
Motors below 1 hp	110/220 V
Motors between 1 hp and 250 hp	480 V
Motors between 250 hp and 5,000 hp	4,160 V
Motors above 5,000 hp	13,800 V

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Parameter	Value
Steam and CT generators	24,000 V
Grid Interconnection voltage	345 kV
<u>Water and Waste Water</u>	
Makeup Water	The water supply is 50 percent from a local POTW and 50 percent from groundwater and is assumed to be in sufficient quantities to meet plant makeup requirements. Makeup for potable, process, and deionized water is drawn from municipal sources.
Process Wastewater	Storm water that contacts equipment surfaces is collected and treated for discharge through a permitted discharge.
Sanitary Waste Disposal	Design includes a packaged domestic sewage treatment plant with effluent discharged to the industrial wastewater treatment system. Sludge is hauled off site. Packaged plant is sized for 5.68 cubic meters per day (1,500 gallons per day).
Water Discharge	Blowdown will be treated for chloride and metals and discharged to the spray dryer evaporator.

5.7.2 Sparing Philosophy

Single trains are used throughout the design with exceptions where equipment capacity requires an additional train. There is no redundancy other than normal sparing of rotating equipment. The plant design consists of the following major subsystems:

- One dry-bottom, wall-fired PC supercritical boiler (1 x 100%)
- Two SCR reactors (2 x 50%)
- One DSI system (1 x 100%)
- One ACI system (1 x 100%)
- Two single-stage, in-line, multi-compartment fabric filters (2 x 50%)
- One wet limestone forced oxidation positive pressure absorber (1 x 100%)
- One steam turbine (1 x 100%)

5.7.3 Process Description

The supercritical flexible PC process description is nearly identical to the supercritical baseload PC process description (see Section 5.3.3); therefore, it is not repeated here.

5.7.4 Case B12A-F1 – PC Supercritical Flexible Plant with Tier 1 Flexibility Options

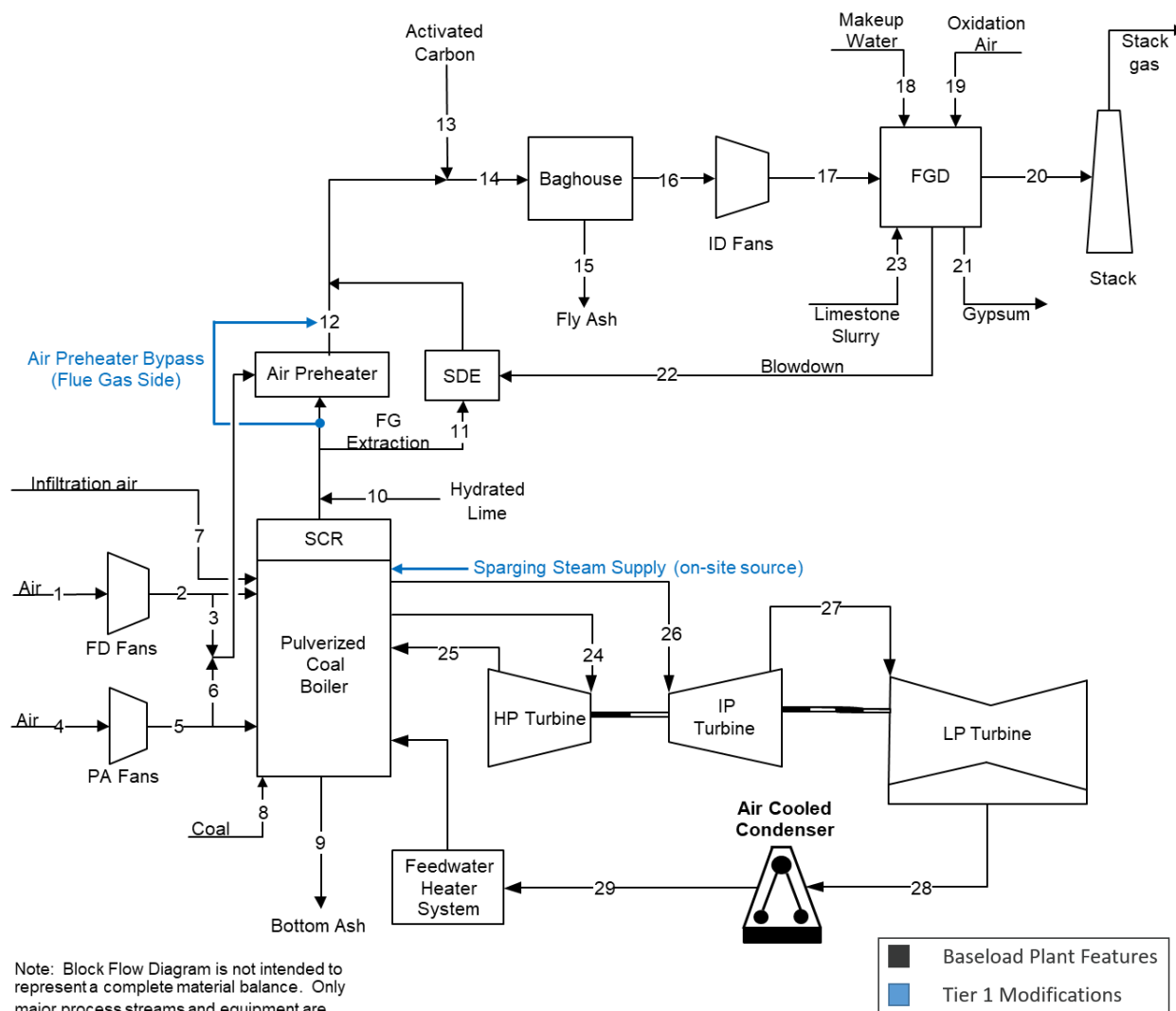
The plant configuration for Case B12A-F1, supercritical flexible plant with Tier 1 flexibility options, is similar to Case B12A-F0. Major modifications to the plant include the installation of a

flue gas side air preheater bypass, and installation of a sparging steam supply system. The full list of Tier 1 flexibility options was presented in Exhibit 4-14. The nominal gross plant output was maintained at 300 MW.

5.7.5 Case B12A-F1 – Full Load Performance Results

The BFD for Case B12A-F1 is shown in Exhibit 5-148. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 5-149. Full stream tables are only provided for the 100 percent load point.

Exhibit 5-148. Case B12A-F1 block flow diagram



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-149. Case B12A-F1 stream table, supercritical unit with Tier 1 flexibility options

	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	27,991	27,991	922	4,940	4,940	1,020	558	0	0	0
V-L Flowrate (kg/hr)	807,739	807,739	26,601	142,542	142,542	29,436	16,107	0	0	5
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	93,332	1,988	503
Temperature (°C)	15	21	21	15	23	23	15	15	1,316	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	36.30	36.30	30.23	38.73	38.73	30.23	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-91.51	-91.51	-97.58	-89.08	-89.08	-97.58	-2,119.02	1,312.68	-13,402.95
Density (kg/m ³)	1.2	1.3	1.3	1.2	1.3	1.3	1.2	---	---	1,003.6
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015
V-L Flowrate (lb _{mol} /hr)	61,710	61,710	2,032	10,890	10,890	2,249	1,231	0	0	1
V-L Flowrate (lb/hr)	1,780,761	1,780,761	58,645	314,252	314,252	64,895	35,509	0	0	11
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	205,762	4,383	1,109
Temperature (°F)	59	70	70	59	74	74	59	59	2,400	59
Pressure (psia)	14.7	15.6	15.6	14.7	16.0	16.0	14.7	14.7	14.3	14.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	15.6	15.6	13.0	16.7	16.7	13.0	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-39.3	-39.3	-42.0	-38.3	-38.3	-42.0	-911.0	564.3	-5,762.2
Density (lb/ft ³)	0.076	0.079	0.079	0.076	0.080	0.080	0.076	---	---	62.650

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-149. Case B12A-F1 stream table, supercritical unit with Tier 1 flexibility options, cont'd

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction										
Ar	0.0087	0.0088	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081
CO ₂	0.1463	0.1379	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0889	0.0844	0.0000	0.0918	0.0000	0.0918	0.0918	0.9967	0.0099	0.1512
HCl	0.0001	0.0001	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
N ₂	0.7312	0.7336	0.0000	0.7277	0.0000	0.7277	0.7277	0.0000	0.7732	0.6801
O ₂	0.0226	0.0332	0.0000	0.0325	0.0000	0.0325	0.0325	0.0000	0.2074	0.0360
SO ₂	0.0021	0.0020	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.1148	0.0000	0.0000	0.0006	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0001	0.8852	0.0000	0.0000	0.0028	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	1,683	33,672	0	35,639	2	35,637	35,637	4,964	1,506	39,846
V-L Flowrate (kg/hr)	50,050	999,637	0	1,054,937	230	1,054,701	1,054,701	90,827	43,466	1,144,972
Solids Flowrate (kg/hr)	431	8,122	20	8,654	8,659	0	0	816	0	0
Temperature (°C)	384	143	15	143	143	143	156	27	15	57
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	---	---	289.08	302.74	---	30.23	297.86
AspenPlus Enthalpy (kJ/kg) ^B	-2,278.03	-2,399.41	-6.79	-2,459.22	-1,001.46	-2,471.50	-2,457.84	-15,763.99	-97.58	-2,944.15
Density (kg/m ³)	0.5	0.8	---	0.8	2,150.2	0.8	0.9	1,002.4	1.2	1.1
V-L Molecular Weight	29.738	29.687	---	29.600	104.953	29.596	29.596	18.297	28.857	28.735
V-L Flowrate (lb _{mol} /hr)	3,710	74,235	0	78,571	5	78,566	78,566	10,944	3,321	87,845
V-L Flowrate (lb/hr)	110,342	2,203,822	0	2,325,737	508	2,325,217	2,325,217	200,240	95,826	2,524,231
Solids Flowrate (lb/hr)	950	17,907	45	19,078	19,090	0	0	1,799	0	0
Temperature (°F)	724	289	59	289	289	289	312	80	59	135
Pressure (psia)	14.3	14.0	14.7	14.0	14.0	13.8	15.1	14.7	14.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	---	---	124.3	130.2	---	13.0	128.1
AspenPlus Enthalpy (Btu/lb) ^B	-979.4	-1,031.6	-2.9	-1,057.3	-430.5	-1,062.6	-1,056.7	-6,777.3	-42.0	-1,265.8
Density (lb/ft ³)	0.033	0.052	---	0.051	134.232	0.051	0.054	62.580	0.076	0.067

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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Exhibit 5-149. Case B12A-F1 stream table, supercritical unit with Tier 1 flexibility options, cont'd

	21	22	23	24	25	26	27	28	29
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	85	284	1,171	48,442	36,579	36,579	32,721	28,585	32,818
V-L Flowrate (kg/hr)	1,526	5,249	21,096	872,699	658,981	658,981	589,472	514,974	591,220
Solids Flowrate (kg/hr)	13,727	80	9,031	0	0	0	0	0	0
Temperature (°C)	15	57	15	593	343	593	288	45	45
Pressure (MPa, abs)	0.10	0.10	0.10	24.23	4.85	4.11	0.51	0.01	1.31
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	3,477.96	3,052.30	3,658.08	3,037.83	2,403.96	191.45
AspenPlus Enthalpy (kJ/kg) ^B	-12,513.34	-15,495.43	-14,994.25	-12,502.33	-12,928.00	-12,322.21	-12,942.47	-13,576.33	-15,788.84
Density (kg/m ³)	880.9	979.4	1,003.7	69.2	18.9	10.5	2.0	0.1	990.5
V-L Molecular Weight	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	187	626	2,581	106,797	80,643	80,643	72,137	63,020	72,351
V-L Flowrate (lb/hr)	3,364	11,573	46,509	1,923,971	1,452,805	1,452,805	1,299,562	1,135,323	1,303,418
Solids Flowrate (lb/hr)	30,263	176	19,910	0	0	0	0	0	0
Temperature (°F)	59	135	59	1,100	649	1,100	550	114	114
Pressure (psia)	14.7	14.7	14.7	3,514.7	702.9	595.9	74.5	1.4	190.2
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	1,495.3	1,312.3	1,572.7	1,306.0	1,033.5	82.3
AspenPlus Enthalpy (Btu/lb) ^B	-5,379.8	-6,661.8	-6,446.4	-5,375.0	-5,558.0	-5,297.6	-5,564.3	-5,836.8	-6,788.0
Density (lb/ft ³)	54.996	61.143	62.658	4.319	1.181	0.655	0.126	0.004	61.838

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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At full load, the plant produces a net output of 273 MWe at a net plant efficiency of 38.8 percent (HHV basis). Full load performance for Case B12A-F1 is summarized in Exhibit 5-150. Exhibit 5-151 presents a detailed breakdown of auxiliary power requirements at full load.

Exhibit 5-150. Case B12A-F1 plant performance summary

Performance Summary	
Percent Load	100%
Total Gross Power, MWe	300
Nameplate Capacity, MWe	300
Total Auxiliaries, MWe	27
Total Auxiliaries, % of Gross Power	9.1%
Net Power, MWe	273
HHV Net Plant Efficiency, %	38.8%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,286 (8,802)
LHV Net Plant Efficiency, %	40.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,957 (8,490)
HHV Boiler Efficiency, %	87.5%
LHV Boiler Efficiency, %	90.7%
Steam Turbine Cycle Efficiency, %	48.8%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,384 (6,999)
Condenser Duty, GJ/hr (MMBtu/hr)	1,142 (1,082)
As-Received Coal Feed, kg/hr (lb/hr)	93,332 (205,762)
Limestone Sorbent Feed, kg/hr (lb/hr)	9,031 (19,910)
HHV Thermal Input, kWt	703,493
LHV Thermal Input, kWt	678,528
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (0.9)
Excess Air, %	20.0%

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Exhibit 5-151. Case B12A-F1 plant power summary

Power Summary	
Percent Load	100%
Steam Turbine Power, MWe	300
Total Gross Power, MWe	300
Nameplate Capacity	300
Auxiliary Load Summary	
Activated Carbon Injection, kWe	14
Air Cooled Condenser Fans	3,580
Ancillary Glycol Cooling Loops	250
Ash Handling, kWe	315
Baghouse, kWe	42
Boiler Circulation Pump, kWe	0
Boiler Feedwater Pump, kWe	11,040
Coal Handling and Conveying, kWe	200
Condensate Pumps, kWe	286
Dry Sorbent Injection, kWe	25
Flue Gas Desulfurizer, kWe	1,440
Forced Draft Fans, kWe	1,410
Ground Water Pumps, kWe	24
Induced Draft Fans, kWe	4,150
Miscellaneous Balance of Plant, ^A kWe	1,250
Primary Air Fans, kWe	355
Pulverizers, kWe	1,030
SCR, kWe	15
Sorbent Handling & Reagent Preparation, kWe	435
Spray Dryer Evaporator, kWe	103
Steam Turbine Auxiliaries, kWe	350
Transformer Losses, kWe	970
Total Auxiliaries, MWe	27
Net Power, MWe	273

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

5.7.5.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B12A-F1 is presented in Exhibit 5-152. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

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Exhibit 5-152. Case B12A-F1 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	654 (721)	0.293 (0.645)
NO _x	0.038 (0.087)	709 (782)	0.318 (0.700)
Particulate	0.005 (0.011)	91 (101)	0.041 (0.090)
Hg	1.61E-7 (3.75E-7)	0.003 (0.003)	1.36E-6 (3.00E-6)
CO ₂	86 (201)	1,625,746 (1,792,078)	728 (1,605)
CO ₂ ^C	-	-	801 (1,765)
mg/Nm ³			
Particulate Concentration ^{D,E}	15.34		

^A Calculations based on an 85% capacity factor

^B Emissions based on gross power, except where otherwise noted

^C CO₂ emissions based on net power instead of gross power

^D Concentration of particles in the flue gas after the baghouse

^E Normal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.35 lb/MMBtu using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 75.0 percent to about 0.09 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and FGD system) is 94.5 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 5-153. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-153. Case B12A-F1 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	59,494 (131,162)	Stack Gas	59,588 (131,369)
Air (CO ₂)	137 (303)	FGD Product	71 (156)
PAC	20 (45)	Baghouse	732 (1,614)
FGD Reagent	916 (2,020)	Bottom Ash	178 (392)
Total	60,568 (133,531)	Total	60,568 (133,531)

Exhibit 5-154 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-154. Case B12A-F1 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	2,339 (5,157)	FGD Product	2,200 (4,850)
		Stack Gas	46 (101)
		Baghouse	94 (206)
Total	2,339 (5,157)	Total	2,339 (5,157)

Exhibit 5-155 shows the water balance for Case B12A-F1.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is reused as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from ground water. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

Exhibit 5-155. Case B12A-F1 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Desulfurizer Makeup	1.0 (257)	–	1.0 (257)	–	1.0 (257)
Deaerator Vent	–	–	–	0.0 (7.7)	0.0 (-7.7)
Condenser Makeup	0.0 (7.7)	–	0.0 (7.7)	–	0.0 (7.7)
BFW Makeup	0.0 (7.7)	–	0.0 (7.7)	–	0.0 (7.7)
Cooling Tower	–	–	–	–	–
BFW Blowdown	–	–	–	–	–
Total	1.0 (265)	–	1.0 (265)	0.0 (7.7)	1.0 (257)

5.7.5.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B12A-F1 PC boiler, the FGD unit, and steam cycle as shown in Exhibit 5-156 and Exhibit 5-157.

An overall plant energy balance is provided in tabular form in Exhibit 5-158. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-150) is calculated by multiplying the power out by the full load generator efficiency of 98.5 percent.

Exhibit 5-156. Case B12A-F1 energy and mass balance, supercritical PC boiler

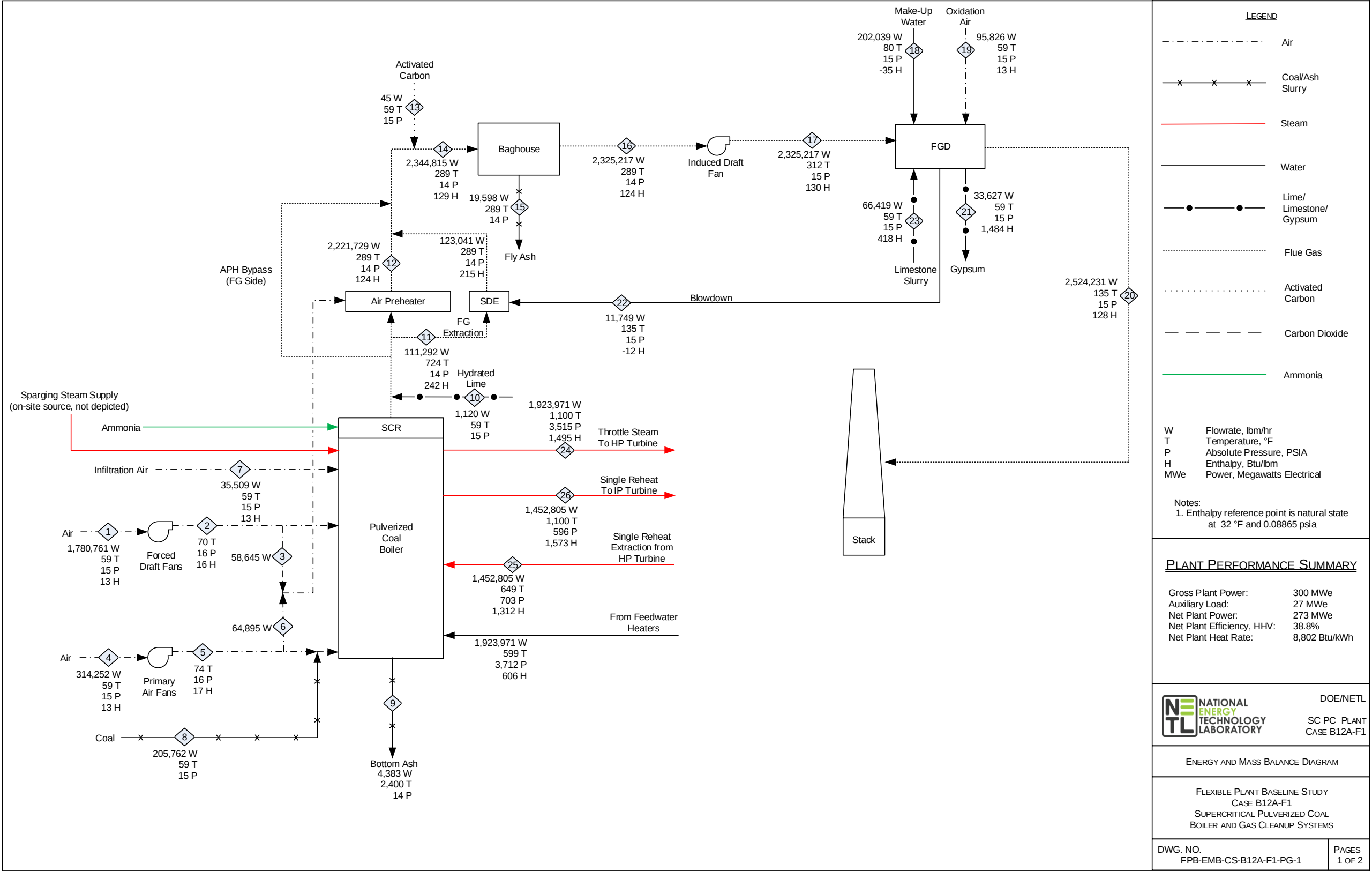
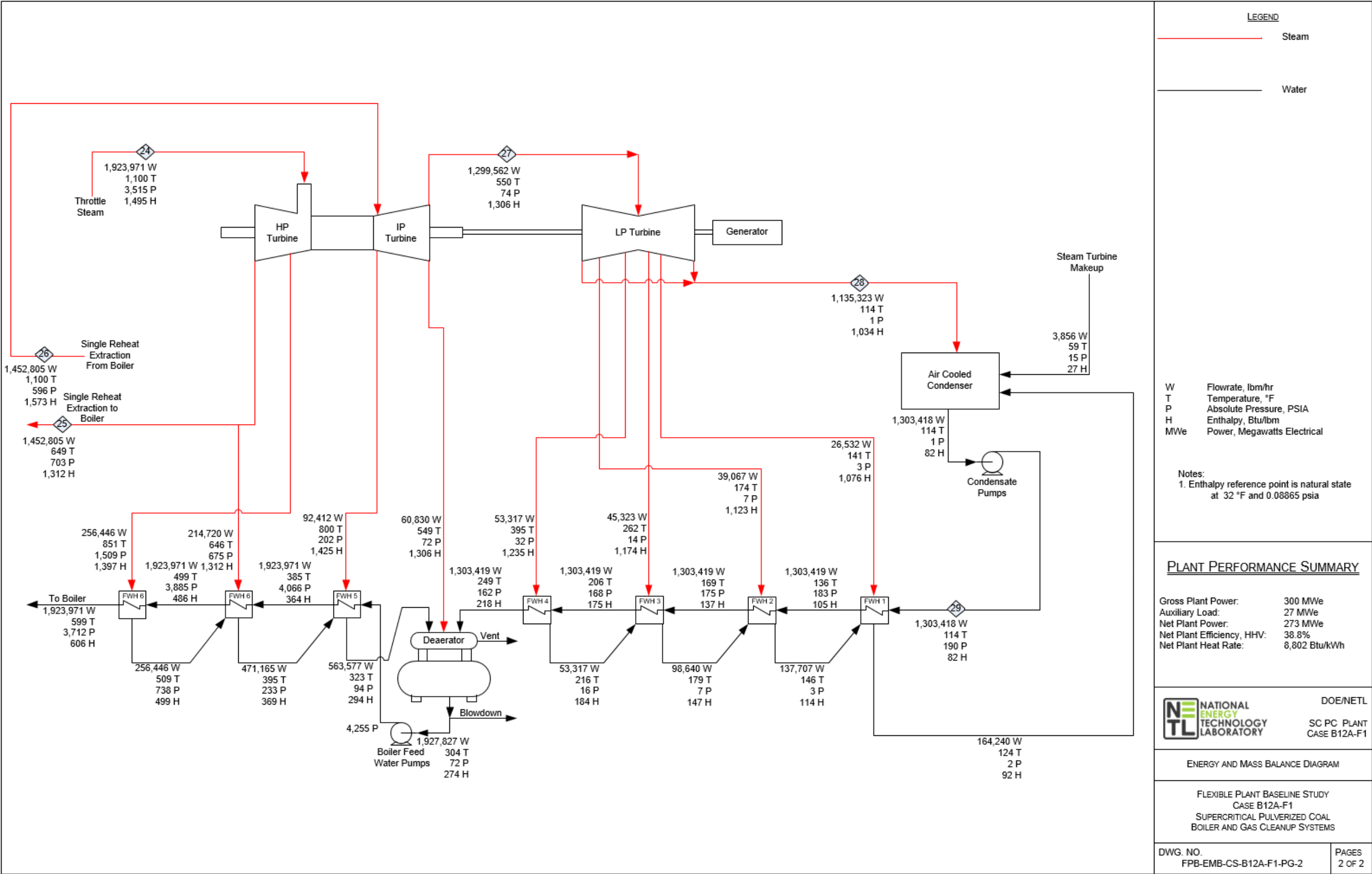


Exhibit 5-157. Case B12A-F1 energy and mass balance, supercritical steam cycle



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Exhibit 5-158. Case B12A-F1 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	2,533 (2,400)	2.1 (2.0)	–	2,535 (2,402)
Air	–	29 (28)	–	29 (28)
Raw Water Makeup	–	3.8 (3.6)	–	3.8 (3.6)
Limestone	–	0.2 (0.2)	–	0.2 (0.2)
Auxiliary Power	–	–	98 (93)	98 (93)
Total	2,533 (2,400)	35 (33)	98 (93)	2,666 (2,527)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	2.6 (2.5)	–	2.6 (2.5)
Fly Ash	–	0.9 (0.9)	–	0.9 (0.9)
Stack Gas	–	341 (323)	–	341 (323)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Gypsum	–	0.9 (0.8)	–	0.9 (0.8)
Motor Losses and Design Allowances	–	–	17 (16)	17 (16)
Air Cooled Condenser Load ^A	–	1,142 (1,082)	–	1,142 (1,082)
Blowdown Streams and Deaerator Vent	–	1.1 (1.1)	–	1.1 (1.1)
<i>Ambient Losses^B</i>	–	68 (65)	–	68 (65)
Power	–	–	1,080 (1,024)	1,080 (1,024)
Total	0.0 (0.0)	1,557 (1,476)	1,097 (1,040)	2,654 (2,516)
<i>Unaccounted Energy^C</i>	–	–	–	12 (11)

^A Includes condenser load only

^B Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^C By difference

5.7.6 Case B12A-F1 – Part Load Performance Results

Plant performance results are summarized at each discrete load point in Exhibit 5-159. Exhibit 5-160 displays a detailed breakdown of the auxiliary power requirement at each discrete load point. Air emissions at each discrete load point are summarized in Exhibit 5-161.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-159. Case B12A-F1 part load plant performance summary

Performance Summary					
Percent Load	100%	75%	50%	30%	20%
Total Gross Power, MWe	300	225	150	90	60
Nameplate Capacity, MWe	300	300	300	300	300
Total Auxiliaries, MWe	27	20	14	9	7
Total Auxiliaries, % of Gross Power	9.1%	9.1%	9.5%	10.5%	11.5%
Net Power, MWe	273	205	136	81	53
HHV Net Plant Efficiency, %	38.8%	38.1%	36.8%	34.9%	33.5%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,286 (8,802)	9,461 (8,967)	9,788 (9,277)	10,302 (9,764)	10,756 (10,195)
LHV Net Plant Efficiency, %	40.2%	39.5%	38.1%	36.2%	34.7%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,957 (8,490)	9,125 (8,649)	9,441 (8,948)	9,936 (9,418)	10,375 (9,833)
HHV Boiler Efficiency, %	87.5%	87.5%	87.6%	87.6%	87.7%
LHV Boiler Efficiency, %	90.7%	90.7%	90.8%	90.9%	90.9%
Steam Turbine Cycle Efficiency, %	48.8%	47.8%	46.4%	44.6%	43.2%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,384 (6,999)	7,526 (7,133)	7,757 (7,352)	8,078 (7,656)	8,342 (7,907)
Condenser Duty, GJ/hr (MMBtu/hr)	1,142 (1,082)	881 (835)	617 (585)	397 (377)	280 (266)
As-Received Coal Feed, kg/hr (lb/hr)	93,332 (205,762)	71,309 (157,209)	48,964 (107,947)	30,573 (67,403)	21,042 (46,390)
Limestone Sorbent Feed, kg/hr (lb/hr)	9,031 (19,910)	6,914 (15,243)	4,767 (10,509)	2,990 (6,593)	2,064 (4,551)
HHV Thermal Input, kWt	703,493	537,493	369,068	230,447	158,607
LHV Thermal Input, kWt	678,528	518,419	355,971	222,269	152,978
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)	0.004 (1.0)	0.004 (1.0)	0.004 (1.0)	0.004 (1.1)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (0.9)	0.004 (1.0)	0.004 (1.0)	0.004 (0.9)	0.004 (1.0)
Excess Air, %	20.0%	22.1%	26.9%	33.0%	37.0%

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Exhibit 5-160. Case B12A-F1 part load plant power summary

Power Summary					
Percent Load	100%	75%	50%	30%	20%
Steam Turbine Power, MWe	300	225	150	90	60
Total Gross Power, MWe	300	225	150	90	60
Nameplate Capacity, MWe	300	300	300	300	300
Auxiliary Load Summary					
Activated Carbon Injection, kWe	14	10	7	5	3
Air Cooled Condenser Fans, kWe	3,580	3,570	2,510	1,500	930
Ancillary Glycol Cooling Loops, kWe	250	250	250	250	250
Ash Handling, kWe	315	238	160	98	66
Baghouse, kWe	42	32	21	13	9
Boiler Circulation Pump, kWe	0	0	0	83	55
Boiler Feedwater Pump, kWe	11,040	6,450	3,540	1,890	1,210
Coal Handling and Conveying, kWe	200	150	110	70	50
Condensate Pumps, kWe	286	187	123	82	61
Dry Sorbent Injection, kWe	25	18	10	5	3
Flue Gas Desulfurizer, kWe	1,440	1,310	1,280	1,100	890
Forced Draft Fans, kWe	1,410	1,150	820	460	250
Ground Water Pumps, kWe	24	18	14	9	7
Induced Draft Fans, kWe	4,150	3,260	2,270	1,380	920
Miscellaneous Balance of Plant, ^A kWe	1,250	1,250	1,250	1,250	1,250
Primary Air Fans, kWe	355	295	220	101	55
Pulverizers, kWe	1,030	790	540	340	230
SCR, kWe	15	13	10	7	5
Sorbent Handling and Reagent Preparation, kWe	435	333	230	144	99
Spray Dryer Evaporator, kWe	103	78	54	33	23
Steam Turbine Auxiliaries, kWe	350	350	350	350	350
Transformer Losses, kWe	970	730	490	300	200
Total Auxiliaries, MWe	27	20	14	9	7
Net Power, MWe	273	205	136	81	53

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-161. Case B12A-F1 part load air emissions summary

Emissions Summary					
Percent Load	100%	75%	50%	30%	20%
SO ₂ , kg/MWhgross (lb/MWhgross)	0.293 (0.645)	0.299 (0.659)	0.309 (0.681)	0.323 (0.712)	0.335 (0.738)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	728 (1,605)	742 (1,636)	766 (1,688)	799 (1,761)	826 (1,821)
CO ₂ , kg/MWhnet (lb/MWhnet)	801 (1,765)	816 (1,800)	846 (1,866)	893 (1,968)	934 (2,058)
Particulate Concentration, ^{A,B} mg/Nm ³	15.34	14.81	13.84	12.70	11.95

^A Concentration of particles in the flue gas after the baghouse

^B Normal conditions given at 32°F and 14.696 psia

Case B12A-F1 air emissions remained below the environmental target emission limits across the entire load range. Hg, NO_x, and PM emissions are maintained at constant levels across the load. SO₂ emissions increase as load is reduced but are kept below the environmental target emission limit.

Exhibit 5-162 displays the Case B12A-F1 itemized efficiencies (HHV net plant efficiency, HHV boiler efficiency, and steam cycle efficiency) and normalized auxiliary power consumption across the load range.

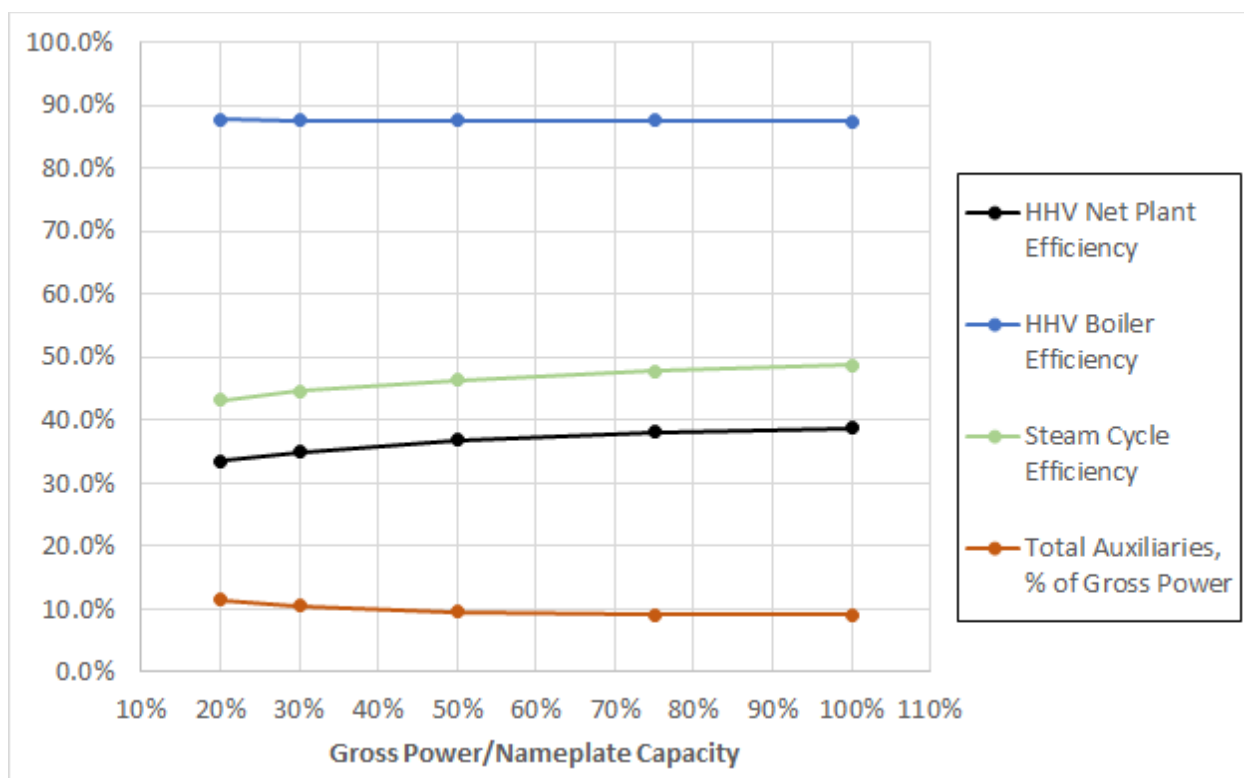
Itemized efficiencies exhibit trends similar to those of Case B12A-F0. HHV net plant efficiency and steam cycle efficiency decrease as load is reduced, while HHV boiler efficiency improves slightly. However, compared to Case B12A-F0, the HHV net plant efficiency and steam cycle efficiency experience a smaller penalty as load is reduced.

No flexibility options were implemented that impacted the modeled boiler efficiency, and it remains consistent with Case B12A-F0.

The improvement in the part load steam cycle efficiency is due primarily to the implementation of an electric driven BFW pump. Utilizing an electric driven BFW pump rather than a steam driven BFW pump eliminates the steam extraction required for the BFW pump steam turbine. Instead, the BFW pump power requirement is considered an auxiliary load and consequently no longer impacts the steam cycle efficiency.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-162. Case B12A-F1 part load itemized efficiencies



5.7.7 Case B12A-F1 – Major Equipment List

Case B12A-F1 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	20 tonne (20 ton)	2	1
9	Feeder	Vibratory	80 tonne/hr (80 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	150 tonne/hr (170 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	80 tonne (80 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	150 tonne/hr (170 tph)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Coal Silo w/ Vent Filter and Slide Gates	Field erected	340 tonne (400 ton)	3	0
18	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 4 tonne (4 ton) Feeder - 20 kg/hr (50 lb/hr)	1	0
19	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 90 tonne (100 ton) Feeder - 560 kg/hr (1,230 lb/hr)	1	0
20	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
21	Limestone Feeder	Belt	38 tonne/hr (42 tph)	1	0
22	Limestone Conveyor No. 1	Belt	38 tonne/hr (42 tph)	1	0
23	Limestone Reclaim Hopper	N/A	7 tonne (8 ton)	1	0
24	Limestone Reclaim Feeder	Belt	30 tonne/hr (33 tph)	1	0
25	Limestone Conveyor No. 2	Belt	30 tonne/hr (33 tph)	1	0
26	Limestone Day Bin	w/ actuator	119 tonne (131 ton)	2	0

Case B12A-F1 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	17 tonne/hr (19 tph)	6	0
2	Coal Pulverizer	Rotary (Vertical)	17 tonne/hr (19 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	10 tonne/hr (11 tph)	1	1
4	Limestone Ball Mill	Rotary	10 tonne/hr (11 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	38,600 liters (10,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	650 lpm @ 10m H ₂ O (170 gpm @ 40 ft H ₂ O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	160 lpm (40 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	215,000 liters (57,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	450 lpm @ 9m H ₂ O (120 gpm @ 30 ft H ₂ O)	1	1

Case B12A-F1 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	116,000 liters (31,000 gal)	2	0
2	Condensate Pumps	Vertical canned	10,900 lpm @ 200 m H ₂ O (2,900 gpm @ 500 ft H ₂ O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	962,000 kg/hr (2,121,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump	Barrel type, multi-stage, centrifugal	16,100 lpm @ 3,600 m H ₂ O (4,300 gpm @ 11,700 ft H ₂ O)	1	1
5	N/A				

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	960,000 kg/hr (2,120,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	960,000 kg/hr (2,120,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	960,000 kg/hr (2,120,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m³/min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m³/min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	37 GJ/hr (35 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	14,600 lpm @ 30 m H ₂ O (3,900 gpm @ 100 ft H ₂ O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	240 lpm @ 20 m H ₂ O (60 gpm @ 60 ft H ₂ O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	240 lpm @ 270 m H ₂ O (60 gpm @ 880 ft H ₂ O)	2	1
23	Filtered Water Pumps	Stainless steel, single suction	500 lpm @ 50 m H ₂ O (130 gpm @ 160 ft H ₂ O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	480,000 liter (127,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 870 m³/min (30,550 acfm) @ 384°C (724°F) & 0.1 MPa (14 psia) Blowdown - 50 lpm (10 gpm) @ 20,020 ppmw Cl ⁻	2	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case B12A-F1 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	960,000 kg/hr steam @ 24.1 MPa/593°C/593°C (2,120,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	78,000 kg/hr, 1,100 m ³ /min @ 107 cm WG (173,000 lb/hr, 37,800 acfm @ 42 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	444,000 kg/hr, 6,100 m ³ /min @ 76 cm WG (979,000 lb/hr, 214,100 acfm @ 30 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	580,000 kg/hr, 11,900 m ³ /min @ 116 cm WG (1,279,000 lb/hr, 420,400 acfm @ 46 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	1,090,000 kg/hr (2,410,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	40 m ³ /min @ 108 cm WG (1,400 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	45,000 liter (12,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	9 lpm @ 90 m H ₂ O (2 gpm @ 300 ft H ₂ O)	2	1

Case B12A-F1 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	580,000 kg/hr (1,279,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	20,000 m ³ /min (695,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	114,000 lpm @ 65 m H ₂ O (30,000 gpm @ 210 ft H ₂ O)	3	1
4	Bleed Pumps	Horizontal centrifugal	1,910 lpm (500 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	330 m ³ /min @ 0.3 MPa (11,520 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	470 lpm (130 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	15 tonne/hr (17 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	290 lpm @ 13 m H ₂ O (80 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	190,000 lpm (50,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	680 lpm @ 21 m H ₂ O (180 gpm @ 70 ft H ₂ O)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Activated Carbon Injectors	---	20 kg/hr (50 lb/hr)	1	0
13	Hydrated Lime Injectors	---	560 kg/hr (1,230 lb/hr)	1	0

Case B12A-F1 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	122 m (400 ft) high x 4.1 m (14 ft) diameter	1	0

Case B12A-F1 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	311 MW 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Air-cooled Condenser	Forced draft, direct, A-frame air-cooled condenser	1,260 GJ/hr (1,190 MMBtu/hr), Condensing temperature 45°C (114°F), Ambient temperature 15°C (59°F)	1	0

Case B12A-F1 – Account 9: Auxiliary Cooling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Glycol Cooling Loops	Industrial grade, air to glycol, closed loop heat exchanger	10 GJ/hr (14 MMBtu/hr) heat duty	5	0

Case B12A-F1 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	—	—	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	—	—	2	0
3	Clinker Grinder	—	2.2 tonne/hr (2.4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	—	—	6	0
5	Pyrites Transfer Tank	—	—	1	0
6	Pyrite Reject Water Pump	—	—	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	—	4	0
8	Bottom Ash Storage Silo	—	—	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	—	—	12	0
10	Air Heater Hopper (part of boiler scope of supply)	—	—	10	0
11	Air Blower	—	9 m ³ /min @ 0.2 MPa (310 scfm @ 24 psi)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Fly Ash Silo	Reinforced concrete	580 tonne (640 ton)	2	0
13	Slide Gate Valves	—	—	2	0
14	Unloader	—	—	1	0
15	Telescoping Unloading Chute	—	50 tonne/hr (60 tph)	1	0

Case B12A-F1 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 310 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 25 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Generator	Sized for black start capability	3500 kW, 480 V, 3-ph, 60 Hz	2	0

Case B12A-F1 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers, alarm management, HMIs, data historian, hard-wired control interface panels, and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor cabinets with redundant input/output, I/O cabinets, various I/C buses	Spare 25% I/O and processor bandwidth	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant	1	0

The following items represent the modifications to the major equipment categories for the Case B12A-F1 design basis, along with narrative regarding process description modifications. The Case B12A-F1 plant design includes the design features of Case B12A-F0 with the following modifications:

- **Account 2 — Coal and Sorbent Preparation and Feed**
 - Mill quantity estimated to increase from four for the baseload plant to approximately six for the Case B12A-F1 flexible plant

- Increased (vertical roller) mill quantity will operate in a similar manner/philosophy compared to the baseload plant from a startup, shutdown and load change perspective; as outlined in the literature summary, there is a significant accumulation of mill operation best practices from existing coal-fired EGUs that include the operational of the mill shutdown scheme on SCR inlet temperatures, flame stability, radiant section coal ash slagging and steam temperatures. [24] [40]
- Increased number of mills will allow for lower burner-level heat release (BLHR) (MBtu/hr/ft^2), which allows for more granular low-load heat release control; based on Black & Veatch experience with evaluating boiler design parameters, lowering the BLHR allows for more even dispersion of the burner heat release, which leads to improvement heat absorption patterns in the radiant section of the boiler and is viewed as a means of proactively reducing the ash slagging buildup severity.
- **Account 3 — Feedwater and Miscellaneous System and Equipment**
 - Steam-driven BFW pump replaced with medium-voltage electric-driven BFW pump
 - Steam extraction for previous BFP turbine is eliminated.
 - The BFP electric motor operates at a constant speed with the shaft speed of the BFP modulated mechanically through use of a hydraulic coupling and/or planetary gear set.
 - Feedwater system control valves modulate the pressure to the desired operating point during the sliding pressure operation.
 - This mechanical speed modulation provides pump efficiency improvements by eliminating throttling as a means of pressure control in exchange for speed control; the hydraulic coupling will exhibit reduced mechanical efficiency at significantly reduced loads (leading to the implementation of the VFD components in Tier 3).
 - Varying the shaft speed of the BFP modulates the pressure to the desired operating point during the sliding pressure operation.
 - Additional equipment added to natural gas auxiliary boiler and balance of plant to provide sparging steam.
- **Account 4 — Boiler and Accessories**
 - The economizer, SCR, and air heater gas-side bypasses can be implemented via small/moderate duct runs and control damper(s); no significant major equipment added; air heater air-side bypass achieved in a similar manner; economizer water-side bypass similarly can be equipped with small/moderate piping and control valve additions (no significant major equipment necessary).

- All bypass functionality is operated in order to maintain water/flue gas temperature set points established within the control system; these bypass systems will likely be utilized predominantly during startup/shutdown and reduced (<50%) load conditions.
- **Account 11 — Accessory Electric Plant**
 - Emergency diesel (or natural gas) generator would likely be increased in size (from current rating of 750 kW) to allow for plant black start capability.
 - Operation of the emergency reciprocating engine generator will largely be consistent with the functionality outlined in the baseload plant design; the notable change will be that the reciprocating engine generator outlined by Case B12A-F1 will be upsized for an increased nameplate capacity, equipped with larger battery storage units, and equipped with suitable switchgear to allow for full black start capabilities.
 - A 5,000 kW generator was selected for Case B11A-F1. For Case B12A-F1, a 2 x 3,500 kW configuration was selected to avoid having to use a generator larger than 5,000 kW which falls into a 'medium-speed' application which is not recommended. This also provides redundancy for Case B12A-F1.
 - EGUs equipping these reciprocating engine generator units in the past 10–15 years have advanced the operational maturity of the technology and have developed a broad OEM base for these units across various fuel (diesel and/or natural gas) and operational demand (continuous or standby) bases, based on Black & Veatch experience with this technology.

5.7.8 Case B12A-F1 – Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-163 shows a detailed breakdown of the capital costs; Exhibit 5-164 shows the owner's costs, along with the TOC; and Exhibit 5-165 shows the initial and annual O&M costs.

The estimated TPC of the Case B12A-F1 plant is \$703 million. The project contingency is 13.3 percent of the TPC.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-163. Case B12A-F1 total plant cost summary

Case:		B12A-F1	Supercritical PC Flexible Plant (Tier 1)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	
1		Coal & Sorbent Handling								
1.1	Coal Receive & Unload	\$422	\$0	\$190	\$0	\$613	\$107	\$0	\$108	\$828
1.2	Coal Stackout & Reclaim	\$1,387	\$0	\$310	\$0	\$1,697	\$297	\$0	\$299	\$2,293
1.3	Coal Conveyors	\$14,731	\$0	\$3,505	\$0	\$18,236	\$3,191	\$0	\$3,214	\$24,641
1.4	Other Coal Handling	\$1,640	\$0	\$345	\$0	\$1,985	\$347	\$0	\$350	\$2,682
1.5	Sorbent Receive & Unload	\$96	\$0	\$29	\$0	\$125	\$22	\$0	\$22	\$169
1.6	Sorbent Stackout & Reclaim	\$523	\$0	\$95	\$0	\$618	\$108	\$0	\$109	\$835
1.7	Sorbent Conveyors	\$929	\$202	\$225	\$0	\$1,356	\$237	\$0	\$239	\$1,832
1.8	Other Sorbent Handling	\$55	\$13	\$28	\$0	\$96	\$17	\$0	\$17	\$129
1.9	Coal & Sorbent Handling Foundations	\$0	\$681	\$898	\$0	\$1,579	\$276	\$0	\$278	\$2,134
	Subtotal	\$19,784	\$896	\$5,624	\$0	\$26,304	\$4,603	\$0	\$4,636	\$35,543
2		Coal & Sorbent Preparation & Feed								
2.1	Coal Crushing & Drying	\$899	\$0	\$173	\$0	\$1,072	\$188	\$0	\$189	\$1,448
2.2	Prepared Coal Storage & Feed	\$3,160	\$0	\$680	\$0	\$3,841	\$672	\$0	\$677	\$5,190
2.5	Sorbent Preparation Equipment	\$397	\$17	\$81	\$0	\$495	\$87	\$0	\$87	\$669
2.6	Sorbent Storage & Feed	\$640	\$0	\$241	\$0	\$881	\$154	\$0	\$155	\$1,190
2.9	Coal & Sorbent Feed Foundation	\$0	\$262	\$230	\$0	\$491	\$86	\$0	\$87	\$664
	Subtotal	\$5,096	\$279	\$1,405	\$0	\$6,780	\$1,187	\$0	\$1,195	\$9,162
3		Feedwater & Miscellaneous BOP Systems								
3.1	Feedwater System	\$1,361	\$2,333	\$1,167	\$0	\$4,861	\$851	\$0	\$857	\$6,568
3.2	Water Makeup & Pretreating	\$2,168	\$217	\$1,228	\$0	\$3,613	\$632	\$0	\$849	\$5,095
3.3	Other Feedwater Subsystems	\$884	\$290	\$275	\$0	\$1,449	\$254	\$0	\$255	\$1,958
3.4	Service Water Systems	\$607	\$1,159	\$3,752	\$0	\$5,517	\$966	\$0	\$1,297	\$7,779
3.5	Other Boiler Plant Systems	\$269	\$98	\$245	\$0	\$612	\$107	\$0	\$108	\$826
3.6	Natural Gas Pipeline and Start-Up System	\$1,315	\$57	\$42	\$0	\$1,414	\$247	\$0	\$249	\$1,911
3.7	Waste Water Treatment Equipment	\$3,403	\$0	\$2,086	\$0	\$5,489	\$961	\$0	\$1,290	\$7,740
3.8	Spray Dryer Evaporator	\$6,399	\$0	\$3,705	\$0	\$10,105	\$1,768	\$0	\$2,375	\$14,248
3.9	Miscellaneous Plant Equipment	\$89	\$12	\$45	\$0	\$146	\$25	\$0	\$34	\$205
	Subtotal	\$16,495	\$4,164	\$12,546	\$0	\$33,205	\$5,811	\$0	\$7,314	\$46,330
4		Pulverized Coal Boiler & Accessories								
4.9	Pulverized Coal Boiler & Accessories	\$129,677	\$0	\$84,686	\$0	\$214,363	\$37,514	\$0	\$37,782	\$289,659
4.10	Selective Catalytic Reduction System	\$8,758	\$0	\$5,720	\$0	\$14,478	\$2,534	\$0	\$2,552	\$19,563
4.11	Boiler Balance of Plant	\$477	\$0	\$311	\$0	\$788	\$138	\$0	\$139	\$1,065
4.12	Primary Air System	\$523	\$0	\$342	\$0	\$865	\$151	\$0	\$152	\$1,169
4.13	Secondary Air System	\$1,063	\$0	\$694	\$0	\$1,757	\$307	\$0	\$310	\$2,374
4.14	Induced Draft Fans	\$1,992	\$0	\$1,301	\$0	\$3,293	\$576	\$0	\$580	\$4,450
4.15	Major Component Rigging	\$34	\$0	\$22	\$0	\$56	\$10	\$0	\$10	\$76

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B12A-F1	Supercritical PC Flexible Plant (Tier 1)				Estimate Type: Cost Base:			Conceptual Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost \$/1,000
				Direct	Indirect			Process	Project	
4.16	Boiler Foundations	\$0	\$142	\$125	\$0	\$266	\$47	\$0	\$47	\$360
	Subtotal	\$142,524	\$142	\$93,201	\$0	\$235,867	\$41,277	\$0	\$41,572	\$318,715
5		Flue Gas Cleanup								
5.2	WFGD Absorber Vessels & Accessories	\$34,246	\$0	\$7,322	\$0	\$41,568	\$7,274	\$0	\$7,326	\$56,169
5.3	Other FGD	\$119	\$0	\$134	\$0	\$253	\$44	\$0	\$45	\$342
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$978	\$215	\$962	\$0	\$2,155	\$377	\$0	\$380	\$2,912
5.9	Particulate Removal (Bag House & Accessories)	\$1,133	\$0	\$714	\$0	\$1,847	\$323	\$0	\$326	\$2,496
5.12	Gas Cleanup Foundations	\$0	\$61	\$54	\$0	\$115	\$20	\$0	\$20	\$155
5.13	Gypsum Dewatering System	\$309	\$0	\$52	\$0	\$361	\$63	\$0	\$64	\$487
	Subtotal	\$36,785	\$276	\$9,238	\$0	\$46,299	\$8,102	\$0	\$8,160	\$62,562
7		Ductwork & Stack								
7.3	Ductwork	\$0	\$323	\$225	\$0	\$548	\$96	\$0	\$97	\$741
7.4	Stack	\$4,093	\$0	\$2,378	\$0	\$6,471	\$1,132	\$0	\$1,141	\$8,744
7.5	Duct & Stack Foundations	\$0	\$77	\$92	\$0	\$169	\$30	\$0	\$40	\$238
	Subtotal	\$4,093	\$401	\$2,695	\$0	\$7,188	\$1,258	\$0	\$1,277	\$9,723
8		Steam Turbine & Accessories								
8.1	Steam Turbine Generator & Accessories	\$41,057	\$0	\$4,616	\$0	\$45,673	\$7,993	\$0	\$8,050	\$61,716
8.2	Steam Turbine Plant Auxiliaries	\$819	\$0	\$1,742	\$0	\$2,561	\$448	\$0	\$451	\$3,460
8.3	Condenser & Auxiliaries ^A	\$15,483	\$0	\$5,253	\$0	\$20,737	\$3,629	\$0	\$3,655	\$28,021
8.4	Steam Piping	\$16,174	\$0	\$6,555	\$0	\$22,729	\$3,978	\$0	\$4,006	\$30,713
8.5	Turbine Generator Foundations	\$0	\$86	\$142	\$0	\$228	\$40	\$0	\$54	\$322
	Subtotal	\$73,534	\$86	\$18,308	\$0	\$91,928	\$16,087	\$0	\$16,216	\$124,231
9		Cooling Water System								
9.6	Component Cooling Water System ^B	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
	Subtotal	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
10		Ash & Spent Sorbent Handling Systems								
10.6	Ash Storage Silos	\$466	\$0	\$1,426	\$0	\$1,892	\$331	\$0	\$333	\$2,556
10.7	Ash Transport & Feed Equipment	\$1,749	\$0	\$1,733	\$0	\$3,482	\$609	\$0	\$614	\$4,705
10.9	Ash/Spent Sorbent Foundation	\$0	\$299	\$367	\$0	\$665	\$116	\$0	\$156	\$938
	Subtotal	\$2,215	\$299	\$3,526	\$0	\$6,039	\$1,057	\$0	\$1,103	\$8,199
11		Accessory Electric Plant								
11.1	Generator Equipment	\$1,473	\$0	\$1,111	\$0	\$2,585	\$452	\$0	\$456	\$3,493
11.2	Station Service Equipment	\$2,623	\$0	\$225	\$0	\$2,848	\$498	\$0	\$502	\$3,848
11.3	Switchgear & Motor Control	\$4,365	\$0	\$757	\$0	\$5,122	\$896	\$0	\$903	\$6,921
11.4	Conduit & Cable Tray	\$0	\$592	\$1,705	\$0	\$2,297	\$402	\$0	\$405	\$3,103
11.5	Wire & Cable	\$0	\$1,164	\$2,080	\$0	\$3,244	\$568	\$0	\$572	\$4,383
11.6	Protective Equipment	\$32	\$0	\$111	\$0	\$144	\$25	\$0	\$25	\$194
11.7	Standby Equipment	\$417	\$0	\$385	\$0	\$801	\$140	\$0	\$141	\$1,083

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B12A-F1	Supercritical PC Flexible Plant (Tier 1)				Estimate Type: Cost Base:			Conceptual Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	
11.8	Main Power Transformers	\$3,929	\$0	\$80	\$0	\$4,009	\$702	\$0	\$707	\$5,417
11.9	Electrical Foundations	\$0	\$87	\$221	\$0	\$307	\$54	\$0	\$72	\$434
	Subtotal	\$12,838	\$1,842	\$6,676	\$0	\$21,356	\$3,737	\$0	\$3,782	\$28,875
12		Instrumentation & Control								
12.1	Pulverized Coal Boiler Control Equipment	\$331	\$0	\$59	\$0	\$390	\$68	\$0	\$69	\$527
12.3	Steam Turbine Control Equipment	\$327	\$0	\$37	\$0	\$364	\$64	\$0	\$64	\$491
12.5	Signal Processing Equipment	\$316	\$0	\$56	\$0	\$373	\$65	\$0	\$66	\$504
12.6	Control Boards, Panels & Racks	\$99	\$0	\$60	\$0	\$159	\$28	\$0	\$28	\$215
12.7	Distributed Control System Equipment	\$3,301	\$0	\$589	\$0	\$3,889	\$681	\$0	\$686	\$5,256
12.8	Instrument Wiring & Tubing	\$295	\$236	\$945	\$0	\$1,477	\$258	\$0	\$260	\$1,996
12.9	Other Instrumentation & Controls Equipment	\$351	\$0	\$813	\$0	\$1,164	\$204	\$0	\$205	\$1,573
	Subtotal	\$5,020	\$236	\$2,559	\$0	\$7,816	\$1,368	\$0	\$1,377	\$10,561
13		Improvements to Site								
13.1	Site Preparation	\$0	\$183	\$3,910	\$0	\$4,093	\$716	\$0	\$962	\$5,772
13.2	Site Improvements	\$0	\$1,004	\$1,326	\$0	\$2,330	\$408	\$0	\$547	\$3,285
13.3	Site Facilities	\$828	\$0	\$868	\$0	\$1,696	\$297	\$0	\$399	\$2,391
	Subtotal	\$828	\$1,187	\$6,104	\$0	\$8,119	\$1,421	\$0	\$1,908	\$11,448
14		Buildings & Structures								
14.2	Boiler Building	\$0	\$6,120	\$5,378	\$0	\$11,498	\$2,012	\$0	\$2,027	\$15,537
14.3	Steam Turbine Building	\$0	\$6,187	\$5,762	\$0	\$11,949	\$2,091	\$0	\$2,106	\$16,146
14.4	Administration Building	\$0	\$553	\$584	\$0	\$1,137	\$199	\$0	\$200	\$1,536
14.6	Water Treatment Buildings	\$0	\$150	\$137	\$0	\$287	\$50	\$0	\$51	\$387
14.7	Machine Shop	\$0	\$248	\$165	\$0	\$413	\$72	\$0	\$0	\$486
14.8	Warehouse	\$0	\$193	\$193	\$0	\$386	\$67	\$0	\$68	\$521
14.9	Other Buildings & Structures	\$0	\$139	\$118	\$0	\$258	\$45	\$0	\$45	\$348
14.10	Waste Treating Building & Structures	\$0	\$221	\$670	\$0	\$890	\$156	\$0	\$157	\$1,203
	Subtotal	\$0	\$13,810	\$13,007	\$0	\$26,818	\$4,693	\$0	\$4,654	\$36,165
	Total	\$319,810	\$23,618	\$175,348	\$0	\$518,776	\$90,786	\$0	\$93,380	\$702,942

^AACC; ^B Component cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
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Exhibit 5-164. Case B12A-F1 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$6,420
1-Month Maintenance Materials	\$930
1-Month Non-Fuel Consumables	\$535
1-Month Waste Disposal	\$333
25% of 1-Month Fuel Cost at 100% CF	\$976
2% of TPC	\$14,059
Total	\$23,254
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$8,853
0.5% of TPC (spare parts)	\$3,515
Total	\$12,368
Other Costs	
Initial Cost for Catalyst and Chemicals	\$879
Land	\$117
Other Owner's Costs	\$105,441
Financing Costs	\$18,979
Total Overnight Costs (TOC)	\$863,980

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Exhibit 5-165. Case B12A-F1 initial and annual operating and maintenance costs

Case:	B12A-F1	– Supercritical PC Flexible Plant (Tier 1)			Cost Base:	Dec 2018
Plant Size (MW, gross):	300	Heat Rate-net (Btu/kWh):			8,802	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$ /hour		Skilled Operator:	2.0	
Operating Labor Burden:	30.0	% of base		Operator:	5.0	
Labor O-H Charge Rate:	25.0	% of labor		Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	9.0	
Fixed Operating Costs						
					Annual Cost (\$)	
Annual Operating Labor:					\$3,945,942	
Maintenance Labor:					\$6,326,476	
Administrative & Support Labor:					\$2,568,105	
Property Taxes and Insurance:					\$14,058,837	
Total:					\$26,899,360	
Variable Operating Costs						
					Annual Cost (\$)	
Maintenance Material:					\$11,164,370 x CF	
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)	
Water (/1000 gallons):	0	191	\$1.90	\$0	\$132,327 x CF	
Makeup and Waste Water Treatment Chemicals (ton):	0	0.568	\$550.00	\$0	\$114,106 x CF	
Brominated Activated Carbon (ton):	0	0.542	\$1,600.00	\$0	\$316,533 x CF	
Enhanced Hydrated Lime (ton):	0	13.44	\$240.00	\$0	\$1,177,734 x CF	
Limestone (ton):	0	239	\$22.00	\$0	\$1,918,504 x CF	
Ammonia (19 wt%, ton):	0	22.6	\$300.00	\$0	\$2,473,448 x CF	
SCR Catalyst (ft³):	5,861	5.35	\$150.00	\$879,194	\$293,065 x CF	
Subtotal:				\$879,194	\$6,425,716 x CF	
Waste Disposal						
Fly Ash (ton):	0	235	\$38.00	\$0	\$3,261,861 x CF	
Bottom Ash (ton):	0	52.6	\$38.00	\$0	\$729,438 x CF	
SCR Catalyst (ft³):	0	5.35	\$2.50	\$0	\$4,884 x CF	
Subtotal:				\$0	\$3,996,183 x CF	
By-Products						
Gypsum (ton):	0	363	\$0.00	\$0	\$0	
Subtotal:				\$0	\$0	
Variable Operating Costs Total:				\$879,194	\$21,586,270 x CF	
Fuel Cost						
Illinois Number 6 (ton):	0	2,469	\$51.96	\$0	\$46,826,518 x CF	
Fuel Costs Total:				\$0	\$46,826,518 x CF	

5.7.8.1 Cost Differential Justifications

The primary contributors to the capital cost differential when comparing Case B12A-F1 to Case B12A-F0 are outlined below:

- Flexibility Option 52 — Online performance monitoring
- Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives
- Flexibility Option 7 — Economizer and feedwater heater bypass streams
- Flexibility Option 30 — Air heater bypass stream(s)
- Flexibility Option 31 — SCR reactor bypass stream
- Flexibility Option 41 — Application of ‘continuous coupled’ last stage blades to reduce flutter and dynamic stresses during low load operation
- Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Flexibility Option 81 — Investment in redundant/higher accuracy steam turbine casing metal temperature instruments
- Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation

The justifications for the capital cost differentials when comparing Case B12A-F1 to Case B12A-F0 are outlined below:

- Accounts 2.2 and 2.9 costs increase due to the coal system design modifications and equipment additions. The following flexibility options impacted the cost of accounts 2.2 and 2.9:
 - Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, and burner level
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
- Account 3.1 cost increases due to the increase in equipment and sub-system design for feedwater system engineering and installation. The following flexibility options impacted the cost of Account 3.1:
 - Flexibility Option 4 — Steam sparging
 - Flexibility Option 22 — Enhanced water chemistry monitoring and system response to cycling
- Account 3.2 cost increases due to an increase in engineering design, equipment, and material required for implementing additional testing and pretreating equipment (including the FFA and FFP equipment). The following flexibility options impacted the cost of Account 3.2:
 - Flexibility Option 22 — Enhanced water chemistry monitoring and system response to cycling
 - Flexibility Option 43 — Use of film forming amines or products to protect equipment from corrosion during layup and operation

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- Account 3.4 cost increases due to service water required for the reciprocating engine, and the upgrades to the water chemistry monitoring system are expected to include additional equipment for the service water system. The following flexibility options impacted the cost of Account 3.4:
 - Flexibility Option 9 — Equipping the EGU with black start capability (e.g., reciprocating engine units)
 - Flexibility Option 22 — Enhanced water chemistry monitoring and system response to cycling
- Account 3.5 cost increases due to an increase in cost of the miscellaneous balance of plant systems that serve feedwater, steam, water treatment and service water systems such as engineered pipe supports, instrument routing, instrument installation, cooling water lines, instrument air lines, actuation air lines, damper seal air (if needed), etc. Replacement of all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives results in a 'price deduct' of Account 3; this deduct was counteracted by the increases in cost due to the other flexibility options impacting Account 3, and these competing factors ultimately resulted in a net increase of Account 3 cost. The following flexibility options impacted the cost of Account 3.5:
 - Flexibility Option 4 — Steam sparging
 - Flexibility Option 11 — Draft system isolation modifications to retain boiler heat as long as possible during shutdown periods
 - Flexibility Option 43 — Use of film forming amines or products to protect equipment from corrosion during layup and operation
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
 - Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives
- Account 3.9 cost increases due to an increased number of components (valves, drains, actuators) and engineering design and installation labor required for miscellaneous feedwater or steam-system-related areas. The following flexibility options impacted the cost of Account 3.9:
 - Flexibility Option 4 — Steam sparging
 - Flexibility Option 7 — Economizer and feedwater heater bypass streams
 - Flexibility Option 15 — Main steam warmup line to accelerate pipe wall temperature rise during startup
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Overall, the Account 4.9 cost demonstrates a net increase as a result of the Tier 1 flexibility options due to the addition of new standalone equipment, sub-system

features within the boiler island components, and additional engineering and installation labor required for these options. The following flexibility options impacted the cost of Account 4.9:

- Flexibility Option 4 — Steam sparging
 - Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, and burner level
 - Flexibility Option 7 — Economizer and feedwater heater bypass streams
 - Flexibility Option 11 — Draft system isolation modifications to retain boiler heat as long as possible during shutdown periods
 - Flexibility Option 30 — Air heater bypass stream(s)
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
 - Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Account 4.10 (Selective Catalytic Reduction System) cost increases due to the SCR OEM equipment design and fabrication differences (e.g., additional reactor penetrations) for the SCR reactor module knowing that an SCR bypass will be equipped in addition to the new build SCR bypass duct cost. The following flexibility options impacted the cost of Account 4.10:
 - Flexibility Option 31 — SCR reactor bypass stream
- Account 4.11 cost increases due to the additional equipment requiring boiler balance of plant sub-system engineering design (e.g., instrument air lines, electrical routing, more intricate pipe routing for clash avoidance, additional maintenance access points) and material installation. The following flexibility options impacted the cost of Account 4.11:
 - Flexibility Option 4 — Steam sparging
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
 - Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation
- Account 4.12 cost increases due to modifications to the coal system, which have a related impact on primary air system (e.g., number of PA ducts and headers, number of PA control dampers, safety instrumentation). The following flexibility options impacted the cost of Account 4.12:
 - Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, and burner level

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- Flexibility Option 11 — Draft system isolation modifications to retain boiler heat as long as possible during shutdown periods
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
- Account 4.15 cost increases due to the additional material supply and installation labor required for the major component rigging with the addition of new equipment, specifically the equipment that is erected at height above grade. The following flexibility options impacted the cost of Account 4.15:
 - Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, burner level
 - Flexibility Option 15 — Main steam warmup line to accelerate pipe wall temperature rise during startup
 - Flexibility Option 29 — Economizer gas-side bypass stream
 - Flexibility Option 30 — Air heater bypass stream(s)
 - Flexibility Option 31 — SCR bypass stream
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
- Account 7.3 increased due to the cost for the air heater (flue gas) bypass duct; when comparing the SCR bypass duct to the air heater bypass duct, the relative costs of these ductwork additions appropriately align with each other due to the higher duct cost being appropriate for the higher-temperature and longer-distance SCR gas bypass; the air heater bypass duct would be expected to be much shorter than the SCR bypass duct; additionally, the air heater bypass would be designed to a lower design temperature (i.e., lower grade carbon steel) due to its location in the gas path (thereby further reducing costs). The following flexibility options impacted the cost of Account 7.3:
 - Flexibility Option 30 — Air heater bypass stream(s)
- Account 8.1 cost increases due to the addition of equipment to the steam turbine island and scope of supply; this additional equipment would require additional engineering and installation hours. The following flexibility options impacted the cost of Account 8.1:
 - Flexibility Option 18 — Electric-resistance heating blankets for the steam turbine casing sections to pre-heat the casing
 - Flexibility Option 41 — Application of ‘continuous coupled’ last stage blades to reduce flutter and dynamic stresses during low load operation
- Account 8.2 cost increases due to the addition of ancillary components, such as instruments or instrument connection features to the steam turbine auxiliaries that would require additional engineering design and material supply. The following flexibility options impacted the cost of Account 8.2:

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- Flexibility Option 7 — Economizer and feedwater heater bypass streams
 - Flexibility Option 17 — Additional thermocouples to measure the steam-metal temperature differentials
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
 - Flexibility Option 81 — Investment in redundant and higher accuracy steam turbine casing metal temperature instruments
- Account 8.3 cost increases due to additional sub-system design engineering activities and equipment components added. The following flexibility options impacted the cost of Account 8.3:
 - Flexibility Option 57 — Self-cleaning condenser design with stable backpressure target
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Account 8.4 cost increases due to an increase in engineering design, material, and installation labor required for implementing the modifications to the steam piping; the additional steam cycle instruments would be expected to increase the cost of the steam piping due to the need for additional instrument penetrations, supports and drip legs. The following flexibility options impacted the cost of Account 8.4:
 - Flexibility Option 4/15 — Steam sparging/main steam warmup line
 - Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives (cost decrease associated with implementing this option since a steam line would be removed from the plant design)
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions (cost increase to 8.4 due to increases in number of instrument locations, drip legs and supports)
- Accounts 11.3–11.6 costs increase due to the addition of equipment or additional sub-systems within the plant design. Adding equipment has compulsory impacts to the plant's electrical system design (e.g., MCCs, switchgear, protective relays, cable trays, cable wiring, etc.) resulting from the addition of new equipment (even when considering the NOAK plant estimate methodology). The following flexibility options impacted the cost of accounts 11.3–11.6:
 - Flexibility Option 18 — Electric-resistance heating blankets for the steam turbine casing sections to pre-heat the casing
 - Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives
 - Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills

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- Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation
 - Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
 - Flexibility Option 81 — Investment in redundant and higher accuracy steam turbine casing metal temperature instruments
- Account 11.7 cost increased due to the increase in the size of the reciprocating engine generator; this cost increase was applied to Account 11.7 'Standby Equipment' due to its title of 'Emergency Generator' in the Account 11 Equipment List.
 - Flexibility Option 9 — Equipping the EGU with black start capability (e.g., reciprocating engine units)
- Account 11.9 cost increased due to the additional electrical equipment requiring additional foundation engineering design, material supply, and installation cost. The following flexibility options impacted the cost of Account 11.9:
 - Flexibility Option 18 — Electric-resistance heating blankets for the steam turbine casing sections to pre-heat the casing
 - Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives
- Account 12 cost increased due to the increase in hardware and software components associated with the Case B12A-F1 flexibility options; the implementation of these options requires additional equipment (hardware) supply, material supply (e.g., wiring, conduit, raceway), installation hours for physically installing the components and commissioning hours where specialists program and tune the system prior to commercial operation. The following flexibility options impacted the cost of Account 12:
 - Flexibility Option 4/15 — Steam sparging/main steam warmup line
 - Flexibility Option 5 — Furnace heating utilizing small dedicated coal feeder, pulverizer, burner level
 - Flexibility Option 9 — Equipping the EGU with black start capability (e.g., reciprocating engine units)
 - Flexibility Option 11 — Draft system isolation modifications to retain boiler heat as long as possible during shutdown periods
 - Flexibility Option 17 — Additional thermocouples to measure the steam-metal temperature differentials
 - Flexibility Option 22 — Enhanced water chemistry monitoring and system response to cycling
 - Flexibility Option 25 — Replace all steam turbine driven pumps (e.g., boiler feed pump) with electric motor drives

- Flexibility Option 29 — Economizer gas-side bypass stream
- Flexibility Option 30 — Air heater bypass stream(s)
- Flexibility Option 31 — SCR bypass stream
- Flexibility Option 36 — Designing the boiler with a larger number of smaller sized mills
- Flexibility Option 43 — Use of film forming amines or products to protect equipment from corrosion during layup and operation
- Flexibility Option 52 — Online performance monitoring
- Flexibility Option 61 — Application of advanced air heater sealing systems that maintain low air in-leakage during startup and low load operation
- Flexibility Option 78 — Implement additional steam cycle instruments to improve cycle isolation during low load conditions
- Flexibility Option 81 — Investment in redundant/higher accuracy steam turbine casing metal temperature instruments; closer monitoring of these temperatures allows for more accurate tracking of design life/maintenance overhaul projections

The justifications for the O&M cost differentials when comparing Case B12A-F1 to Case B12A-F0 are outlined below:

- Maintenance Material and Labor costs are increased from 1.6 percent of TPC in Case B12A-F0 to 2.3 percent of TPC in Case B12A-F1, which is considered a reasonable average increase in proactive maintenance and standardized maintenance programs for high cycling PC EGUs. However, the actual cost of maintenance material and labor would be dependent upon the specific operational profile of the plant.

5.7.9 Case B12A-F2 – PC Supercritical Flexible Plant with Tier 1 and 2 Flexibility Options

The following subsections outline the Case B12A-F2 BFD modifications, full and part load performance results, and cost estimates.

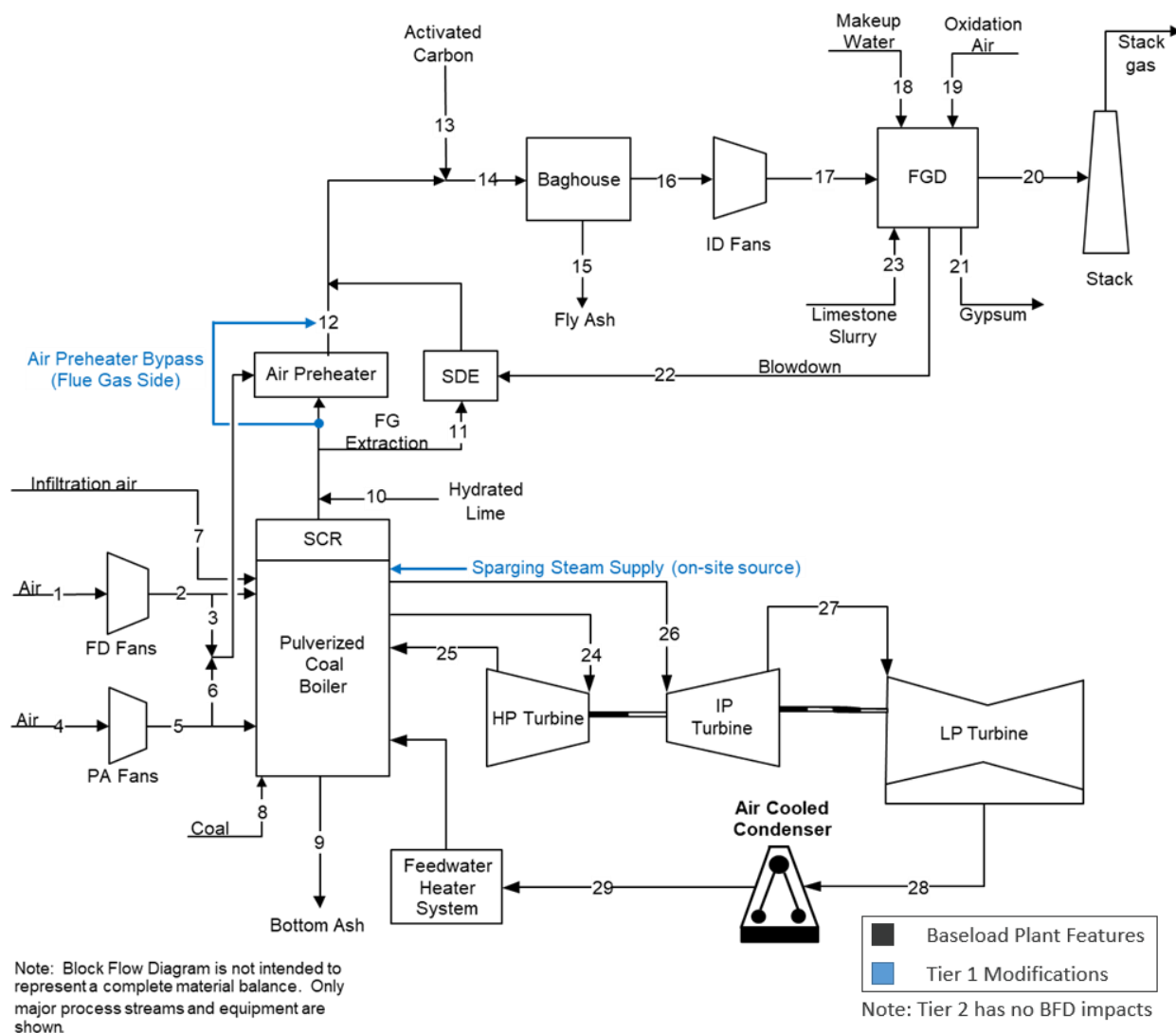
The plant configuration for Case B12A-F2, supercritical flexible plant with Tier 1 and 2 flexibility options, is identical to Case B12A-F1. The full list of Tier 2 flexibility options was presented in Exhibit 4-15. The nominal gross plant output was maintained at 300 MW.

5.7.10 Case B12A-F2 – Full Load Performance Results

The BFD for Case B12A-F2 is shown in Exhibit 5-166. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 5-167. Full stream tables are only provided for the 100 percent load point.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-166. Case B12A-F2 block flow diagram



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-167. Case B12A-F2 stream table, supercritical unit with tiers 1–2 flexibility options

	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	27,991	27,991	922	4,940	4,940	1,020	558	0	0	0
V-L Flowrate (kg/hr)	807,739	807,739	26,601	142,542	142,542	29,436	16,107	0	0	5
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	93,332	1,988	503
Temperature (°C)	15	21	21	15	23	23	15	15	1,316	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	36.30	36.30	30.23	38.73	38.73	30.23	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-91.51	-91.51	-97.58	-89.08	-89.08	-97.58	-2,119.02	1,312.68	-13,402.95
Density (kg/m ³)	1.2	1.3	1.3	1.2	1.3	1.3	1.2	---	---	1,003.6
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015
V-L Flowrate (lb _{mol} /hr)	61,710	61,710	2,032	10,890	10,890	2,249	1,231	0	0	1
V-L Flowrate (lb/hr)	1,780,761	1,780,761	58,645	314,252	314,252	64,895	35,509	0	0	11
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	205,762	4,383	1,109
Temperature (°F)	59	70	70	59	74	74	59	59	2,400	59
Pressure (psia)	14.7	15.6	15.6	14.7	16.0	16.0	14.7	14.7	14.3	14.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	15.6	15.6	13.0	16.7	16.7	13.0	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-39.3	-39.3	-42.0	-38.3	-38.3	-42.0	-911.0	564.3	-5,762.2
Density (lb/ft ³)	0.076	0.079	0.079	0.076	0.080	0.080	0.076	---	---	62.650

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-167. Case B12A-F2 stream table, supercritical unit with tiers 1–2 flexibility options, cont'd

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction										
Ar	0.0087	0.0088	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081
CO ₂	0.1463	0.1379	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0889	0.0844	0.0000	0.0918	0.0000	0.0918	0.0918	0.9967	0.0099	0.1512
HCl	0.0001	0.0001	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
N ₂	0.7312	0.7336	0.0000	0.7277	0.0000	0.7277	0.7277	0.0000	0.7732	0.6801
O ₂	0.0226	0.0332	0.0000	0.0325	0.0000	0.0325	0.0325	0.0000	0.2074	0.0360
SO ₂	0.0021	0.0020	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.1148	0.0000	0.0000	0.0006	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0001	0.8852	0.0000	0.0000	0.0028	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	1,683	33,672	0	35,639	2	35,637	35,637	4,964	1,506	39,846
V-L Flowrate (kg/hr)	50,050	999,637	0	1,054,937	230	1,054,701	1,054,701	90,827	43,466	1,144,972
Solids Flowrate (kg/hr)	431	8,122	20	8,654	8,659	0	0	816	0	0
Temperature (°C)	384	143	15	143	143	143	156	27	15	57
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	---	---	289.08	302.74	---	30.23	297.86
AspenPlus Enthalpy (kJ/kg) ^B	-2,278.03	-2,399.41	-6.79	-2,459.22	-1,001.46	-2,471.50	-2,457.84	-15,763.99	-97.58	-2,944.15
Density (kg/m ³)	0.5	0.8	---	0.8	2,150.2	0.8	0.9	1,002.4	1.2	1.1
V-L Molecular Weight	29.738	29.687	---	29.600	104.953	29.596	29.596	18.297	28.857	28.735
V-L Flowrate (lb _{mol} /hr)	3,710	74,235	0	78,571	5	78,566	78,566	10,944	3,321	87,845
V-L Flowrate (lb/hr)	110,342	2,203,822	0	2,325,737	508	2,325,217	2,325,217	200,240	95,826	2,524,231
Solids Flowrate (lb/hr)	950	17,907	45	19,078	19,090	0	0	1,799	0	0
Temperature (°F)	724	289	59	289	289	289	312	80	59	135
Pressure (psia)	14.3	14.0	14.7	14.0	14.0	13.8	15.1	14.7	14.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	---	---	124.3	130.2	---	13.0	128.1
AspenPlus Enthalpy (Btu/lb) ^B	-979.4	-1,031.6	-2.9	-1,057.3	-430.5	-1,062.6	-1,056.7	-6,777.3	-42.0	-1,265.8
Density (lb/ft ³)	0.033	0.052	---	0.051	134.232	0.051	0.054	62.580	0.076	0.067

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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Exhibit 5-167. Case B12A-F2 stream table, supercritical unit with tiers 1–2 flexibility options, cont'd

	21	22	23	24	25	26	27	28	29
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	85	284	1,171	48,442	36,579	36,579	32,721	28,585	32,818
V-L Flowrate (kg/hr)	1,526	5,249	21,096	872,699	658,981	658,981	589,472	514,974	591,220
Solids Flowrate (kg/hr)	13,727	80	9,031	0	0	0	0	0	0
Temperature (°C)	15	57	15	593	343	593	288	45	45
Pressure (MPa, abs)	0.10	0.10	0.10	24.23	4.85	4.11	0.51	0.01	1.31
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	3,477.96	3,052.30	3,658.08	3,037.83	2,403.96	191.45
AspenPlus Enthalpy (kJ/kg) ^B	-12,513.34	-15,495.43	-14,994.25	-12,502.33	-12,928.00	-12,322.21	-12,942.47	-13,576.33	-15,788.84
Density (kg/m ³)	880.9	979.4	1,003.7	69.2	18.9	10.5	2.0	0.1	990.5
V-L Molecular Weight	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	187	626	2,581	106,797	80,643	80,643	72,137	63,020	72,351
V-L Flowrate (lb/hr)	3,364	11,573	46,509	1,923,971	1,452,805	1,452,805	1,299,562	1,135,323	1,303,418
Solids Flowrate (lb/hr)	30,263	176	19,910	0	0	0	0	0	0
Temperature (°F)	59	135	59	1,100	649	1,100	550	114	114
Pressure (psia)	14.7	14.7	14.7	3,514.7	702.9	595.9	74.5	1.4	190.2
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	1,495.3	1,312.3	1,572.7	1,306.0	1,033.5	82.3
AspenPlus Enthalpy (Btu/lb) ^B	-5,379.8	-6,661.8	-6,446.4	-5,375.0	-5,558.0	-5,297.6	-5,564.3	-5,836.8	-6,788.0
Density (lb/ft ³)	54.996	61.143	62.658	4.319	1.181	0.655	0.126	0.004	61.838

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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At full load, the plant produces a net output of 273 MWe at a net plant efficiency of 38.8 percent (HHV basis). Full load performance for Case B12A-F2 is summarized in Exhibit 5-168. Exhibit 5-169 presents a detailed breakdown of auxiliary power requirements at full load.

Exhibit 5-168. Case B12A-F2 plant performance summary

Performance Summary	
Percent Load	100%
Total Gross Power, MWe	300
Nameplate Capacity, MWe	300
Total Auxiliaries, MWe	27
Total Auxiliaries, % of Gross Power	9.1%
Net Power, MWe	273
HHV Net Plant Efficiency, %	38.8%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,286 (8,802)
LHV Net Plant Efficiency, %	40.2%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,957 (8,490)
HHV Boiler Efficiency, %	87.5%
LHV Boiler Efficiency, %	90.7%
Steam Turbine Cycle Efficiency, %	48.8%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,384 (6,999)
Condenser Duty, GJ/hr (MMBtu/hr)	1,142 (1,082)
As-Received Coal Feed, kg/hr (lb/hr)	93,332 (205,762)
Limestone Sorbent Feed, kg/hr (lb/hr)	9,031 (19,910)
HHV Thermal Input, kWt	703,493
LHV Thermal Input, kWt	678,528
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (0.9)
Excess Air, %	20.0%

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Exhibit 5-169. Case B12A-F2 plant power summary

Power Summary	
Percent Load	100%
Steam Turbine Power, MWe	300
Total Gross Power, MWe	300
Nameplate Capacity	300
Auxiliary Load Summary	
Activated Carbon Injection, kWe	14
Air Cooled Condenser Fans	3,580
Ancillary Glycol Cooling Loops	250
Ash Handling, kWe	315
Baghouse, kWe	42
Boiler Circulation Pump, kWe	0
Boiler Feedwater Pump, kWe	11,040
Coal Handling and Conveying, kWe	200
Condensate Pumps, kWe	286
Dry Sorbent Injection, kWe	25
Flue Gas Desulfurizer, kWe	1,440
Forced Draft Fans, kWe	1,410
Ground Water Pumps, kWe	24
Induced Draft Fans, kWe	4,150
Miscellaneous Balance of Plant, ^A kWe	1,250
Primary Air Fans, kWe	355
Pulverizers, kWe	1,030
SCR, kWe	15
Sorbent Handling & Reagent Preparation, kWe	435
Spray Dryer Evaporator, kWe	103
Steam Turbine Auxiliaries, kWe	350
Transformer Losses, kWe	970
Total Auxiliaries, MWe	27
Net Power, MWe	273

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

5.7.10.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B12A-F2 is presented in Exhibit 5-170. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-170. Case B12A-F2 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	654 (721)	0.293 (0.645)
NO _x	0.038 (0.087)	709 (782)	0.318 (0.700)
Particulate	0.005 (0.011)	91 (101)	0.041 (0.090)
Hg	1.61E-7 (3.75E-7)	0.003 (0.003)	1.36E-6 (3.00E-6)
CO ₂	86 (201)	1,625,746 (1,792,078)	728 (1,605)
CO ₂ ^C	-	-	801 (1,765)
mg/Nm ³			
Particulate Concentration ^{D,E}	15.34		

^A Calculations based on an 85% capacity factor

^B Emissions based on gross power, except where otherwise noted

^C CO₂ emissions based on net power instead of gross power

^D Concentration of particles in the flue gas after the baghouse

^E Normal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.35 lb/MMBtu using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 75.0 percent to about 0.09 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and FGD system) is 94.5 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 5-171. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-171. Case B12A-F2 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	59,494 (131,162)	Stack Gas	59,588 (131,369)
Air (CO ₂)	137 (303)	FGD Product	71 (156)
PAC	20 (45)	Baghouse	732 (1,614)
FGD Reagent	916 (2,020)	Bottom Ash	178 (392)
Total	60,568 (133,531)	Total	60,568 (133,531)

Exhibit 5-172 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-172. Case B12A-F2 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	2,339 (5,157)	FGD Product	2,200 (4,850)
		Stack Gas	46 (101)
		Baghouse	94 (206)
Total	2,339 (5,157)	Total	2,339 (5,157)

Exhibit 5-173 shows the water balance for Case B12A-F2.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is reused as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from ground water. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-173. Case B12A-F2 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Desulfurizer Makeup	1.0 (257)	–	1.0 (257)	–	1.0 (257)
Deaerator Vent	–	–	–	0.0 (7.7)	0.0 (–7.7)
Condenser Makeup	0.0 (7.7)	–	0.0 (7.7)	–	0.0 (7.7)
BFW Makeup	0.0 (7.7)	–	0.0 (7.7)	–	0.0 (7.7)
Cooling Tower	–	–	–	–	–
BFW Blowdown	–	–	–	–	–
Total	1.0 (265)	–	1.0 (265)	0.0 (7.7)	1.0 (257)

5.7.10.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B12A-F2 PC boiler, the FGD unit, and steam cycle as shown in Exhibit 5-174 and Exhibit 5-175.

An overall plant energy balance is provided in tabular form in Exhibit 5-176. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-168) is calculated by multiplying the power out by the full load generator efficiency of 98.5 percent.

Exhibit 5-174. Case B12A-F2 energy and mass balance, supercritical PC boiler

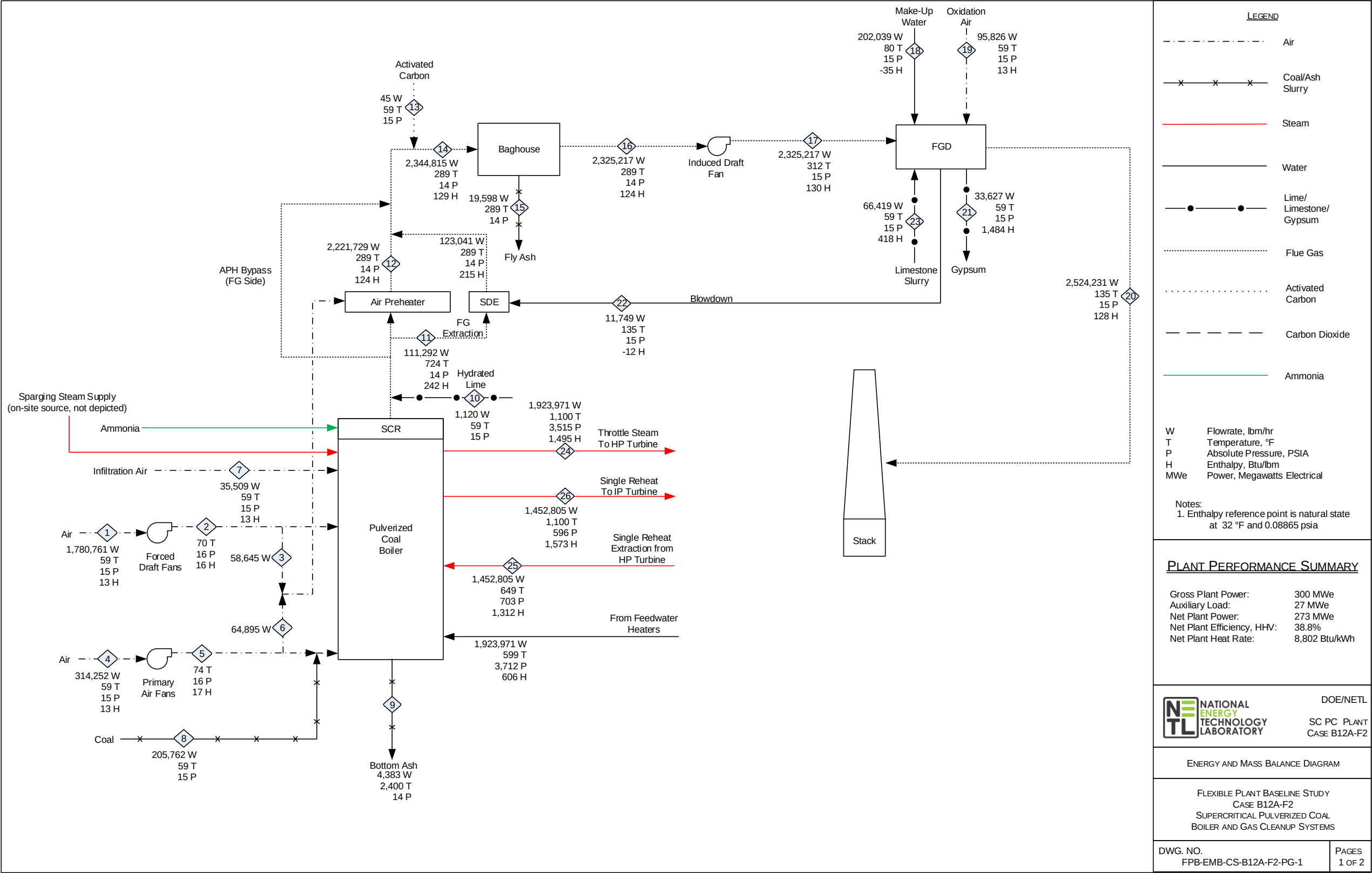
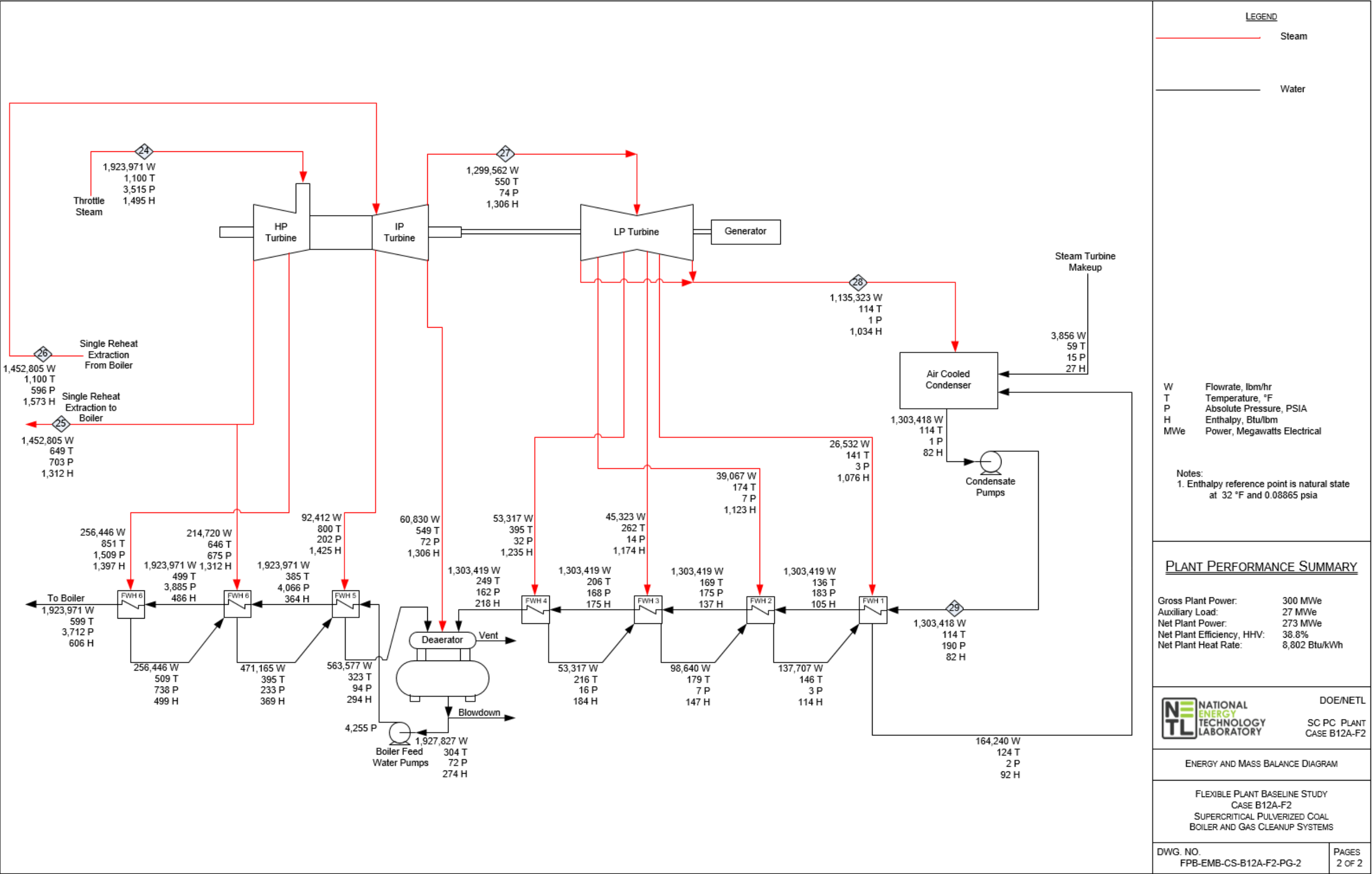


Exhibit 5-175. Case B12A-F2 energy and mass balance, supercritical steam cycle



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-176. Case B12A-F2 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	2,533 (2,400)	2.1 (2.0)	–	2,535 (2,402)
Air	–	29 (28)	–	29 (28)
Raw Water Makeup	–	3.8 (3.6)	–	3.8 (3.6)
Limestone	–	0.2 (0.2)	–	0.2 (0.2)
Auxiliary Power	–	–	98 (93)	98 (93)
Total	2,533 (2,400)	35 (33)	98 (93)	2,666 (2,527)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	2.6 (2.5)	–	2.6 (2.5)
Fly Ash	–	0.9 (0.9)	–	0.9 (0.9)
Stack Gas	–	341 (323)	–	341 (323)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Gypsum	–	0.9 (0.8)	–	0.9 (0.8)
Motor Losses and Design Allowances	–	–	17 (16)	17 (16)
Air Cooled Condenser Load ^A	–	1,142 (1,082)	–	1,142 (1,082)
Blowdown Streams and Deaerator Vent	–	1.1 (1.1)	–	1.1 (1.1)
<i>Ambient Losses^B</i>	–	68 (65)	–	68 (65)
Power	–	–	1,080 (1,024)	1,080 (1,024)
Total	0.0 (0.0)	1,557 (1,476)	1,097 (1,040)	2,654 (2,516)
<i>Unaccounted Energy^C</i>	–	–	–	12 (11)

^A Includes condenser load only

^B Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^C By difference

5.7.11 Case B12A-F2 – Part Load Performance Results

Plant performance results are summarized at each discrete load point in Exhibit 5-177.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-178 displays a detailed breakdown of the auxiliary power consumption at each discrete load point. Air emissions at each discrete load point are summarized in Exhibit 5-179.

Exhibit 5-177. Case B12A-F2 part load plant performance summary

Performance Summary					
Percent Load	100%	75%	50%	30%	20%
Total Gross Power, MWe	300	225	150	90	60
Nameplate Capacity, MWe	300	300	300	300	300
Total Auxiliaries, MWe	27	20	14	9	7
Total Auxiliaries, % of Gross Power	9.1%	9.1%	9.5%	10.4%	11.2%
Net Power, MWe	273	205	136	81	53
HHV Net Plant Efficiency, %	38.8%	38.1%	36.8%	35.0%	33.6%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,286 (8,802)	9,461 (8,967)	9,788 (9,277)	10,287 (9,750)	10,714 (10,155)
LHV Net Plant Efficiency, %	40.2%	39.5%	38.1%	36.3%	34.8%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,957 (8,490)	9,125 (8,649)	9,441 (8,948)	9,922 (9,404)	10,334 (9,794)
HHV Boiler Efficiency, %	87.5%	87.5%	87.6%	87.6%	87.7%
LHV Boiler Efficiency, %	90.7%	90.7%	90.8%	90.9%	90.9%
Steam Turbine Cycle Efficiency, %	48.8%	47.8%	46.4%	44.6%	43.2%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,384 (6,999)	7,526 (7,133)	7,757 (7,352)	8,078 (7,656)	8,342 (7,907)
Condenser Duty, GJ/hr (MMBtu/hr)	1,142 (1,082)	881 (835)	617 (585)	397 (377)	280 (266)
As-Received Coal Feed, kg/hr (lb/hr)	93,332 (205,762)	71,309 (157,209)	48,964 (107,947)	30,573 (67,403)	21,042 (46,390)
Limestone Sorbent Feed, kg/hr (lb/hr)	9,031 (19,910)	6,914 (15,243)	4,767 (10,509)	2,990 (6,593)	2,064 (4,551)
HHV Thermal Input, kWt	703,493	537,493	369,068	230,447	158,607
LHV Thermal Input, kWt	678,528	518,419	355,971	222,269	152,978
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)	0.004 (1.0)	0.004 (1.0)	0.004 (1.0)	0.004 (1.1)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (0.9)	0.004 (1.0)	0.004 (1.0)	0.004 (0.9)	0.004 (1.0)
Excess Air, %	20.0%	22.1%	26.9%	33.0%	37.0%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-178. Case B12A-F2 part load plant power summary

Power Summary					
Percent Load	100%	75%	50%	30%	20%
Steam Turbine Power, MWe	300	225	150	90	60
Total Gross Power, MWe	300	225	150	90	60
Nameplate Capacity, MWe	300	300	300	300	300
Auxiliary Load Summary					
Activated Carbon Injection, kWe	14	10	7	5	3
Air Cooled Condenser Fans, kWe	3,580	3,570	2,510	1,500	930
Ancillary Glycol Cooling Loops, kWe	250	250	250	250	250
Ash Handling, kWe	315	238	160	98	66
Baghouse, kWe	42	32	21	13	9
Boiler Circulation Pump, kWe	0	0	0	83	55
Boiler Feedwater Pump, kWe	11,040	6,450	3,540	1,890	1,210
Coal Handling and Conveying, kWe	200	150	110	70	50
Condensate Pumps, kWe	286	187	123	82	61
Dry Sorbent Injection, kWe	25	18	10	5	3
Flue Gas Desulfurizer, kWe	1,440	1,310	1,280	990	680
Forced Draft Fans, kWe	1,410	1,150	820	460	250
Ground Water Pumps, kWe	24	18	14	9	7
Induced Draft Fans, kWe	4,150	3,260	2,270	1,380	920
Miscellaneous Balance of Plant, ^A kWe	1,250	1,250	1,250	1,250	1,250
Primary Air Fans, kWe	355	295	220	101	55
Pulverizers, kWe	1,030	790	540	340	230
SCR, kWe	15	13	10	7	5
Sorbent Handling and Reagent Preparation, kWe	435	333	230	144	99
Spray Dryer Evaporator, kWe	103	78	54	33	23
Steam Turbine Auxiliaries, kWe	350	350	350	350	350
Transformer Losses, kWe	970	730	490	290	200
Total Auxiliaries, MWe	27	20	14	9	7
Net Power, MWe	273	205	136	81	53

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-179. Case B12A-F2 part load air emissions summary

Emissions Summary					
Percent Load	100%	75%	50%	30%	20%
SO ₂ , kg/MWhgross (lb/MWhgross)	0.293 (0.645)	0.299 (0.659)	0.309 (0.681)	0.323 (0.712)	0.335 (0.738)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	728 (1,605)	742 (1,636)	766 (1,688)	799 (1,761)	826 (1,821)
CO ₂ ^B , kg/MWhnet (lb/MWhnet)	801 (1,765)	816 (1,800)	846 (1,866)	891 (1,965)	930 (2,050)
Particulate Concentration ^{A,B} , mg/Nm ³	15.34	14.81	13.84	12.70	11.95

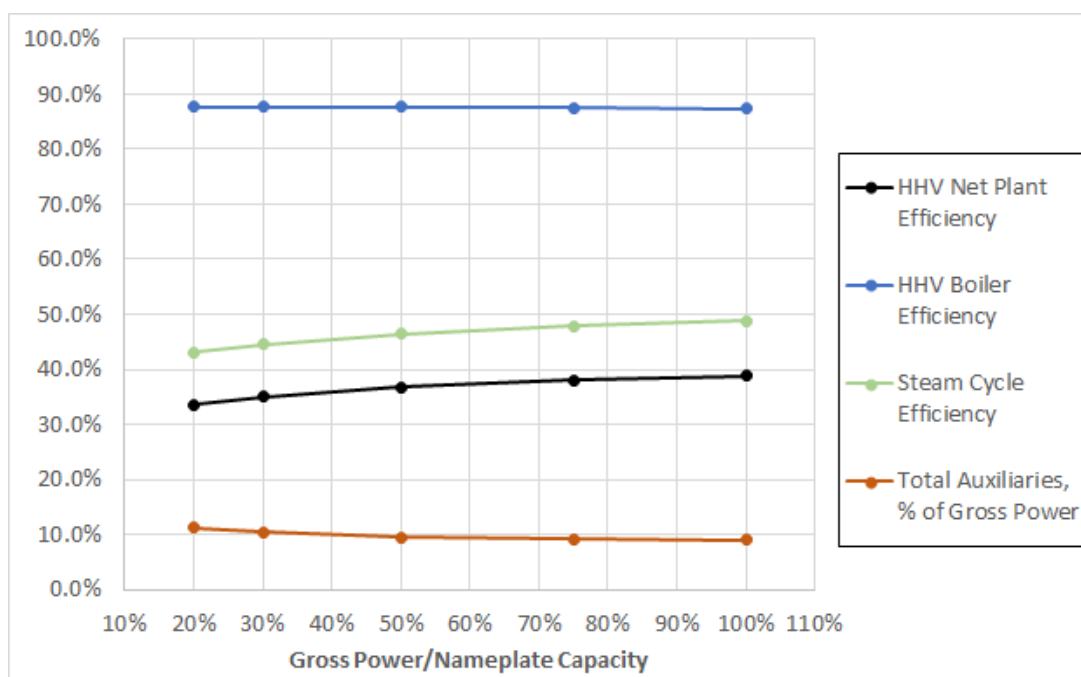
^A Concentration of particles in the flue gas after the baghouse

^B Normal conditions given at 32°F and 14.696 psia

Case B12A-F2 air emissions remained below the environmental target emission limits across the entire load range. Hg, NO_x, and PM emissions are maintained at constant levels across the load. SO₂ emissions increase as load is reduced but are kept below the environmental target emission limit.

Exhibit 5-180 displays the Case B12A-F2 itemized efficiencies (HHV net plant efficiency, HHV boiler efficiency, and steam cycle efficiency) and normalized auxiliary power consumption across the load range.

Exhibit 5-180. Case B12A-F2 part load itemized efficiencies



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Compared to Case B12A-F1, Case B12A-F2 has a slightly improved HHV net plant heat rate at loads below 50 percent due to the decrease in WFGD power consumption from auxiliary load optimization. The HHV boiler efficiency and steam cycle efficiency remains consistent with Case B12A-F1.

5.7.12 Case B12A-F2 – Major Equipment List

Case B12A-F2 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	20 tonne (20 ton)	2	1
9	Feeder	Vibratory	80 tonne/hr (80 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	150 tonne/hr (170 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	80 tonne (80 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/tripper	150 tonne/hr (170 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Coal Silo w/ Vent Filter and Slide Gates	Field erected	340 tonne (400 ton)	3	0
18	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 4 tonne (4 ton) Feeder - 20 kg/hr (50 lb/hr)	1	0
19	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 90 tonne (100 ton) Feeder - 560 kg/hr (1,230 lb/hr)	1	0
20	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
21	Limestone Feeder	Belt	38 tonne/hr (42 tph)	1	0
22	Limestone Conveyor No. 1	Belt	38 tonne/hr (42 tph)	1	0
23	Limestone Reclaim Hopper	N/A	7 tonne (8 ton)	1	0
24	Limestone Reclaim Feeder	Belt	30 tonne/hr (33 tph)	1	0
25	Limestone Conveyor No. 2	Belt	30 tonne/hr (33 tph)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
26	Limestone Day Bin	w/ actuator	119 tonne (131 ton)	2	0

Case B12A-F2 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	17 tonne/hr (19 tph)	6	0
2	Coal Pulverizer	Rotary (Vertical)	17 tonne/hr (19 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	10 tonne/hr (11 tph)	1	1
4	Limestone Ball Mill	Rotary	10 tonne/hr (11 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	38,600 liters (10,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	650 lpm @ 10m H ₂ O (170 gpm @ 40 ft H ₂ O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	160 lpm (40 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	215,000 liters (57,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	450 lpm @ 9m H ₂ O (120 gpm @ 30 ft H ₂ O)	1	1

Case B12A-F2 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	116,000 liters (31,000 gal)	2	0
2	Condensate Pumps	Vertical canned	10,900 lpm @ 200 m H ₂ O (2,900 gpm @ 500 ft H ₂ O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	962,000 kg/hr (2,121,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump	Barrel type, multi-stage, centrifugal	16,100 lpm @ 3,600 m H ₂ O (4,300 gpm @ 11,700 ft H ₂ O)	1	1
5	N/A				
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	960,000 kg/hr (2,120,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	960,000 kg/hr (2,120,000 lb/hr)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	HP Feedwater heater 8	Horizontal U-tube	960,000 kg/hr (2,120,000 lb/hr)	1	0
13	Auxiliary Boiler	Shop fabricated, water tube	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	37 GJ/hr (35 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	14,600 lpm @ 30 m H ₂ O (3,900 gpm @ 100 ft H ₂ O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	240 lpm @ 20 m H ₂ O (60 gpm @ 60 ft H ₂ O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	240 lpm @ 270 m H ₂ O (60 gpm @ 880 ft H ₂ O)	2	1
23	Filtered Water Pumps	Stainless steel, single suction	500 lpm @ 50 m H ₂ O (130 gpm @ 160 ft H ₂ O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	480,000 liter (127,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	–	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 870 m ³ /min (30,550 acfm) @ 384°C (724°F) & 0.1 MPa (14 psia) Blowdown - 50 lpm (10 gpm) @ 20,020 ppmw Cl ⁻	2	1

Case B12A-F2 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	960,000 kg/hr steam @ 24.1 MPa/593°C/593°C (2,120,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
2	Primary Air Fan	Centrifugal	78,000 kg/hr, 1,100 m ³ /min @ 107 cm WG (173,000 lb/hr, 37,800 acfm @ 42 in. WG)	2	0
3	Forced Draft Fan	Centrifugal	444,000 kg/hr, 6,100 m ³ /min @ 76 cm WG (979,000 lb/hr, 214,100 acfm @ 30 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	580,000 kg/hr, 11,900 m ³ /min @ 116 cm WG (1,279,000 lb/hr, 420,400 acfm @ 46 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	1,090,000 kg/hr (2,410,000 lb/hr)	2	0
6	SCR Catalyst	–	–	3	0
7	Dilution Air Blower	Centrifugal	40 m ³ /min @ 108 cm WG (1,400 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	45,000 liter (12,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	9 lpm @ 90 m H ₂ O (2 gpm @ 300 ft H ₂ O)	2	1

Case B12A-F2 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	580,000 kg/hr (1,279,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	20,000 m ³ /min (695,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	114,000 lpm @ 65 m H ₂ O (30,000 gpm @ 210 ft H ₂ O)	3	1
4	Bleed Pumps	Horizontal centrifugal	1,910 lpm (500 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	330 m ³ /min @ 0.3 MPa (11,520 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	470 lpm (130 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	15 tonne/hr (17 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	290 lpm @ 13 m H ₂ O (80 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	190,000 lpm (50,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	680 lpm @ 21 m H ₂ O (180 gpm @ 70 ft H ₂ O)	1	1

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
12	Activated Carbon Injectors	---	20 kg/hr (50 lb/hr)	1	0
13	Hydrated Lime Injectors	---	560 kg/hr (1,230 lb/hr)	1	0

Case B12A-F2 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	122 m (400 ft) high x 4.1 m (14 ft) diameter	1	0

Case B12A-F2 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	311 MW 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Air-cooled Condenser	Forced draft, direct, A-frame air-cooled condenser	1,260 GJ/hr (1,190 MMBtu/hr), Condensing temperature 45°C (114°F), Ambient temperature 15°C (59°F)	1	0

Case B12A-F2 – Account 9: Auxiliary Cooling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Glycol Cooling Loops	Industrial grade, air to glycol, closed loop heat exchanger	10 GJ/hr (14 MMBtu/hr) heat duty	5	0

Case B12A-F2 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	2.2 tonne/hr (2.4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
8	Bottom Ash Storage Silo	—	—	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	—	—	12	0
10	Air Heater Hopper (part of boiler scope of supply)	—	—	10	0
11	Air Blower	—	9 m ³ /min @ 0.2 MPa (310 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	580 tonne (640 ton)	2	0
13	Slide Gate Valves	—	—	2	0
14	Unloader	—	—	1	0
15	Telescoping Unloading Chute	—	50 tonne/hr (60 tph)	1	0

Case B12A-F2 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 310 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 25 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Generator	Sized for black start capability	3500 kW, 480 V, 3-ph, 60 Hz	2	0

Case B12A-F2 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers, alarm management, HMIs, data historian, hard-wired control interface panels, and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor cabinets with redundant input/output, I/O cabinets, various I/C buses	Spare 25% I/O and processor bandwidth	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant	1	0

The following items represent the modifications to the major equipment categories for the Case B12A-F2 design basis, along with narrative regarding process description modifications. Case B12A-F2 flexible plant design includes the design features of the Case B12A-F1 plant with the following modifications:

- **Account 4 — Boiler and Accessories**
 - The modifications/changes to the boiler's burner arrangement to include an even lower BLHR burner row is typically outlined during detailed design with the boiler OEM; smaller burner rows (or their integration within the existing rows) will likely not impact the overall unit cost significantly due to their incorporation during original design of the plant; additional/supplemental coal burners will operate according to standard operating principles for coal-fired burners.
- **Account 5 — Flue Gas Cleanup**
 - Auxiliary load optimization was assumed to reduce the normalized WFGD power requirement at low loads; normalized WFGD power consumption will increase at low loads; prudent operation of recycle pumps allows for reduction of the low-load power consumption penalty; specific achievement/degrees of auxiliary load optimization/reduction at low load will depend on operator training and system tuning at reduced loads.
- **General**
 - No other significant major equipment category updates as a result of the Case B12A-F2 flexibility options; the additional condensate drains and thermocouples are considered small-scale capital cost components with no significant impact on the plant performance other than improved automation and control of the plant by the operators.
 - Additional (automated) condensate drains and blowdown lines will operate automatically based on predetermined set points within the control system.
 - Additional thermocouples/flame scanners installed in the boiler will operate within the control system to provide further granularity of monitoring furnace temperatures, as well as flame health (particularly important during low load); the upgrades to flame detection sensors and software have also been linked to increased regularity and reproducibility of startups, which contributes to lowering equipment fatigue during startups and overall cost of startups. [24] [40] [18]

5.7.13 Case B12A-F2– Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-181 shows a detailed breakdown of the capital costs; Exhibit 5-182 shows the owner's costs, along with the TOC; and Exhibit 5-183 shows the initial and annual O&M costs.

The estimated TPC of the Case B12A-F2 plant is \$717 million. The project contingency is 13.3 percent of the TPC.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-181. Case B12A-F2 total plant cost details

Case:		B12A-F2	Supercritical PC Flexible Plant (Tiers 1–2)				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	
1		Coal & Sorbent Handling								
1.1	Coal Receive & Unload	\$422	\$0	\$190	\$0	\$613	\$107	\$0	\$108	\$828
1.2	Coal Stackout & Reclaim	\$1,387	\$0	\$310	\$0	\$1,697	\$297	\$0	\$299	\$2,293
1.3	Coal Conveyors	\$14,731	\$0	\$3,505	\$0	\$18,236	\$3,191	\$0	\$3,214	\$24,641
1.4	Other Coal Handling	\$1,640	\$0	\$345	\$0	\$1,985	\$347	\$0	\$350	\$2,682
1.5	Sorbent Receive & Unload	\$96	\$0	\$29	\$0	\$125	\$22	\$0	\$22	\$169
1.6	Sorbent Stackout & Reclaim	\$523	\$0	\$95	\$0	\$618	\$108	\$0	\$109	\$835
1.7	Sorbent Conveyors	\$929	\$202	\$225	\$0	\$1,356	\$237	\$0	\$239	\$1,832
1.8	Other Sorbent Handling	\$55	\$13	\$28	\$0	\$96	\$17	\$0	\$17	\$129
1.9	Coal & Sorbent Handling Foundations	\$0	\$681	\$898	\$0	\$1,579	\$276	\$0	\$278	\$2,134
	Subtotal	\$19,784	\$896	\$5,624	\$0	\$26,304	\$4,603	\$0	\$4,636	\$35,543
2		Coal & Sorbent Preparation & Feed								
2.1	Coal Crushing & Drying	\$899	\$0	\$173	\$0	\$1,072	\$188	\$0	\$189	\$1,448
2.2	Prepared Coal Storage & Feed	\$3,220	\$0	\$693	\$0	\$3,913	\$685	\$0	\$690	\$5,287
2.5	Sorbent Preparation Equipment	\$397	\$17	\$81	\$0	\$495	\$87	\$0	\$87	\$669
2.6	Sorbent Storage & Feed	\$640	\$0	\$241	\$0	\$881	\$154	\$0	\$155	\$1,190
2.9	Coal & Sorbent Feed Foundation	\$0	\$262	\$230	\$0	\$491	\$86	\$0	\$87	\$664
	Subtotal	\$5,155	\$279	\$1,418	\$0	\$6,852	\$1,199	\$0	\$1,208	\$9,259
3		Feedwater & Miscellaneous BOP Systems								
3.1	Feedwater System	\$1,361	\$2,333	\$1,167	\$0	\$4,861	\$851	\$0	\$857	\$6,568
3.2	Water Makeup & Pretreating	\$2,168	\$217	\$1,228	\$0	\$3,613	\$632	\$0	\$849	\$5,095
3.3	Other Feedwater Subsystems	\$888	\$291	\$277	\$0	\$1,456	\$255	\$0	\$257	\$1,967
3.4	Service Water Systems	\$607	\$1,159	\$3,752	\$0	\$5,517	\$966	\$0	\$1,297	\$7,779
3.5	Other Boiler Plant Systems	\$270	\$98	\$245	\$0	\$613	\$107	\$0	\$108	\$828
3.6	Natural Gas Pipeline and Start-Up System	\$1,315	\$57	\$42	\$0	\$1,414	\$247	\$0	\$249	\$1,911
3.7	Waste Water Treatment Equipment	\$3,403	\$0	\$2,086	\$0	\$5,489	\$961	\$0	\$1,290	\$7,740
3.8	Spray Dryer Evaporator	\$6,399	\$0	\$3,705	\$0	\$10,105	\$1,768	\$0	\$2,375	\$14,248
3.9	Miscellaneous Plant Equipment	\$90	\$12	\$46	\$0	\$148	\$26	\$0	\$35	\$209
	Subtotal	\$16,502	\$4,166	\$12,548	\$0	\$33,216	\$5,813	\$0	\$7,316	\$46,344
4		Pulverized Coal Boiler & Accessories								
4.9	Pulverized Coal Boiler & Accessories	\$135,933	\$0	\$88,772	\$0	\$224,704	\$39,323	\$0	\$39,604	\$303,631
4.10	Selective Catalytic Reduction System	\$8,758	\$0	\$5,720	\$0	\$14,478	\$2,534	\$0	\$2,552	\$19,563
4.11	Boiler Balance of Plant	\$487	\$0	\$318	\$0	\$805	\$141	\$0	\$142	\$1,088
4.12	Primary Air System	\$523	\$0	\$342	\$0	\$865	\$151	\$0	\$152	\$1,169
4.13	Secondary Air System	\$1,063	\$0	\$694	\$0	\$1,757	\$307	\$0	\$310	\$2,374
4.14	Induced Draft Fans	\$1,992	\$0	\$1,301	\$0	\$3,293	\$576	\$0	\$580	\$4,450
4.15	Major Component Rigging	\$34	\$0	\$22	\$0	\$56	\$10	\$0	\$10	\$76

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B12A-F2	Supercritical PC Flexible Plant (Tiers 1–2)				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	
4.16	Boiler Foundations	\$0	\$142	\$125	\$0	\$266	\$47	\$0	\$47	\$360
	Subtotal	\$148,790	\$142	\$97,293	\$0	\$246,225	\$43,089	\$0	\$43,397	\$332,711
5		Flue Gas Cleanup								
5.2	WFGD Absorber Vessels & Accessories	\$34,246	\$0	\$7,322	\$0	\$41,568	\$7,274	\$0	\$7,326	\$56,169
5.3	Other FGD	\$119	\$0	\$134	\$0	\$253	\$44	\$0	\$45	\$342
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$978	\$215	\$962	\$0	\$2,155	\$377	\$0	\$380	\$2,912
5.9	Particulate Removal (Bag House & Accessories)	\$1,133	\$0	\$714	\$0	\$1,847	\$323	\$0	\$326	\$2,496
5.12	Gas Cleanup Foundations	\$0	\$61	\$54	\$0	\$115	\$20	\$0	\$20	\$155
5.13	Gypsum Dewatering System	\$309	\$0	\$52	\$0	\$361	\$63	\$0	\$64	\$487
	Subtotal	\$36,785	\$276	\$9,238	\$0	\$46,299	\$8,102	\$0	\$8,160	\$62,562
7		Ductwork & Stack								
7.3	Ductwork	\$0	\$323	\$225	\$0	\$548	\$96	\$0	\$97	\$741
7.4	Stack	\$4,093	\$0	\$2,378	\$0	\$6,471	\$1,132	\$0	\$1,141	\$8,744
7.5	Duct & Stack Foundations	\$0	\$77	\$92	\$0	\$169	\$30	\$0	\$40	\$238
	Subtotal	\$4,093	\$401	\$2,695	\$0	\$7,188	\$1,258	\$0	\$1,277	\$9,723
8		Steam Turbine & Accessories								
8.1	Steam Turbine Generator & Accessories	\$41,057	\$0	\$4,616	\$0	\$45,673	\$7,993	\$0	\$8,050	\$61,716
8.2	Steam Turbine Plant Auxiliaries	\$819	\$0	\$1,742	\$0	\$2,561	\$448	\$0	\$451	\$3,460
8.3	Condenser & Auxiliaries ^A	\$15,483	\$0	\$5,253	\$0	\$20,737	\$3,629	\$0	\$3,655	\$28,021
8.4	Steam Piping	\$16,174	\$0	\$6,555	\$0	\$22,729	\$3,978	\$0	\$4,006	\$30,713
8.5	Turbine Generator Foundations	\$0	\$86	\$142	\$0	\$228	\$40	\$0	\$54	\$322
	Subtotal	\$73,534	\$86	\$18,308	\$0	\$91,928	\$16,087	\$0	\$16,216	\$124,231
9		Cooling Water System								
9.6	Component Cooling Water System ^B	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
	Subtotal	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
10		Ash & Spent Sorbent Handling Systems								
10.6	Ash Storage Silos	\$466	\$0	\$1,426	\$0	\$1,892	\$331	\$0	\$333	\$2,556
10.7	Ash Transport & Feed Equipment	\$1,749	\$0	\$1,733	\$0	\$3,482	\$609	\$0	\$614	\$4,705
10.9	Ash/Spent Sorbent Foundation	\$0	\$299	\$367	\$0	\$665	\$116	\$0	\$156	\$938
	Subtotal	\$2,215	\$299	\$3,526	\$0	\$6,039	\$1,057	\$0	\$1,103	\$8,199
11		Accessory Electric Plant								
11.1	Generator Equipment	\$1,473	\$0	\$1,111	\$0	\$2,585	\$452	\$0	\$456	\$3,493
11.2	Station Service Equipment	\$2,635	\$0	\$226	\$0	\$2,861	\$501	\$0	\$504	\$3,866
11.3	Switchgear & Motor Control	\$4,405	\$0	\$764	\$0	\$5,169	\$905	\$0	\$911	\$6,985
11.4	Conduit & Cable Tray	\$0	\$599	\$1,726	\$0	\$2,326	\$407	\$0	\$410	\$3,142
11.5	Wire & Cable	\$0	\$1,178	\$2,106	\$0	\$3,284	\$575	\$0	\$579	\$4,438
11.6	Protective Equipment	\$32	\$0	\$112	\$0	\$145	\$25	\$0	\$26	\$196
11.7	Standby Equipment	\$417	\$0	\$385	\$0	\$801	\$140	\$0	\$141	\$1,083
11.8	Main Power Transformers	\$3,929	\$0	\$80	\$0	\$4,009	\$702	\$0	\$707	\$5,417

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Case:		B12A-F2	Supercritical PC Flexible Plant (Tiers 1–2)				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	
11.9	Electrical Foundations	\$0	\$87	\$221	\$0	\$307	\$54	\$0	\$72	\$434
	Subtotal	\$12,891	\$1,864	\$6,732	\$0	\$21,487	\$3,760	\$0	\$3,805	\$29,053
12 Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	\$337	\$0	\$60	\$0	\$397	\$70	\$0	\$70	\$537
12.3	Steam Turbine Control Equipment	\$331	\$0	\$37	\$0	\$368	\$64	\$0	\$65	\$497
12.5	Signal Processing Equipment	\$320	\$0	\$57	\$0	\$377	\$66	\$0	\$66	\$509
12.6	Control Boards, Panels & Racks	\$100	\$0	\$61	\$0	\$161	\$28	\$0	\$28	\$217
12.7	Distributed Control System Equipment	\$3,349	\$0	\$597	\$0	\$3,947	\$691	\$0	\$696	\$5,333
12.8	Instrument Wiring & Tubing	\$300	\$240	\$959	\$0	\$1,499	\$262	\$0	\$264	\$2,025
12.9	Other Instrumentation & Controls Equipment	\$356	\$0	\$825	\$0	\$1,181	\$207	\$0	\$208	\$1,596
	Subtotal	\$5,093	\$240	\$2,597	\$0	\$7,930	\$1,388	\$0	\$1,398	\$10,715
13 Improvements to Site										
13.1	Site Preparation	\$0	\$183	\$3,910	\$0	\$4,093	\$716	\$0	\$962	\$5,772
13.2	Site Improvements	\$0	\$1,004	\$1,326	\$0	\$2,330	\$408	\$0	\$547	\$3,285
13.3	Site Facilities	\$828	\$0	\$868	\$0	\$1,696	\$297	\$0	\$399	\$2,391
	Subtotal	\$828	\$1,187	\$6,104	\$0	\$8,119	\$1,421	\$0	\$1,908	\$11,448
14 Buildings & Structures										
14.2	Boiler Building	\$0	\$6,120	\$5,378	\$0	\$11,498	\$2,012	\$0	\$2,027	\$15,537
14.3	Steam Turbine Building	\$0	\$6,187	\$5,762	\$0	\$11,949	\$2,091	\$0	\$2,106	\$16,146
14.4	Administration Building	\$0	\$553	\$584	\$0	\$1,137	\$199	\$0	\$200	\$1,536
14.6	Water Treatment Buildings	\$0	\$150	\$137	\$0	\$287	\$50	\$0	\$51	\$387
14.7	Machine Shop	\$0	\$248	\$165	\$0	\$413	\$72	\$0	\$0	\$486
14.8	Warehouse	\$0	\$193	\$193	\$0	\$386	\$67	\$0	\$68	\$521
14.9	Other Buildings & Structures	\$0	\$139	\$118	\$0	\$258	\$45	\$0	\$45	\$348
14.10	Waste Treating Building & Structures	\$0	\$221	\$670	\$0	\$890	\$156	\$0	\$157	\$1,203
	Subtotal	\$0	\$13,810	\$13,007	\$0	\$26,818	\$4,693	\$0	\$4,654	\$36,165
	Total	\$326,267	\$23,645	\$179,550	\$0	\$529,462	\$92,656	\$0	\$95,264	\$717,382

^AACC; ^B Component cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
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Exhibit 5-182. Case B12A-F2 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$6,501
1-Month Maintenance Materials	\$949
1-Month Non-Fuel Consumables	\$535
1-Month Waste Disposal	\$333
25% of 1-Month Fuel Cost at 100% CF	\$976
2% of TPC	\$14,348
Total	\$23,643
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$8,853
0.5% of TPC (spare parts)	\$3,587
Total	\$12,440
Other Costs	
Initial Cost for Catalyst and Chemicals	\$879
Land	\$117
Other Owner's Costs	\$107,607
Financing Costs	\$19,369
Total Overnight Costs (TOC)	\$881,438

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-183. Case B12A-F2 initial and annual operating and maintenance costs

Case:	B12A-F2	– Supercritical PC Flexible Plant (Tiers 1–2)			Cost Base:	Dec 2018
Plant Size (MW, gross):	300	Heat Rate-net (Btu/kWh):			8,802	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$ /hour		Skilled Operator:	2.0	
Operating Labor Burden:	30.0	% of base		Operator:	5.0	
Labor O-H Charge Rate:	25.0	% of labor		Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	9.0	
Fixed Operating Costs						
					Annual Cost (\$)	
Annual Operating Labor:					\$3,945,942	
Maintenance Labor:					\$6,456,438	
Administrative & Support Labor:					\$2,600,595	
Property Taxes and Insurance:					\$14,347,640	
Total:					\$27,350,615	
Variable Operating Costs						
					Annual Cost (\$)	
Maintenance Material:					\$11,393,714 x CF	
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)	
Water (/1000 gallons):	0	191	\$1.90	\$0	\$132,327 x CF	
Makeup and Waste Water Treatment Chemicals (ton):	0	0.568	\$550.00	\$0	\$114,106 x CF	
Brominated Activated Carbon (ton):	0	0.542	\$1,600.00	\$0	\$316,533 x CF	
Enhanced Hydrated Lime (ton):	0	13.44	\$240.00	\$0	\$1,177,734 x CF	
Limestone (ton):	0	239	\$22.00	\$0	\$1,918,504 x CF	
Ammonia (19 wt%, ton):	0	22.6	\$300.00	\$0	\$2,473,448 x CF	
SCR Catalyst (ft³):	3,286	5.35	\$150.00	\$879,194	\$293,065 x CF	
Subtotal:				\$879,194	\$6,425,716 x CF	
Waste Disposal						
Fly Ash (ton):	0	235	\$38.00	\$0	\$3,261,861 x CF	
Bottom Ash (ton):	0	52.6	\$38.00	\$0	\$729,438 x CF	
SCR Catalyst (ft³):	5,861	5.35	\$2.50	\$0	\$4,884 x CF	
Subtotal:				\$0	\$3,996,183 x CF	
By-Products						
Gypsum (ton):	0	363	\$0.00	\$0	\$0	
Subtotal:				\$0	\$0	
Variable Operating Costs Total:				\$879,194	\$21,815,614 x CF	
Fuel Cost						
Illinois Number 6 (ton):	0	2,469	\$51.96	\$0	\$46,826,518 x CF	
Fuel Costs Total:				\$0	\$46,826,518 x CF	

5.7.13.1 Cost Differential Justifications

The primary contributors to the capital cost differential when comparing Case B12A-F2 to Case B12A-F1 are outlined below:

- Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter

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- Flexibility Option 34 — Installation of more robust direct flame detection sensors and more thermocouples to monitor temperatures within the boiler
- Flexibility Option 10 — Installation of additional condensate drains and instrumentation for condensate detection in all boiler headers and piping systems

The justifications for the capital cost differentials when comparing Case B12A-F2 to Case B12A-F1 are outlined below:

- Account 2.2 cost increases due to modifications to the coal system. The following flexibility option impacted the cost of Account 2.2:
 - Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
- Account 2.9 is not expected to increase because the modifications to the burner design (Flexibility Option 27) would not be expected to impact the foundations.
- Accounts 3.3, 3.5, and 3.9 increase due to an increase in engineering design, equipment, and material required for additional components installed within the boiler drum, boiler steam headers, and steam piping. The following flexibility options impacted the cost of accounts 3.3, 3.5, and 3.9:
 - Flexibility Option 10 — Installation of condensate drains and instrumentation for condensate detection in all boiler headers and piping systems
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)
- Account 4.9 cost increases due to the additional equipment provided by the boiler OEM, additional sub-system features within the boiler island components (e.g., header and piping drain taps), additional engineering and installation labor required for these options. The following flexibility options impacted the cost of Account 4.9:
 - Flexibility Option 10 — Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems
 - Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
 - Flexibility Option 34 — Installation of direct flame detection sensors and more thermocouples to monitor temperatures within the boiler
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)
- Account 4.11 cost increases due to the additional equipment requiring boiler balance of plant sub-system engineering design (e.g., instrument air lines, electrical routing, more intricate pipe routing for clash avoidance, and additional maintenance access points) and material installation. The following flexibility options impacted the cost of Account 4.11:

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- Flexibility Option 10 — Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems
 - Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)
- Account 11 (sub-accounts 11.2, 11.4–11.6) cost increases due to the installation of additional instrumentation and auxiliary power wiring, controls wiring, and communications wiring to operate the additional components. The following flexibility options impacted the cost of Account 11:
 - Flexibility Option 10 — Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems
 - Flexibility Option 34 — Installation of direct flame detection sensors and more thermocouples to monitor temperatures within the boiler
 - Flexibility Option 49 — Auxiliary load optimization
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)
- Account 11.3 cost increases due to the expected relay/MCC modifications required for greater optimization of auxiliary load demand at reduced plant loads; these expected upgrades would not be expected to have foundation cost increase impacts. The following flexibility option impacted the cost of Account 11.3:
 - Flexibility Option 49 — Auxiliary load optimization
- Account 12 cost increased due to the additional equipment (hardware) supply, material supply (e.g., wiring, conduit, raceway), installation hours for physically installing the components and commissioning hours where specialists program and tune the system prior to commercial operation. The following flexibility options impacted the cost of Account 12:
 - Flexibility Option 10 — Installation of condensate drains, and instrumentation for condensate detection, in all boiler headers and piping systems
 - Flexibility Option 27 — Low-load coal burner flame stabilization with dedicated flame stabilization burner with lower heat input than igniter
 - Flexibility Option 34 — Installation of direct flame detection sensors and more thermocouples to monitor temperatures within the boiler
 - Flexibility Option 51 — Automated boiler blowdown and drains (full monitoring and operator control from control room)
 - Flexibility Option 65 — Automated prioritization of plant alarm signals to allow for simplified triage of plant information received in the control room

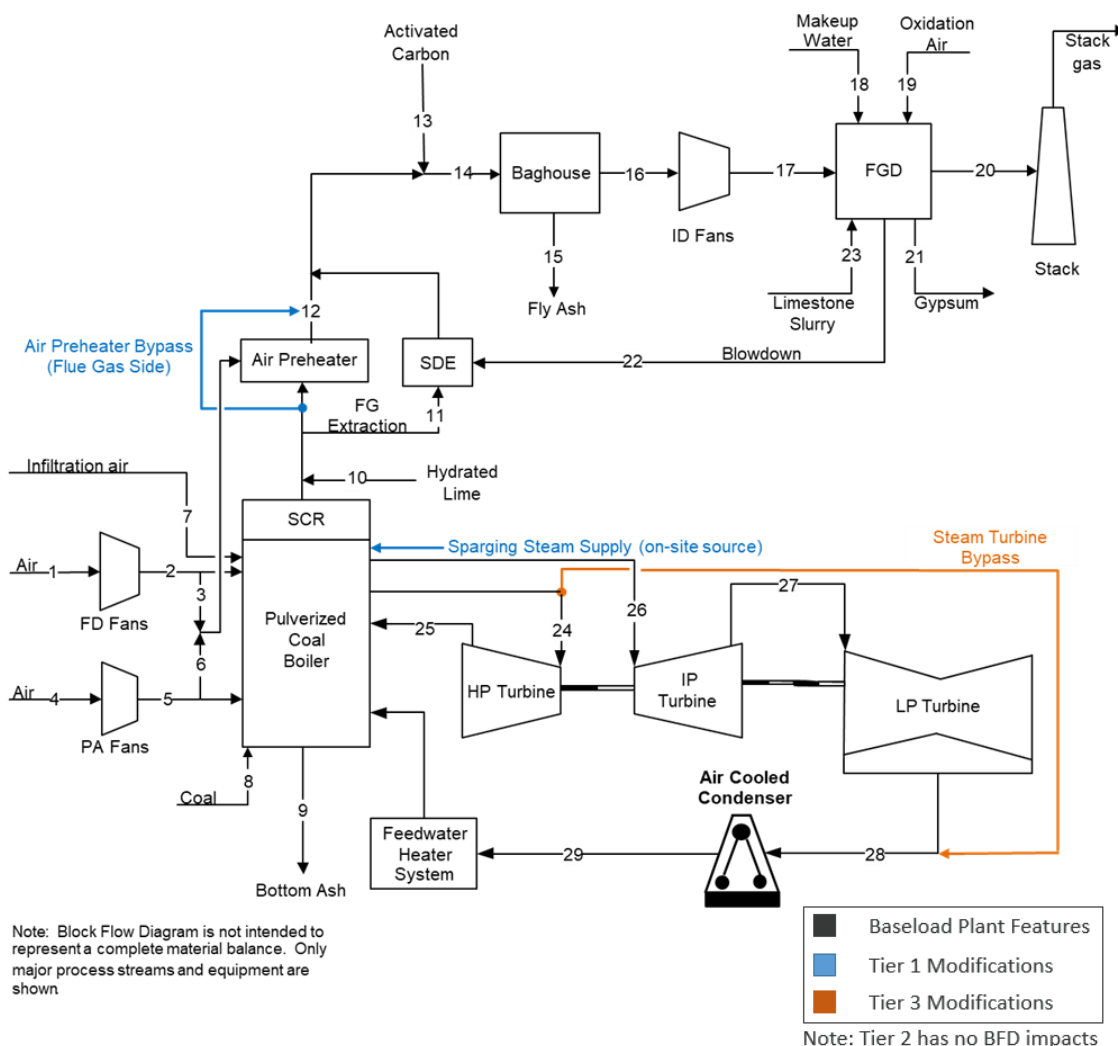
5.7.14 Case B12A-F3– PC Supercritical Flexible Plant with Tier 1, 2, and 3 Flexibility Options

The plant configuration for Case B12A-F3, supercritical flexible plant with Tier 1, 2, and 3 flexibility options, is similar to Case B12A-F2. Major modifications to the plant include the installation of a steam turbine bypass line. The full list of Tier 3 flexibility options was presented in Exhibit 4-16. The nominal gross plant output was maintained at 300 MW.

5.7.15 Case B12A-F3– Full Load Performance Results

The BFD for Case B12A-F3 is shown in Exhibit 5-184. Stream tables that outline process data for the numbered streams in the BFD are provided in Exhibit 5-185. Full stream tables are only provided for the 100 percent load point.

Exhibit 5-184. Case B12A-F3 block flow diagram



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-185. Case B12A-F3 stream table, supercritical unit with tiers 1–3 flexibility options

	1	2	3	4	5	6	7	8	9	10
V-L Mole Fraction										
Ar	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0092	0.0000	0.0000	0.0000
CO ₂	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000
O ₂	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	27,991	27,991	922	4,940	4,940	1,020	558	0	0	0
V-L Flowrate (kg/hr)	807,742	807,742	26,601	142,543	142,543	29,436	16,107	0	0	5
Solids Flowrate (kg/hr)	0	0	0	0	0	0	0	93,332	1,988	503
Temperature (°C)	15	21	21	15	23	23	15	15	1,316	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	30.23	36.30	36.30	30.23	38.69	38.69	30.23	---	---	---
AspenPlus Enthalpy (kJ/kg) ^B	-97.58	-91.51	-91.51	-97.58	-89.12	-89.12	-97.58	-2,119.02	1,312.68	-13,402.95
Density (kg/m ³)	1.2	1.3	1.3	1.2	1.3	1.3	1.2	---	---	1,003.6
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015
V-L Flowrate (lb _{mol} /hr)	61,710	61,710	2,032	10,890	10,890	2,249	1,231	0	0	1
V-L Flowrate (lb/hr)	1,780,767	1,780,767	58,646	314,253	314,253	64,896	35,509	0	0	11
Solids Flowrate (lb/hr)	0	0	0	0	0	0	0	205,763	4,383	1,109
Temperature (°F)	59	70	70	59	74	74	59	59	2,400	59
Pressure (psia)	14.7	15.6	15.6	14.7	16.0	16.0	14.7	14.7	14.3	14.7
Steam Table Enthalpy (Btu/lb) ^A	13.0	15.6	15.6	13.0	16.6	16.6	13.0	---	---	---
AspenPlus Enthalpy (Btu/lb) ^B	-42.0	-39.3	-39.3	-42.0	-38.3	-38.3	-42.0	-911.0	564.3	-5,762.2
Density (lb/ft ³)	0.076	0.079	0.079	0.076	0.080	0.080	0.076	---	---	62.650

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-185. Case B12A-F3 stream table, supercritical unit with tiers 1–3 flexibility options, cont'd

	11	12	13	14	15	16	17	18	19	20
V-L Mole Fraction										
Ar	0.0087	0.0088	0.0000	0.0087	0.0000	0.0087	0.0087	0.0000	0.0092	0.0081
CO ₂	0.1463	0.1379	0.0000	0.1372	0.0000	0.1372	0.1372	0.0000	0.0003	0.1245
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.0889	0.0844	0.0000	0.0918	0.0000	0.0918	0.0918	0.9967	0.0099	0.1512
HCl	0.0001	0.0001	0.0000	0.0001	0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
N ₂	0.7312	0.7336	0.0000	0.7277	0.0000	0.7277	0.7277	0.0000	0.7732	0.6801
O ₂	0.0226	0.0332	0.0000	0.0325	0.0000	0.0325	0.0325	0.0000	0.2074	0.0360
SO ₂	0.0021	0.0020	0.0000	0.0020	0.0000	0.0020	0.0020	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0000	0.0000	0.1148	0.0000	0.0000	0.0006	0.0000	0.0000
CaCl ₂	0.0000	0.0000	0.0000	0.0001	0.8852	0.0000	0.0000	0.0028	0.0000	0.0000
Total	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	1,683	33,673	0	35,639	2	35,637	35,637	4,964	1,506	39,846
V-L Flowrate (kg/hr)	50,050	999,641	0	1,054,941	230	1,054,705	1,054,705	90,825	43,466	1,144,973
Solids Flowrate (kg/hr)	431	8,122	20	8,654	8,659	0	0	816	0	0
Temperature (°C)	384	143	15	143	143	143	156	27	15	57
Pressure (MPa, abs)	0.10	0.10	0.10	0.10	0.10	0.09	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	---	---	289.08	302.74	---	30.23	297.86
AspenPlus Enthalpy (kJ/kg) ^B	-2,278.03	-2,399.41	-6.79	-2,459.22	-1,001.46	-2,471.50	-2,457.85	-15,763.98	-97.58	-2,944.12
Density (kg/m ³)	0.5	0.8	---	0.8	2,150.2	0.8	0.9	1,002.4	1.2	1.1
V-L Molecular Weight	29.738	29.687	---	29.600	104.953	29.596	29.596	18.297	28.857	28.735
V-L Flowrate (lb _{mol} /hr)	3,710	74,235	0	78,572	5	78,567	78,567	10,944	3,321	87,845
V-L Flowrate (lb/hr)	110,342	2,203,831	0	2,325,746	508	2,325,226	2,325,226	200,234	95,827	2,524,233
Solids Flowrate (lb/hr)	950	17,907	45	19,078	19,090	0	0	1,799	0	0
Temperature (°F)	724	289	59	289	289	289	312	80	59	135
Pressure (psia)	14.3	14.0	14.7	14.0	14.0	13.8	15.1	14.7	14.7	14.8
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	---	---	124.3	130.2	---	13.0	128.1
AspenPlus Enthalpy (Btu/lb) ^B	-979.4	-1,031.6	-2.9	-1,057.3	-430.5	-1,062.6	-1,056.7	-6,777.3	-42.0	-1,265.7
Density (lb/ft ³)	0.033	0.052	---	0.051	134.232	0.051	0.054	62.580	0.076	0.067

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-185. Case B12A-F3 stream table, supercritical unit with tiers 1–3 flexibility options, cont'd

	21	22	23	24	25	26	27	28	29
V-L Mole Fraction									
Ar	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO ₂	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H ₂ O	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₂	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO ₃	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
NaCl	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CaCl ₂	0.0000	0.0048	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flowrate (kg _{mol} /hr)	85	284	1,171	48,442	36,579	36,579	32,721	28,585	32,818
V-L Flowrate (kg/hr)	1,526	5,249	21,096	872,698	658,981	658,981	589,472	514,974	591,221
Solids Flowrate (kg/hr)	13,727	80	9,031	0	0	0	0	0	0
Temperature (°C)	15	57	15	593	343	593	288	45	45
Pressure (MPa, abs)	0.10	0.10	0.10	24.23	4.85	4.11	0.51	0.01	1.31
Steam Table Enthalpy (kJ/kg) ^A	---	---	---	3,477.96	3,052.30	3,658.08	3,037.83	2,403.96	191.45
AspenPlus Enthalpy (kJ/kg) ^B	-12,513.34	-15,495.43	-14,994.25	-12,502.33	-12,928.00	-12,322.21	-12,942.47	-13,576.33	-15,788.84
Density (kg/m ³)	880.9	979.4	1,003.7	69.2	18.9	10.5	2.0	0.1	990.5
V-L Molecular Weight	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flowrate (lb _{mol} /hr)	187	626	2,581	106,797	80,643	80,643	72,137	63,020	72,351
V-L Flowrate (lb/hr)	3,364	11,573	46,509	1,923,970	1,452,805	1,452,805	1,299,563	1,135,323	1,303,419
Solids Flowrate (lb/hr)	30,263	176	19,910	0	0	0	0	0	0
Temperature (°F)	59	135	59	1,100	649	1,100	550	114	114
Pressure (psia)	14.7	14.7	14.7	3,514.7	702.9	595.9	74.5	1.4	190.2
Steam Table Enthalpy (Btu/lb) ^A	---	---	---	1,495.3	1,312.3	1,572.7	1,306.0	1,033.5	82.3
AspenPlus Enthalpy (Btu/lb) ^B	-5,379.8	-6,661.8	-6,446.4	-5,375.0	-5,558.0	-5,297.6	-5,564.3	-5,836.8	-6,788.0
Density (lb/ft ³)	54.996	61.143	62.658	4.319	1.181	0.655	0.126	0.004	61.838

^A Steam table reference conditions are 32.02°F and 0.089 psia

^B Aspen thermodynamic reference state is the component's constituent elements in an ideal gas state at 25°C and 1 atm

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At full load, the plant produces a net output of 273 MWe at a net plant efficiency of 38.9 percent (HHV basis). Full load performance for Case B12A-F3 is summarized in Exhibit 5-186. Exhibit 5-187 presents a detailed breakdown of auxiliary power requirements at full load.

Exhibit 5-186. Case B12A-F3 plant performance summary

Performance Summary	
Percent Load	100%
Total Gross Power, MWe	300
Nameplate Capacity, MWe	300
Total Auxiliaries, MWe	27
Total Auxiliaries, % of Gross Power	8.9%
Net Power, MWe	273
HHV Net Plant Efficiency, %	38.9%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,264 (8,781)
LHV Net Plant Efficiency, %	40.3%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,935 (8,469)
HHV Boiler Efficiency, %	87.5%
LHV Boiler Efficiency, %	90.7%
Steam Turbine Cycle Efficiency, %	48.8%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,384 (6,999)
Condenser Duty, GJ/hr (MMBtu/hr)	1,142 (1,082)
As-Received Coal Feed, kg/hr (lb/hr)	93,332 (205,763)
Limestone Sorbent Feed, kg/hr (lb/hr)	9,031 (19,910)
HHV Thermal Input, kWt	703,496
LHV Thermal Input, kWt	678,530
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (0.9)
Excess Air, %	20.0%

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Exhibit 5-187. Case B12A-F3 plant power summary

Power Summary	
Percent Load	100%
Steam Turbine Power, MWe	300
Total Gross Power, MWe	300
Nameplate Capacity	300
Auxiliary Load Summary	
Activated Carbon Injection, kWe	14
Air Cooled Condenser Fans	3,580
Ancillary Glycol Cooling Loops	250
Ash Handling, kWe	315
Baghouse, kWe	42
Boiler Circulation Pump, kWe	0
Boiler Feedwater Pump, kWe	10,200
Coal Handling and Conveying, kWe	200
Condensate Pumps, kWe	286
Dry Sorbent Injection, kWe	25
Flue Gas Desulfurizer, kWe	1,440
Forced Draft Fans, kWe	1,460
Ground Water Pumps, kWe	24
Induced Draft Fans, kWe	4,270
Miscellaneous Balance of Plant, ^A kWe	1,250
Primary Air Fans, kWe	364
Pulverizers, kWe	1,030
SCR, kWe	15
Sorbent Handling & Reagent Preparation, kWe	435
Spray Dryer Evaporator, kWe	103
Steam Turbine Auxiliaries, kWe	350
Transformer Losses, kWe	970
Total Auxiliaries, MWe	27
Net Power, MWe	273

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

5.7.15.1 Environmental Performance

The environmental targets for emissions of Hg, NO_x, SO₂, and PM were presented in Section 4.4. A summary of the plant air emissions for Case B12A-F3 is presented in Exhibit 5-188. SO₂ emissions are utilized as a surrogate for HCl emissions; therefore, HCl is not reported.

Exhibit 5-188. Case B12A-F3 air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year) ^A	kg/MWh (lb/MWh) ^B
SO ₂	0.035 (0.081)	654 (721)	0.293 (0.645)
NO _x	0.038 (0.087)	709 (782)	0.318 (0.700)
Particulate	0.005 (0.011)	91 (101)	0.041 (0.090)
Hg	1.61E-7 (3.75E-7)	0.003 (0.003)	1.36E-6 (3.00E-6)
CO ₂	86 (201)	1,625,752 (1,792,085)	728 (1,605)
CO ₂ ^C	-	-	799 (1,761)
mg/Nm ³			
Particulate Concentration ^{D,E}	15.34		

^A Calculations based on an 85% capacity factor

^B Emissions based on gross power, except where otherwise noted

^C CO₂ emissions based on net power instead of gross power

^D Concentration of particles in the flue gas after the baghouse

^E Normal conditions given at 32°F and 14.696 psia

SO₂ emissions are controlled using a wet limestone forced oxidation scrubber that achieves a removal efficiency of 98 percent. The byproduct calcium sulfate is dewatered and stored on site. The wallboard grade material can potentially be marketed and sold, but since it is highly dependent on local market conditions, no byproduct credit was taken. The saturated flue gas exiting the scrubber is vented through the plant stack.

NO_x boiler emissions are controlled to about 0.35 lb/MMBtu using LNBs and OFA. An SCR unit then further reduces the NO_x concentration by 75.0 percent to about 0.09 lb/MMBtu.

Particulate emissions are controlled using a pulse jet fabric filter, which operates at an efficiency of 99.9 percent.

The total reduction in mercury emission via the combined control equipment (SCR, ACI, fabric filter, DSI, and FGD system) is 94.5 percent.

CO₂ emissions represent the uncontrolled discharge from the process.

The carbon balance for the plant is shown in Exhibit 5-189. The carbon input to the plant consists of carbon in the coal, carbon in the air, PAC, and carbon in the limestone reagent used in the FGD absorber. Carbon in the air is not neglected here since the Aspen model accounts for air components throughout. Carbon leaves the plant mostly as CO₂ through the stack; however, the PAC is captured in the fabric filter, unburned carbon remains in the bottom ash, and some leaves as gypsum.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-189. Case B12A-F3 carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	59,494 (131,163)	Stack Gas	59,588 (131,370)
Air (CO ₂)	137 (303)	FGD Product	71 (156)
PAC	20 (45)	Baghouse	732 (1,614)
FGD Reagent	916 (2,020)	Bottom Ash	178 (392)
Total	60,569 (133,531)	Total	60,569 (133,531)

Exhibit 5-190 shows the sulfur balance for the plant. Sulfur input comes solely from the sulfur in the coal. Sulfur output includes the sulfur recovered from the FGD as gypsum, sulfur captured in the fabric filter via hydrated lime, and sulfur emitted in the stack gas.

Exhibit 5-190. Case B12A-F3 sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	2,339 (5,157)	FGD Product	2,200 (4,850)
		Stack Gas	46 (101)
		Baghouse	94 (206)
Total	2,339 (5,157)	Total	2,339 (5,157)

Exhibit 5-191 shows the water balance for Case B12A-F3.

Water demand represents the total amount of water required for a particular process. Some water is recovered within the process and is reused as internal recycle. The difference between demand and recycle is raw water withdrawal. Raw water withdrawal is defined as the water removed from the ground or diverted from a POTW for use in the plant and was assumed to be provided 50 percent by a POTW and 50 percent from ground water. Raw water withdrawal can be represented by the water metered from a raw water source and used in the plant processes for all purposes, such as FGD makeup, BFW makeup, and cooling tower makeup. The difference between water withdrawal and process water discharge is defined as water consumption and can be represented by the portion of the raw water withdrawn that is evaporated, transpired, incorporated into products or otherwise not returned to the water source from which it was withdrawn. Water consumption represents the net impact of the plant process on the water source.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-191. Case B12A-F3 water balance

Water Use	Water Demand	Internal Recycle	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)	m ³ /min (gpm)
Desulfurizer Makeup	1.0 (257)	–	1.0 (257)	–	1.0 (257)
Deaerator Vent	–	–	–	0.0 (7.7)	0.0 (-7.7)
Condenser Makeup	0.0 (7.7)	–	0.0 (7.7)	–	0.0 (7.7)
BFW Makeup	0.0 (7.7)	–	0.0 (7.7)	–	0.0 (7.7)
Cooling Tower	–	–	–	–	–
BFW Blowdown	–	–	–	–	–
Total	1.0 (265)	–	1.0 (265)	0.0 (7.7)	1.0 (257)

5.7.15.2 Energy and Mass Balance Diagrams

An energy and mass balance diagram is shown for the Case B12A-F3 PC boiler, the FGD unit, and steam cycle as shown in Exhibit 5-192 and Exhibit 5-193.

An overall plant energy balance is provided in tabular form in Exhibit 5-194. The power out is the steam turbine power prior to generator losses. The power at the generator terminals (shown in Exhibit 5-186) is calculated by multiplying the power out by the full load generator efficiency of 98.5 percent.

Exhibit 5-192. Case B12A-F3 energy and mass balance, supercritical PC boiler

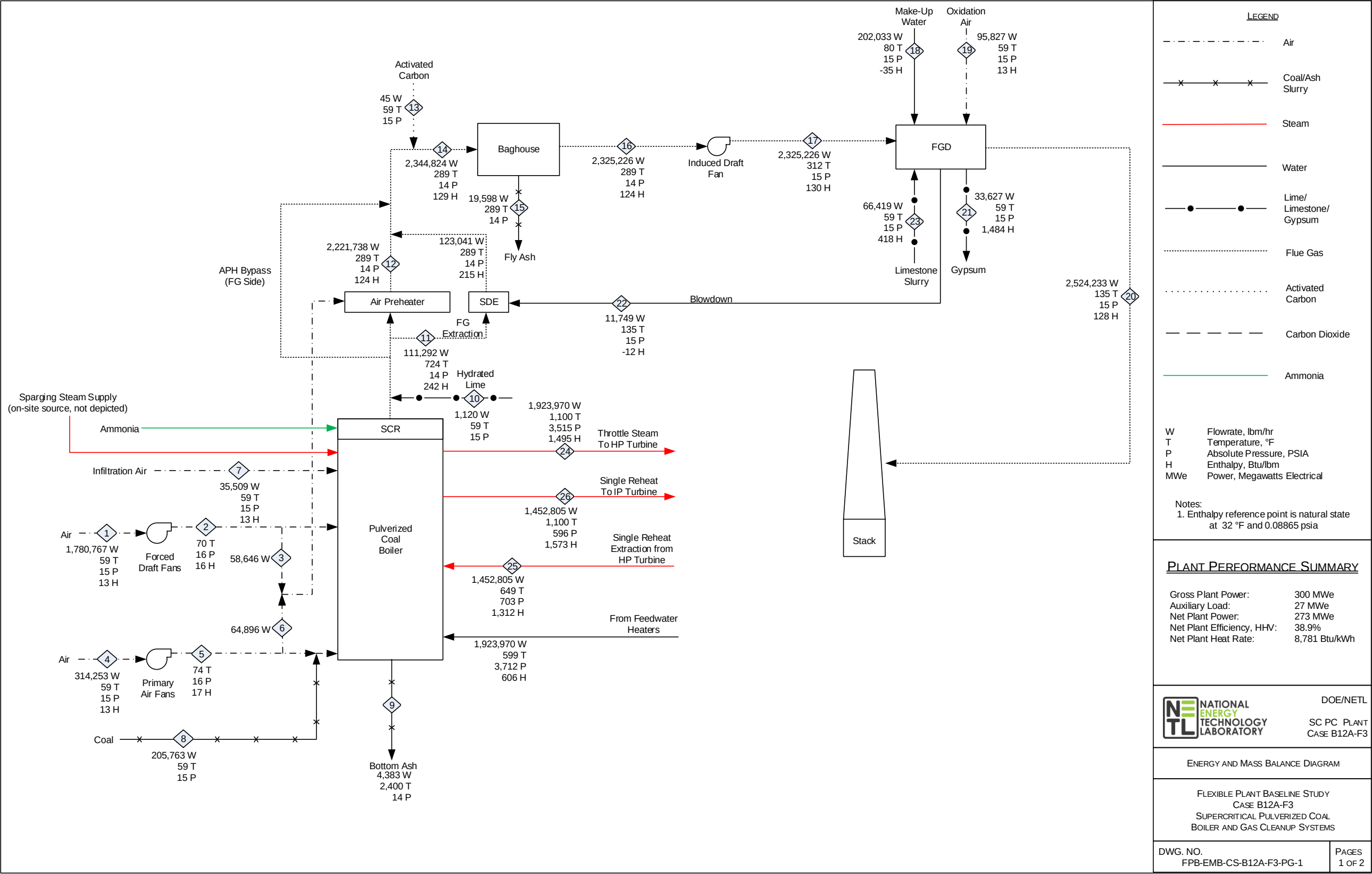
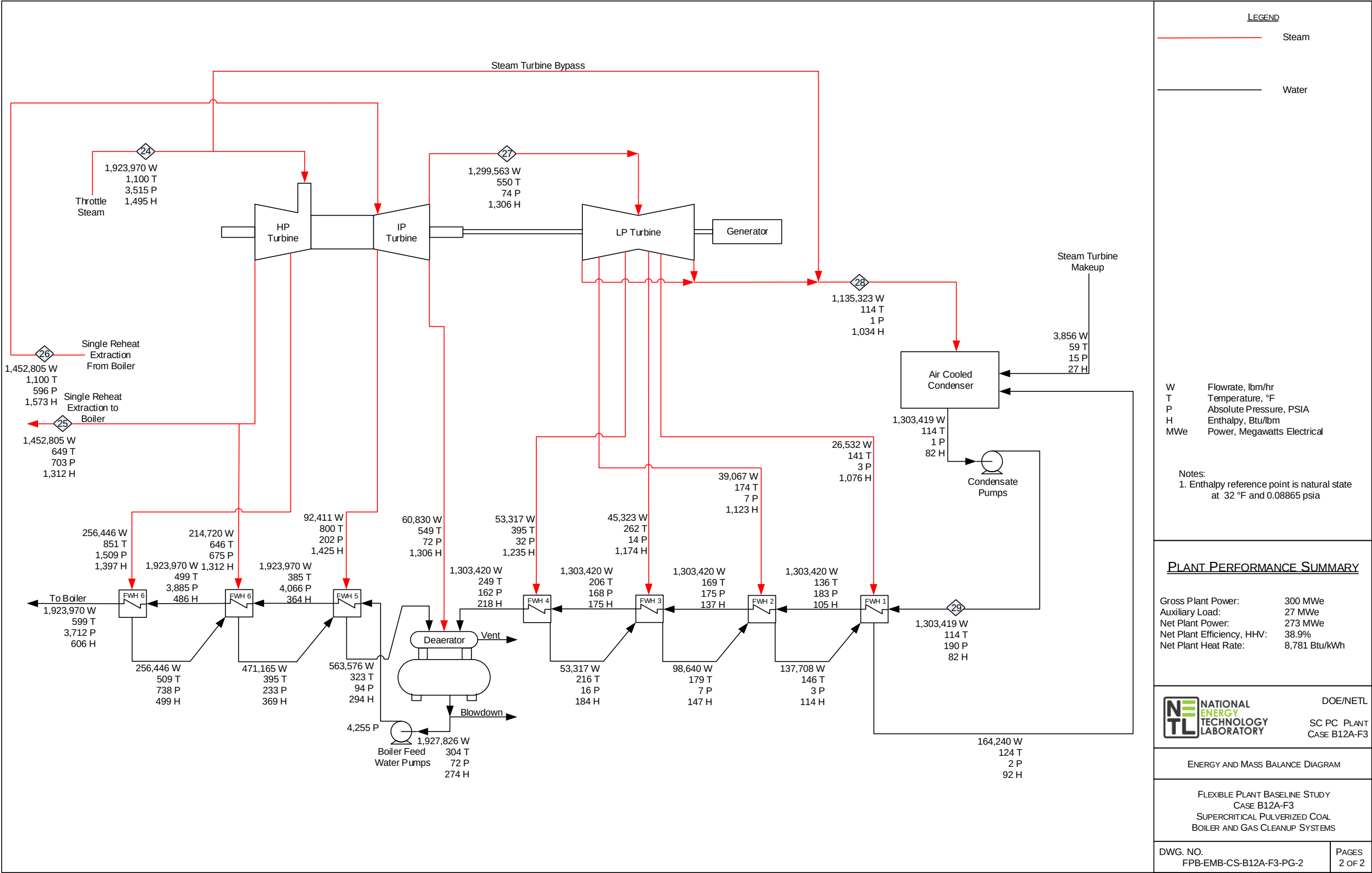


Exhibit 5-193. Case B12A-F3 energy and mass balance, supercritical steam cycle



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-194. Case B12A-F3 overall energy balance (0°C [32°F] reference)

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	2,533 (2,400)	2.1 (2.0)	–	2,535 (2,402)
Air	–	29 (28)	–	29 (28)
Raw Water Makeup	–	3.8 (3.6)	–	3.8 (3.6)
Limestone	–	0.2 (0.2)	–	0.2 (0.2)
Auxiliary Power	–	–	96 (91)	96 (91)
Total	2,533 (2,400)	35 (33)	96 (91)	2,664 (2,525)
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	2.6 (2.5)	–	2.6 (2.5)
Fly Ash	–	0.9 (0.9)	–	0.9 (0.9)
Stack Gas	–	341 (323)	–	341 (323)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Gypsum	–	0.9 (0.8)	–	0.9 (0.8)
Motor Losses and Design Allowances	–	–	17 (16)	17 (16)
Air Cooled Condenser Load ^A	–	1,142 (1,082)	–	1,142 (1,082)
Blowdown Streams and Deaerator Vent	–	1.1 (1.1)	–	1.1 (1.1)
<i>Ambient Losses^B</i>	–	68 (65)	–	68 (65)
Power	–	–	1,080 (1,024)	1,080 (1,024)
Total	0.0 (0.0)	1,557 (1,476)	1,097 (1,040)	2,654 (2,516)
<i>Unaccounted Energy^C</i>	–	–	–	9.6 (9.1)

^A Includes condenser load only

^B Ambient losses include all losses to the environment through radiation, convection, etc. Sources of these losses include the boiler, reheater, superheater, and transformers

^C By difference

5.7.16 Case B12A-F3 – Part Load Performance Results

Plant performance results are summarized at each discrete load point in Exhibit 5-195. Exhibit 5-196 displays a detailed breakdown of the auxiliary power consumption at each discrete load point. Air emissions at each discrete load point are summarized in Exhibit 5-197.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
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Exhibit 5-195. Case B12A-F3 part load plant performance summary

Performance Summary					
Percent Load	100%	75%	50%	30%	20%
Total Gross Power, MWe	300	225	150	90	60
Nameplate Capacity, MWe	300	300	300	300	300
Total Auxiliaries, MWe	27	19	12	7	5
Total Auxiliaries, % of Gross Power	8.9%	8.4%	8.0%	8.2%	8.6%
Net Power, MWe	273	206	138	83	55
HHV Net Plant Efficiency, %	38.9%	38.3%	37.3%	35.8%	34.5%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,264 (8,781)	9,394 (8,904)	9,640 (9,137)	10,056 (9,531)	10,426 (9,882)
LHV Net Plant Efficiency, %	40.3%	39.7%	38.7%	37.1%	35.8%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,935 (8,469)	9,061 (8,588)	9,298 (8,813)	9,699 (9,193)	10,056 (9,531)
HHV Boiler Efficiency, %	87.5%	87.5%	87.5%	87.5%	87.6%
LHV Boiler Efficiency, %	90.7%	90.7%	90.7%	90.7%	90.8%
Steam Turbine Cycle Efficiency, %	48.8%	47.8%	46.4%	44.6%	43.1%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,384 (6,999)	7,526 (7,133)	7,758 (7,353)	8,079 (7,657)	8,344 (7,908)
Condenser Duty, GJ/hr (MMBtu/hr)	1,142 (1,082)	881 (835)	617 (585)	397 (377)	280 (265)
As-Received Coal Feed, kg/hr (lb/hr)	93,332 (205,763)	71,336 (157,269)	49,012 (108,054)	30,615 (67,495)	21,070 (46,451)
Limestone Sorbent Feed, kg/hr (lb/hr)	9,031 (19,910)	6,917 (15,249)	4,771 (10,519)	2,995 (6,602)	2,067 (4,557)
HHV Thermal Input, kWt	703,496	537,696	369,433	230,763	158,815
LHV Thermal Input, kWt	678,530	518,615	356,323	222,574	153,179
Raw Water Withdrawal, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (1.0)	0.004 (1.0)	0.004 (1.0)	0.004 (0.9)	0.004 (1.0)
Raw Water Consumption, (m ³ /min)/MWnet (gpm/MWnet)	0.004 (0.9)	0.004 (0.9)	0.004 (1.0)	0.003 (0.9)	0.004 (1.0)
Excess Air, %	20.0%	22.1%	26.9%	33.0%	37.0%

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-196. Case B12A-F3 part load plant power summary

Power Summary					
Percent Load	100%	75%	50%	30%	20%
Steam Turbine Power, MWe	300	225	150	90	60
Total Gross Power, MWe	300	225	150	90	60
Nameplate Capacity, MWe	300	300	300	300	300
Auxiliary Load Summary					
Activated Carbon Injection, kWe	14	10	7	5	3
Air Cooled Condenser Fans, kWe	3,580	3,570	2,510	1,500	930
Ancillary Glycol Cooling Loops, kWe	250	250	250	250	250
Ash Handling, kWe	315	238	160	98	66
Baghouse, kWe	42	32	21	13	9
Boiler Circulation Pump, kWe	0	0	0	83	55
Boiler Feedwater Pump, kWe	10,200	5,430	2,330	860	400
Coal Handling and Conveying, kWe	200	150	110	70	50
Condensate Pumps, kWe	286	187	123	82	61
Dry Sorbent Injection, kWe	25	18	10	5	3
Flue Gas Desulfurizer, kWe	1,440	1,310	1,280	990	680
Forced Draft Fans, kWe	1,460	1,030	560	230	100
Ground Water Pumps, kWe	24	18	13	9	7
Induced Draft Fans, kWe	4,270	2,870	1,560	700	360
Miscellaneous Balance of Plant, ^A kWe	1,250	1,250	1,250	1,250	1,250
Primary Air Fans, kWe	364	283	189	77	39
Pulverizers, kWe	1,030	790	540	340	230
SCR, kWe	15	13	10	7	5
Sorbent Handling and Reagent Preparation, kWe	435	333	230	144	100
Spray Dryer Evaporator, kWe	103	78	54	33	23
Steam Turbine Auxiliaries, kWe	350	350	350	350	350
Transformer Losses, kWe	970	730	480	290	190
Total Auxiliaries, MWe	27	19	12	7	5
Net Power, MWe	273	206	138	83	55

^A Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-197. Case B12A-F3 part load air emissions summary

Emissions Summary					
Percent Load	100%	75%	50%	30%	20%
SO ₂ , kg/MWhgross (lb/MWhgross)	0.293 (0.645)	0.299 (0.659)	0.309 (0.682)	0.324 (0.713)	0.335 (0.739)
NO _x , kg/MWhgross (lb/MWhgross)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)	0.318 (0.700)
Particulate, kg/MWhgross (lb/MWhgross)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)	0.041 (0.090)
Hg, kg/MWhgross (lb/MWhgross)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)	1.36E-6 (3.00E-6)
CO ₂ , kg/MWhgross (lb/MWhgross)	728 (1,605)	742 (1,637)	767 (1,690)	800 (1,764)	827 (1,823)
CO ₂ , kg/MWhnet (lb/MWhnet)	799 (1,761)	811 (1,787)	833 (1,837)	871 (1,921)	905 (1,995)
Particulate Concentration, ^{A,B} mg/Nm ³	15.34	14.80	13.83	12.68	11.93

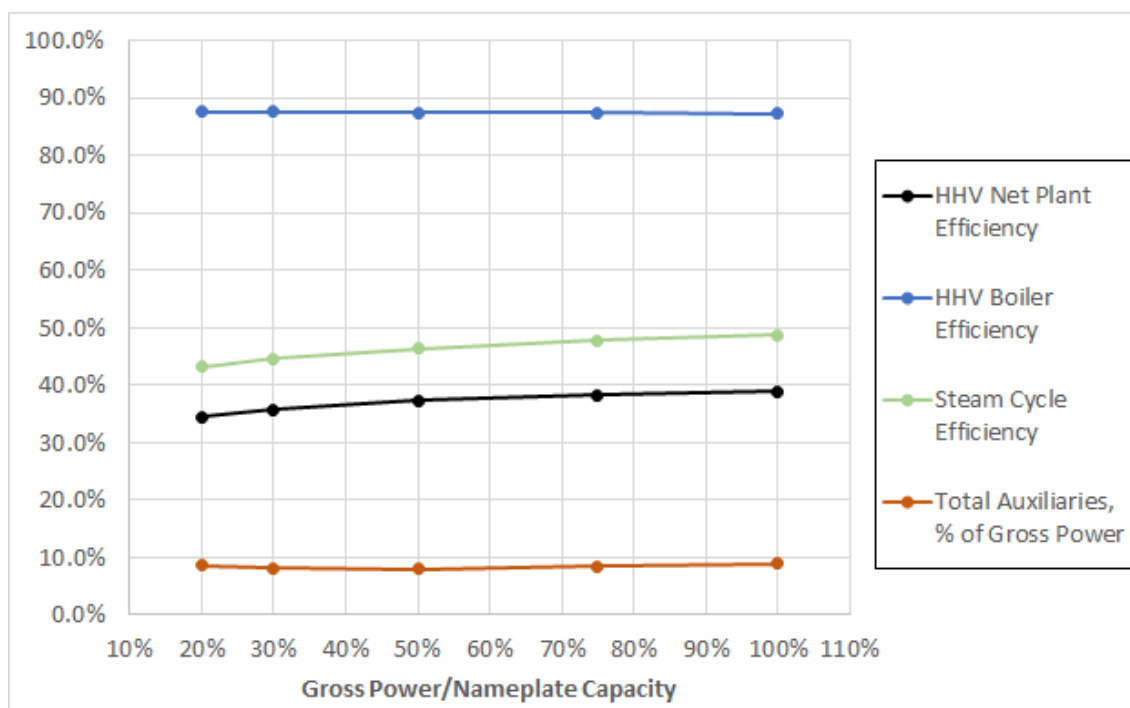
^A Concentration of particles in the flue gas after the baghouse

^B Normal conditions given at 32°F and 14.696 psia

Case B12A-F3 air emissions remained below the environmental target emission limits across the entire load range. Hg, NO_x, and PM emissions are maintained at constant levels across the load. SO₂ emissions increase as load is reduced but are kept below the environmental target emission limit.

Exhibit 5-198 displays the Case B12A-F3 itemized efficiencies (HHV net plant efficiency, HHV boiler efficiency, and steam cycle efficiency) and normalized auxiliary power consumption across the load range.

Exhibit 5-198. Case B12A-F3 part load itemized efficiencies



CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

The Case B12A-F3 itemized heat rates are similar to those presented in Case B12A-F2. VFDs lead to a reduced auxiliary power consumption for the BFW pump and the PA, FD, and ID fans, which leads to a moderate reduction in the HHV NPHR compared to Case B12A-F2. Additionally, VFDs have a small impact on the modeled boiler heat rate due to their impact on PA and FD fan isentropic efficiency, but the impact is small, and has little effect on the overall NPHR.

5.7.17 Case B12A-F3 – Major Equipment List

Case B12A-F3 – Account 1: Coal and Sorbent Handling

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Bottom Trestle Dumper and Receiving Hoppers	N/A	180 tonne (200 ton)	2	0
2	Feeder	Belt	570 tonne/hr (630 tph)	2	0
3	Conveyor No. 1	Belt	1,130 tonne/hr (1,250 tph)	1	0
4	Transfer Tower No. 1	Enclosed	N/A	1	0
5	Conveyor No. 2	Belt	1,130 tonne/hr (1,250 tph)	1	0
6	As-Received Coal Sampling System	Two-stage	N/A	1	0
7	Stacker/Reclaimer	Traveling, linear	1,130 tonne/hr (1,250 tph)	1	0
8	Reclaim Hopper	N/A	20 tonne (20 ton)	2	1
9	Feeder	Vibratory	80 tonne/hr (80 tph)	2	1
10	Conveyor No. 3	Belt w/ tripper	150 tonne/hr (170 tph)	1	0
11	Crusher Tower	N/A	N/A	1	0
12	Coal Surge Bin w/ Vent Filter	Dual outlet	80 tonne (80 ton)	2	0
13	Crusher	Impactor reduction	8 cm x 0 - 3 cm x 0 (3 in x 0 - 1-1/4 in x 0)	2	0
14	As-Fired Coal Sampling System	Swing hammer	N/A	1	1
15	Conveyor No. 4	Belt w/trippper	150 tonne/hr (170 tph)	1	0
16	Transfer Tower No. 2	Enclosed	N/A	1	0
17	Coal Silo w/ Vent Filter and Slide Gates	Field erected	340 tonne (400 ton)	3	0
18	Activated Carbon Storage Silo and Feeder System	Shop assembled	Silo - 4 tonne (4 ton) Feeder - 20 kg/hr (50 lb/hr)	1	0
19	Hydrated Lime Storage Silo and Feeder System	Shop assembled	Silo - 90 tonne (100 ton) Feeder - 560 kg/hr (1,230 lb/hr)	1	0
20	Limestone Truck Unloading Hopper	N/A	30 tonne (40 ton)	1	0
21	Limestone Feeder	Belt	38 tonne/hr (42 tph)	1	0
22	Limestone Conveyor No. 1	Belt	38 tonne/hr (42 tph)	1	0
23	Limestone Reclaim Hopper	N/A	7 tonne (8 ton)	1	0
24	Limestone Reclaim Feeder	Belt	30 tonne/hr (33 tph)	1	0
25	Limestone Conveyor No. 2	Belt	30 tonne/hr (33 tph)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
26	Limestone Day Bin	w/ actuator	119 tonne (131 ton)	2	0

Case B12A-F3 – Account 2: Coal and Sorbent Preparation and Feed

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Coal Feeder	Gravimetric	17 tonne/hr (19 tph)	6	0
2	Coal Pulverizer	Rotary (Vertical)	17 tonne/hr (19 tph)	6	0
3	Limestone Weigh Feeder	Gravimetric	10 tonne/hr (11 tph)	1	1
4	Limestone Ball Mill	Rotary	10 tonne/hr (11 tph)	1	1
5	Limestone Mill Slurry Tank with Agitator	N/A	38,600 liters (10,000 gal)	1	1
6	Limestone Mill Recycle Pumps	Horizontal centrifugal	650 lpm @ 10m H ₂ O (170 gpm @ 40 ft H ₂ O)	1	1
7	Hydrocyclone Classifier	4 active cyclones in a 5-cyclone bank	160 lpm (40 gpm) per cyclone	1	1
8	Distribution Box	2-way	N/A	1	1
9	Limestone Slurry Storage Tank with Agitator	Field erected	215,000 liters (57,000 gal)	1	1
10	Limestone Slurry Feed Pumps	Horizontal centrifugal	450 lpm @ 9m H ₂ O (120 gpm @ 30 ft H ₂ O)	1	1

Case B12A-F3 – Account 3: Feedwater and Miscellaneous Balance of Plant Systems

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Demineralized Water Storage Tank	Vertical, cylindrical, outdoor	116,000 liters (31,000 gal)	2	0
2	Condensate Pumps	Vertical canned	10,900 lpm @ 200 m H ₂ O (2,900 gpm @ 500 ft H ₂ O)	1	1
3	Deaerator and Storage Tank	Horizontal spray type	962,000 kg/hr (2,121,000 lb/hr), 5 min. tank	1	0
4	Boiler Feed Pump	Barrel type, multi-stage, centrifugal	16,100 lpm @ 3,600 m H ₂ O (4,300 gpm @ 11,700 ft H ₂ O)	1	1
5	N/A				
6	LP Feedwater Heater 1A/1B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
7	LP Feedwater Heater 2A/2B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
8	LP Feedwater Heater 3A/3B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
9	LP Feedwater Heater 4A/4B	Horizontal U-tube	330,000 kg/hr (720,000 lb/hr)	2	0
10	HP Feedwater Heater 6	Horizontal U-tube	960,000 kg/hr (2,120,000 lb/hr)	1	0
11	HP Feedwater Heater 7	Horizontal U-tube	960,000 kg/hr (2,120,000 lb/hr)	1	0
12	HP Feedwater heater 8	Horizontal U-tube	960,000 kg/hr (2,120,000 lb/hr)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
13	Auxiliary Boiler	Shop fabricated, electrode boiler	20,000 kg/hr, 2.8 MPa, 343°C (40,000 lb/hr, 400 psig, 650°F)	1	0
14	Gas Pipeline	Underground, coated carbon steel, wrapped cathodic protection	N/A - For Start-up Only	1	0
15	Service Air Compressors	Flooded screw	28 m ³ /min @ 0.7 MPa (1,000 scfm @ 100 psig)	2	1
16	Instrument Air Dryers	Duplex, regenerative	28 m ³ /min (1,000 scfm)	2	1
17	Closed Cycle Cooling Heat Exchangers	Shell and tube	37 GJ/hr (35 MMBtu/hr) each	2	0
18	Closed Cycle Cooling Water Pumps	Horizontal centrifugal	14,600 lpm @ 30 m H ₂ O (3,900 gpm @ 100 ft H ₂ O)	2	1
19	Engine-Driven Fire Pump	Vertical turbine, diesel engine	3,785 lpm @ 88 m H ₂ O (1,000 gpm @ 290 ft H ₂ O)	1	1
20	Fire Service Booster Pump	Two-stage horizontal centrifugal	2,650 lpm @ 64 m H ₂ O (700 gpm @ 210 ft H ₂ O)	1	1
21	Raw Water Pumps	Stainless steel, single suction	240 lpm @ 20 m H ₂ O (60 gpm @ 60 ft H ₂ O)	2	1
22	Ground Water Pumps	Stainless steel, single suction	240 lpm @ 270 m H ₂ O (60 gpm @ 880 ft H ₂ O)	2	1
23	Filtered Water Pumps	Stainless steel, single suction	500 lpm @ 50 m H ₂ O (130 gpm @ 160 ft H ₂ O)	2	1
24	Filtered Water Tank	Vertical, cylindrical	480,000 liter (127,000 gal)	1	0
25	Makeup Water Demineralizer	Multi-media filter, cartridge filter, RO membrane assembly, electrodeionization unit	330 lpm (90 gpm)	1	1
26	Liquid Waste Treatment System	—	10 years, 24-hour storm	1	0
27	Process Water Treatment	Spray dryer evaporator	Flue Gas - 870 m ³ /min (30,550 acfm) @ 384°C (724°F) & 0.1 MPa (14 psia) Blowdown - 50 lpm (10 gpm) @ 20,020 ppmw Cl ⁻	2	1

Case B12A-F3 – Account 4: Pulverized Coal Boiler and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Boiler	Supercritical, once-through, wall-fired, low NOx burners, overfire air	960,000 kg/hr steam @ 24.1 MPa/593°C/593°C (2,120,000 lb/hr steam @ 3,500 psig/1,100°F/1,100°F)	1	0
2	Primary Air Fan	Centrifugal	78,000 kg/hr, 1,100 m ³ /min @ 107 cm WG (173,000 lb/hr, 37,800 acfm @ 42 in. WG)	2	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

3	Forced Draft Fan	Centrifugal	444,000 kg/hr, 6,100 m ³ /min @ 76 cm WG (979,000 lb/hr, 214,100 acfm @ 30 in. WG)	2	0
4	Induced Draft Fan	Centrifugal	580,000 kg/hr, 11,900 m ³ /min @ 116 cm WG (1,279,000 lb/hr, 420,400 acfm @ 46 in. WG)	2	0
5	SCR Reactor Vessel	Space for spare layer	1,090,000 kg/hr (2,410,000 lb/hr)	2	0
6	SCR Catalyst	—	—	3	0
7	Dilution Air Blower	Centrifugal	40 m ³ /min @ 108 cm WG (1,400 acfm @ 42 in. WG)	2	1
8	Ammonia Storage	Horizontal tank	45,000 liter (12,000 gal)	5	0
9	Ammonia Feed Pump	Centrifugal	9 lpm @ 90 m H ₂ O (2 gpm @ 300 ft H ₂ O)	2	1

Case B12A-F3 – Account 5: Flue Gas Cleanup

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Fabric Filter	Single stage, high-ratio with pulse-jet online cleaning system	580,000 kg/hr (1,279,000 lb/hr) 99.9% efficiency	2	0
2	Absorber Module	Counter-current open spray	20,000 m ³ /min (695,000 acfm)	1	0
3	Recirculation Pumps	Horizontal centrifugal	114,000 lpm @ 65 m H ₂ O (30,000 gpm @ 210 ft H ₂ O)	3	1
4	Bleed Pumps	Horizontal centrifugal	1,910 lpm (500 gpm) at 20 wt% solids	2	1
5	Oxidation Air Blowers	Centrifugal	330 m ³ /min @ 0.3 MPa (11,520 acfm @ 37 psia)	2	1
6	Agitators	Side entering	50 hp	5	1
7	Dewatering Cyclones	Radial assembly, 5 units each	470 lpm (130 gpm) per cyclone	2	0
8	Vacuum Filter Belt	Horizontal belt	15 tonne/hr (17 tph) of 50 wt % slurry	2	1
9	Filtrate Water Return Pumps	Horizontal centrifugal	290 lpm @ 13 m H ₂ O (80 gpm @ 40 ft H ₂ O)	1	1
10	Filtrate Water Return Storage Tank	Vertical, lined	190,000 lpm (50,000 gal)	1	0
11	Process Makeup Water Pumps	Horizontal centrifugal	680 lpm @ 21 m H ₂ O (180 gpm @ 70 ft H ₂ O)	1	1
12	Activated Carbon Injectors	—	20 kg/hr (50 lb/hr)	1	0
13	Hydrated Lime Injectors	—	560 kg/hr (1,230 lb/hr)	1	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case B12A-F3 – Account 7: Ductwork and Stack

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Stack	Reinforced concrete with FRP liner	122 m (400 ft) high x 4.1 m (14 ft) diameter	1	0

Case B12A-F3 – Account 8: Steam Turbine and Accessories

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Steam Turbine	Commercially available advanced steam turbine	311 MW 24.1 MPa/593°C/593°C (3500 psig/1100°F/1100°F)	1	0
2	Steam Turbine Generator	Hydrogen cooled, static excitation	350 MVA @ 0.9 p.f., 24 kV, 60 Hz, 3-phase	1	0
3	Air-cooled Condenser	Forced draft, direct, A-frame air-cooled condenser	1,260 GJ/hr (1,190 MMBtu/hr), Condensing temperature 45°C (114°F), Ambient temperature 15°C (59°F)	1	0

Case B12A-F3 – Account 9: Auxiliary Cooling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Glycol Cooling Loops	Industrial grade, air to glycol, closed loop heat exchanger	10 GJ/hr (14 MMBtu/hr) heat duty	5	0

Case B12A-F3 – Account 10: Ash and Spent Sorbent Handling System

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	Economizer Hopper (part of boiler scope of supply)	–	–	4	0
2	Bottom Ash Hopper (part of boiler scope of supply)	–	–	2	0
3	Clinker Grinder	–	2.2 tonne/hr (2.4 tph)	1	1
4	Pyrites Hopper (part of pulverizer scope of supply included with boiler)	–	–	6	0
5	Pyrites Transfer Tank	–	–	1	0
6	Pyrite Reject Water Pump	–	–	1	0
7	Pneumatic Transport Line	Fully-dry, isolatable	–	4	0
8	Bottom Ash Storage Silo	–	–	1	1
9	Baghouse Hopper (part of baghouse scope of supply)	–	–	12	0
10	Air Heater Hopper (part of boiler scope of supply)	–	–	10	0
11	Air Blower	–	9 m ³ /min @ 0.2 MPa (310 scfm @ 24 psi)	1	1
12	Fly Ash Silo	Reinforced concrete	580 tonne (640 ton)	2	0

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
13	Slide Gate Valves	–	–	2	0
14	Unloader	–	–	1	0
15	Telescoping Unloading Chute	–	50 tonne/hr (60 tph)	1	0

Case B12A-F3 – Account 11: Accessory Electric Plant

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	STG Transformer	Oil-filled	24 kV/345 kV, 320 MVA, 3-ph, 60 Hz	1	0
2	High Voltage Transformer	Oil-filled	345 kV/13.8 kV, 0 MVA, 3-ph, 60 Hz	2	0
3	Medium Voltage Transformer	Oil-filled	24 kV/4.16 kV, 24 MVA, 3-ph, 60 Hz	1	1
4	Low Voltage Transformer	Dry ventilated	4.16 kV/480 V, 4 MVA, 3-ph, 60 Hz	1	1
5	STG Isolated Phase Bus Duct and Tap Bus	Aluminum, self-cooled	24 kV, 3-ph, 60 Hz	1	0
6	Medium Voltage Switchgear	Metal clad	4.16 kV, 3-ph, 60 Hz	1	1
7	Low Voltage Switchgear	Metal enclosed	480 V, 3-ph, 60 Hz	1	1
8	Emergency Generator	Sized for black start capability	3,500 kW, 480 V, 3-ph, 60 Hz	2	0
9	Boiler Feed Pump Motor VFD	Medium voltage, air-cooled	10,200 kW, 4160 V, 3-ph, 60 Hz	1	0
10	ID Fan Motor VFD	Medium voltage, air-cooled	4,270 kW, 4160 V, 3-ph, 60 Hz	1	0
11	FD Fan Motor VFD	Medium voltage, air-cooled	1,460 kW, 4160 V, 3-ph, 60 Hz	1	0
12	PA Fan Motor VFD	Medium voltage, air-cooled	360 kW, 4160 V, 3-ph, 60 Hz	1	0

Case B12A-F3 – Account 12: Instrumentation and Control

Equipment No.	Description	Type	Design Condition	Operating Qty.	Spares
1	DCS - Main Control	Monitor/keyboard; Operator printer (laser color); Engineering printer (laser B&W)	Operator stations/printers, alarm management, HMIs, data historian, hard-wired control interface panels, and engineering stations/printers	1	0
2	DCS - Processor	Microprocessor cabinets with redundant input/output, I/O cabinets, various I/C buses	Spare 25% I/O and processor bandwidth	1	0
3	DCS - Data Highway	Fiber optic	Fully redundant	1	0

The Case B12A-F3 plant design includes the design features of the Case B12A-F2 plant with the following modifications:

- **Account 3 — Feedwater and Miscellaneous Systems and Equipment**
 - Medium-voltage electric-driven BFW pump outfitted with VFD
 - VFD equipment varies the frequency and voltage fed to the BFW pump medium-voltage electric motor to control flow/pressure via speed control.
 - Speed control allows for the pump to (largely) operate within a region of “constant efficiency” at its maximum capability curve for a specific flow rate; this constant efficiency is the predominant benefit of utilizing “speed control” in lieu of “throttling” when establishing means of flow control.
 - Typically, speed control pumps will still be equipped with a standard outlet throttling valve to serve as a secondary means of flow control (if needed).
 - Based on Black & Veatch experience with the equipment, a frequently noted operational advantage to the VFD equipment is that it can be remotely located from the BFW pump medium voltage electric motor; based on estimates from established VFD OEMs, the VFD enclosure can be remotely located hundreds of feet away from the motor it serves (when equipped with the appropriate cabling material).
 - Rollout of the VFD equipment was limited to only the largest electrical consumers within the plant (i.e., BFW pump, ID fan, FD fan, PA fan) in order to control electrical equipment costs of the VFD units.
 - Natural gas auxiliary boiler removed and replaced with an “electrode boiler”
 - Electrode boiler(s) produces saturated steam at the design pressure and will predominantly serve as the onsite sparging steam supply.
 - A pump that is internal to the vessel pumps feedwater into the electrode boiler vessel (typically operated on 4.16–13.8 kV); the water contacts the electrodes and steam is produced.
 - The electrode boiler would be served by the plant’s auxiliary power system when the plant is operating; when the plant is not operating, the electrode boiler could be fed from the site’s substation (requiring consumption of grid back-feed power for a short period of time during startup) or from the emergency generator. This operational decision is typically made by plant operations personnel based on seasonal energy prices, emergency generator operating hours, and fuel availability.
 - As with any sparging steam supply, feedwater-level water quality is preferred by the OEMs to reduce the mineral deposits within the electrode boiler internals.
 - Addition of a steam turbine bypass line
 - Steam turbine bypass line likely only utilized during startup, shutdown, or plant “trip” conditions to allow the decoupling of the boiler/steam turbine, thereby improving equipment protection and plant control.

- The use of the steam turbine bypass during startup has been linked to improved steam/material temperature matching during startups and shutdowns. [15] [38]
- **Account 4 — Boiler and Accessories**
 - Converting a burner row to “indirect firing”
 - This supplemental coal-firing is predominantly used at reduced loads (likely less than 30% load); additionally, application of indirect firing has been linked to reducing the “inertia” in the firing system, which provides additional benefits to ramp rate. [25]
 - Primary air is decoupled from the coal supply; multiple channels/lines used to compartmentalize the air/coal streams.
 - This firing technique allows for lower primary air flow rates and lower NOX production levels at reduced loads; this burner row outfitted for indirect firing can also be used to reduce startup times. [18]
 - BFW pump, PA, FD, and ID fans outfitted with VFDs to the existing electric motors
 - VFD equipment varies the frequency and voltage fed to the fans’ medium-voltage electric motors to control flow/pressure via speed control; as mentioned in the Tier 1 discussion, these VFD units can be remotely located up to hundreds of feet from the motor(s) served.
 - Speed control allows for the fan to (largely) operate within a region of constant efficiency at its maximum capability curve for a specific flow rate; this constant efficiency is the predominant benefit of utilizing speed control in lieu of throttling when establishing means of flow control.
 - As mentioned above, rollout of the VFD equipment was limited to only the largest electrical consumers within the plant (i.e., BFP, ID Fan, FD Fan, PA Fan) in order to control electrical equipment costs of the VFD units.
 - Typically, speed control (centrifugal) fans will still be outfitted with standard inlet guide vanes to allow for fast-response flow control (if needed).
- **Account 11 — Accessory Electric Plant**
 - Application of VFDs on large electric motors; no significant cost impacts to the plant electrical distribution or auxiliary system design as a result of the VFD components

5.7.18 Case B12A-F3– Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-199 shows a detailed breakdown of the capital costs; Exhibit 5-200 shows the owner’s costs, along with the TOC; and Exhibit 5-201 shows the initial and annual O&M costs.

The estimated TPC of the Case B12A-F3 plant is \$835 million. The project contingency is 13.3 percent of the TPC.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-199. Case B12A-F3 total plant cost details

Case:		B12A-F3	Supercritical PC Flexible Plant (Tiers 1–3)				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
1 Coal & Sorbent Handling										
1.1	Coal Receive & Unload	\$422	\$0	\$190	\$0	\$613	\$107	\$0	\$108	\$828
1.2	Coal Stackout & Reclaim	\$1,387	\$0	\$310	\$0	\$1,697	\$297	\$0	\$299	\$2,293
1.3	Coal Conveyors	\$14,731	\$0	\$3,505	\$0	\$18,236	\$3,191	\$0	\$3,214	\$24,641
1.4	Other Coal Handling	\$1,640	\$0	\$345	\$0	\$1,985	\$347	\$0	\$350	\$2,682
1.5	Sorbent Receive & Unload	\$96	\$0	\$29	\$0	\$125	\$22	\$0	\$22	\$169
1.6	Sorbent Stackout & Reclaim	\$523	\$0	\$95	\$0	\$618	\$108	\$0	\$109	\$835
1.7	Sorbent Conveyors	\$929	\$202	\$225	\$0	\$1,356	\$237	\$0	\$239	\$1,832
1.8	Other Sorbent Handling	\$55	\$13	\$28	\$0	\$96	\$17	\$0	\$17	\$129
1.9	Coal & Sorbent Handling Foundations	\$0	\$681	\$898	\$0	\$1,579	\$276	\$0	\$278	\$2,134
	Subtotal	\$19,784	\$896	\$5,624	\$0	\$26,304	\$4,603	\$0	\$4,636	\$35,543
2 Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	\$899	\$0	\$173	\$0	\$1,072	\$188	\$0	\$189	\$1,448
2.2	Prepared Coal Storage & Feed	\$3,578	\$0	\$770	\$0	\$4,348	\$761	\$0	\$766	\$5,876
2.5	Sorbent Preparation Equipment	\$397	\$17	\$81	\$0	\$495	\$87	\$0	\$87	\$669
2.6	Sorbent Storage & Feed	\$640	\$0	\$241	\$0	\$881	\$154	\$0	\$155	\$1,190
2.9	Coal & Sorbent Feed Foundation	\$0	\$273	\$239	\$0	\$512	\$90	\$0	\$90	\$692
	Subtotal	\$5,514	\$290	\$1,505	\$0	\$7,309	\$1,279	\$0	\$1,288	\$9,876
3 Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	\$1,361	\$2,333	\$1,167	\$0	\$4,861	\$851	\$0	\$857	\$6,568
3.2	Water Makeup & Pretreating	\$2,168	\$217	\$1,228	\$0	\$3,613	\$632	\$0	\$849	\$5,094
3.3	Other Feedwater Subsystems	\$888	\$291	\$277	\$0	\$1,456	\$255	\$0	\$257	\$1,967
3.4	Service Water Systems	\$607	\$1,159	\$3,752	\$0	\$5,517	\$966	\$0	\$1,297	\$7,779
3.5	Other Boiler Plant Systems	\$270	\$98	\$245	\$0	\$613	\$107	\$0	\$108	\$828
3.6	Natural Gas Pipeline and Start-Up System	\$1,315	\$57	\$42	\$0	\$1,414	\$247	\$0	\$249	\$1,911
3.7	Waste Water Treatment Equipment	\$3,403	\$0	\$2,086	\$0	\$5,489	\$961	\$0	\$1,290	\$7,740
3.8	Spray Dryer Evaporator	\$6,399	\$0	\$3,705	\$0	\$10,105	\$1,768	\$0	\$2,375	\$14,248
3.9	Miscellaneous Plant Equipment	\$1,234	\$162	\$627	\$0	\$2,022	\$354	\$0	\$475	\$2,852
	Subtotal	\$17,645	\$4,316	\$13,129	\$0	\$35,090	\$6,141	\$0	\$7,756	\$48,987
4 Pulverized Coal Boiler & Accessories										
4.9	Pulverized Coal Boiler & Accessories	\$175,380	\$0	\$114,533	\$0	\$289,913	\$50,735	\$0	\$51,097	\$391,746
4.10	Selective Catalytic Reduction System	\$8,758	\$0	\$5,720	\$0	\$14,478	\$2,534	\$0	\$2,552	\$19,563
4.11	Boiler Balance of Plant	\$497	\$0	\$324	\$0	\$821	\$144	\$0	\$145	\$1,110
4.12	Primary Air System	\$523	\$0	\$342	\$0	\$865	\$151	\$0	\$152	\$1,169
4.13	Secondary Air System	\$1,063	\$0	\$694	\$0	\$1,757	\$307	\$0	\$310	\$2,374
4.14	Induced Draft Fans	\$1,992	\$0	\$1,301	\$0	\$3,293	\$576	\$0	\$580	\$4,450
4.15	Major Component Rigging	\$34	\$0	\$22	\$0	\$56	\$10	\$0	\$10	\$76
4.16	Boiler Foundations	\$0	\$143	\$126	\$0	\$269	\$47	\$0	\$47	\$364
	Subtotal	\$188,248	\$143	\$123,062	\$0	\$311,453	\$54,504	\$0	\$54,894	\$420,851

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B12A-F3	Supercritical PC Flexible Plant (Tiers 1–3)				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
5 Flue Gas Cleanup										
5.2	WFGD Absorber Vessels & Accessories	\$34,246	\$0	\$7,322	\$0	\$41,568	\$7,274	\$0	\$7,326	\$56,169
5.3	Other FGD	\$119	\$0	\$134	\$0	\$253	\$44	\$0	\$45	\$342
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$978	\$215	\$962	\$0	\$2,155	\$377	\$0	\$380	\$2,912
5.9	Particulate Removal (Bag House & Accessories)	\$1,133	\$0	\$714	\$0	\$1,847	\$323	\$0	\$326	\$2,496
5.12	Gas Cleanup Foundations	\$0	\$61	\$54	\$0	\$115	\$20	\$0	\$20	\$155
5.13	Gypsum Dewatering System	\$309	\$0	\$52	\$0	\$361	\$63	\$0	\$64	\$487
	Subtotal	\$36,785	\$276	\$9,238	\$0	\$46,299	\$8,102	\$0	\$8,160	\$62,562
7 Ductwork & Stack										
7.3	Ductwork	\$0	\$323	\$225	\$0	\$548	\$96	\$0	\$97	\$741
7.4	Stack	\$4,093	\$0	\$2,378	\$0	\$6,471	\$1,132	\$0	\$1,141	\$8,744
7.5	Duct & Stack Foundations	\$0	\$77	\$92	\$0	\$169	\$30	\$0	\$40	\$238
	Subtotal	\$4,093	\$401	\$2,695	\$0	\$7,188	\$1,258	\$0	\$1,277	\$9,723
8 Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	\$49,016	\$0	\$5,511	\$0	\$54,526	\$9,542	\$0	\$9,610	\$73,679
8.2	Steam Turbine Plant Auxiliaries	\$850	\$0	\$1,807	\$0	\$2,657	\$465	\$0	\$468	\$3,590
8.3	Condenser & Auxiliaries ^A	\$16,190	\$0	\$5,493	\$0	\$21,684	\$3,795	\$0	\$3,822	\$29,300
8.4	Steam Piping	\$18,833	\$0	\$7,633	\$0	\$26,466	\$4,632	\$0	\$4,665	\$35,762
8.5	Turbine Generator Foundations	\$0	\$86	\$142	\$0	\$228	\$40	\$0	\$54	\$322
	Subtotal	\$84,889	\$86	\$20,585	\$0	\$105,561	\$18,473	\$0	\$18,619	\$142,653
9 Cooling Water System										
9.6	Component Cooling Water System ^B	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
	Subtotal	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
10 Ash & Spent Sorbent Handling Systems										
10.6	Ash Storage Silos	\$466	\$0	\$1,426	\$0	\$1,892	\$331	\$0	\$333	\$2,556
10.7	Ash Transport & Feed Equipment	\$1,749	\$0	\$1,733	\$0	\$3,482	\$609	\$0	\$614	\$4,705
10.9	Ash/Spent Sorbent Foundation	\$0	\$299	\$367	\$0	\$665	\$116	\$0	\$156	\$938
	Subtotal	\$2,215	\$299	\$3,526	\$0	\$6,039	\$1,057	\$0	\$1,103	\$8,199
11 Accessory Electric Plant										
11.1	Generator Equipment	\$1,473	\$0	\$1,111	\$0	\$2,585	\$452	\$0	\$456	\$3,493
11.2	Station Service Equipment	\$2,683	\$0	\$230	\$0	\$2,914	\$510	\$0	\$514	\$3,937
11.3	Switchgear & Motor Control	\$8,762	\$0	\$1,520	\$0	\$10,283	\$1,799	\$0	\$1,812	\$13,894
11.4	Conduit & Cable Tray	\$0	\$616	\$1,774	\$0	\$2,390	\$418	\$0	\$421	\$3,229
11.5	Wire & Cable	\$0	\$1,211	\$2,165	\$0	\$3,375	\$591	\$0	\$595	\$4,561
11.6	Protective Equipment	\$32	\$0	\$112	\$0	\$145	\$25	\$0	\$26	\$196
11.7	Standby Equipment	\$417	\$0	\$385	\$0	\$801	\$140	\$0	\$141	\$1,083
11.8	Main Power Transformers	\$3,929	\$0	\$80	\$0	\$4,009	\$702	\$0	\$707	\$5,417
11.9	Electrical Foundations	\$0	\$93	\$236	\$0	\$329	\$58	\$0	\$77	\$464
	Subtotal	\$17,297	\$1,919	\$7,614	\$0	\$26,830	\$4,695	\$0	\$4,748	\$36,274
12 Instrumentation & Control										

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B12A-F3	Supercritical PC Flexible Plant (Tiers 1–3)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
12.1	Pulverized Coal Boiler Control Equipment	\$359	\$0	\$64	\$0	\$423	\$74	\$0	\$75	\$571
12.3	Steam Turbine Control Equipment	\$344	\$0	\$39	\$0	\$382	\$67	\$0	\$67	\$517
12.5	Signal Processing Equipment	\$332	\$0	\$59	\$0	\$391	\$69	\$0	\$69	\$529
12.6	Control Boards, Panels & Racks	\$103	\$0	\$63	\$0	\$167	\$29	\$0	\$29	\$225
12.7	Distributed Control System Equipment	\$3,471	\$0	\$619	\$0	\$4,089	\$716	\$0	\$721	\$5,526
12.8	Instrument Wiring & Tubing	\$311	\$248	\$994	\$0	\$1,553	\$272	\$0	\$274	\$2,098
12.9	Other Instrumentation & Controls Equipment	\$369	\$0	\$855	\$0	\$1,224	\$214	\$0	\$216	\$1,654
	Subtotal	\$5,289	\$248	\$2,693	\$0	\$8,230	\$1,440	\$0	\$1,451	\$11,121
13 Improvements to Site										
13.1	Site Preparation	\$0	\$183	\$3,910	\$0	\$4,093	\$716	\$0	\$962	\$5,772
13.2	Site Improvements	\$0	\$1,004	\$1,326	\$0	\$2,330	\$408	\$0	\$547	\$3,285
13.3	Site Facilities	\$828	\$0	\$868	\$0	\$1,696	\$297	\$0	\$399	\$2,391
	Subtotal	\$828	\$1,187	\$6,104	\$0	\$8,119	\$1,421	\$0	\$1,908	\$11,448
14 Buildings & Structures										
14.2	Boiler Building	\$0	\$6,120	\$5,378	\$0	\$11,498	\$2,012	\$0	\$2,027	\$15,537
14.3	Steam Turbine Building	\$0	\$6,187	\$5,762	\$0	\$11,949	\$2,091	\$0	\$2,106	\$16,146
14.4	Administration Building	\$0	\$553	\$584	\$0	\$1,137	\$199	\$0	\$200	\$1,536
14.6	Water Treatment Buildings	\$0	\$150	\$137	\$0	\$287	\$50	\$0	\$51	\$387
14.7	Machine Shop	\$0	\$248	\$165	\$0	\$413	\$72	\$0	\$0	\$486
14.8	Warehouse	\$0	\$193	\$193	\$0	\$386	\$67	\$0	\$68	\$521
14.9	Other Buildings & Structures	\$0	\$139	\$118	\$0	\$258	\$45	\$0	\$45	\$348
14.10	Waste Treating Building & Structures	\$0	\$221	\$670	\$0	\$890	\$156	\$0	\$157	\$1,203
	Subtotal	\$0	\$13,810	\$13,007	\$0	\$26,818	\$4,693	\$0	\$4,654	\$36,165
	Total	\$383,183	\$23,872	\$209,242	\$0	\$616,298	\$107,852	\$0	\$110,680	\$834,829

^AACC; ^BComponent cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-200. Case B12A-F3 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$7,162
1-Month Maintenance Materials	\$1,105
1-Month Non-Fuel Consumables	\$603
1-Month Waste Disposal	\$333
25% of 1-Month Fuel Cost at 100% CF	\$976
2% of TPC	\$16,697
Total	\$26,876
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$8,989
0.5% of TPC (spare parts)	\$4,174
Total	\$13,163
Other Costs	
Initial Cost for Catalyst and Chemicals	\$904
Land	\$117
Other Owner's Costs	\$125,224
Financing Costs	\$22,540
Total Overnight Costs (TOC)	\$1,023,654

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-201. Case B12A-F3 initial and annual operating and maintenance costs

Case:	B12A-F3	– Supercritical PC Flexible Plant (Tiers 1–3)			Cost Base:	Dec 2018
Plant Size (MW, gross):	300	Heat Rate-net (Btu/kWh):			8,781	
Operating & Maintenance Labor						
Operating Labor				Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$/hour		Skilled Operator:	2.0	
Operating Labor Burden:	30.0	% of base		Operator:	5.0	
Labor O-H Charge Rate:	25.0	% of labor		Foreman:	1.0	
				Lab Techs, etc.:	1.0	
				Total:	9.0	
Fixed Operating Costs						
					Annual Cost (\$)	
Annual Operating Labor:					\$3,945,942	
Maintenance Labor:					\$7,513,464	
Administrative & Support Labor:					\$2,864,852	
Property Taxes and Insurance:					\$16,696,587	
Total:					\$31,020,844	
Variable Operating Costs						
					Annual Cost (\$)	
Maintenance Material:					\$13,259,054 x CF	
Consumables						
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)	
Water (/1000 gallons):	0	191	\$1.90	\$0	\$132,321 x CF	
Makeup and Waste Water Treatment Chemicals (ton):	0	0.568	\$550.00	\$0	\$114,100 x CF	
Brominated Activated Carbon (ton):	0	0.542	\$1,600.00	\$0	\$316,534 x CF	
Enhanced Hydrated Lime (ton):	0	13.44	\$240.00	\$0	\$1,177,739 x CF	
Limestone (ton):	0	239	\$22.00	\$0	\$1,918,511 x CF	
Ammonia (19 wt%, ton):	0	22.6	\$300.00	\$0	\$2,473,460 x CF	
SCR Catalyst (ft³):	5,861	5.35	\$150.00	\$879,197	\$293,066 x CF	
Fuel additive for boiler slagging/fouling mitigation (gal)	1,000	89.2	\$25.00	\$25,000	\$813,982 x CF	
Subtotal:				\$904,197	\$7,239,712 x CF	
Waste Disposal						
Fly Ash (ton):	0	235	\$38.00	\$0	\$3,261,873 x CF	
Bottom Ash (ton):	0	52.6	\$38.00	\$0	\$729,440 x CF	
SCR Catalyst (ft³):	0	5.35	\$2.50	\$0	\$4,884 x CF	
Subtotal:				\$0	\$3,996,198 x CF	
By-Products						
Gypsum (ton):	0	363	\$0.00	\$0	\$0	
Subtotal:				\$0	\$0	
Variable Operating Costs Total:				\$904,197	\$24,494,964 x CF	
Fuel Cost						
Illinois Number 6 (ton):	0	2,469	\$51.96	\$0	\$46,826,691 x CF	
Fuel Costs Total:				\$0	\$46,826,691 x CF	

5.7.18.1 Cost Differential Justifications

The primary contributors to the capital cost differential when comparing Case B12A-F3 to Case B12A-F2 are outlined below:

- Flexibility Option 60 — Application of variable speed drives on large electric motors

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Flexibility Option 1 — Use of advanced materials to reduce tube and pressure wall thickness requirements to improve rate of warm-up
- Flexibility Option 13 — Use of advanced materials to reduce turbine casing thickness and reduce STG warm-up times
- Flexibility Option 14 — Turbine blade coatings for improved resistance to water impingement
- Flexibility Option 37 — STG steam turbine bypass to condenser
- Flexibility Option 3 — Increase the number of headers to decrease header size and warm-up time
- Flexibility Option 2 — Decrease drum holding time to reduce drum diameter and drum wall thickness
- Flexibility Option 31 — Converting a burner row to indirect firing
- Flexibility Option 80 — Utilization of electrode boiler for fast saturated steam production for supporting plant systems

The justifications for the capital cost differentials when comparing Case B12A-F3 to Case B12A-F2 are outlined below:

- Account 2.2 cost increases due to changes to the silos, feeders, and mills. Account 2.1 cost does not increase since it would not be impacted by changing the number of coal silos; all upstream conveyors, transfer stations, and belts would likely remain consistent regardless of the downstream changes to the coal system. The following flexibility options impacted the cost of Account 2.2:
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 47 — Fuel additive for slagging, fouling and erosion
- Account 2.9 cost increases due to additional equipment foundations required for supplement silos/blowers for the indirect firing system, and for the modularized pump skids and drip feed piping for the fuel additive system (which drips a low flow of additive onto the coal conveyors upstream of the coal silos). The following flexibility options impacted the cost of Account 2.9:
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 47 — Fuel additives for slagging/fouling mitigation
- Account 3.9 cost increases due to additional equipment added for faster sparging steam supply. The following flexibility option impacted the cost of Account 3.9:
 - Flexibility Option 80 — Utilization of electrode boiler for fast saturated steam production for supporting plant systems
- Account 4.9 cost increases due to the additional equipment provided by the boiler OEM, additional sub-system features within the boiler island components (e.g., header and

drum interconnection modifications and implementation of advanced materials), additional engineering and installation labor required for these options. The following flexibility options impacted the cost of Account 4.9:

- Flexibility Option 1 — Use of advanced materials to reduce tube and pressure wall thickness requirements to improve rate of warm-up
 - Flexibility Option 2 — Decrease drum holding time to reduce drum diameter and drum wall thickness
 - Flexibility Option 3 — Increase the number of headers to decrease header size and warm-up time
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 45 — Neural networks and online combustion optimizer
- Account 4.11 cost increases due to the additional equipment requiring boiler balance of plant sub-system engineering design (e.g., instrument air lines, electrical routing, more intricate pipe routing for clash avoidance, additional maintenance access points) and material installation. The following flexibility options impacted the cost of Account 4.11:
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 33 — Intelligent soot blowing for managing heat transfer within the boiler
- Account 4.16 cost increases due to the additional foundation requirements to accommodate the installation of the electrode boiler. The following flexibility option impacted the cost of Account 4.16:
 - Flexibility Option 80 — Utilization of electrode boiler for fast saturated steam production for supporting plant systems
- Account 8.1 cost increases due to the addition of equipment features within the steam turbine island OEM's scope of supply; this additional equipment would result in additional equipment cost, additional engineering man-hours and installation hours. The following flexibility options impacted the cost of Account 8.1:
 - Flexibility Option 13 — Use of advanced materials to reduce turbine casing thickness and reduce STG warm-up times
 - Flexibility Option 14 — Turbine blade coatings for improved resistance to water impingement
 - Flexibility Option 19 — Use of a steam-cooled turbine outer casing to reduce casing thickness
- Account 8.2 cost increases due to the addition of ancillary components, such as bypass lines, additional instruments and instrument connection features to the steam turbine auxiliaries; these additional features would require additional engineering design and material supply. The following flexibility options impacted the cost of Account 8.2:

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

- Flexibility Option 19 — Use of a steam-cooled turbine outer casing to reduce casing thickness
 - Flexibility Option 37 — STG steam bypass to condenser
- Account 8.3 cost increases due to the additional engineering, material supply and OEM equipment modifications necessary to accommodate the steam turbine bypass to the existing ACC. This additional sub-system feature would also require additional installation man-hours. The following flexibility option impacted the cost of Account 8.3:
 - Flexibility Option 37 — STG steam bypass to condenser
- Account 8.4 cost increases due to an increase in engineering design, material, and installation labor required for implementing the modifications to the steam piping required to accommodate the turbine casing modifications and the additional steam line to the ACC for bypass functionality. The following flexibility options impacted the cost of Account 8.4:
 - Flexibility Option 19 — Use of a steam-cooled turbine outer casing to reduce casing thickness
 - Flexibility Option 37 — STG steam bypass to condenser
- Account 11.3 cost increases due to installation of VFDs for the BFW pump and fans (PA, FD, and ID). VFDs were incorporated into Account 11.3 because of their alignment with the 'Switchgear and Motor Control' category of equipment; assigning the VFD equipment to this electrical-related category is common for plant design and procurement practices.
- Account 11 (sub-accounts 11.2–11.5 and 11.9) cost increases due to the additional control wiring and cabling for communications and/or power supply to ancillary components and the compulsory cable tray and conduit required to route the wiring and cabling. The following flexibility options impacted the cost of Account 11:
 - Flexibility Option 32 — Converting a burner row to indirect firing
 - Flexibility Option 33 — Intelligent soot blowing for managing heat transfer within the boiler
 - Flexibility Option 45 — Neural networks and online combustion optimizer
 - Flexibility Option 47 — Fuel additives for slagging/fouling mitigation
- Account 11.9 cost increases due to the foundation requirements of the VFD cabinets/enclosures; the enclosures that house the VFDs typically require poured foundations for support due to their size and weight. It would be expected that these VFD foundations would be separate from main building foundations. No other modifications to accounts 11.2, 11.4, 11.5, 11.6, or 11.7 were expected to have a cost increase impact on Account 11.9; the reason for this is that the majority of the electrical components are direct wall-mounted or “anchor-in-place” to the existing foundation within the boiler and steam turbine buildings.

- Account 12 cost increases significantly due to the additional equipment added to the plant design; it is not only the complexity of the controls system that impacts Account 12 costs, but also the number of components that must be integrated (e.g., electrode boiler, VFD units, additional process steam piping, combustion analyzer(s), indirect firing, intelligent sootblowing). The addition of these components to the plant DCS would be expected to increase the cost of the controls system.

The justifications for the O&M cost differentials when comparing Case B12A-F3 to Case B12A-F2 are outlined below:

- An additional variable O&M cost is introduced due to Flexibility Option 47 — Fuel additive for slagging/fouling mitigation. This highly modularized fuel additive system applies a slurry compound drip-feed to the coal as it is transported on the coal conveyors to the tripper level directly above the coal silos. The application of this option adds an additional consumable stream, which is reflected in the Case B12A-F3 O&M costs.
 - This additional consumable stream accounts for an 11.5 percent increase in (non-fuel) variable operating costs from Case B12A-F2 to Case B12A-F3.

5.7.19 Case B12A-F4 – PC Supercritical Flexible Plant with Tier 1, 2, 3, and 4 Flexibility Options

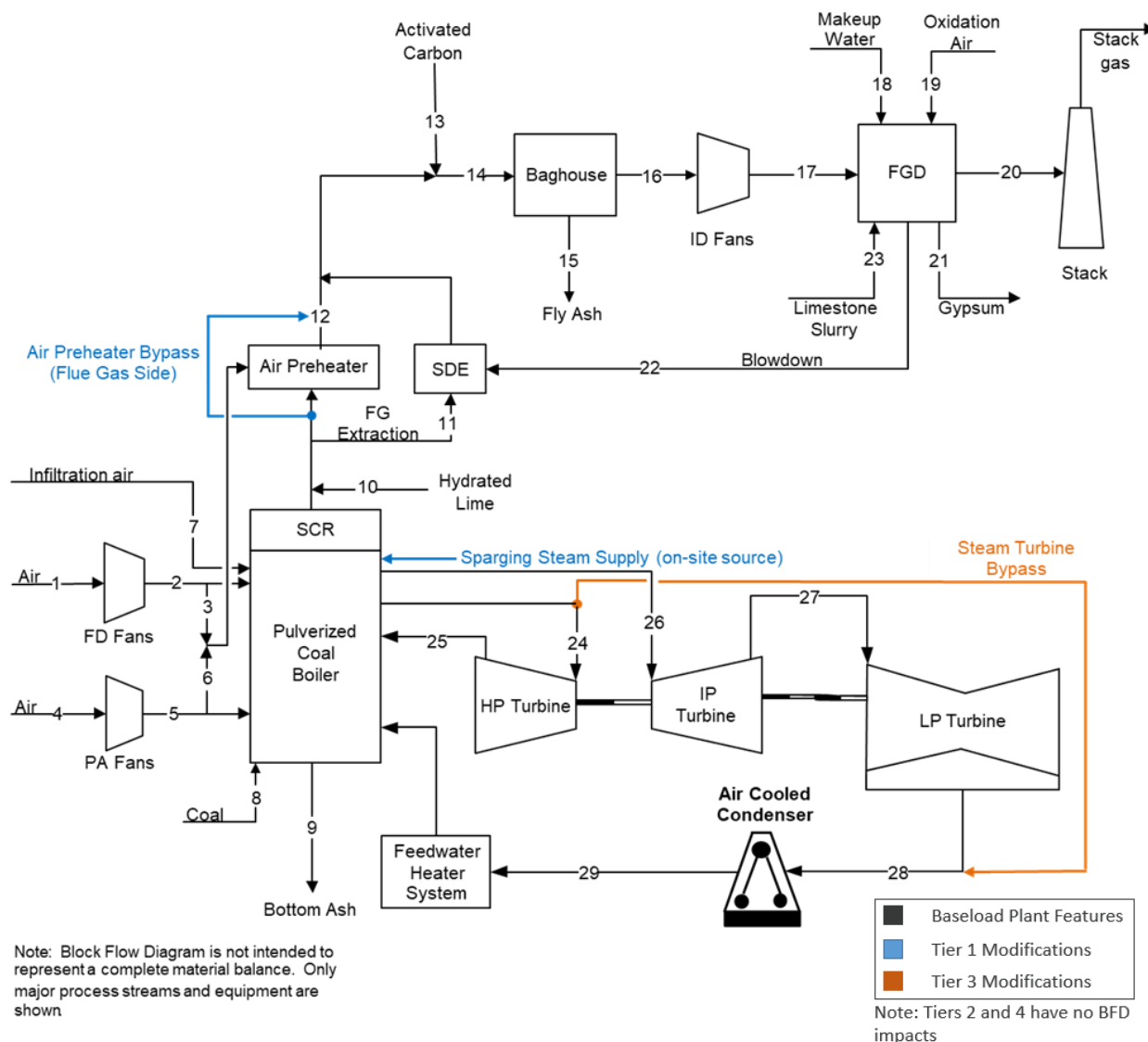
The plant configuration for Case B12A-F4, supercritical flexible plant with tiers 1–4 flexibility options, is identical to Case B12A-F3. The full list of Tier 3 flexibility options was presented in Exhibit 4-17. The nominal gross plant output was maintained at 300 MW.

5.7.20 Case B12A-F4 – Full Load Performance Results

The BFD for Case B12A-F4 is shown in Exhibit 5-202. Case B12A-F4 stream tables and full load performance results are identical to Case B12A-F3 (see Section 5.4.15); therefore, they are not repeated here.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-202. Case B12A-F4 block flow diagram



5.7.21 Case B12A-F4 – Part Load Performance Results

Case B12A-F4 Part load performance results are identical to Case B12A-F3 (see Section 5.4.16); therefore, they are not repeated here.

5.7.22 Case B12A-F4 – Major Equipment List

The Case B12A-F4 equipment list is identical to the Case B12A-F3 equipment list (see Section 5.4.17); therefore, it is not repeated here.

The Case B12A-F4 flexible plant design basis includes the design features of the Case B12A-F3 flexible plant with the following modifications:

- **Account 4 – Boiler and Accessories**

- Equipping water cannons in lieu of other distributed soot blowing devices; this equipment changeout was not anticipated to significantly impact overall capital cost/design of the boiler; no anticipated impacts to the major boiler/feedwater equipment categories.
 - No significant operational/process changes due to deployment of water cannons; water cannons will be equipped in the upper radiant section of the boiler and managed by the soot blower management system.
- **Account 8 — Steam Turbine Generator and Auxiliaries**
 - Enhanced turbine seals considered to be an “internal” steam turbine design feature; not anticipated to significantly impact overall capital cost/design of the steam turbine; no anticipated impacts to the major equipment categories.
 - Enhanced turbine seals not anticipated to impact standard steam turbine operation/procedures.

5.7.23 Case B12A-F4 – Cost Estimating

The cost estimating methodology was described previously in Section 4.9. Exhibit 5-203 shows a detailed breakdown of the capital costs; Exhibit 5-204 shows the owner’s costs, along with the TOC; and Exhibit 5-205 shows the initial and annual O&M costs.

The estimated TPC of the Case B12A-F4 plant is \$843 million. The project contingency is 13.3 percent of the TPC.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-203. Case B12A-F4 total plant cost details

Case:		B12A-F4	Supercritical PC Flexible Plant (Tiers 1–4)				Estimate Type:		Conceptual	
							Cost Base:		Dec 2018	
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	
1		Coal & Sorbent Handling								
1.1	Coal Receive & Unload	\$422	\$0	\$190	\$0	\$613	\$107	\$0	\$108	\$828
1.2	Coal Stackout & Reclaim	\$1,387	\$0	\$310	\$0	\$1,697	\$297	\$0	\$299	\$2,293
1.3	Coal Conveyors	\$14,731	\$0	\$3,505	\$0	\$18,236	\$3,191	\$0	\$3,214	\$24,641
1.4	Other Coal Handling	\$1,640	\$0	\$345	\$0	\$1,985	\$347	\$0	\$350	\$2,682
1.5	Sorbent Receive & Unload	\$96	\$0	\$29	\$0	\$125	\$22	\$0	\$22	\$169
1.6	Sorbent Stackout & Reclaim	\$523	\$0	\$95	\$0	\$618	\$108	\$0	\$109	\$835
1.7	Sorbent Conveyors	\$929	\$202	\$225	\$0	\$1,356	\$237	\$0	\$239	\$1,832
1.8	Other Sorbent Handling	\$55	\$13	\$28	\$0	\$96	\$17	\$0	\$17	\$129
1.9	Coal & Sorbent Handling Foundations	\$0	\$681	\$898	\$0	\$1,579	\$276	\$0	\$278	\$2,134
	Subtotal	\$19,784	\$896	\$5,624	\$0	\$26,304	\$4,603	\$0	\$4,636	\$35,543
2		Coal & Sorbent Preparation & Feed								
2.1	Coal Crushing & Drying	\$899	\$0	\$173	\$0	\$1,072	\$188	\$0	\$189	\$1,448
2.2	Prepared Coal Storage & Feed	\$3,578	\$0	\$770	\$0	\$4,348	\$761	\$0	\$766	\$5,876
2.5	Sorbent Preparation Equipment	\$397	\$17	\$81	\$0	\$495	\$87	\$0	\$87	\$669
2.6	Sorbent Storage & Feed	\$640	\$0	\$241	\$0	\$881	\$154	\$0	\$155	\$1,190
2.9	Coal & Sorbent Feed Foundation	\$0	\$273	\$239	\$0	\$512	\$90	\$0	\$90	\$692
	Subtotal	\$5,514	\$290	\$1,505	\$0	\$7,309	\$1,279	\$0	\$1,288	\$9,876
3		Feedwater & Miscellaneous BOP Systems								
3.1	Feedwater System	\$1,361	\$2,333	\$1,167	\$0	\$4,861	\$851	\$0	\$857	\$6,568
3.2	Water Makeup & Pretreating	\$2,168	\$217	\$1,228	\$0	\$3,613	\$632	\$0	\$849	\$5,094
3.3	Other Feedwater Subsystems	\$888	\$291	\$277	\$0	\$1,456	\$255	\$0	\$257	\$1,967
3.4	Service Water Systems	\$607	\$1,159	\$3,752	\$0	\$5,517	\$966	\$0	\$1,297	\$7,779
3.5	Other Boiler Plant Systems	\$270	\$98	\$245	\$0	\$613	\$107	\$0	\$108	\$828
3.6	Natural Gas Pipeline and Start-Up System	\$1,315	\$57	\$42	\$0	\$1,414	\$247	\$0	\$249	\$1,911
3.7	Waste Water Treatment Equipment	\$3,403	\$0	\$2,086	\$0	\$5,489	\$961	\$0	\$1,290	\$7,740
3.8	Spray Dryer Evaporator	\$6,399	\$0	\$3,705	\$0	\$10,105	\$1,768	\$0	\$2,375	\$14,248
3.9	Miscellaneous Plant Equipment	\$1,234	\$162	\$627	\$0	\$2,022	\$354	\$0	\$475	\$2,852
	Subtotal	\$17,645	\$4,316	\$13,129	\$0	\$35,090	\$6,141	\$0	\$7,756	\$48,987
4		Pulverized Coal Boiler & Accessories								
4.9	Pulverized Coal Boiler & Accessories	\$178,578	\$0	\$116,621	\$0	\$295,199	\$51,660	\$0	\$52,029	\$398,888
4.10	Selective Catalytic Reduction System	\$8,758	\$0	\$5,720	\$0	\$14,478	\$2,534	\$0	\$2,552	\$19,563
4.11	Boiler Balance of Plant	\$500	\$0	\$327	\$0	\$827	\$145	\$0	\$146	\$1,118
4.12	Primary Air System	\$523	\$0	\$342	\$0	\$865	\$151	\$0	\$152	\$1,169
4.13	Secondary Air System	\$1,063	\$0	\$694	\$0	\$1,757	\$307	\$0	\$310	\$2,374
4.14	Induced Draft Fans	\$1,992	\$0	\$1,301	\$0	\$3,293	\$576	\$0	\$580	\$4,450
4.15	Major Component Rigging	\$34	\$0	\$22	\$0	\$56	\$10	\$0	\$10	\$76
4.16	Boiler Foundations	\$0	\$143	\$126	\$0	\$269	\$47	\$0	\$47	\$364

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B12A-F4	Supercritical PC Flexible Plant (Tiers 1–4)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O.& Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
	Subtotal	\$191,449	\$143	\$125,153	\$0	\$316,745	\$55,430	\$0	\$55,826	\$428,002
5 Flue Gas Cleanup										
5.2	WFGD Absorber Vessels & Accessories	\$34,246	\$0	\$7,322	\$0	\$41,568	\$7,274	\$0	\$7,326	\$56,169
5.3	Other FGD	\$119	\$0	\$134	\$0	\$253	\$44	\$0	\$45	\$342
5.6	Mercury Removal (Dry Sorbent Injection/Activated Carbon Injection)	\$978	\$215	\$962	\$0	\$2,155	\$377	\$0	\$380	\$2,912
5.9	Particulate Removal (Bag House & Accessories)	\$1,133	\$0	\$714	\$0	\$1,847	\$323	\$0	\$326	\$2,496
5.12	Gas Cleanup Foundations	\$0	\$61	\$54	\$0	\$115	\$20	\$0	\$20	\$155
5.13	Gypsum Dewatering System	\$309	\$0	\$52	\$0	\$361	\$63	\$0	\$64	\$487
	Subtotal	\$36,785	\$276	\$9,238	\$0	\$46,299	\$8,102	\$0	\$8,160	\$62,562
7 Ductwork & Stack										
7.3	Ductwork	\$0	\$323	\$225	\$0	\$548	\$96	\$0	\$97	\$741
7.4	Stack	\$4,093	\$0	\$2,378	\$0	\$6,471	\$1,132	\$0	\$1,141	\$8,744
7.5	Duct & Stack Foundations	\$0	\$77	\$92	\$0	\$169	\$30	\$0	\$40	\$238
	Subtotal	\$4,093	\$401	\$2,695	\$0	\$7,188	\$1,258	\$0	\$1,277	\$9,723
8 Steam Turbine & Accessories										
8.1	Steam Turbine Generator & Accessories	\$49,465	\$0	\$5,561	\$0	\$55,026	\$9,630	\$0	\$9,698	\$74,354
8.2	Steam Turbine Plant Auxiliaries	\$854	\$0	\$1,816	\$0	\$2,670	\$467	\$0	\$471	\$3,608
8.3	Condenser & Auxiliaries ^A	\$16,190	\$0	\$5,493	\$0	\$21,684	\$3,795	\$0	\$3,822	\$29,300
8.4	Steam Piping	\$18,833	\$0	\$7,633	\$0	\$26,466	\$4,632	\$0	\$4,665	\$35,762
8.5	Turbine Generator Foundations	\$0	\$86	\$142	\$0	\$228	\$40	\$0	\$54	\$322
	Subtotal	\$85,343	\$86	\$20,645	\$0	\$106,074	\$18,563	\$0	\$18,709	\$143,346
9 Cooling Water System										
9.6	Component Cooling Water System ^B	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
	Subtotal	\$599	\$0	\$459	\$0	\$1,058	\$185	\$0	\$186	\$1,430
10 Ash & Spent Sorbent Handling Systems										
10.6	Ash Storage Silos	\$466	\$0	\$1,426	\$0	\$1,892	\$331	\$0	\$333	\$2,556
10.7	Ash Transport & Feed Equipment	\$1,749	\$0	\$1,733	\$0	\$3,482	\$609	\$0	\$614	\$4,705
10.9	Ash/Spent Sorbent Foundation	\$0	\$299	\$367	\$0	\$665	\$116	\$0	\$156	\$938
	Subtotal	\$2,215	\$299	\$3,526	\$0	\$6,039	\$1,057	\$0	\$1,103	\$8,199
11 Accessory Electric Plant										
11.1	Generator Equipment	\$1,473	\$0	\$1,111	\$0	\$2,585	\$452	\$0	\$456	\$3,493
11.2	Station Service Equipment	\$2,683	\$0	\$230	\$0	\$2,914	\$510	\$0	\$514	\$3,937
11.3	Switchgear & Motor Control	\$8,762	\$0	\$1,520	\$0	\$10,283	\$1,799	\$0	\$1,812	\$13,894
11.4	Conduit & Cable Tray	\$0	\$616	\$1,774	\$0	\$2,390	\$418	\$0	\$421	\$3,229
11.5	Wire & Cable	\$0	\$1,211	\$2,165	\$0	\$3,375	\$591	\$0	\$595	\$4,561
11.6	Protective Equipment	\$32	\$0	\$112	\$0	\$145	\$25	\$0	\$26	\$196
11.7	Standby Equipment	\$417	\$0	\$385	\$0	\$801	\$140	\$0	\$141	\$1,083
11.8	Main Power Transformers	\$3,929	\$0	\$80	\$0	\$4,009	\$702	\$0	\$707	\$5,417
11.9	Electrical Foundations	\$0	\$93	\$236	\$0	\$329	\$58	\$0	\$77	\$464

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case:		B12A-F4	Supercritical PC Flexible Plant (Tiers 1–4)				Estimate Type:			Conceptual
							Cost Base:			Dec 2018
Item No.	Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost	Eng'g CM H.O. & Fee	Contingencies		Total Plant Cost
				Direct	Indirect			Process	Project	\$/1,000
	Subtotal	\$17,297	\$1,919	\$7,614	\$0	\$26,830	\$4,695	\$0	\$4,748	\$36,274
12 Instrumentation & Control										
12.1	Pulverized Coal Boiler Control Equipment	\$359	\$0	\$64	\$0	\$423	\$74	\$0	\$75	\$571
12.3	Steam Turbine Control Equipment	\$344	\$0	\$39	\$0	\$382	\$67	\$0	\$67	\$517
12.5	Signal Processing Equipment	\$332	\$0	\$59	\$0	\$391	\$69	\$0	\$69	\$529
12.6	Control Boards, Panels & Racks	\$103	\$0	\$63	\$0	\$167	\$29	\$0	\$29	\$225
12.7	Distributed Control System Equipment	\$3,471	\$0	\$619	\$0	\$4,089	\$716	\$0	\$721	\$5,526
12.8	Instrument Wiring & Tubing	\$311	\$248	\$994	\$0	\$1,553	\$272	\$0	\$274	\$2,098
12.9	Other Instrumentation & Controls Equipment	\$369	\$0	\$855	\$0	\$1,224	\$214	\$0	\$216	\$1,654
	Subtotal	\$5,289	\$248	\$2,693	\$0	\$8,230	\$1,440	\$0	\$1,451	\$11,121
13 Improvements to Site										
13.1	Site Preparation	\$0	\$183	\$3,910	\$0	\$4,093	\$716	\$0	\$962	\$5,772
13.2	Site Improvements	\$0	\$1,004	\$1,326	\$0	\$2,330	\$408	\$0	\$547	\$3,285
13.3	Site Facilities	\$828	\$0	\$868	\$0	\$1,696	\$297	\$0	\$399	\$2,391
	Subtotal	\$828	\$1,187	\$6,104	\$0	\$8,119	\$1,421	\$0	\$1,908	\$11,448
14 Buildings & Structures										
14.2	Boiler Building	\$0	\$6,120	\$5,378	\$0	\$11,498	\$2,012	\$0	\$2,027	\$15,537
14.3	Steam Turbine Building	\$0	\$6,187	\$5,762	\$0	\$11,949	\$2,091	\$0	\$2,106	\$16,146
14.4	Administration Building	\$0	\$553	\$584	\$0	\$1,137	\$199	\$0	\$200	\$1,536
14.6	Water Treatment Buildings	\$0	\$150	\$137	\$0	\$287	\$50	\$0	\$51	\$387
14.7	Machine Shop	\$0	\$248	\$165	\$0	\$413	\$72	\$0	\$0	\$486
14.8	Warehouse	\$0	\$193	\$193	\$0	\$386	\$67	\$0	\$68	\$521
14.9	Other Buildings & Structures	\$0	\$139	\$118	\$0	\$258	\$45	\$0	\$45	\$348
14.10	Waste Treating Building & Structures	\$0	\$221	\$670	\$0	\$890	\$156	\$0	\$157	\$1,203
	Subtotal	\$0	\$13,810	\$13,007	\$0	\$26,818	\$4,693	\$0	\$4,654	\$36,165
	Total	\$386,838	\$23,872	\$211,393	\$0	\$622,103	\$108,868	\$0	\$111,703	\$842,673

^AACC; ^B Component cooling water system consists of a closed loop system and glycol-to-air heat exchangers. The system utilizes a 45 percent solution of glycol and water

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
FLEXIBLE OPERATION

Exhibit 5-204. Case B12A-F4 owner's costs

Description	\$/1,000
Pre-Production Costs	
6 Months All Labor	\$7,206
1-Month Maintenance Materials	\$1,115
1-Month Non-Fuel Consumables	\$603
1-Month Waste Disposal	\$333
25% of 1-Month Fuel Cost at 100% CF	\$976
2% of TPC	\$16,853
Total	\$27,087
Inventory Capital	
60-day supply of fuel and consumables at 100% CF	\$8,989
0.5% of TPC (spare parts)	\$4,213
Total	\$13,202
Other Costs	
Initial Cost for Catalyst and Chemicals	\$904
Land	\$117
Other Owner's Costs	\$126,401
Financing Costs	\$22,752
Total Overnight Costs (TOC)	\$1,033,137

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-205. Case B12A-F4 initial and annual operating and maintenance costs

Case:	B12A-F4 – Supercritical PC Flexible Plant (Tiers 1–4)			Cost Base:	Dec 2018
Plant Size (MW, gross):	300	Heat Rate-net (Btu/kWh):			8,781
Operating & Maintenance Labor					
Operating Labor			Operating Labor Requirements per Shift		
Operating Labor Rate (base):	38.50	\$/hour	Skilled Operator:	2.0	
Operating Labor Burden:	30.0	% of base	Operator:	5.0	
Labor O-H Charge Rate:	25.0	% of labor	Foreman:	1.0	
			Lab Techs, etc.:	1.0	
			Total:	9.0	
Fixed Operating Costs					
				Annual Cost (\$)	
Annual Operating Labor:				\$3,945,942	
Maintenance Labor:				\$7,584,060	
Administrative & Support Labor:				\$2,882,501	
Property Taxes and Insurance:				\$16,853,467	
Total:				\$31,265,969	
Variable Operating Costs					
				Annual Cost (\$)	
Maintenance Material:				\$13,383,635 x CF	
Consumables					
	Initial Fill	Per Day	Per Unit	Initial Fill	Annual Cost (\$)
Water (/1000 gallons):	0	191	\$1.90	\$0	\$132,321 x CF
Makeup and Waste Water Treatment Chemicals (ton):	0	0.568	\$550.00	\$0	\$114,100 x CF
Brominated Activated Carbon (ton):	0	0.542	\$1,600.00	\$0	\$316,534 x CF
Enhanced Hydrated Lime (ton):	0	13.44	\$240.00	\$0	\$1,177,739 x CF
Limestone (ton):	0	239	\$22.00	\$0	\$1,918,511 x CF
Ammonia (19 wt%, ton):	0	22.6	\$300.00	\$0	\$2,473,460 x CF
SCR Catalyst (ft³):	5,861	5.35	\$150.00	\$879,197	\$293,066 x CF
Fuel additive for boiler slagging/fouling mitigation (gal)	1,000	89.2	\$25.00	\$25,000	\$813,982 x CF
Subtotal:				\$904,197	\$7,239,712 x CF
Waste Disposal					
Fly Ash (ton):	0	132	\$38.00	\$0	\$3,261,873 x CF
Bottom Ash (ton):	0	29.5	\$38.00	\$0	\$729,440 x CF
SCR Catalyst (ft³):	0	3.00	\$2.50	\$0	\$4,884 x CF
Subtotal:				\$0	\$3,996,198 x CF
By-Products					
Gypsum (ton):	0	363	\$0.00	\$0	\$0
Subtotal:				\$0	\$0
Variable Operating Costs Total:				904,197	\$24,619,546 x CF
Fuel Cost					
Illinois Number 6 (ton):	0	2,469	\$51.96	\$0	\$46,826,691 x CF
Fuel Costs Total:				\$0	\$46,826,691 x CF

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-206. Case B12A-F4 Synchronization startup and shutdown costs

Event to Synchronization		Hot Start	Warm Start	Cold Start	Shutdown
Energy and Duration					
Energy Produced	MWh	-	-	-	-
Duration	hr	0.3	0.8	2.1	0.1
NG Heat Input (HHV)	MMBtu	146	358	927	26
Coal Heat Input (HHV)	MMBtu	-	-	-	-
House Energy Consumed	MWh	0.6	1.4	3.6	0.1
Aux Boiler Energy	MWh	5.8	11.5	23.0	-
Costs					
Variable O&M Cost	\$	100	300	700	-
Natural Gas Cost	\$	600	1,600	4,100	100
Coal Cost	\$	-	-	-	-
House Energy Cost	\$	400	800	1,600	-
Total Cost for Event	\$	1,100	2,700	6,400	100

Exhibit 5-207. Case B12A-F4 full load startup and shutdown costs

Event to Full Load		Hot Start	Warm Start	Cold Start	Shutdown
Energy and Duration					
Energy Produced	MWh	75.5	127.0	322.2	107.5
Duration	hr	1.0	2.0	5.0	1.0
NG Heat Input (HHV)	MMBtu	307	654	1,295	367
Coal Heat Input (HHV)	MMBtu	728	1,235	3,404	898
House Energy Consumed	MWh	4.2	7.6	19.0	5.1
Aux Boiler Energy	MWh	11.5	23.0	46.0	-
Costs					
Variable O&M Cost	\$	800	1,500	3,800	1,000
Natural Gas Cost	\$	1,300	2,900	5,700	1,600
Coal Cost	\$	1,600	2,800	7,600	2,000
House Energy Cost	\$	900	1,800	3,900	300
Total Cost for Event	\$	4,600	9,000	21,000	4,900

5.7.23.1.1 Cost Differential Justifications

The contributors to the capital cost differential when comparing Case B12A-F4 to Case B12A-F3 are outlined below:

- Flexibility Option 16 — Advanced turbine seals to improve clearances during startup
- Flexibility Option 46 — Water cannons for sootblowing within the boiler radiant section

The Tier 4 flexibility options did not result in impacts to the performance or operational metrics of the plant (e.g., heat rate, auxiliary power usage, water usage). Therefore, there are no changes to the plant O&M costs when compared to Case B12A-F3. The O&M costs for the Case B12A-F4 plant increased slightly due to the shift in TPC.

The justifications for the capital cost differentials when comparing Case B12A-F4 to Case B12A-F3 are outlined below:

- Account 4.9 (Pulverized Coal Boiler & Accessories) and Account 4.11 (Boiler Balance of Plant) costs increase due to the increase in engineering design and additional equipment within the boiler island scope of supply. The following flexibility option impacted the cost of Account 4.9 and Account 4.11:
 - Flexibility Option 46 — Water cannons for sootblowing within the boiler radiant section
- Account 8.1 (Steam Turbine Generator & Accessories) and Account 8.2 (Steam Turbine Plant Auxiliaries) costs increase due to the increase in additional equipment within the steam turbine scope of supply. The following flexibility option impacted the cost of Account 8.1 and Account 8.2:
 - Flexibility Option 16 — Advanced turbine seals to improve clearances during startup

Tier 4 only includes two flexibility options (improved turbine seals and water cannons), the implementation of which do not result in a significant cost increase (BEC increased by approximately \$5,805,000, relative to Case B12A-F3) due to the new-build methodology used for the cost estimation.

While the magnitude of the cost impact of these options is not significant, relative to the other tiers of flexibility options presented, they remain in the ‘High Cost/Low Performance’ impact tier because they add cost without an appreciable return on performance improvement.

5.8 SUPERCRITICAL PC CASE SUMMARY

5.8.1 Performance Results

Exhibit 5-208 shows the performance and environmental profile summary for all cases at full and minimum sustainable load.^k As shown, the normalized raw water consumption (gpm/MW-gross) at full load is 3.9 percent lower in the flexible plants (cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4) than in the baseload plant (Case B12A-F0). At the minimum loads, the normalized raw water consumption is 1.4 percent lower in the flexible plants (cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4) than in the baseload plant (Case B12A-F0).^l

^k As discussed in Section 4.8.1, sustainable load is an operating point that is tenable for an indefinite period of time between outages, whereas, achievable load is an operating point that is tenable for a shorter period of time (<12 hours) in order to withstand atypical operating conditions (e.g., overnight operation, equipment malfunction, and weather events affecting grid dispatch)

^l The minimum load for Case B12A-F0 is 40 percent, whereas the minimum load for cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4 is 20 percent.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Exhibit 5-208. Performance summary and environmental profile for supercritical cases

Case Name	Baseload		Flexible							
	B12A-F0		B12A-F1		B12A-F2		B12A-F3		B12A-F4	
Load	Full Load (100%)	Min. Stable Load ^A (40%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)	Full Load (100%)	Min. Stable Load ^A (20%)
PERFORMANCE										
Nameplate Capacity	300	300	300	300	300	300	300	300	300	300
Gross Power Output (MWe)	300	120	300	60	300	60	300	60	300	60
Auxiliary Power Requirement (MWe)	17	9	27	7	27	7	27	5	27	5
Total Auxiliaries (% of Gross Power)	5.5%	7.7%	9.1%	11.5%	9.1%	11.2%	8.9%	8.6%	8.9%	8.6%
Net Power Output (MWe)	283	111	273	53	273	53	273	55	273	55
Coal Flow Rate (lb/hr)	214,007	89,486	205,762	46,390	205,762	46,390	205,763	46,451	205,763	46,451
Natural Gas Flow Rate (lb/hr)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
HHV Thermal Input (kWt)	731,682	305,949	703,493	158,607	703,493	158,607	703,496	158,815	703,496	158,815
Net Plant HHV Efficiency (%)	38.7%	36.2%	38.8%	33.5%	38.8%	33.6%	38.9%	34.5%	38.9%	34.5%
Net Plant HHV Heat Rate (Btu/kWh)	8,810	9,425	8,802	10,195	8,802	10,155	8,781	9,882	8,781	9,882
Raw Water Withdrawal (gpm)	276	115	265	57	265	57	265	57	265	57
Process Water Discharge (gpm)	8	3	8	1	8	1	8	1	8	1
Raw Water Consumption (gpm)	268	112	257	55	257	55	257	55	257	55
CO ₂ Emissions (lb/MMBtu)	201	201	201	202	201	202	201	202	201	202
CO ₂ Emissions (lb/MWh-gross)	1,669	1,751	1,605	1,821	1,605	1,821	1,605	1,823	1,605	1,823
CO ₂ Emissions (lb/MWh-net)	1,767	1,897	1,766	2,058	1,766	2,050	1,761	1,995	1,761	1,995
SO ₂ Emissions (lb/MMBtu)	0.081	0.081	0.081	0.082	0.081	0.082	0.081	0.082	0.081	0.082
SO ₂ Emissions (lb/MWh-gross)	0.671	0.708	0.645	0.738	0.645	0.738	0.645	0.739	0.645	0.739
NO _x Emissions (lb/MMBtu)	0.084	0.080	0.087	0.078	0.087	0.078	0.087	0.078	0.087	0.078
NO _x Emissions (lb/MWh-gross)	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700
PM Emissions (lb/MMBtu)	0.011	0.010	0.011	0.010	0.011	0.010	0.011	0.010	0.011	0.010
PM Emissions (lb/MWh-gross)	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090	0.090
Hg Emissions (lb/TBtu)	0.360	0.345	0.375	0.333	0.375	0.333	0.375	0.332	0.375	0.332
Hg Emissions (lb/MWh-gross) ^B	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06	3.00E-06

^A Minimum stable load is the operating point that is tenable for an indefinite period of time between outages

^B As discussed in Section 4.4.1, the mercury capture units were designed to attain the emissions target of 3.00x10⁻⁶ lb/MWh-gross

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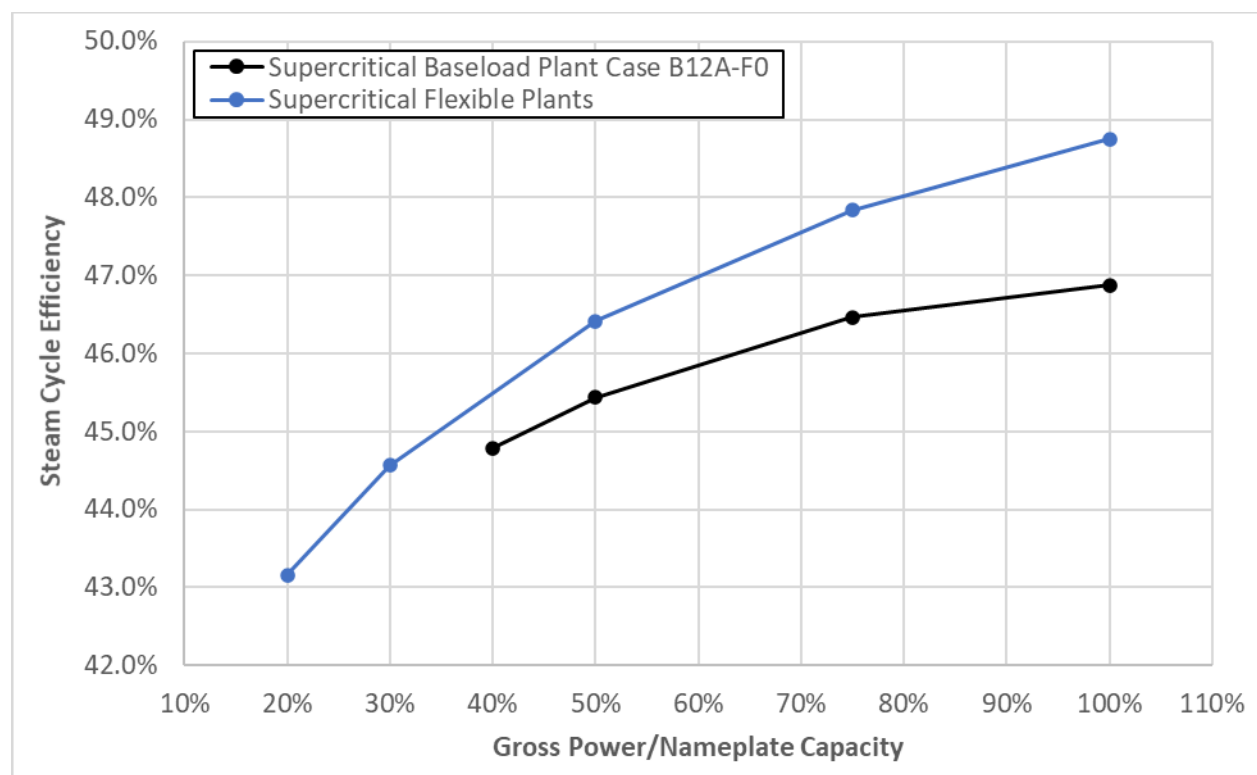
EPA promulgated a New Source Performance Standard on October 23, 2015, for emissions of CO₂ for new fossil fuel-fired electric utility generating units; the limit for new steam generating units was set as 1,400 lb-CO₂/MWh-gross. [11] A December 2018 proposed update to 111(b) set the limit for new steam generating units based on size. For small-scale ($\leq 2,000$ MMBtu/hr heat input) PC plants, the limit is 2,000 lb-CO₂/MWh-gross, while that of larger ($>2,000$ MMBtu/hr heat input) PC plants is 1,900 lb-CO₂/MWh-gross. [12]

As all supercritical cases within this study are classified as larger-scale EGUs, they would be required to maintain their emissions below 1,900 lb-CO₂/MWh-gross on a 12-operating-month average. This regulation is always applicable—even during startup and shutdown periods.

For the supercritical baseload and flexible plant cases, all emissions limits, including CO₂, were met across all loads assessed.

Exhibit 5-209 presents a comparison of the baseload and flexible plant part load steam cycle efficiencies. Only Case B12A-F0 and Case B12A-F1 are shown, since all four flexible plant cases (cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4) have the same steam cycle efficiency.

Exhibit 5-209. Steam cycle efficiency cross case comparison for supercritical cases

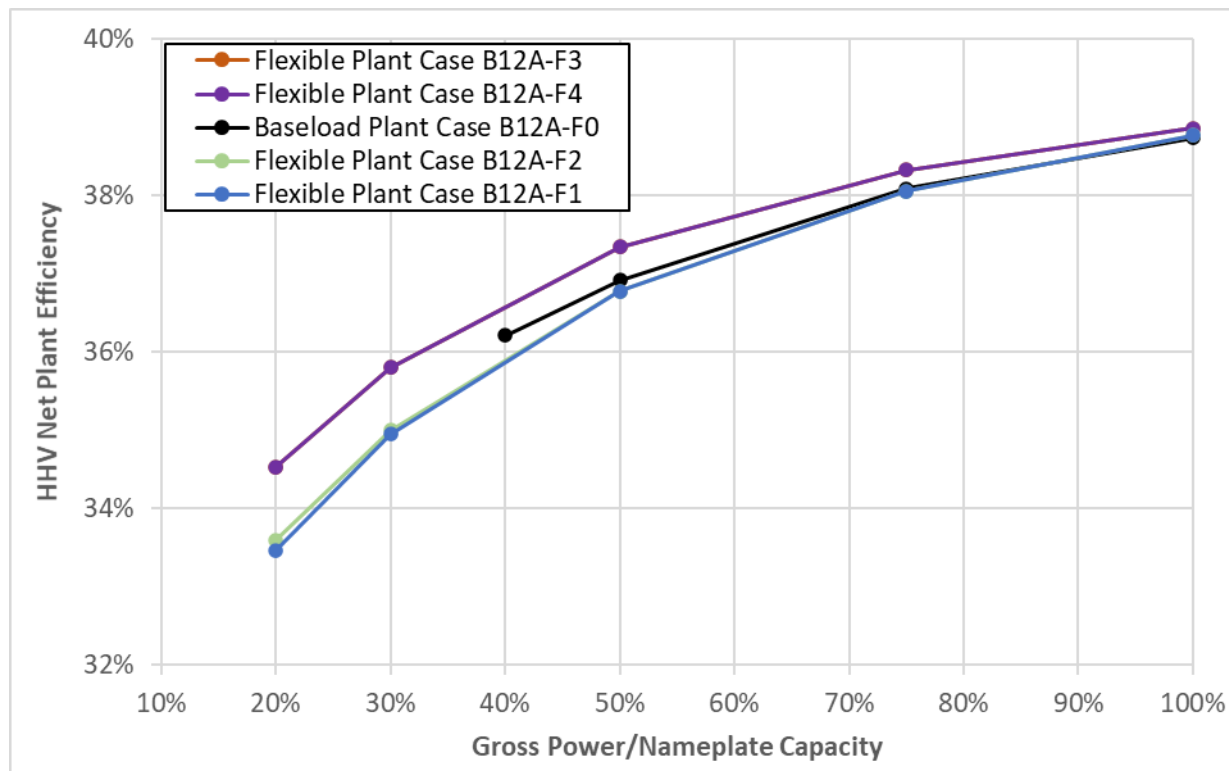


At full load, the baseload and flexible plant steam cycle efficiencies are similar; however, the flexible plant case has a slightly improved (1.9 percentage points) steam cycle efficiency due to the use of an electric driven BFW pump. Switching to an electric driven BFW pump eliminates the steam extraction required for a steam driven BFW pump, improving the steam cycle

efficiency. However, the electric power required for driving the electric driven BFW pump is noted as an increase in the plant auxiliary power requirements.

A graph of the net plant efficiency (HHV basis) across the load range for each case is provided in Exhibit 5-210; note that Case B12A-F0 performance is reported at 100, 75, 50, and 40 percent load, while cases cases B12A-F1, B12A-F2, B12A-F3, and B12A-F4 performance is reported at 100, 75, 50, 30, and 20 percent load—the discrete load points used for modeling were modified for the flexible plant cases to reflect its reduced minimum load.

Exhibit 5-210. HHV Net plant efficiency for supercritical cases



Note: The HHV net plant efficiency curves for cases B12A-F3 and B12A-F4 are overlapping

As shown in Exhibit 5-210, the flexibility options introduced in:

- Case B12A-F1 (Tier 1) increase the net plant efficiency at high loads and reduce the net plant efficiency at 50 percent load and below, relative to Case B12A-F0.
- Case B12A-F2 (Tier 2) result in an increase in net plant efficiency below 30 percent load, relative to Case B12A-F1.
- Case B12A-F3 (Tier 3) result in the greatest improvement to net plant efficiency.
- Case B12A-F4 (Tier 4) did not result in a noticeable improvement in plant performance.

The following flexibility options were the primary contributor to the net plant efficiency change in each case:

- Case B12A-F1: Steam turbine driven pumps replaced with electric motor drives

- Case B12A-F2: Auxiliary load optimization
- Case B12A-F3: Outfitting large electric motors with VFD units

Because sliding pressure operation is implemented into the supercritical baseload plant, the net plant efficiency penalty across the load range was not as substantial as that of the subcritical plant (Case B11A-F0). The Case B12A-F0 HHV net plant efficiency decreases from 38.7 percent at full load to 36.2 percent at minimum load, which corresponds to an efficiency penalty of approximately 6.5 percent.

Compared to Case B12A-F0, Case B12A-F1 has a similar HHV net plant efficiency at full load as well as a similar efficiency penalty across the comparable load range. The BFW pump was switched to an electric driven pump to eliminate flexibility limits imposed by a steam driven pump. The Case B12A-F1 HHV net plant efficiency decreases from 38.8 percent at full load to 33.5 percent at minimum load, which corresponds to an efficiency penalty of approximately 13.7 percent. Compared to Case B12A-F0, the Case B12A-F1 minimum load HHV net plant efficiency is reduced by 2.7 percentage points, or approximately 7.6 percent. The reduction in minimum efficiency is partially due to the concurrent reduction in minimum load (from 40 to 20 percent) compared to Case B12A-F0.

Case B12A-F2 has identical performance to Case B12A-F1 at loads above 30 percent. At 30 percent load and below, Case B12A-F2 has a slightly improved net plant efficiency due to the reduced FGD normalized power requirement. The Case B12A-F2 HHV net plant efficiency decreases from 38.8 percent at full load to 33.6 percent at minimum load, which corresponds to an efficiency penalty of approximately 13.3 percent. Compared to Case B12A-F1, the Case B12A-F2 minimum load HHV net plant efficiency is improved by 0.1 percentage points, or approximately 0.4 percent.

Case B12A-F3 has a similar full load efficiency compared to Case B12A-F2 but achieves an improved efficiency as load is reduced. Installation of VFDs improves the part load efficiency of major rotating equipment, and the efficiency improvement is more noticeable as load is further reduced. The Case B12A-F3 HHV net plant efficiency decreases from 38.9 percent at full load to 34.5 percent at minimum load, which corresponds to a minimum load efficiency penalty of approximately 11.1 percent. Compared to Case B12A-F2, the minimum load HHV net plant efficiency is improved by 0.9 percentage points, or approximately 2.8 percent.

Compared to the baseload plant, all flexible plant cases achieve higher efficiencies at full load, but cases B12A-F1 and B12A-F2 demonstrate lower efficiencies at 75 percent load and below while cases B12A-F3 and B12A-F4 demonstrate higher efficiencies. The improvement in efficiency for cases B12A-F3 and B12A-F4 becomes greater as load is reduced, indicating that the more often a plant operates at low loads, the more benefit they will see on net plant efficiency from installation of the flexibility options in Tier 3. Exhibit 5-211 presents an efficiency comparison at the lowest common load point of 50 percent.

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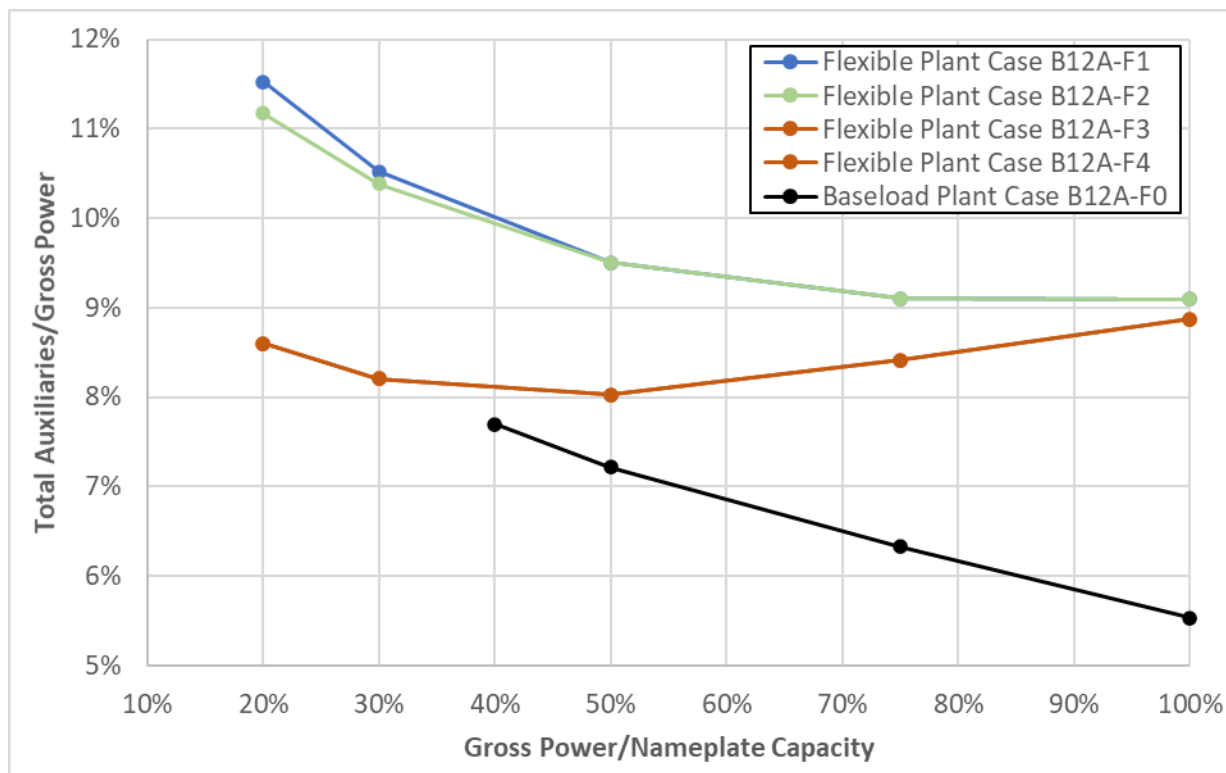
Exhibit 5-211. HHV Net plant efficiency comparison at 50 percent load for supercritical cases

Case	HHV Net Plant Efficiency at 50% Load	Incremental Improvement	Total Improvement
Baseload (B12A-F0)	36.9%	--	--
B12A-F1	36.8%	-0.4%	-0.4%
B12A-F2	36.8%	0.0%	-0.4%
B12A-F3	37.3%	1.5%	1.2%
B12A-F4	37.3%	0.0%	1.2%

Case B12A-F1 shows an efficiency reduction at 50 percent load, while Case B12A-F3 shows a notable improvement in efficiency, with VFDs offering a reduction in the auxiliary load. Case B12A-F3 offers the most substantial improvement in efficiency.

Exhibit 5-212 presents a cumulative case comparison of total normalized auxiliary load (as a percent of gross output) across the load range.

Exhibit 5-212. Normalized auxiliary power consumption cross-case comparison for supercritical cases



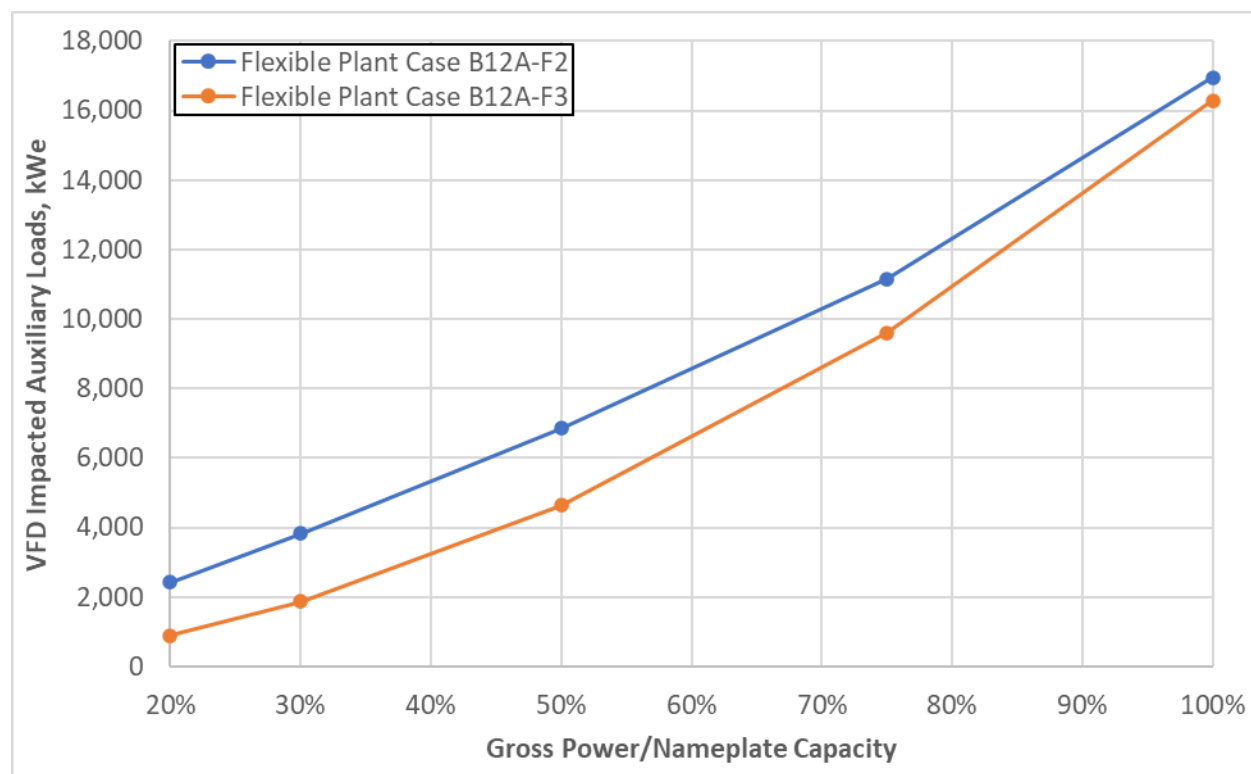
Case B12A-F1 has a higher auxiliary power requirement compared to Case B12A-F0, which is a consequence of utilizing an electric driven BFW pump that extracts power as an auxiliary power requirement rather than utilizing a steam driven BFW pump. In addition, the hydraulic coupling that is required for modulating the BFW pump outlet pressure is a source of inefficiency that

leads to a higher power consumption. Despite this, the gap in normalized auxiliary loads between Case B12A-F1 and Case B12A-F0 decreases slightly with load. The normalized auxiliary power consumption of the electric driven BFW pump does not increase as rapidly as load is reduced, since the BFW pump outlet pressure is allowed to decrease with plant load.

Case B12A-F2 normalized auxiliary power consumption is very similar to Case B12A-F1, with a slight reduction at loads below 50 percent. This is due to the auxiliary load optimization that reduces the FGD system normalized power requirement at low loads.

The Case B12A-F3 normalized auxiliary load is notably reduced compared to Case B12A-F2. Installation of VFDs increases the efficiency of the BFW pump and the PA, FD, and ID fans. In addition, it eliminates the need for a hydraulic coupling since the VFD allows for modulation of the BFW pump outlet pressure. This results in decreased normalized auxiliary power consumption as load is reduced at higher loads; below 50 percent load, the normalized auxiliary power consumption is affected more significantly by relatively constant auxiliary loads, such as the ancillary glycol cooling loops and plant control systems. With a lower load requirement compared to relatively constant auxiliary loads and thus a lower impact, the operation of the boiler circulation pump at loads below 35 percent contributes to the increase in normalized auxiliary power consumption at low loads as well. The total auxiliary load for the components that are impacted by VFDs is shown for Case B11A-F2 and Case B11A-F3 in Exhibit 5-213.

Exhibit 5-213. VFD impacted auxiliary loads for supercritical cases



5.8.2 Flexibility Metric Results Comparison

For each flexibility metric, performance comparisons of the discrete breakpoints have been prepared based on the grouping and cumulative implementation of the flexibility options. The tabulated summary of the quantitative breakpoints between the various flexibility metrics is presented in Exhibit 5-214. The flexibility metrics total plant cost and O&M cost were omitted from the quantitative breakpoint table as they are covered in a separate section.

While not quantified in this study, there are competing influences of the implemented flexibility options for each of the flexibility metrics. For example, the addition of variable frequency drives, an electrode boiler, a steam turbine bypass, and a fuel additive system in Case B12A-F3 improves several flexibility metrics; however, the addition of equipment accumulates single-points of failure within the plant design, which begins to effectively reduce availability. Additional examples of trade-offs associated with several flexibility options are provided in Section. 4.7.2.

Exhibit 5-214. Quantitative breakpoints for flexibility metrics

Flexibility Metric Quantitative Breakpoint Estimates	Case B12A-F0 (Baseload)	Case B12A-F1 (Tier 1)	Case B12A-F2 (Tiers 1–2)	Case B12A-F3 (Tiers 1–3)	Case B12A-F4 (Tiers 1–4)
Startup Time to Full Load					
Cold Start ^A to Full Load, Hours	7–15	5–6	5–6	4–5	4–5
Warm Start ^B to Full Load, Hours	3–6	1–2	1–2	1–2	1–2
Hot Start ^C to Full Load, Hours	1–3	0.5–1.0	0.5–1.0	0.5–1.0	0.5–1.0
Ramp Rate, % Load ^D per Minute	3–5	5–7	7–8	8–9	8–9
Minimum Stable Load (Emissions-Compliant, No Supplemental Firing), % Load ^D	40	20	20	20	20
Minimum Achievable Load (Emissions-Compliant, No Supplemental Firing), % Load ^D	30	15	15	12.5	12.5
Design Life, Years	30	30+	30+	30+	30+
Availability/Reliability (New Construction)					
Equivalent Availability Factor, %	88–90	90–92	92–94	92–94	92–94
Equivalent Forced Outage Rate, %	5–8	4–6	4–5	4–5	4–5
Planned Outages					
Plant Maintenance Outage (Spring/Fall)					
Frequency, Outage/Year	1–2	2–4	2–4	2–4	2–4
Duration, Days	1–7	1–4	1–4	1–4	1–4

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Flexibility Metric Quantitative Breakpoint Estimates	Case B12A-F0 (Baseload)	Case B12A-F1 (Tier 1)	Case B12A-F2 (Tiers 1–2)	Case B12A-F3 (Tiers 1–3)	Case B12A-F4 (Tiers 1–4)
Plant/Boiler Outage(s)					
Frequency, Years/Outage	1–2	2	2	2	2
Duration, Weeks	2–4	2	2	2	2
Steam Turbine Generator Outage(s)					
Frequency, Years/Outage	6–9	9–11	9–11	9–11	9–11
Duration, Weeks	6	4–6	4–6	4–6	4–6
Number of Starts, Per Year	10–20	30–60	30–60	30–60	30–60

^A Cold Start – Offline greater than 48 hours

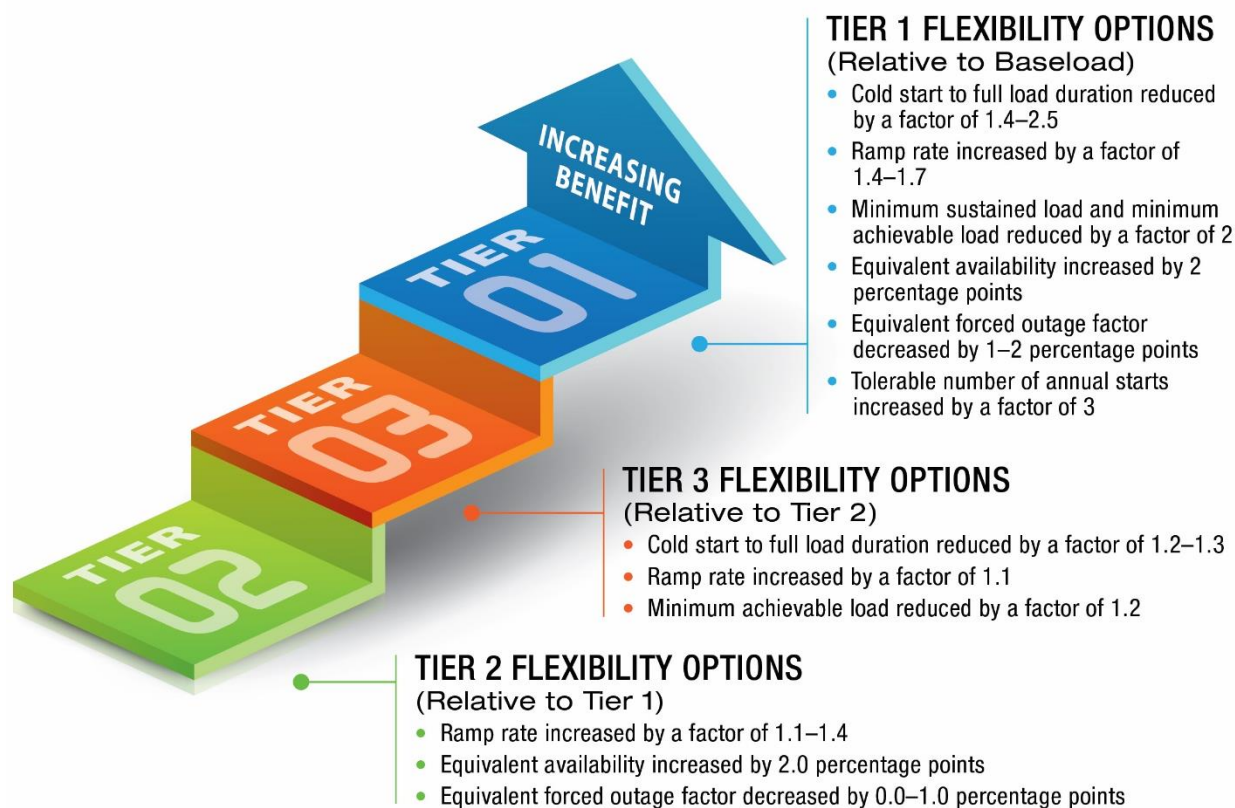
^B Warm Start – Offline between 8 and 48 hours

^C Hot Start – Offline less than eight hours

^D Ramp rate is often communicated as the ability to change load in percent full-load per minute

As illustrated in Exhibit 5-215, the flexibility options introduced in Case B11A-F1 (Tier 1) are perceived to provide the greatest value-added improvement to the flexibility metrics, followed by those introduced in Case B11A-F3 (Tier 3) and Case B11A-F2 (Tier 2). The flexibility options introduced in Case B11A-F4 (Tier 4) did not result in a noticeable improvement in flexibility metrics.

Exhibit 5-215. Primary observations on the impact of flexibility options on flexibility metrics



The following narrative describes the major contributing factors to the flexibility metric breakpoints shown in Exhibit 5-214.

- **Startup Time: Cold Start to Full Load:** The most significant breakpoint is established following the implementation of the Tier 1 flexibility options (e.g., steam sparging, EGU with black start capability, main steam warmup line, and electric-resistance blankets for pre-heating the turbine casing shell); implementing the Tier 2 flexibility options is not anticipated to create a significant shift/break in the cold start time already achieved through the Tier 1 flexibility options; the next (and final) breakpoint for cold start time is achieved through implementation of the Tier 3 flexibility options, including installation of advanced materials to reduce tube thicknesses, decreasing the drum diameter, and increasing the number of feedwater/steam headers to improve furnace heat absorption patterns. The methodology for developing these startup time breakpoints for the 'Cold Start to Full Load' operating scenario was based on industry references [24] [40] in addition to in-house Black & Veatch data from existing coal-fired EGUs studying and/or implementing design features to improve cold startup time.
- **Startup Time: Warm Start to Full Load:** Similar to the previous startup time flexibility metric, improvement of the warm start time diminishes after implementation of the Tier 1 flexibility options; this flexibility metric is estimated to remain approximately constant for cases 2–4. The methodology for the 'Warm Start to Full Load' metric breakpoints was based on industry references [24] [40] that outlined startup times empirically achieved by coal-fired plants or results of modeled plant performance following design improvements; the values outlined in these references generally aligned with Black & Veatch in-house data for this specific metric.
- **Startup Time: Hot Start to Full Load:** Similar to the previous startup time flexibility metric, improvement of the warm start time diminishes after implementation of the Tier 1 flexibility options; the flexibility metric most benefitted by the Tier 1 flexibility options is the cold startup to full load timeframe; no significant hot start to full-load timeframe breakpoints are estimated for cases 2–4. The methodology for the 'Hot Start to Full Load' metric breakpoints was based on industry references [24] [40] that outlined empirically achieved startup times for various plants or results of modeled plant performance following design improvements; the values outlined in these references generally aligned with Black & Veatch in-house data for this specific metric.
- **Ramp Rate:** The improvement to ramp rate starts with the implementation of the advanced online performance monitoring, water chemistry monitoring, electric BFW pump, and various flue gas/water-side bypasses equipped as part of the Tier 1 flexibility options; a marginal ramp rate breakpoint is achieved in Tier 2 due to enhanced operator training and additional flame detection/stabilization means; the final breakpoint for ramp rate is after implementation of the Tier 3 flexibility options due to installation of advanced creep-strength materials, online combustion optimizer, and the drum/header modifications that allow for more evenly dispersed heat absorption patterns in the furnace under high ramp rate conditions; the ramp rate of the plant will be closely coordinated with the boiler and steam turbine OEM to ensure that recommended

thermal gradient rates are monitored closely. The methodology for developing the ramp rate values and breakpoint changes associated with application of the flexibility options (e.g., indirect firing, smaller headers) was based on literature summary sources [25] [13] and Black & Veatch in-house references for the capabilities of existing coal-fired EGUs built for baseload operation (including recent OEM/EGU feedback during user-group conferences and industry meetings); the ramp rates characterized in the quantitative breakpoint table were estimated to be approximately constant across the load range for the 150 MW (gross) subcritical plant; for larger EGUs it has been observed that load shedding ramp rate (the rate of decreasing load) tends to be greater than the increasing-load ramp rate (the rate of increasing load) in addition to subcritical plants tending to exhibit a higher average ramp rate across their load range than a suitably equivalent supercritical [24] [40] plant.

- **Minimum Stable Load (Emissions-Compliant, No Supplemental Firing):** The differentiation between minimum “stable” load and minimum “achievable” load is outlined in Section 4.8.1; the primary contributors to the breakpoint following the implementation of the Tier 1 flexibility options are the sliding pressure operation, increased number of smaller-sized mills, various flue gas/water-side bypasses available, the detailed boiler and steam cycle tuning at reduced loads, and the application of the “continuous-coupled” last-stage blades in the steam turbine; the minimum stable load is expected to hold approximately constant for the further plant cases. The methodology for developing the minimum load values and breakpoint shifts associated with application of the flexibility options (e.g., operational tuning, smaller mills) was based on literature summary sources [24] [40] [25] outlining case studies of empirical and modeled minimum load improvements following implementation of specific flexibility options; these references and the values outlined for minimum stable load aligned with Black & Veatch experience and in-house data; the minimum stable load was intended to characterize a tenable load point for the flexible plant performance modeling.
- **Minimum Achievable Load (Emissions-Compliant, No Supplemental Firing):** The differentiation between minimum stable load and minimum achievable load is outlined in Section 4.8.1; the minimum achievable load scenario is characterized by remaining emissions compliant while also targeting shorter overall timeframe of operation in the achievable range; the flexibility options that equipped the plant for the minimum stable load breakpoints above are what also establish the breakpoint for this flexibility metric; however, the addition of the Tier 3 flexibility options, including indirect firing, VFD units, the steam turbine bypass, and intelligent soot blowing system, all contribute to the estimated breakpoint shown for minimum achievable load shown; these estimated values were sourced from the literature summary as well as other plants that have set a precedence for aggressive turndown/load reduction capabilities (for short periods of time). The methodology for developing the quantitative values and breakpoints for the minimum achievable load values was (similar to the other minimum load metric) based on literature summary sources [24] [40] [25] outlining case studies of empirical and modeled minimum load improvements following implementation of specific flexibility options; these references and the values outlined for minimum stable load aligned with

Black & Veatch experience and in-house data; the minimum achievable load is an extension of the minimum stable load, intended to characterize a more aggressive (offset by shorter duration) load point that has been empirically demonstrated by existing (retrofitted) EGUs or modeled performance results.

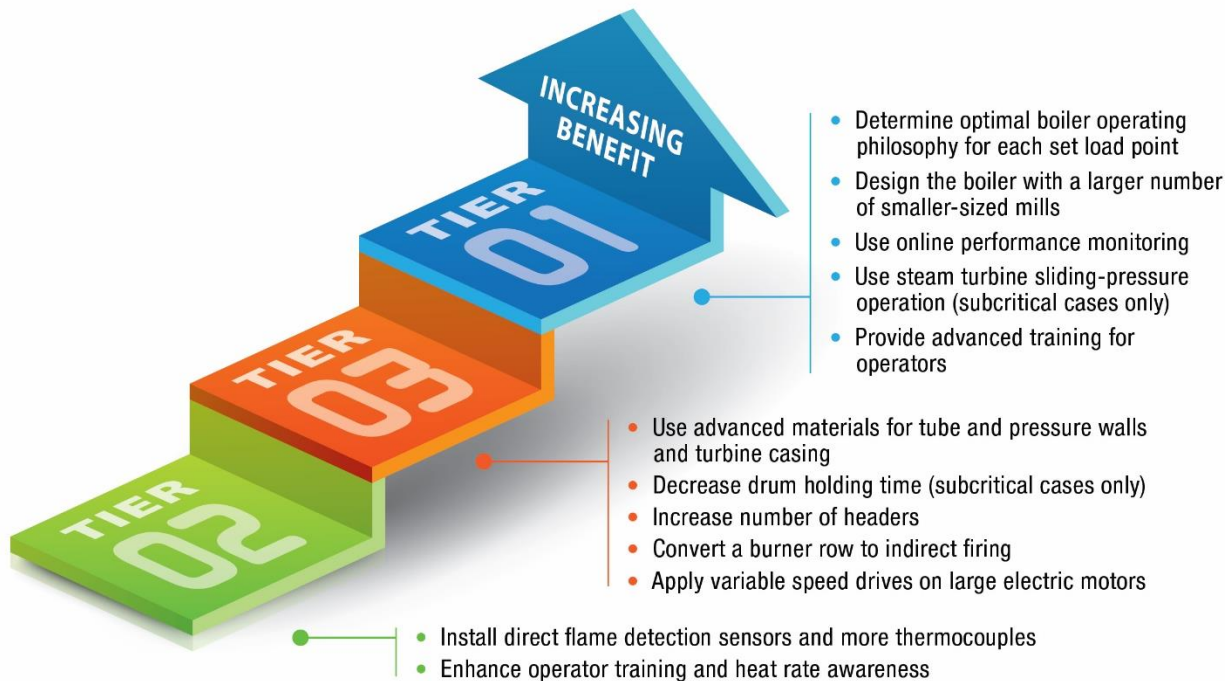
- **Design Life:** The flexible plant cases exhibit a marginally improved forecast on the expected operating life of the plant; utilization of the advanced online performance monitoring and diagnostics, enhanced operator training, and strict adherence to inspection programs (e.g., HEP/FAC) and layup procedures are the contributing factors to this marginal expected improvement in expected operating life of the plant design(s); however, there is no significant breakpoint established by any flexibility options proposed that would appreciably increase the design life of the plant. The values and breakpoints outlined in the quantitative breakpoint table are based on Black & Veatch experience with equipment manufacturers regarding the expected operating life for components from reputable and proven equipment suppliers.
- **Availability/Reliability–EAF:** The marginal shift in EAF following the implementation of the Tier 1 flexibility options is generally attributed to implementation of analysis/targeted maintenance based on the NERC-GADS data analysis, implementation of advanced online performance monitoring, and the ability for operators to diagnose and mitigate plant heat rate issues in real time; the next marginal breakpoint is associated with the continuation of the advanced training of operators to improve situation awareness; following the implementation of the Tier 2 flexibility options, the EAF was expected to level off due to additional equipment added to site (e.g., VFDs, electrode boiler[s]) as part of Tier 3, which tends to have the effect of leveling off the top-end availability thresholds deemed achievable. These EAF values and breakpoints align with Black & Veatch in-house data for industry-leading coal-fired plants aligned to the size and design features of the flexible plant cases. The values and increases of the EAF value reflect a general trend of plants that implement the more advanced inspection and testing methods outlined in the cumulative tiers; this data is based on in-house Black & Veatch information for existing plants.
- **Availability/Reliability–EFOR:** In a similar manner as EAF, the plant's EFOR is expected to exhibit a breakpoint following the Tier 1 flexibility options, followed by another marginal breakpoint resulting from the Tier 2 flexibility options; the flexibility options that contribute to improved EAF also contribute to reducing EFOR. The EFOR values and breakpoints align with Black & Veatch in-house data for industry-leading coal-fired units conceptually aligned with the size and design features of the flexible plant cases; the values and breakpoints of the EFOR values reflect a general trend of units that implement the more advanced inspection and testing methods outlined in the cumulative tiers, offset in certain cases by the increase in cycling [49] operation; this data is aligned with in-house Black & Veatch information for existing units.
- **Plant, Boiler, and Steam Turbine Generator Maintenance Outages:** The plant designs utilize established and proven technology that would fit into a traditional outage program/pattern for a coal-fired plant of the size outlined in this study (150 MWgross);

the trend reflected in the quantitative breakpoint table is intended to reflect that while the baseload plant would be expected to operate based on fewer annual outages that are longer in duration, the plant outage and maintenance philosophy is likely to cumulatively result in approximately the same number of outage days, but reaching that goal through a greater number of shorter duration outages; this trend is reflected in existing coal and gas-fired EGUs that are transitioning to a higher cycling duty. The number of outages and duration of these outages was developed based on Black & Veatch in-house information for typical plant maintenance programs and practices of industry-leading coal-fired EGUs.

- **Number of Starts:** The flexible plant cases have the ability to accept a higher number of starts as compared to the baseload plant design due predominantly to the higher redundancy in steam turbine casing thermocouples for thermal gradient tracking, the electric-resistance blankets for the steam turbine casing, the implementation of advanced online performance monitoring, and the targeted modification/tuning of startup/shutdown protocols to specifically lower component fatigue stresses; these components (in addition to others) are what equip the plant to significantly increase the acceptable/design number of starts per year without creating significant negative impacts on the overall plant health; following the breakpoint established from the Tier 1 flexibility options, there are no further expected breakpoints in the acceptable or design number of starts per year based on the tiers 2–4 flexibility options. The increase in perceived number of starts reflects a range that existing coal plants have experienced in the past due to changing dispatch characteristics and challenges of achieving suitable (e.g., overnight) minimum load. The benefits of the options associated with improving the number of starts was primarily sourced from Black & Veatch in-house data regarding typical number of starts for coal plants that are looking to implement cycling and load flexibility improvements in response to changing dispatch market conditions.

It can be noted that there are no flexibility metric breakpoints or performance advantages associated with the implementation of the Case B11A-F4 flexibility options (high-cost/low-performance impact). Following the qualitative and quantitative comparison of the application of the flexibility options and various flexible plant cases, the flexibility options illustrated in Exhibit 5-216 are those that were perceived to provide the greatest contribution to the improvement of plant flexibility.

Exhibit 5-216. The relative impact of flexibility options on flexibility metrics



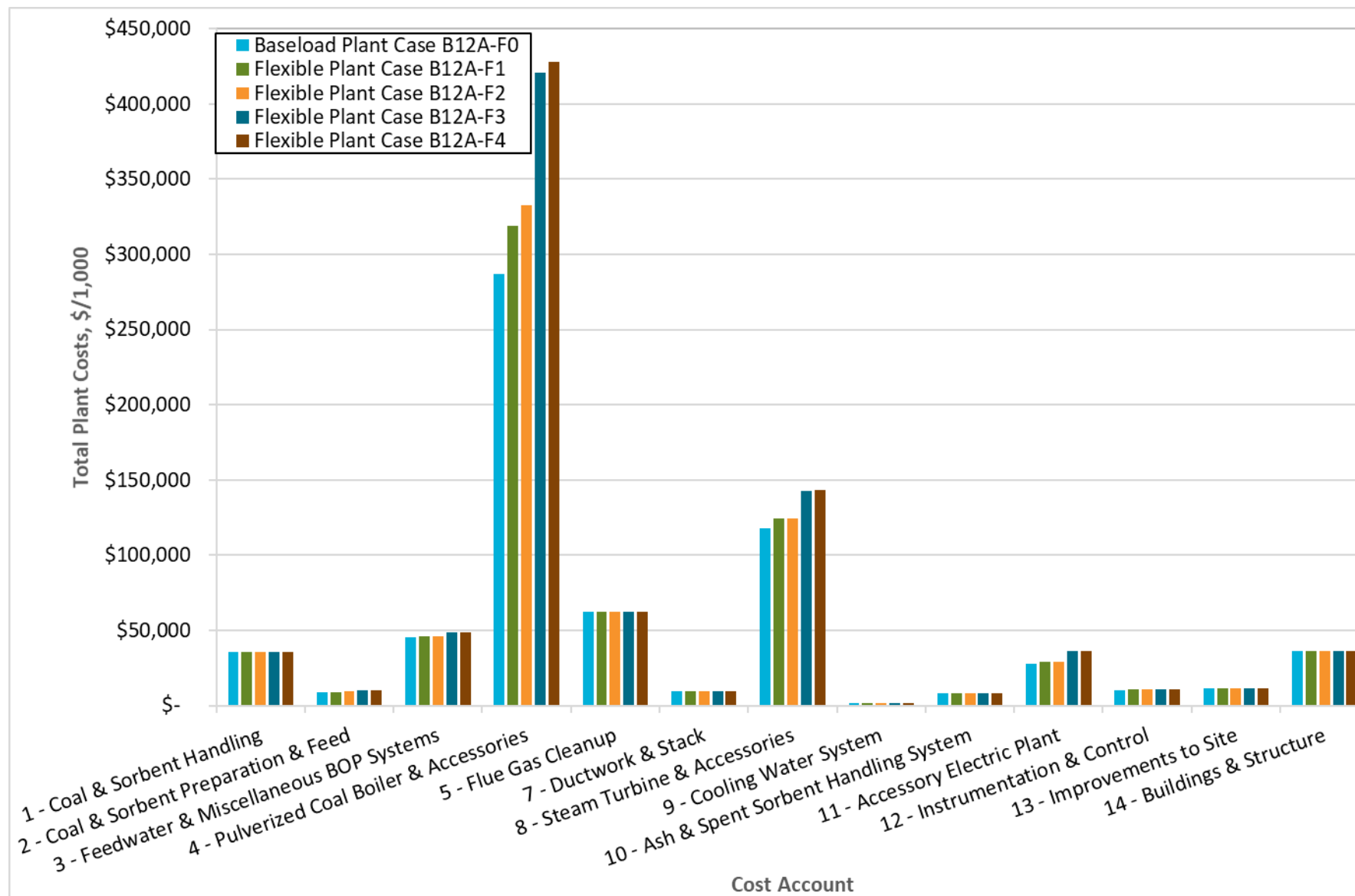
5.8.3 Cost Results

Exhibit 5-217 presents the capital cost summary by cost account for each supercritical PC case. The following observations can be made:

- None of the flexibility options implemented in this study impact the capital costs of the coal and sorbent handling system (Account 1), flue gas cleanup systems (Account 5), cooling water system (Account 9), ash and spent sorbent handling system (Account 10), improvements to site (Account 13), or buildings and structures (Account 14)
- The boiler (Account 4) and steam turbine (Account 8) accounts represent the greatest portions of the TPC and the two accounts together make up at least 90 percent of the cost increases that result from implementation of the flexibility options in all cases. As these accounts are frequently cited as the primary limiters for flexible operation, it is reasonable that the majority of the costs for improving plant flexibility are associated with these accounts.

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Exhibit 5-217. Total plant cost summary by cost account for supercritical cases

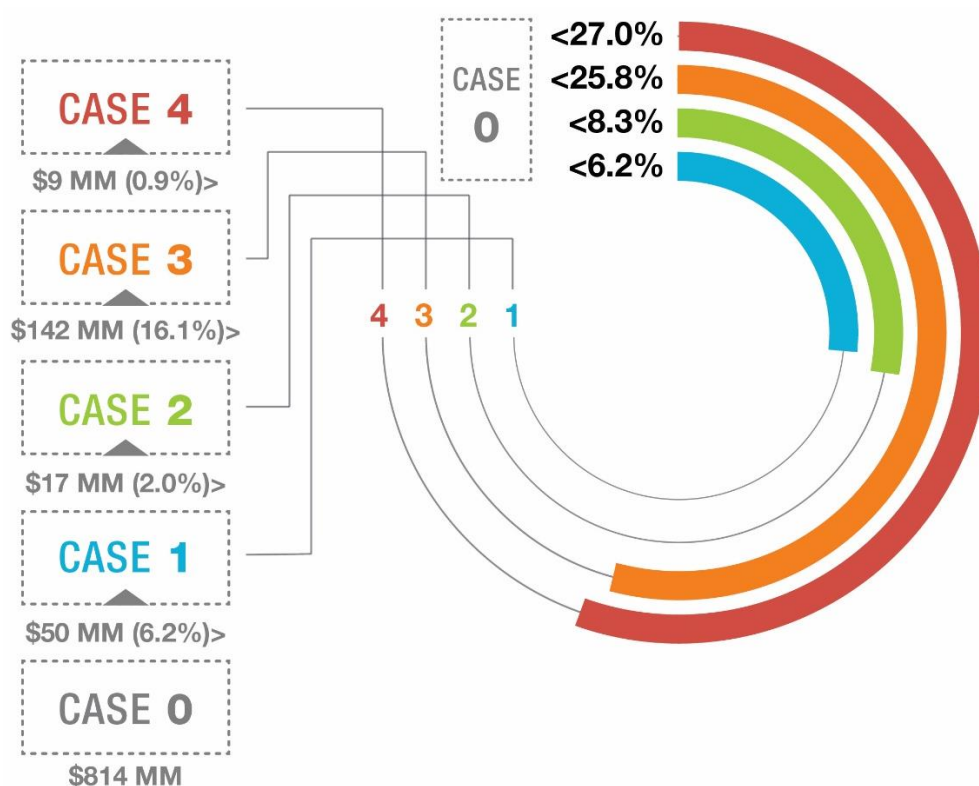


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The relative impact of each case on total overnight cost (TOC) is illustrated in Exhibit 5-218. As shown, each subsequent addition of a tier of design options for improving the flexibility of a plant results in a corresponding increase in costs. While the flexibility options included in Case B12A-F1 (Tier 1) are individually considered to be “low-cost” options, the large number (37) of flexibility options included in Case B12A-F1 resulted in a TOC increase of \$50 million (6.2 percent), relative to Case B12A-F0. This relative increase in TPC is only exceeded by the flexibility options introduced in Case B12A-F3 (Tier 3), which resulted in a \$142 million (16.1 percent) increase in TOC, relative to Case B12A-F2.

Further study is needed to determine the cost of individual options and which options would offer the greatest improvement to flexibility and plant performance.

Exhibit 5-218. Relative total overnight cost impact for supercritical cases



The TOC cost components of each case are presented in Exhibit 5-219 and summarized in Exhibit 5-220.

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Exhibit 5-219. Total overnight cost, by component, for supercritical cases

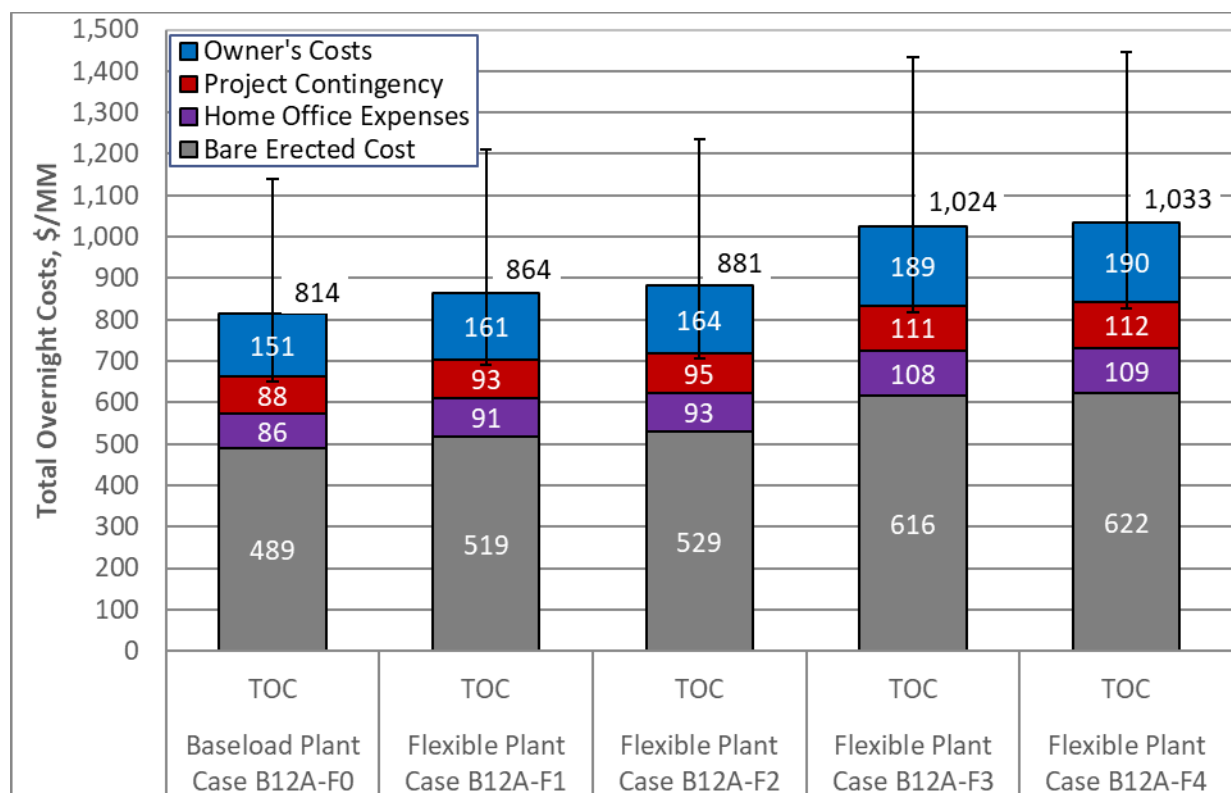


Exhibit 5-220. Summary of cost components for supercritical cases

	Pulverized Coal Boiler				
	PC Supercritical Baseload	PC Supercritical Flexible			
	Case B12A-F0	Case B12A-F1	Case B12A-F2	Case B12A-F3	Case B12A-F4
CAPITAL COST					
Total Plant Cost (2018\$/MM)	662	703	717	835	843
Bare Erected Cost	489	519	529	616	622
Home Office Expenses	86	91	93	108	109
Project Contingency	88	93	95	111	112
Process Contingency	0	0	0	0	0
Total Overnight Cost (2018\$/MM)	814	864	881	1,024	1,033
Owner's Costs	151	161	164	189	190
O&M COST					
Fixed Costs (2018\$/MM)	23	27	27	31	31
Variable Costs (2018\$/MM)	18 x CF	22 x CF	22 x CF	24 x CF	25 x CF
Fuel Costs (2018\$/MM)	49 x CF	47 x CF	47 x CF	47 x CF	47 x CF

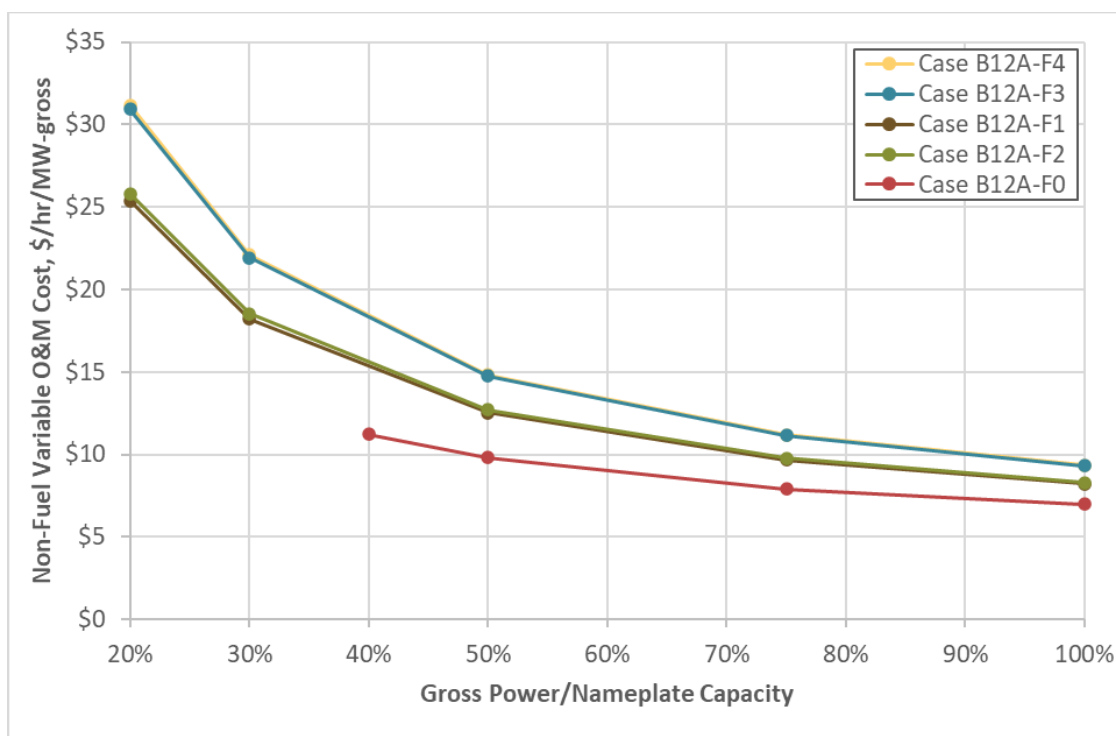
The following observations about O&M costs can be made:

- The fixed O&M costs of the flexible plant cases as a percentage of TPC range from 3.7 percent (Case B12A-F4) to 3.8 percent (Case B12A-F1), with the largest increases in fixed O&M costs occurring from Case B12A-F0 to Case B12A-F1, and Case B12A-F2 to Case B12A-F3.
 - The increase in fixed O&M costs between the baseload (Case B12A-F0) plant and Case B12A-F1 can be attributed to the increase in maintenance labor cost as a percentage of TPC (0.92 percent of TPC for cases 1–4; 0.64 percent for Case B12A-F0), which is due to the proactive maintenance programs implemented by high cycling plants, and to the increase in staff headcount (one additional skilled operator per shift).
 - The increase in fixed O&M costs between Case B12A-F2 and Case B12A-F3 can be attributed to the relatively large increase in TPC.
- The variable O&M costs experience the largest increase between Case B12A-F0 to Case B12A-F1, and Case B12A-F2 to Case B12A-F3.
 - The slight reduction in Case B12A-F1 consumables cost (due to an improvement in plant efficiency compared to Case B12A-F0) is outweighed by the increase in maintenance material costs as a percentage of TPC (1.38 percent of TPC for cases 1–4; 0.96 percent for Case B12A-F0), which is due to the proactive maintenance programs implemented by high cycling plants.
 - The increase in variable O&M costs between Case B12A-F2 and Case B12A-F3 is attributed to the additional consumable stream added as part of the Tier 3 group of flexibility options (Option 47 — Fuel additives for slagging/fouling mitigation); these additives are typically magnesium hydroxide and other related minerals; the additive can be shipped in either liquid form or solid reagent form, which would then be mixed with plant water to form the final slurry solution.
- Fuel costs are similar between all cases. A slight reduction is seen between Case B12A-F0 and Case B12A-F1 due to the improved plant efficiency.

The non-fuel variable O&M and fuel costs are presented as a function of plant load on an hourly basis in Exhibit 5-221 and Exhibit 5-222, respectively. These charts assume that the plant is operating at reduced loads 100 percent of the year (service factor of 1). If the service factor is reduced, the maintenance materials costs would be reduced.

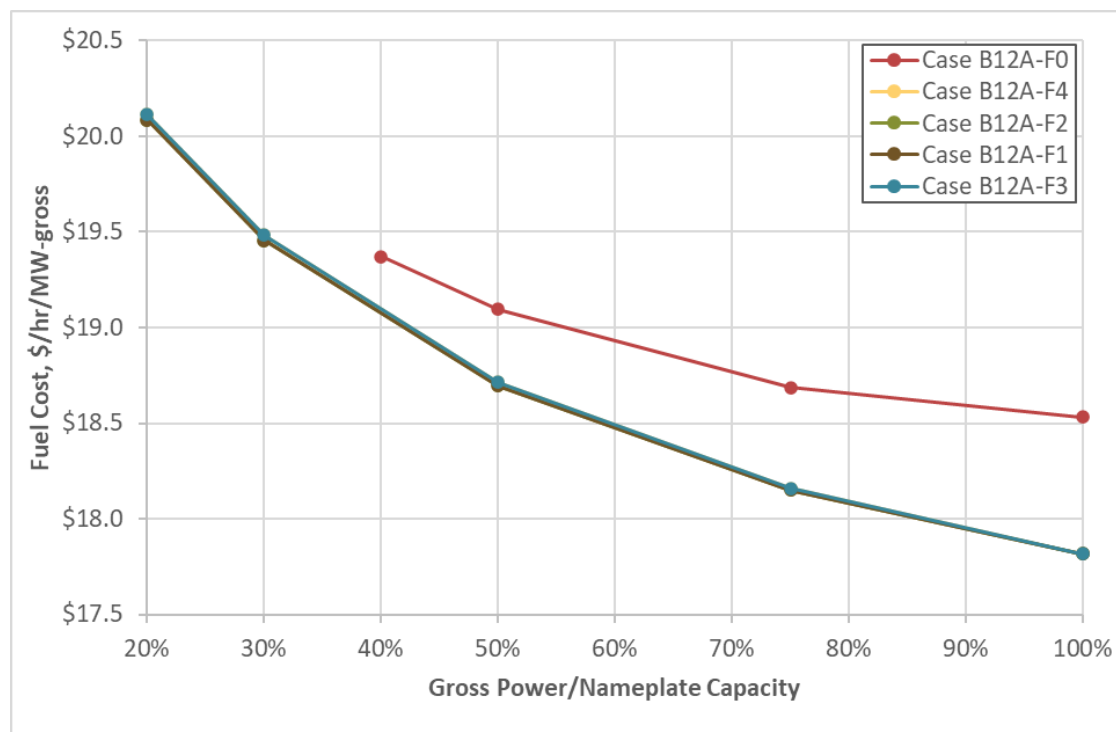
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Exhibit 5-221. Non-fuel variable O&M costs as a function of plant load



Note: The cost curves for Cases B12A-F3-F4 are overlapping

Exhibit 5-222. Fuel costs as a function of plant load



Note: The cost curves for Cases B12A-F1-F4 are overlapping

5.9 PC CASE SUMMARY

The design conditions of the subcritical and supercritical PC plants assessed in this study differ, primarily, in their gross plant output and steam conditions, as shown in Exhibit 5-223.

Exhibit 5-223. Full-load steam conditions for all cases

Full-Load Steam Conditions		
Steam Parameter	B11A-F0 (Subcritical)	B12A-F0 (Supercritical)
Power Output, MWe	150	300
Steam Cycle, MPa/°C/°C (psia/°F/°F)	12.4/538/538 (1,800/1,000/1,000)	24.1/593/593 (3,500/1,100/1,100)
Steam Turbine	Constant-Pressure Main Steam	Sliding Pressure Main Steam

In addition, as it is standard for supercritical PC plants to be designed with sliding-pressure operation and a condensate polishing system, and all supercritical PC plants use a Benson boiler, the following flexibility options were only applied to flexible subcritical PC cases.

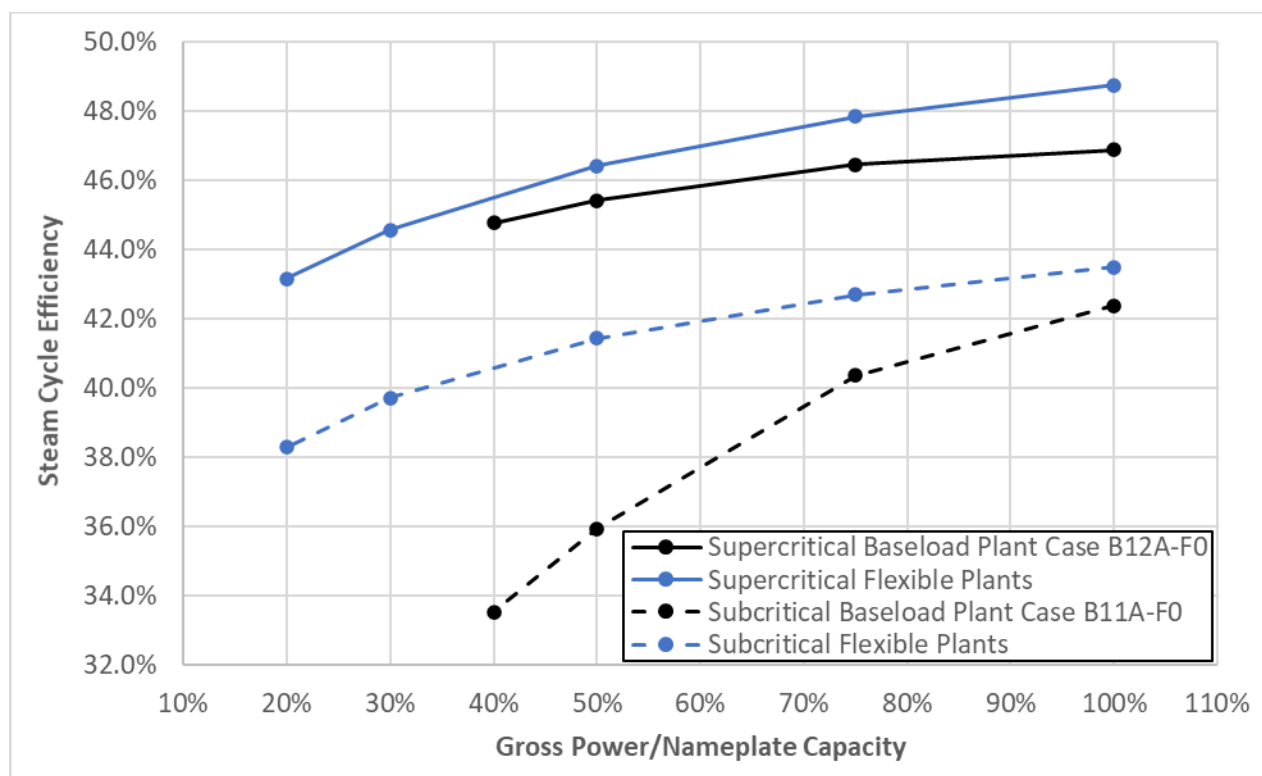
- Flexibility Option 2 (Tier 3): Decrease drum holding time to reduce drum diameter and drum wall thickness
- Flexibility Option 12 (Tier 3): Use of condensate polishing system to maintain cycle chemistry parameters during shutdown and layup periods and reduce startup times
- Flexibility Option 59 (Tier 1): Steam turbine sliding-pressure operation

The effects of these differences on the cost and performance impacts resulting from the inclusion of the tiers of flexibility options are discussed in the balance of this section.

5.9.1 Performance Results

Exhibit 5-224 presents a comparison of the baseload and flexible plant part load steam cycle efficiencies. As all of the flexible plant cases within the same steam cycle classification have the same steam cycle efficiency, only one line is plotted for each. As shown, the supercritical plants all have higher steam cycle efficiencies than the subcritical plants due to the higher quality steam conditions of the supercritical plants.

Exhibit 5-224. Steam cycle efficiency cross case comparison, all cases

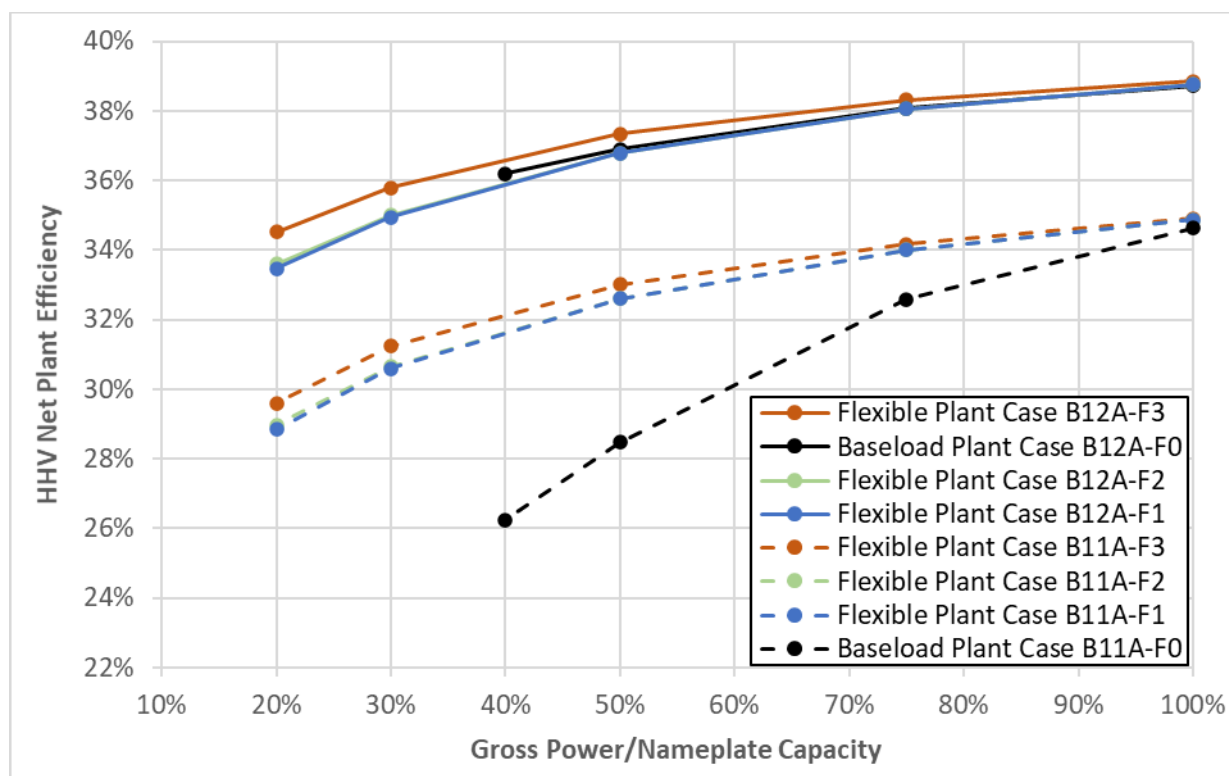


The utilization of an electric driven BFW pump in the flexible plant cases means that the steam extraction required for a steam driven BFW pump is eliminated and that the power requirement is reflected in the auxiliary load, rather than the steam turbine efficiency, which results in higher steam cycle efficiencies than the respective baseload plants.

While the flexible and baseload supercritical plants are convergent as load decreases, they are divergent in the subcritical plants due to the use of constant pressure main steam in the subcritical baseload plant. Constant pressure operation results in throttle losses from expanding main steam through the control valve; this efficiency penalty becomes more drastic as load is reduced.

Exhibit 5-225 provides a comparison of the net plant efficiency (HHV basis) for all cases.

Exhibit 5-225. HHV Net plant efficiency for all cases



Note: The HHV net plant efficiency curves for cases B11A-F3/B11A-F4 and B12A-F3/B12A-F4 are overlapping

In general, the net plant efficiencies reflect the steam cycle efficiencies shown in Exhibit 5-224. However, the increased auxiliary load resulting from the utilization of an electric driven BFW pump in the flexible cases reduces the benefit of the improved steam cycle efficiency. Additionally, an electric driven pump is inherently less efficient due to the conversion between mechanical – electrical – mechanical energy. While the electric pump is more efficient at lower loads, the hydraulic coupling losses negates this benefit, resulting in a lower net plant efficiency for the flexible cases.

The CO₂ emissions for all supercritical cases and all full-load subcritical cases are below the established limit (see Section 4.4.3); however, in subcritical cases the CO₂ exceed the established limit at their minimum load, with Case B11A-F0 exceeding by 16.9 percent, cases B11A-F1 and B11A-F2 exceeding by 2.6 percent, and cases B11A-F3 and B11A-F4 exceeding by 2.8 percent.

5.9.2 Flexibility Metric Results Comparison

The subcritical and supercritical plants have identical flexibility metric results for all cases. The results are available in Sections 5.5.2 (Subcritical) and 5.8.2 (Supercritical).

The subcritical and supercritical flexibility metrics shown in the tables have the same ranges. The uncertainty and relatively large range of startup times given (especially for Case B11A-F0 and B12A-F0) apply to both plants. The literature review showed significant variability in startup times depending on many factors. Although supercritical plants can have faster theoretical

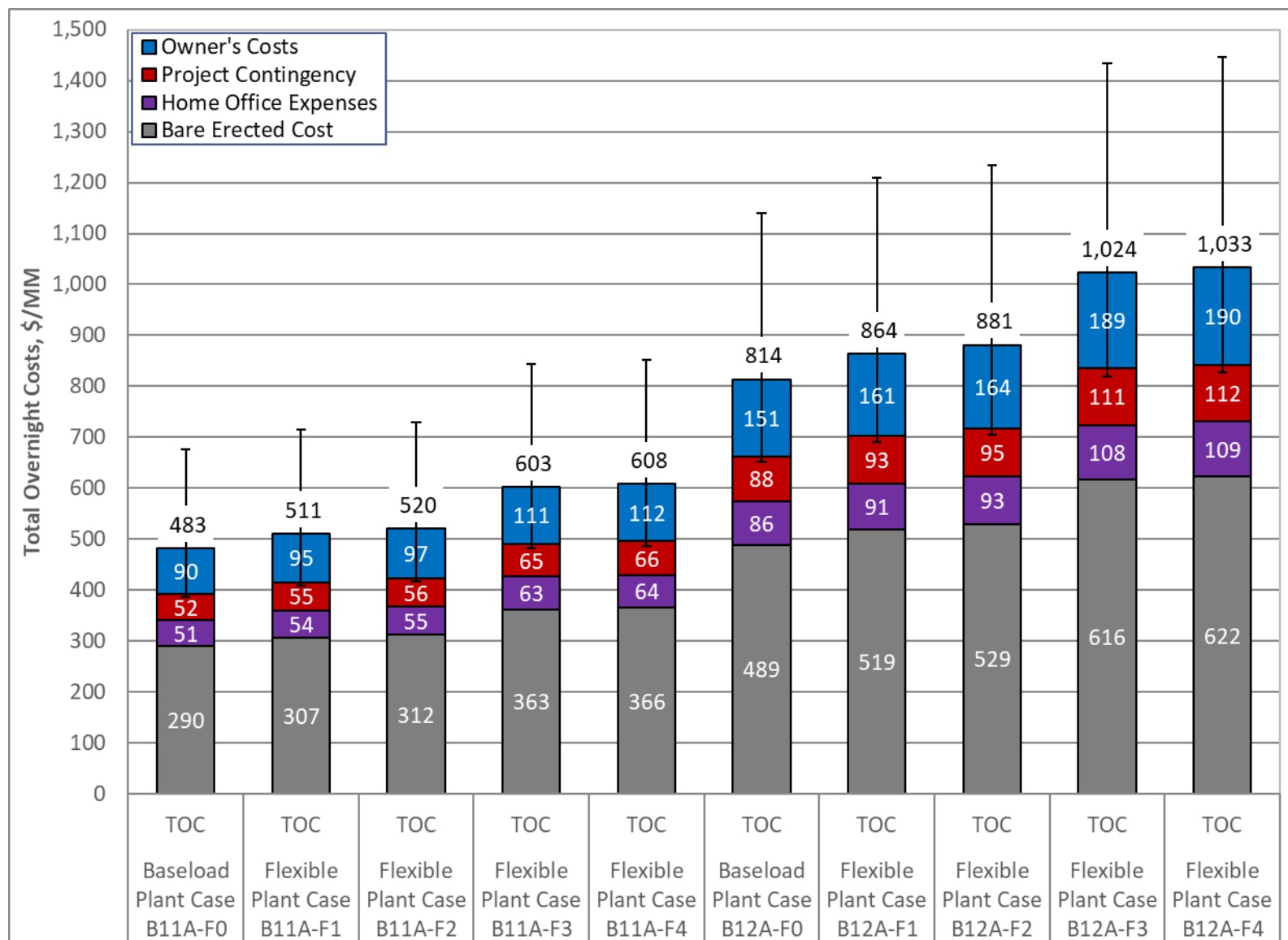
startup times they often have strict water quality and other plant BOP requirements that can lengthen ideal startup times. The uncertain and unproven nature of the flexible coal plants, especially considering Tier 3 and Tier 4, necessitates a high degree of uncertainty in startup characteristics that often vary extremely not only from site to site, but from start to start.

5.9.3 Cost Results

Exhibit 5-226 presents a comparison of TOC for all subcritical and supercritical PC baseload cases and a summary of those cost components is shown in Exhibit 5-227. As the subcritical and supercritical plants are not of the same size, a direct comparison cannot be made. However, some general observations are:

- Despite not including Flexibility Option 59 (steam turbine sliding-pressure operation) the introduction of the low-cost Tier 1 flexibility options had a greater impact on cost in the supercritical plant (Case B12A-F1) than in the subcritical plant (Case B11A-F1), with the TOC of Case B12A-F1 increasing by 6.2 percent and the TOC of Case B11A-F1 increasing by 5.9 percent.
- Despite not including flexibility options 2 (decrease drum holding time) or 12 (use of condensate polishing system) the introduction of the Tier 3 flexibility options had a greater impact on cost in the supercritical plant (Case B12A-F3) than in the subcritical plant (Case B11A-F3), with the TOC of Case B12A-F3 increasing by 16.1 percent, relative to Case B12A-F2 and the TOC of Case B11A-F3 increasing by 15.8 percent, relative to Case B11A-F2.

Exhibit 5-226. Total overnight cost, by component, for all cases



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Exhibit 5-227. Summary of cost components for all cases

Cost	Pulverized Coal Boiler									
	Subcritical					Supercritical				
	B11A-F0	B11A-F1	B11A-F2	B11A-F3	B11A-F4	B12A-F0	B12A-F1	B12A-F2	B12A-F3	B12A-F4
Total Plant Cost (2018\$/MM)	393	416	423	491	496	662	703	717	835	843
Bare Erected Cost	290	307	312	363	366	489	519	529	616	622
Home Office Expenses	51	54	55	63	64	86	91	93	108	109
Project Contingency	52	55	56	65	66	88	93	95	111	112
Process Contingency	0	0	0	0	0	0	0	0	0	0
Total Overnight Cost (2018\$/MM)	483	511	520	603	608	814	864	881	1,024	1,033
Owner's Costs	90	95	97	111	112	151	161	164	189	190
Fixed Costs (2018\$/MM)	14	17	17	19	19	23	27	27	31	31
Variable Costs (2018\$/MM)	10 x CF	12 x CF	13 x CF	14 x CF	14 x CF	18 x CF	22 x CF	22 x CF	24 x CF	25 x CF
Fuel Costs (2018\$/MM)	27 x CF	26 x CF	26 x CF	26 x CF	26 x CF	49 x CF	47 x CF	47 x CF	47 x CF	47 x CF

6 KEY TAKEAWAYS AND RECOMMENDATIONS

The key takeaways from this study are as follows:

- Of the flexibility metrics identified through available literature, the minimum load, ramp rate, and startup time (cold to full load) appear to be the most critical for PC plants competing with other flexible generation assets in current power markets:
 - Minimum Load — The improvement (i.e., reduction) of minimum load allows for the flexible plant to dispatch at lower loads and reduce uncompensated costs during low or no dispatch periods; improvements in minimum load also eliminate frequency of shutdown and startup cycles, which contributes to an improved operating life and reduced O&M costs due to a decrease of thermal cycles.
 - Ramp Rate — Improvements in ramp rate allow the flexible plant to reach dispatchable load faster (improving total energy export) in addition to reducing load more quickly (reducing uncompensated costs during low dispatch periods); both capabilities contribute to the economic competitiveness of the flexible plant.
 - Startup Time (Cold to Full Load) — Reducing startup times reduces uncompensated costs during startup and improves unit operation economic competitiveness.
- Cases B11A-F3 and B12A-F3 represent the most flexible and efficient plant configurations presented in this report, with an associated TOC plant premium of 25 and 26 percent, respectively, over that of a baseload plant (Cases B11A-F0 and B12A-F0).
 - The most significant improvement in plant flexibility and efficiency is realized through the implementation of Tier 1 flexibility options—most notably the conversion to sliding pressure operation (subcritical only).
 - The second most significant improvement in plant flexibility and efficiency is realized through the implementation of Tier 3 flexibility options—most notably the addition of the VFD units.

6.1 RECOMMENDATIONS FOR FUTURE WORK

The intent of this study was to fully characterize the configuration, design, performance capabilities, and cost of a plant specifically designed for flexible operation. Among the analyses and literature items reviewed, there remain areas where future work (outside the scope of this study) is recommended to advance discussions/analyses targeting improved competitiveness of coal-fired EGUs. A list of these items designated as recommendations for future work is outlined below:

- Identify impacts of significantly increasing amount of advanced alloy usage in boiler tube applications and the associated impacts to cost/tertiary impacts to adjacent sub-systems such as boiler foundations and structural steel design.

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- Identify second-tier market dispatch impacts; specifically, quantify the independent system operator/regional transmission organization impacts of multiple flexible coal plants operating in a specific region.
- Integrate regional-specific constraints on the plant to determine suitability.
- Perform additional sensitivity analyses of the impact of variation in coal constituents (e.g., carbon, sulfur, moisture, ash) and coal type on flexible plant design features and configuration (e.g., CFB vs PC firing sub-bituminous coal).
- Assess how the major plant features would translate to a physical “proof of concept” plant.
- Integrate highly advanced (not commercially proven) technology in the plant design to assess the impact on performance/cost.
- Identify specific plant configuration/design characteristics that could be changed to make the plant design “capture ready,” and ultimately incorporate post-combustion carbon capture systems into the plant designs.
- Integrate opportunity fuels (e.g., biomass, refuse-derived fuel) to improve plant economic viability.
- Identify how distributed energy resources, such as energy storage (batteries, thermal energy storage, etc.), could be incorporated in the reference plant design basis to improve plant flexibility and overall economic viability.
- Characterize the effects (sensitivity) of variations in the flexible plants’ CF on the plants’ O&M cost(s).
- Development of normalized cost reporting bases (e.g., \$/kW) and cost of electricity (\$/kWh) estimates were omitted from this analysis; future consideration regarding the valuation of the flexibility metrics is also an opportunity for future work.

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APPENDIX: PERFORMANCE CURVES

A.1 CASE B11A-F0

Performance curves developed for Case B11A-F0 are outlined in Exhibit A-1 through Exhibit A-4. These performance curves served as the basis for performance modeling and were developed consistent with the methodology described in Section 4.8. The baseload plant is intended to serve as a comparable reference plant that is equivalent in gross capacity to the flexible plant but designed purely for baseload operation. Accordingly, the baseload plant performance curves only reflect implementation of the flexibility options that were assumed to be installed on the baseload plant (see Section 4.7.1).

Exhibit A-1. Case B11A-F0 performance curves – boiler sub-system

Case	B11A-F0-100	B11A-F0-75	B11A-F0-50	B11A-F0-40
PA Fan Polytropic Efficiency, %	82.0	75.0	70.0	65.0
Secondary Air Fan Polytropic Efficiency, %	82.0	70.0	55.0	48.0
ID Fan Polytropic Efficiency, %	82.0	70.0	55.0	48.0
Radiant Section Outlet Temperature, °F	2,400	2,300	2,100	2,000
Air Preheater Flue Gas Inlet Pressure, psig	-0.43	-0.33	-0.21	-0.15
Air Preheater Flue Gas Outlet Pressure, psig	-0.72	-0.57	-0.38	-0.29
Bottom Ash/Fly Ash Ratio, %/%	20/80	20/80	20/80	20/80
Economizer Outlet Flue Gas Exit Temperature, °F	725	700	675	600
Air Heater (Gas-Side) Outlet Temperature, °F	289	287	283	280
Air Heater (Gas-Side) Acid Gas Condensation Approach Temperature, °F	29	29	29	29
PA Fan Outlet Pressure, psig	1.26	1.26	1.26	1.08
FD Fan Outlet Pressure, psig	0.90	0.79	0.61	0.49
ID Fan Outlet Pressure, psig	0.43	0.40	0.32	0.27
Formation Rate of SO ₃ , ppm	54.0	50.0	40.0	36.0
Unburned Carbon Rate, %	1.50	1.40	1.25	1.13
Infiltration Air Rate, %	2.0	2.0	2.0	2.0
Air Split Between PA and FD Fan: PA/FD, %/%	15/85	15/85	14/86	13/87
Excess Air, %	20.0	22.0	27.0	30.0
Air Leakage from PA and FD Fan, %	6.0	7.0	10.0	10.8
DSI SO ₂ Removal Rate, %	1.0	1.0	1.0	1.0
DSI SO ₃ Removal Rate, %	96.4	96.4	96.4	96.4
DSI HCl Removal Rate, %	30	30	30	30

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Exhibit A-2. Case B11A-F0 performance curves – FGD sub-system

Case	B11A-F0-100	B11A-F0-75	B11A-F0-50	B11A-F0-40
Oxidation ratio: O ₂ :SO ₂ , molar	4:1	4:1	4:1	4:1
Limestone ratio: CaCO ₃ :SO ₂ , molar – Limestone assumed to contain 72.1% CaCO ₃ mol%	1.03:1	1.03:1	1.03:1	1.03:1
Blowdown chloride concentration, ppmw	20,000	20,000	18,000	18,000
Limestone slurry solids content, wt%	30.0	30.0	30.0	30.0
Gypsum solids content, wt%	90.0	90.0	90.0	90.0
SO ₂ removal rate, %	98.0	98.0	98.0	98.0
SO ₃ removal rate, %	16.8	16.8	16.8	16.8
HCl removal rate, %	99.0	99.0	99.0	99.0
Pressure drop, psi	10.0	9.0	7.0	5.6
Outlet temperature, °F	135	135	135	135
Power requirement, kW/lb-SO ₂ /hr	0.145	0.170	0.245	0.285

Exhibit A-3. Case B11A-F0 performance curves – steam cycle sub-system

Case	B11A-F0-100	B11A-F0-75	B11A-F0-50	B11A-F0-40
HP Section Isentropic Efficiency, %	87.91	82.95	70.01	62.60
IP Section Isentropic Efficiency, %	92.93	93.34	93.68	93.80
LP Section Isentropic Efficiency, %	87.44	90.99	90.15	88.58
HP Pressure Ratio	4.08	4.23	4.17	4.09
IP Pressure Ratio	3.77	3.61	3.60	3.64
LP Pressure Ratio	68.48	61.13	46.79	39.10
Main Steam Pressure, psia	1,800	1,800	1,800	1,800
Main Steam Temperature, °F	1,000	1,000	1,000	1,000
Throttle Steam Pressure, psia	1,760	1,350	900	709
Throttle Steam Temperature, °F	993.5	923.2	814.3	759.9
Reheat Steam Pressure, psia	388.2	287.4	194.3	159.2
Reheat Steam Temperature, °F	1,000	1,000	1,000	1,000
Condensate Pump Efficiency, %	80	80	75	68
Blowdown Rate, %	1.0	1.0	1.0	1.0
Feedwater Pump Efficiency, %	80	80	75	72
Feedwater Pump Outlet Pressure, psia	2,270	2,270	2,270	2,270
Feedwater Pump Steam Turbine Isentropic Efficiency, %	80.0	78.5	78.0	77.8

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Case	B11A-F0-100	B11A-F0-75	B11A-F0-50	B11A-F0-40
Feedwater Heaters Pressure Drops, psi	5	5	5	5
Feedwater Heaters Temperature Approaches, °F	10	10	10	10
Superheater Heat Loss, Btu/lb-steam	3.27	3.27	3.27	3.27
Reheater Heat Loss, Btu/lb-steam	2.74	2.74	2.74	2.74
ACC Auxiliary Power Consumption, kW	1,790	1,790	1,230	1,007
No. of Operating Cells, #	16	16	11	9
Cell Motor Size (Per Cell), hp	150	150	150	150

Exhibit A-4. Case B11A-F0 performance curves – auxiliary electrical sub-system

Case	B11A-F0-100	B11A-F0-75	B11A-F0-50	B11A-F0-40
Motor Efficiency <1,000 kW, %	95.0	95.0	95.0	95.0
Motor Efficiency <1,000–10,000 kW, %	96.5	96.5	96.5	96.5
Motor Efficiency >10,000 kW, %	97.0	97.0	97.0	97.0
VFD Efficiency, %	N/A	N/A	N/A	N/A
Generator Efficiency, %	98.50	98.40	98.30	98.25
Circulating Water Pump Efficiency, %	80.0	80.0	75.0	70.4
Ground Water Pumps Efficiency, %	80.0	80.0	75.0	70.4
Cooling Fans Efficiency, % (polytropic)	75.0	65.0	60.0	57.0
Pulverizer Auxiliary Load, kW/tph-coal (as received)	10	10	10	10

A.2 CASE B11A-F1

Case B11A-F1 includes implementation of the Tier 1 flexibility options. To reflect the lower minimum load of the flexible plant cases, the 40 percent load point was removed from all performance curves, and values were added for 30 percent and 20 percent load points.

The first Tier 1 flexibility option that impacted modeled performance was implementation of sliding pressure operation. Constant pressure units (e.g., Case B11A-F0) operate with a constant boiler and main steam line pressure and main steam is throttled (expanded) to meet the steam pressure required at the inlet of the high pressure (HP) steam turbine section, whereas sliding pressure units vary the boiler and main steam line pressure to exactly meet the steam pressure required in the HP steam turbine section, thereby avoiding the inefficiencies of throttle flow control. To model sliding pressure operation, the boiler feedwater (BFW) pump outlet pressure and main steam pressure were reduced along with unit load. This required the addition of a BFW pump hydraulic coupling to allow for modulation of the BFW pump outlet pressure. Additionally, the switch to sliding pressure operation impacted the reheat steam pressure, steam turbine section efficiencies, and steam turbine pressure ratios.

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The second Tier 1 flexibility option that impacted modeled performance was replacement of the steam-driven BFW pump with an electric-driven BFW pump. This eliminates the BFW pump steam turbine along with its associated steam extraction, and the use of an electric drive impacts the efficiency of the BFW pump across the load range.

Exhibit A-5 through Exhibit A-8 outline the performance curves implemented in Case B11A-F1, with modifications or additions to the baseload plant performance curves identified in red text. Other than the additions of 30 percent and 20 percent load points, the major modifications in performance curves from implementation of the Tier 1 flexibility options are seen in the steam cycle sub-system performance curves (Exhibit A-7). The text shown in red denotes modifications to the performance curve values as compared to the previous case.

Exhibit A-5. Case B11A-F1 performance curves – boiler sub-system

Case	B11A-F1-100	B11A-F1-75	B11A-F1-50	B11A-F1-30	B11A-F1-20
PA Fan Polytropic Efficiency, %	82.0	75.0	70.0	60.0	56.0
Secondary Air Fan Polytropic Efficiency, %	82.0	70.0	55.0	40.0	31.8
ID Fan Polytropic Efficiency, %	82.0	70.0	55.0	40.0	31.8
Radiant Section Outlet Temperature, °F	2,400	2,300	2,100	1,880	1,740
Air Preheater Flue Gas Inlet Pressure, psig	-0.43	-0.33	-0.21	-0.09	-0.04
Air Preheater Flue Gas Outlet Pressure, psig	-0.72	-0.57	-0.38	-0.20	-0.10
Bottom Ash/Fly Ash Ratio, %/%	20/80	20/80	20/80	20/80	20/80
Economizer Outlet Flue Gas Exit Temperature, °F	725	700	675	627	600
Air Heater (Gas-Side) Outlet Temperature, °F	289	287	283	277	272
Air Heater (Gas-Side) Acid Gas Condensation Approach Temperature, °F	29	29	29	29	29
PA Fan Outlet Pressure, psig	1.26	1.26	1.26	0.90	0.72
FD Fan Outlet Pressure, psig	0.90	0.79	0.61	0.36	0.22
ID Fan Outlet Pressure, psig	0.43	0.40	0.32	0.22	0.14
Formation Rate of SO ₃ , ppm	54.0	50.0	40.0	30.0	23.4
Unburned Carbon Rate, %	1.50	1.40	1.25	1.00	0.87
Infiltration Air Rate, %	2.0	2.0	2.0	2.0	2.0
Air Split Between PA and FD Fan: PA/FD, %/%	15/85	15/85	14/86	12/88	11/89

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Case	B11A-F1-100	B11A-F1-75	B11A-F1-50	B11A-F1-30	B11A-F1-20
Excess Air, %	20	22	27	33	37
Air Leakage from PA and FD fan, %	6.0	7.0	10.0	12.0	13.6
DSI SO ₂ Removal Rate, %	1.0	1.0	1.0	1.0	1.0
DSI SO ₃ Removal Rate, %	96.4	96.4	96.4	96.4	96.4
DSI HCl Removal Rate, %	30	30	30	30	30

Exhibit A-6. Case B11A-F1 performance curves – FGD sub-system

Case	B11A-F1-100	B11A-F1-75	B11A-F1-50	B11A-F1-30	B11A-F1-20
Oxidation Ratio: O ₂ :SO ₂ , molar	4:1	4:1	4:1	4:1	4:1
Limestone Ratio: CaCO ₃ :SO ₂ , molar – Limestone assumed to contain 72.1% CaCO ₃ mol%	1.03:1	1.03:1	1.03:1	1.03:1	1.03:1
Blowdown Chloride Concentration, ppmw	20,000	20,000	18,000	18,000	18,000
Limestone Slurry Solids Content, wt%	30.0	30.0	30.0	30.0	30.0
Gypsum Solids Content, wt%	90.0	90.0	90.0	90.0	90.0
SO ₂ Removal Rate, %	98.0	98.0	98.0	98.0	98.0
SO ₃ Removal Rate, %	16.8	16.8	16.8	16.8	16.8
HCl Removal Rate, %	99.0	99.0	99.0	99.0	99.0
Pressure Drop, psi	10.0	9.0	7.0	4.0	2.3
Outlet Temperature, °F	135	135	135	130	130
Power Requirement, kW/lb-SO ₂ /hr	0.145	0.170	0.245	0.333	0.389

Exhibit A-7. Case B11A-F1 performance curves – steam cycle sub-system

Case	B11A-F1-100	B11A-F1-75	B11A-F1-50	B11A-F1-30	B11A-F1-20
HP Section Isentropic Efficiency, %	88.0	88.0	88.0	88.0	88.0
IP Section Isentropic Efficiency, %	93.0	93.0	93.0	93.0	93.0
LP Section Isentropic Efficiency, %	87.0	88.0	88.0	90.0	90.3
HP Pressure Ratio	5.00	5.00	5.00	5.00	5.00
IP Pressure Ratio	4.00	4.00	4.00	4.00	4.00
LP Pressure Ratio	56.88	50.34	37.94	26.18	18.72
Main Steam Pressure, psia	1,800	1,350	900	540	360
Main Steam Temperature, °F	1,000	1,000	1,000	1,000	1,000
Throttle Steam Pressure, psia	1,800	1,350	900	540	360

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Case	B11A-F1-100	B11A-F1-75	B11A-F1-50	B11A-F1-30	B11A-F1-20
Throttle Steam Temperature, °F	1,000	1,000	1,000	1,000	1,000
Reheat Steam Pressure, psia	342.9	257.1	171.4	102.9	68.6
Reheat Steam Temperature, °F	1,000	1,000	1,000	1,000	1,000
Condensate Pump Efficiency, %	80	80.0	75	60	52
Blowdown Rate, %	1.0	1.0	1.0	1.0	1.0
Feedwater Pump Efficiency, %	80	80	78	75	73
Feedwater Pump Hydraulic Coupling Efficiency, %	89	82	65	47	35
Feedwater Pump Outlet Pressure, psia	2,270	1,703	1,135	681	454
Feedwater Pump Steam Turbine Isentropic Efficiency, %	N/A	N/A	N/A	N/A	N/A
Feedwater Heaters Pressure Drops, psi	5	5	5	5	5
Feedwater Heaters Temperature Approaches, °F	10	10	10	10	10
Superheater Heat Loss, Btu/lb-steam	3.27	3.27	3.27	3.27	3.27
Reheater Heat Loss, Btu/lb-steam	2.74	2.74	2.74	2.74	2.74
ACC Auxiliary Power Consumption, kW	1,790	1,790	1,230	783	447
No. of Operating Cells, #	16	16	11	7	4
Cell Motor Size (Per Cell), hp	150	150	150	150	150

Exhibit A-8. Case B11A-F1 performance curves – auxiliary electrical sub-system

Case	B11A-F1-100	B11A-F1-75	B11A-F1-50	B11A-F1-30	B11A-F1-20
Motor Efficiency <1,000 kW, %	95.0	95.0	95.0	95.0	95.0
Motor Efficiency <1,000–10,000 kW, %	96.5	96.5	96.5	96.5	96.5
Motor Efficiency >10,000 kW, %	97.0	97.0	97.0	97.0	97.0
VFD Efficiency, %	N/A	N/A	N/A	N/A	N/A
Generator Efficiency, %	98.50	98.40	98.30	98.20	98.15
Circulating Water Pump Efficiency, %	80.0	80.0	75.0	65.0	59.0
Ground Water Pumps Efficiency, %	80.0	80.0	75.0	65.0	59.0
Cooling Fans Efficiency, % (polytropic)	75.0	65.0	60.0	55.0	54.0
Pulverizer Auxiliary Load, kW/tph-coal (as received)	10	10	10	10	10

A.3 CASE B11A-F2

Case B11A-F2 includes implementation of the Tier 1 and Tier 2 flexibility options. The only modification to the performance curves is the estimated plateauing of wet flue gas desulfurization (WFGD) normalized power requirement at reduced loads. Normalized power requirement was assumed to remain consistent at high loads since the WFGD system would still be operating within design specifications. However, at reduced loads, opportunity arises for normalized power requirement optimization by intelligent operation of WFGD recycle pumps. Case B11A-F2 performance curves are shown in Exhibit A-9, with modifications in red text.

Exhibit A-9. Case B11A-F2 performance curves – FGD sub-system

Case	B11A-F2-100	B11A-F2-75	B11A-F2-50	B11A-F2-30	B11A-F2-20
Power requirement, kW/lb-SO ₂ /hr	0.145	0.170	0.245	0.300	0.300

A.4 CASE B11A-F3

Exhibit A-10 outlines the modifications to the performance curves as a result of the Case B11A-F3 flexibility options being implemented (modifications shown in red text) and the updates to the plant block flow diagram (BFD) based on the addition of the Tier 3 flexibility options. As outlined above, the most significant modification to the curves is the leveling of the major fan/pump operating efficiencies. These large auxiliary power consumers can operate in their region of optimal (approximately constant) efficiency due to the use of shaft speed control to establish flow control as opposed to throttling.

As outlined above, the most significant modification to the curves is the leveling of the major fan/pump operating efficiencies. These large auxiliary power consumers can operate in their region of optimal (approximately constant) efficiency due to the use of shaft speed control to establish flow control as opposed to throttling. Case B11A-F3 performance curves are shown in Exhibit A-10, with modifications in red text.

Exhibit A-10. Case B11A-F3 performance curves – auxiliary electrical sub-system

Case	B11A-F3-100	B11A-F3-75	B11A-F3-50	B11A-F3-30	B11A-F3-20
Feedwater Pump Efficiency, %	80	80	80	80	80
PA Fan Polytropic Efficiency, %	82	82	82	82	82
Secondary Air Fan Polytropic Efficiency, %	82	82	82	82	82
ID Fan Polytropic Efficiency, %	82	82	82	82	82
VFD Motor Efficiency, %	97	97	97	97	97

A.5 CASE B11A-F4

The Tier 4 flexibility options had no impact on the plant performance curves. Accordingly, the Case B11A-F4 performance curves are equivalent to those used in Case B11A-F3.

A.6 CASE B12A-F0

Performance curves developed for Case B12A-F0 are outlined in Exhibit A-11 through Exhibit A-14. These performance curves served as the basis for performance modeling and were developed consistent with the methodology described in Section 4.8. The baseload plant is intended to serve as a comparable reference plant that is equivalent in gross capacity to the flexible plant but designed purely for baseload operation. Accordingly, the baseload plant performance curves only reflect implementation of the flexibility options that were assumed to be installed on the baseload plant (see Section 4.7.1).

For Case B12A-F0, the values shown in red text represent modifications from the subcritical baseload Case B11A-F0.

Exhibit A-11. Case B12A-F0 performance curves – boiler sub-system

Case	B12A-F0-100	B12A-F0-75	B12A-F0-50	B12A-F0-40
PA Fan Polytropic Efficiency, %	82.0	75.0	70.0	65.0
Secondary Air Fan Polytropic Efficiency, %	82.0	70.0	55.0	48.0
ID Fan Polytropic Efficiency, %	82.0	70.0	55.0	48.0
Radiant Section Outlet Temperature, °F	2,400	2,300	2,100	2,000
Air Preheater Flue Gas Inlet Pressure, psig	-0.43	-0.33	-0.21	-0.15
Air Preheater Flue Gas Outlet Pressure, psig	-0.72	-0.57	-0.38	-0.29
Bottom Ash/Fly Ash Ratio, %/%	20/80	20/80	20/80	20/80
Economizer Outlet Flue Gas Exit Temperature, °F	725	700	675	600
Air Heater (Gas-Side) Outlet Temperature, °F	289	287	283	280
Air Heater (Gas-Side) Acid Gas Condensation Approach Temperature, °F	29	29	29	29
PA Fan Outlet Pressure, psig	1.26	1.26	1.26	1.08
FD Fan Outlet Pressure, psig	0.90	0.79	0.61	0.49
ID Fan Outlet Pressure, psig	0.43	0.40	0.32	0.27
Formation Rate of SO ₃ , ppm	54	50	40	36
Unburned Carbon Rate, %	1.50	1.40	1.25	1.13
Infiltration Air Rate, %	2.0	2.0	2.0	2.0
Air Split Between PA and FD Fan: PA/FD, %/%	15/85	15/85	14/86	13/87
Excess Air, %	20.0	22.0	27.0	30.0
Air Leakage from PA and FD Fan, %	6.0	7.0	10.0	10.8
DSI SO ₂ Removal Rate, %	1.0	1.0	1.0	1.0
DSI SO ₃ Removal Rate, %	96.4	96.4	96.4	96.4
DSI HCl Removal Rate, %	30	30	30	30

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Exhibit A-12. Case B12A-F0 performance curves – FGD sub-system

Case	B12A-F0-100	B12A-F0-75	B12A-F0-50	B12A-F0-40
Oxidation ratio: O ₂ :SO ₂ , molar	4:1	4:1	4:1	4:1
Limestone ratio: CaCO ₃ :SO ₂ , molar – Limestone assumed to contain 72.1% CaCO ₃ mol%	1.03:1	1.03:1	1.03:1	1.03:1
Blowdown chloride concentration, ppmw	20,000	20,000	18,000	18,000
Limestone slurriesolids content, wt%	30.0	30.0	30.0	30.0
Gypsum solids content, wt%	90.0	90.0	90.0	90.0
SO ₂ removal rate, %	98.0	98.0	98.0	98.0
SO ₃ removal rate, %	16.8	16.8	16.8	16.8
HCl removal rate, %	99.0	99.0	99.0	99.0
Pressure drop, psi	10	9	7	6
Outlet temperature, °F	135	135	135	135
Power requirement, kW/lb-SO ₂ /hr	0.145	0.170	0.245	0.285

Exhibit A-13. Case B12A-F0 performance curves – steam cycle sub-system

Case	B12A-F0-100	B12A-F0-75	B12A-F0-50	B12A-F0-40
HP Section Isentropic Efficiency, %	89.0	89.0	89.0	89.0
IP Section Isentropic Efficiency, %	94.0	94.0	94.0	94.0
LP Section Isentropic Efficiency, %	90.0	91.0	91.0	92.0
HP Pressure Ratio	5.0	5.0	5.0	5.0
IP Pressure Ratio	8.0	8.0	8.0	8.0
LP Pressure Ratio	51.6	45.9	35.4	30.9
Main Steam Pressure, psia	3,500	2,594	1,766	1,436
Main Steam Temperature, °F	1,100	1,100	1,100	1,100
Throttle Steam Pressure, psia	3,500	2,594	1,766	1,436
Throttle Steam Temperature, °F	1,100	1,100	1,100	1,100
Reheat Steam Pressure, psia	593	454	305	246
Reheat Steam Temperature, °F	1,100	1,100	1,100	1,100
Condensate Pump Efficiency, %	80	80	75	68
Blowdown Rate, %	1.0	1.0	1.0	1.0
Feedwater Pump Efficiency, %	80	80	75	72
Feedwater Pump Outlet Pressure, psia	4,259	3,168	2,151	1,749
Feedwater Pump Steam Turbine Isentropic Efficiency, %	80.0	78.5	78.0	77.8

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case	B12A-F0-100	B12A-F0-75	B12A-F0-50	B12A-F0-40
Feedwater Heaters Pressure Drops, psi	5	5	5	5
Feedwater Heaters Temperature Approaches, °F	10	10	10	10
Superheater Heat Loss, Btu/lb-steam	3.27	3.27	3.27	3.27
Reheater Heat Loss, Btu/lb-steam	2.74	2.74	2.74	2.74
ACC Auxiliary Power Consumption, kW	3,580	3,580	2,470	2,020
No. of Operating Cells, #	32	32	22	18
Cell Motor Size (Per Cell), hp	150	150	150	150

Exhibit A-14. Case B12A-F0 performance curves – auxiliary electrical sub-system

Case	B12A-F0-100	B12A-F0-75	B12A-F0-50	B12A-F0-40
Motor Efficiency <1,000 kW, %	95.0	95.0	95.0	95.0
Motor Efficiency <1,000–10,000 kW, %	96.5	96.5	96.5	96.5
Motor Efficiency >10,000 kW, %	97.0	97.0	97.0	97.0
VFD Efficiency, %	N/A	N/A	N/A	N/A
Generator Efficiency, %	98.5	98.4	98.3	98.25
Circulating Water Pump Efficiency, %	80.0	80	75.0	70.4
Ground Water Pumps Efficiency, %	80.0	80	75.0	70.4
Cooling Fans Efficiency, % (polytropic)	75.0	65.0	60.0	57.0
Pulverizer Auxiliary Load, kW/tph-coal (as received)	10	10	10	10

A.7 CASE B12A-F1

Case B12A-F1 includes implementation of the Tier 1 flexibility options. To reflect the lower minimum load of the flexible plant cases, the 40 percent load point was removed from all performance curves, and values were added for 30 percent and 20 percent load points.

Other than the load point changes, the Tier 1 flexibility option that impacted modeled performance was the replacement of the steam-driven BFW pump with an electric-driven BFW pump. This eliminates the BFW pump steam turbine along with its associated steam extraction, and the use of an electric drive impacts the efficiency of the BFW pump across the load range.

Exhibit A-15 through Exhibit A-18 outline the performance curves implemented in Case B12A-F1, with modifications or additions to the baseload plant performance curves identified in red text. Other than the additions of 30 percent and 20 percent load points, the major modifications in performance curves from implementation of the Tier 1 flexibility options are seen in the steam cycle sub-system performance curves (Exhibit A-17). The text shown in red denotes modifications to the performance curve values as compared to the previous case.

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR
FLEXIBLE OPERATION

Exhibit A-15. Case B12A-F1 performance curves – boiler sub-system

Case	B12A-F1-100	B12A-F1-75	B12A-F1-50	B12A-F1-30	B12A-F1-20
PA Fan Polytropic Efficiency, %	82.0	75.0	70.0	60.0	56.0
Secondary Air Fan Polytropic Efficiency, %	82.0	70.0	55.0	40.0	31.8
ID Fan Polytropic Efficiency, %	82.0	70.0	55.0	40.0	31.8
Radiant Section Outlet Temperature, °F	2,400	2,300	2,100	1,880	1,740
Air Preheater Flue Gas Inlet Pressure, psig	-0.43	-0.33	-0.21	-0.09	-0.04
Air Preheater Flue Gas Outlet Pressure, psig	-0.72	-0.57	-0.38	-0.20	-0.10
Bottom Ash/Fly Ash Ratio, %/%	20/80	20/80	20/80	20/80	20/80
Economizer Outlet Flue Gas Exit Temperature, °F	725	700	675	627	600
Air Heater (Gas-Side) Outlet Temperature, °F	289	287	283	280	280
Air Heater (Gas-Side) Acid Gas Condensation Approach Temperature, °F	29	29	29	29	29
PA Fan Outlet Pressure, psig	1.26	1.26	1.26	0.90	0.72
FD Fan Outlet Pressure, psig	0.90	0.79	0.61	0.36	0.22
ID Fan Outlet Pressure, psig	0.43	0.40	0.32	0.22	0.14
Formation Rate of SO ₃ , ppm	54.0	50.0	40.0	30.0	23.4
Unburned Carbon Rate, %	1.50	1.40	1.25	1.00	0.87
Infiltration Air Rate, %	2.0	2.0	2.0	2.0	2.0
Air Split Between PA and FD Fan: PA/FD, %/%	15/85	15/85	14/86	12/88	11/89
Excess Air, %	20	22	27	33	37
Air Leakage from PA and FD fan, %	6.0	7.0	10.0	12.0	13.6
DSI SO ₂ Removal Rate, %	1.0	1.0	1.0	1.0	1.0
DSI SO ₃ Removal Rate, %	96.4	96.4	96.4	96.4	96.4
DSI HCl Removal Rate, %	30	30	30	30	30

Exhibit A-16. Case B12A-F1 performance curves – FGD sub-system

Case	B12A-F1-100	B12A-F1-75	B12A-F1-50	B12A-F1-30	B12A-F1-20
Oxidation Ratio: O ₂ :SO ₂ , molar	4:1	4:1	4:1	4:1	4:1
Limestone Ratio: CaCO ₃ :SO ₂ , molar – Limestone assumed to contain 72.1% CaCO ₃ mol%	1.03:1	1.03:1	1.03:1	1.03:1	1.03:1
Blowdown Chloride Concentration, ppmw	20,000	20,000	18,000	18,000	18,000

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case	B12A-F1-100	B12A-F1-75	B12A-F1-50	B12A-F1-30	B12A-F1-20
Limestone Slurry Solids Content, wt%	30.0	30.0	30.0	30.0	30.0
Gypsum Solids Content, wt%	90.0	90.0	90.0	90.0	90.0
SO ₂ Removal Rate, %	98.0	98.0	98.0	98.0	98.0
SO ₃ Removal Rate, %	16.8	16.8	16.8	16.8	16.8
HCl Removal Rate, %	99.0	99.0	99.0	99.0	99.0
Pressure Drop, psi	10.0	9.0	7.0	4.0	2.3
Outlet Temperature, °F	135	135	135	130	130
Power Requirement, kW/lb-SO ₂ /hr	0.145	0.170	0.245	0.333	0.389

Exhibit A-17. Case B12A-F1 performance curves – steam cycle sub-system

Case	B12A-F1-100	B12A-F1-75	B12A-F1-50	B12A-F1-30	B12A-F1-20
HP Section Isentropic Efficiency, %	89.0	89.0	89.0	89.0	89.0
IP Section Isentropic Efficiency, %	94.0	94.0	94.0	94.0	94.0
LP Section Isentropic Efficiency, %	90.0	91.0	91.0	92.0	92.0
HP Pressure Ratio	5.0	5.0	5.0	5.00	5.00
IP Pressure Ratio	8.0	8.0	8.0	8.00	8.00
LP Pressure Ratio	51.6	45.9	35.4	25.7	18.1
Main Steam Pressure, psia	3,500	2,594	1,766	1,106	776
Main Steam Temperature, °F	1,100	1,100	1,100	1,100	1,100
Throttle Steam Pressure, psia	3,500	2,594	1,766	1,106	776
Throttle Steam Temperature, °F	1,100	1,100	1,100	1,100	1,100
Reheat Steam Pressure, psia	593	454	305	187	128
Reheat Steam Temperature, °F	1,100	1,100	1,100	1,100	1,100
Condensate Pump Efficiency, %	80	80	75	60	52
Blowdown Rate, %	1.0	1.0	1.0	1.0	1.0
Feedwater Pump Efficiency, %	80	80	78	75	73
Feedwater Pump Hydraulic Coupling Efficiency, %	89	82	65	47	35
Feedwater Pump Outlet Pressure, psia	4,259	3,168	2,151	1,348	947
Feedwater Pump Steam Turbine Isentropic Efficiency, %	N/A	N/A	N/A	N/A	N/A
Feedwater Heaters Pressure Drops, psi	5	5	5	5	5
Feedwater Heaters Temperature Approaches, °F	10	10	10	10	10

CONCEPTUAL DESIGN OF PULVERIZED COAL ELECTRICITY GENERATING UNITS FOR FLEXIBLE OPERATION

Case	B12A-F1-100	B12A-F1-75	B12A-F1-50	B12A-F1-30	B12A-F1-20
Superheater Heat Loss, Btu/lb-steam	3.27	3.27	3.27	3.27	3.27
Reheater Heat Loss, Btu/lb-steam	2.74	2.74	2.74	2.74	2.74
ACC Auxiliary Power Consumption, kW	3,580	3,580	2,470	1,565	895
No. of Operating Cells, #	32	32	22	14	8
Cell Motor Size (Per Cell), hp	150	150	150	150	150

Exhibit A-18. Case B12A-F1 performance curves – auxiliary electrical sub-system

Case	B12A-F1-100	B12A-F1-75	B12A-F1-50	B12A-F1-30	B12A-F1-20
Motor Efficiency <1,000 kW, %	95.0	95.0	95.0	95.0	95.0
Motor Efficiency <1,000–10,000 kW, %	96.5	96.5	96.5	96.5	96.5
Motor Efficiency >10,000 kW, %	97.0	97.0	97.0	97.0	97.0
VFD Efficiency, %	N/A	N/A	N/A	N/A	N/A
Generator Efficiency, %	98.5	98.4	98.3	98.2	98.15
Circulating Water Pump Efficiency, %	80.0	80.0	75.0	65.0	59.0
Ground Water Pumps Efficiency, %	80.0	80.0	75.0	65.0	59.0
Cooling Fans Efficiency, % (polytropic)	75.0	65.0	60.0	55.0	54.0
Pulverizer Auxiliary Load, kW/tph-coal (as received)	10	10	10	10	10

A.8 CASE B12A-F2

Case B12A-F2 includes implementation of the Tier 1 and Tier 2 flexibility options. The only modification to the performance curves is the estimated plateauing of WFGD normalized power requirement at reduced loads. Normalized power requirement was assumed to remain consistent at high loads since the WFGD system would still be operating within design specifications. However, at reduced loads, opportunity arises for normalized power requirement optimization by intelligent operation of WFGD recycle pumps. Case B12A-F2 performance curves are shown in Exhibit A-19, with modifications in red text.

Exhibit A-19. Case B12A-F2 performance curves – FGD sub-system

Case	B12A-F2-100	B12A-F2-75	B12A-F2-50	B12A-F2-30	B12A-F2-20
Power requirement, kW/lb-SO ₂ /hr	0.145	0.170	0.245	0.300	0.300

A.9 CASE B12A-F3

Exhibit A-20 outlines the modifications to the performance curves as a result of the Case B12A-F3 flexibility options being implemented (modifications shown in red text) and the updates to the plant BFD based on the addition of the Tier 3 flexibility options. As outlined above, the most

significant modification to the curves is the leveling of the major fan/pump operating efficiencies. These large auxiliary power consumers can operate in their region of optimal (approximately constant) efficiency due to the use of shaft speed control to establish flow control as opposed to throttling.

As outlined above, the most significant modification to the curves is the leveling of the major fan/pump operating efficiencies. These large auxiliary power consumers can operate in their region of optimal (approximately constant) efficiency due to the use of shaft speed control to establish flow control as opposed to throttling. Case B12A-F3 performance curves are shown in Exhibit A-20, with modifications in red text.

Exhibit A-20. Case B12A-F3 performance curves – auxiliary electrical sub-system

Case	B12A-F3-100	B12A-F3-75	B12A-F3-50	B12A-F3-30	B12A-F3-20
Feedwater Pump Efficiency, %	80	80	80	80	80
PA Fan Polytrropic Efficiency, %	82	82	82	82	82
Secondary Air Fan Polytrropic Efficiency, %	82	82	82	82	82
ID Fan Polytrropic Efficiency, %	82	82	82	82	82
VFD Motor Efficiency, %	97	97	97	97	97

A.10 CASE B12A-F4

The Tier 4 flexibility options had no impact on the plant performance curves. Accordingly, the Case B12A-F4 performance curves are equivalent to those used in Case B12A-F3.

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