ADVANCED WATER-RELATED TECHNOLOGY PERFORMANCE DEVELOPMENT

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March 3, 2021

DOE/NETL-2021/2755

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Suggested Citation:
M. Turner, S. Pidaparti, and Eric Grol,"Advanced Water-Related Technology Performance Development," National Energy Technology Laboratory, Pittsburgh, March 3, 2021.

This report was prepared by MESA for the U.S. DOE NETL. This work was completed under DOE NETL Contract Number DE-FE0025912. This work was performed under MESA Activity 201.012.

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TABLE OF CONTENTS

List of Exhibits iii
Acronyms and Abbreviations v
Executive Summary 1
Flue Gas Desulfurization Wastewater Treatment Compliance Technology 2
Chloride Tolerance 2
Equipment Fabrication and Labor of Installation Costs 3
Dry Cooling Systems and Steam Condensers 3
Air-Side HTC 4
Air-Side Pressure Loss Coefficient 4
1 Introduction 5
2 Design Basis 6
2.1 Flue Gas Desulfurization Wastewater Treatment Compliance Technology 6
2.1.1 Site Characteristics 6
2.1.2 Coal Characteristics 8
2.1.3 Limestone Characteristics 11
2.1.4 Environmental Targets 11
2.1.5 Existing Plant Basis 13
2.1.6 Wastewater Treatment System Configuration 15
2.1.7 Cost Estimating Methodology 19
2.1.8 Selected FGD Wastewater Treatment Parameters 22
2.1.9 Study Assumptions 23
2.2 Dry Cooling Systems and Steam Condensers 24
2.2.1 Site Characteristics 24
2.2.2 Environmental Targets 25
2.2.3 Reference Plant Basis 27
2.2.4 Air Cooled Condenser Configuration 28
2.2.5 Performance Estimation Methodology 28
2.2.6 Cost Estimating Methodology 31
2.2.7 Selected ACC Parameters 32
2.2.8 Study Assumptions 33
3 Results, Analysis, and Discussion 34
3.1 Flue Gas Desulfurization Wastewater Treatment Compliance Technology 34
3.1.1 Performance Results 34
3.1.2 Cost Results 34
3.1.3 Sensitivity Analyses 36
3.2 Dry Cooling Systems and Steam Condensers 41

3.2.1 Performance Results 41
3.2.2 Cost Results 41
3.2.3 Sensitivity Analyses 42
4 Recommended R&D Areas of Improvement 49
4.1 Flue Gas Desulfurization Wastewater Treatment Compliance Technology 49
4.1.1 Chloride Concentration 49
4.1.2 Equipment Fabrication and Labor of Installation Costs 49
4.2 Dry Cooling Systems and Steam Condensers 50
4.2.1 Air-Side Heat Transfer Coefficient 50
4.2.2 Air-Side Pressure Loss Coefficient 50
5 References 51
Appendix: Cost and Performance Results 54
A.1 Flue Gas Desulfurization Wastewater Treatment Compliance Technology 54
A.1.1 Performance Results 57
A.1.2 Cost Results 61
A.2 Dry Cooling Systems and Steam Condensers 64
A.2.1 Performance Results 67
A.2.2 Cost Results 71

LIST OF EXHIBITS

Exhibit 2-1. Site characteristics 6
Exhibit 2-2. Site ambient conditions 7
Exhibit 2-3. Design makeup water quality 7
Exhibit 2-4. Design coal characteristics 9
Exhibit 2-5. Coal ash composition 10
Exhibit 2-6. Coal trace elements composition 10
Exhibit 2-7. Limestone composition 11
Exhibit 2-8. Emission limits for SO_2, NOx, PM, Hg, and HCl at existing plants [11], [12] 12
Exhibit 2-9. Discharge limits for wet FGD wastewater from existing sources 13
Exhibit 2-10. Summary description of the existing reference plant 13
Exhibit 2-11. Design basis FGD wastewater quality 14
Exhibit 2-12. Chemical precipitation process configuration 16
Exhibit 2-13. Biological treatment process configuration 18
Exhibit 2-14. Wet FGD wastewater treatment reference costs 19
Exhibit 2-15. Wet FGD wastewater treatment cost correlations 20
Exhibit 2-16. Retrofit difficulty factors 21
Exhibit 2-17. Selected FGD wastewater parameters for sensitivity analyses 22
Exhibit 2-18. Design coal characteristics 25
Exhibit 2-19. MATS and NSPS emission limits for SO_2, NOx, PM, Hg, and HCl 26
Exhibit 2-20. Reference plant design used for analysis of ACCs 27
Exhibit 2-21. Schematic of ACC bay 28
Exhibit 2-22. Adjustable input parameters and key performance model outputs in the ACC spreadsheet model 29
Exhibit 2-23. ACC tube bundle parameters 29
Exhibit 2-24. Comparison between ACC Excel model and STEAMPRO outputs 32
Exhibit 2-25. Selected ACC parameters for sensitivity analyses 33
Exhibit 3-1. Performance results summary 34
Exhibit 3-2. Cost results summary 34
Exhibit 3-3. Retrofit incremental and total LCOE impact 35
Exhibit 3-4. Retrofit incremental LCOE breakdown 36
Exhibit 3-5. LCOE Sensitivity 37
Exhibit 3-6. Water recycle impact on withdrawal rate 38
Exhibit 3-7. Sensitivity of LCOE to bare erected costs 39
Exhibit 3-8. Sensitivity of LCOE to fixed O&M 40
Exhibit 3-9. Sensitivity of LCOE to variable O&M 40
Exhibit 3-10. Performance results summary for reference plant design with updated ACC design 41
Exhibit 3-11. Cost results summary for reference plant design with updated ACC design 41
Exhibit 3-12. Impact of ACC auxiliary power on plant efficiency 42
Exhibit 3-13. Impact of ACC BEC, auxiliary power, and maintenance costs on LCOE 43
Exhibit 3-14. Impact of ACC-related parameters on the ACC auxiliary fan power 44
Exhibit 3-15. Impact of ACC-related parameters on the plant efficiency 44
Exhibit 3-16. Impact of ACC-related parameters on the number of ACC bays 45
Exhibit 3-17. Impact of ACC-related parameters on the LCOE 46

Exhibit 3-18. Impact of steam supply temperature on the ACC auxiliary power (top left), steam cycle efficiency (top right), plant efficiency (bottom left), and LCOE (bottom right) 47
Exhibit 3-19. Impact of tube bundle frontal area on the air-side HTC 48
Exhibit 3-20. Impact of different parameters on the air loss coefficient ($\boldsymbol{k\theta t}$) 48
Exhibit A-1. Block flow diagram 54
Exhibit A-2. Stream table 55
Exhibit A-3. Plant performance summary 57
Exhibit A-4. Plant power summary 58
Exhibit A-5. Air emissions 59
Exhibit A-6. Carbon balance 59
Exhibit A-7. Sulfur balance 59
Exhibit A-8. Water balance 60
Exhibit A-9. Energy balance 60
Exhibit A-10. Total plant cost details 61
Exhibit A-11. Owner's costs 62
Exhibit A-12. Initial and annual operating and maintenance costs 63
Exhibit A-13. Cost of electricity breakdown 64
Exhibit A-14. Block flow diagram 64
Exhibit A-15. Stream table 65
Exhibit A-16. Plant performance summary 67
Exhibit A-17. Plant power summary 68
Exhibit A-18. Air emissions 69
Exhibit A-19. Carbon balance 69
Exhibit A-20. Sulfur balance 69
Exhibit A-21. Water balance 70
Exhibit A-22. Energy balance 70
Exhibit A-23. Total plant cost details 71
Exhibit A-24. Owner's costs 74
Exhibit A-25. Initial and annual operating and maintenance costs 75
Exhibit A-26. Cost of electricity breakdown 76

ACRONYMS AND ABBREVIATIONS

abs	Absolute
ACC	Air cooled condenser
ACI	Activated carbon injection
AGR	Acid gas removal
Ar	Argon
atm	Atmosphere
BACT	Best Available Control Technology
BEC	Bare erected cost
BFW	Boiler feedwater
BOP	Balance of plant
Btu	British thermal unit
$CaCl_2$	Calcium chloride
CF	Capacity factor
CO_2	Carbon dioxide
DOE	Department of Energy
DSI	Dry sorbent injection
EIA	Energy Information Administration
ELG	Effluent limitation guideline
Eng'g CM H.O.& Fee	Engineering, construction management, home office, and fees
EPA	Environmental Protection Agency
FD	Forced draft
FGD	Flue gas desulfurization
ft	Feet
ft^3	Cubic feet
gal	Gallon
GJ	Gigajoule
gpm	Gallons per minute
h, hr	Hour
H_2O	Water
H_2S	Hydrogen sulfide
HCl	Hydrochloric acid
Hg	Mercury
HHV	Higher heating value
HP	High pressure
HTC	Heat transfer coefficient
HVAC	Heating, ventilation, and air conditioning
ID	Induced draft
IOU	Investor-owned utility
IP	Intermediate pressure
ISO	International Organization for Standardization
kg	Kilogram
kJ	Kilojoule
kW, kWe	Kilowatt electric
kWt	Kilowatt thermal
LAER	Lowest Achievable Emission Rate
lb	Pound
lb/hr	Pounds per hour
LCOE	Levelized cost of electricity
LHV	Lower heating value
LP	Low pressure
m	Meter
m^3/min	Cubic meter per minute
MESA	Mission Execution and Strategic Analysis
mg/Nm^3	Milligrams per cubic meter
mm	Millimeter
MMBtu	Million Btu
MPa	Megapascal
MW, MWe	Megawatt electric
MWh	Megawatt-hour
N/A	Not applicable/available
N_2	Nitrogen
NaCl	Sodium chloride
NETL	National Energy Technology Laboratory
NOx	Nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review
NTU	Nephelometric turbidity unit
O&M	Operation and maintenance
O-H	Overhead
O_2	Oxygen
OFA	Overfire air
ORP	Oxidation reduction potential
PA	Primary air
PAC	Powdered activated carbon
PC	Pulverized coal

PM	Particulate matter
POTW	Publicly owned treatment works
ppb	Parts per billion
ppm	Parts per million
ppmw	Parts per million, weight
ppt	Parts per trillion
PSD	Prevention of Significant Deterioration
psi	Pound per square inch
psia	Pound per square inch absolute
psig	Pound per square inch gauge
QGESS	Quality Guidelines for Energy System Studies
R&D	Research and development
SCR	Selective catalytic reduction
SO_2	Sulfur dioxide
SO_3	Sulfur trioxide
T&S	Transport and storage
TASC	Total as-spent cost
TOC	Total overnight cost
tonne	Metric ton
U.S.	United States
V-L	Vapor-liquid
W/K	Watt per Kelvin
W/m^2-K	Watt per square meter Kelvin
wt%	Weight percent
yr	Year
$MM	Millions of dollars
µS/cm	MicroSiemens per centimeter
°C	Degrees Celsius
°F	Degrees Fahrenheit

EXECUTIVE SUMMARY

This study characterizes the cost and performance of two supercritical pulverized coal (PC) power plants: 1) an existing plant (similar to Case B12A from Revision 4 of the Bituminous Baseline [1], modified for surface water discharge and air emissions consistent with limits for existing plants) retrofitted with wet flue gas desulfurization (FGD) wastewater treatment and 2) a greenfield plant (similar to Case B12A from Revision 3 of the Bituminous Baseline [2]) constructed with an air-cooled condenser (ACC).

Sensitivity analyses are completed on various process parameters associated with the wet FGD wastewater treatment system and ACC to determine the impact on the net plant efficiency and levelized cost of electricity (LCOE). Research and development (R&D) targets are recommended for the parameters shown to have the greatest potential impact on cost or performance.

KEY RECOMMENDATIONS

This study recommends the following R&D goals for wet FGD wastewater treatment systems consisting of chemical precipitation and biological processes:

- Improve the chloride tolerance of bacteria used in biological wastewater treatment processes to 40,000 ppm
- Reduce the costs associated with construction/installation by 25 percent by increasing the modularization and pre-fabrication of wastewater treatment equipment – while this study found that cost reduction opportunities for wet FGD wastewater are not significantly impactful, any cost reduction is beneficial.
- In addition to the R&D goals listed above, prior NETL studies have highlighted operational needs. [3] These R&D opportunities include:
    - Develop and improve the reliability of real-time sensors
    - Identify the impact of trace elements on the bacteria (e.g., mapping toxicity interactions)
    - Reduce the impact of non-steady-state operation on bacteria (e.g., fluctuations in flow rate, temperature, and composition) without the use of large capacity equalization tanks.

This study recommends the following R&D goals for an air cooled condenser of the type assumed in this study:

- Improve the air-side heat transfer coefficient by 35 percent
- Reduce the air-side pressure drop across the tube bundle by 50 percent

FLUE GAS DESULFURIZATION WASTEWATER TREATMENT COMPLIANCE TECHNOLOGY

Given the proprietary nature of wastewater treatment systems and the limited information publicly available on wet FGD wastewater treatment systems, specific performance parameters could not be identified in this study to assess their impact on cost or efficiency. Therefore, this study assessed the overall potential impact that cost or performance improvements could have on the plant's LCOE and net plant efficiency.

The addition of wastewater treatment equipment does not offer cost or performance advantages to the existing plant, but rather imposes a cost, and to a lesser extent, performance, penalty. This study estimates that retrofitting a 650 MWe-net, supercritical, non-capture, PC plant with a wet FGD wastewater treatment system consisting of chemical precipitation and biological processes results in a 4.3 percent increase in LCOE, from $35.5/MWh to $37.0/MWh.

Cost reduction opportunities are not significantly impactful due to the water treatment system representing a relatively small percentage of the plant's total cost – A 10 percent reduction in bare erected cost of the wastewater treatment system is an assumed achievable incremental R&D goal. For a reduction of this magnitude, the LCOE retrofit penalty would be reduced from 4.3 percent to 4.0 percent, resulting in an LCOE of $36.9/MWh.

The auxiliary load of the wastewater treatment system, at 51 kW, has a negligible impact on net plant efficiency and does not present R&D opportunities.

The potential exists to reuse the treated wastewater within the power plant. However, this has a negligible impact on LCOE and represents less than one percent of the total plant water demand.

Based on the results of this study, the aspects of the wastewater treatment system that provide the most potential for improvement to the LCOE are 1) improving the chloride tolerance of microorganisms and low-cost chloride tolerant materials or coatings and 2) reducing the equipment fabrication and labor of installation costs.

Chloride Tolerance

Increasing the maximum chloride concentration allows for higher recycle rates within the wet FGD, resulting in wastewater that is lower in volume and higher in contaminant concentration. The lower volume of wastewater requires smaller quantities of consumables, reduces equipment size, reduces system footprint, and reduces auxiliary loads.

Currently, the available wastewater treatment materials of construction that can tolerate chloride concentrations greater than 20,000 ppm come at a cost premium. Furthermore, the microorganisms used in the biological treatment system limit the chloride concentration to 25,000 ppm.

It is recommended that the R&D goal for microorganism tolerance be set at 40,000 ppm, which would be sufficiently high to allow direct application to the majority of wet FGD wastewaters. [4]

Achieving this goal could potentially reduce the LCOE by up to 0.4 percent to $36.9/MWh. It is estimated that up to $1.9 million could be expended in additional equipment costs (exotic materials) to achieve the higher chloride tolerance (40,000 ppm) before the capital cost expenditure outweighs the benefit realized by lower wet FGD wastewater volumes.

Equipment Fabrication and Labor of Installation Costs

The total plant costs associated with retrofitting an existing supercritical pulverized coal boiler with FGD wastewater treatment is approximately $52 million, of which, the costs associated with the equipment fabrication and labor of installation of the wastewater treatment system accounts for approximately $11 million (21 percent) and $12 million (22 percent), respectively.

Much of the wastewater treatment system is currently field fabricated, leading to high construction costs. For retrofit applications, these costs are further increased due to the difficulty associated with construction at an existing site.

Modularization of equipment at power plants can significantly reduce the cost associated with the labor of installation, equipment fabrication, and materials. For example, the modularization of fossil fuel power plants has been estimated to reduce the cost of materials by 30 to 40 percent [5] and the modularization of nuclear power plants has been estimated to reduce the capital cost by up to 15 percent. [6]

Examples of current modularization of wet FGD wastewater treatment equipment includes skid mounted pumps, ultrafiltration units, valve nests, and pipe assemblies, which are pre-fabricated and shipped to the site.

It is recommended that R&D pursue the modularization of FGD wastewater treatment equipment with the goal of reducing the costs associated with equipment fabrication and labor of installation of the wastewater treatment system ($23 million) by 25 percent. Achieving this goal could potentially reduce the LCOE by up to 0.7 percent to $36.7/MWh.

Dry Cooling Systems and Steam Condensers

This study estimates that a greenfield 540 MWe-net, supercritical, non-capture, PC plant with selected air-cooled condenser (ACC) design has a net plant efficiency of 40.0 percent (HHV basis) and LCOE of $67.6/MWh. A high-level sensitivity analysis indicated that reducing ACC capital costs by 50 percent reduces the LCOE by $1.4/MWh (2.1 percent reduction) and a 50 percent reduction in ACC fan power translated to LCOE reduction of $1.1/MWh (1.6 percent reduction). Therefore, an LCOE reduction of 3.7 percent can be achieved by simultaneously reducing the ACC fan power consumption and the capital costs by 50 percent. Reducing ACC maintenance costs are projected to have minimal impact.

Based on the results of this study, the aspects of the ACC that provide the most potential for improvement to the LCOE are 1) improving the air-side heat transfer coefficient (HTC) and 2) reducing the air-side pressure loss.

Air-Side HTC

For the selected reference operating conditions and tube bank design, the air-side HTC ranged from 350,000 – 550,000 W/K (depending on the tube row). Increasing the air-side HTC by 37 percent increased the plant efficiency by 0.1 percentage points and reduced the LCOE by $0.5/MWh (0.7 percent reduction).

Air-Side Pressure Loss Coefficient

For the selected design and operating conditions, the air-side pressure loss coefficient is 30. Reducing the pressure loss coefficient by 54 percent increased the plant efficiency by 0.1 percentage points and reduced the LCOE by $0.35/MWh (0.5 percent reduction).

It is recommended that R&D should seek design and testing of advanced tube-fin geometries that can improve the air-side HTC while minimizing the air-side pressure drop across the tube bundle. The oblique flow of air to tube bundles due to A-frame design is also a large contributor to the air-side pressure loss. Advanced ACC designs which can reduce the ACC A-frame apex angle can also mitigate the air-side pressure loss. It is important to note that any advanced ACC designs developed via R&D shouldn't increase either the ACC capital or maintenance costs to realize the maximum benefits projected in this study.

Improving the steam-side HTC will likely have a minimal impact on plant efficiency and LCOE since air-side HTC is the limiting factor in the case of ACCs. Sensitivity analysis to ACC steam supply temperature (or LP turbine back pressure) indicated that there is an optimum ACC steam supply temperature that minimizes LCOE due to approach to the ambient dry bulb temperature. However, this optimum is likely going to depend on the ambient design conditions and the ACC design. Therefore, any potential improvements to the ACC design could also enable further reduction in turbine back pressure by reducing steam temperature approach to the ambient dry bulb temperature.

1 INTRODUCTION

This study characterizes the cost and performance of two supercritical pulverized coal (PC) power plants: 1) an existing plant retrofitted with wet flue gas desulfurization (FGD) wastewater treatment and 2) a greenfield plant constructed with an air-cooled condenser (ACC).

Sensitivity analyses are completed on various process parameters associated with the wet FGD wastewater treatment system and ACC to determine the impact on the net plant efficiency and levelized cost of electricity (LCOE). Research and development (R&D) targets are recommended for the parameters shown to have the greatest potential impact on cost or performance.

The retrofitted wet FGD wastewater treatment system consists of chemical precipitation and biological treatment, previously evaluated in the NETL study "Techno-Economic Analysis and Evaluation of Wet FGD Wastewater Treatment Processes at Existing Plants." [3] Where the previous analysis assumed a subcritical plant, this study assumes the wastewater treatment system is retrofitted onto a 650 MW-net, supercritical, non-capture, PC plant.

The ACC assessed in this study is installed at a greenfield, 540 MW-net, supercritical, non-capture, PC plant. The ACC design is based on an example problem (Example 8.1.4) from "Air-Cooled Heat Exchangers and Cooling Towers." [7] The balance of plant (BOP) was established in the NETL study "Cost and Performance Impact of Dry and Hybrid Cooling on Fossil Energy Power Systems." [8]

2 DESIGN BASIS

Due to the wet FGD wastewater treatment system being applied as a retrofit to an existing plant, whereas the ACC system is applied to a greenfield plant, the two technology assessments use different design bases. The design basis for the plant with wet FGD wastewater treatment is provided in Section 2.1 and the design basis for the plant with an ACC is provided in Section 2.2.

2.1 FLUE GAS DESULFURIZATION WASTEWATER TREATMENT COMPLIANCE TECHNOLOGY

This section discusses the design basis and cost assumptions used for the assessment of the FGD wastewater treatment system. An Aspen Plus® (Aspen) model was developed and used to generate material and energy balances, which provided a design basis for the major equipment items.

2.1.1 Site Characteristics

The plant being retrofit with a wet FGD wastewater treatment system is assumed to be located at a generic existing site in the midwestern United States (U.S.), with site characteristics and ambient conditions as presented in Exhibit 2-1 and Exhibit 2-2. The ambient conditions are the same as International Organization for Standardization (ISO) conditions.

Exhibit 2-1. Site characteristics

Parameter	Value
Location	Midwestern U.S.
Topography	Level
Size, acres	300
Transportation	Rail or Highway
Ash Disposal	Off-Site
Water	50% Municipal and 50% Ground Water

Exhibit 2-2. 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
Cooling Water Temperature, °F[A]	60
Air composition based on published psychrometric data, mass %	
N_2	75.055
O_2	22.998
Ar	1.280
H_2O	0.616
CO_2	0.050
Total	100.00

[A]The cooling water temperature is the cooling tower cooling water exit temperature, which is set to 8.5°F above ambient wet bulb conditions in ISO cases.

The quality of plant makeup water will vary significantly from source to source (municipal versus ground water), as well as from site to site, and can be expected to vary throughout any given site, particularly if ground water is utilized. For the plant retrofit with a wet FGD wastewater treatment system, 50 percent of the makeup water to the plants 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 2-3.

Exhibit 2-3. 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, µS/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

Parameter	Ground Water (Range)	POTW Water (Range)	Makeup Water (Design Basis)
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.

2.1.2 Coal Characteristics

The characteristics of the design coal (Illinois No. 6) are presented in Exhibit 2-4 and the associated composition of the coal ash and coal trace elements are provided in Exhibit 2-5 and Exhibit 2-6, respectively. The coal properties are from the April 2016 revision of "Quality Guidelines for Energy System Studies (QGESS): Detailed Coal Specifications." [9]

Exhibit 2-4. Design coal characteristics

Rank	Bituminous	
Seam	**Illinois No. 6**	
Source	Old Ben Mine	
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
Sulfur	2.51	2.82
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, kJ/kg (Btu/lb)	26,151 (11,252)	29,544 (12,712)
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

[A]The proximate analysis assumes sulfur as volatile matter.
[B]By difference

Exhibit 2-5. Coal ash composition

Name	Formula	Concentration, %
Silica	SiO_2	45.0
Aluminum Oxide	Al_2O_3	18.0
Titanium Dioxide	TiO_2	1.0
Iron Oxide	Fe_2O_3	20.0
Calcium Oxide	CaO	7.0
Magnesium Oxide	MgO	1.0
Sodium Oxide	Na_2O	0.6
Potassium Oxide	K_2O	1.9
Phosphorus Pentoxide	P_2O_5	0.2
Undetermined	N/A	1.8

Exhibit 2-6. Coal trace elements composition

Name	Formula	Concentration, ppm (dry basis)
Arsenic	As	7.5
Boron	B	90
Beryllium	Be	1.2
Cadmium	Cd	0.5
Chlorine	Cl	1,671
Cobalt	Co	3.5
Chromium	Cr	14
Copper	Cu	9.2
Fluorine	F	93
Mercury	Hg	0.09
Lithium	Li	9.4
Manganese	Mn	38
Molybdenum	Mo	8.4
Nickel	Ni	14
Phosphorus	P	87
Lead	Pb	24
Tin	Sn	0.9
Selenium	Se	1.9
Thorium	Th	1.5
Uranium	U	2.2
Vanadium	V	31
Zinc	Zn	84.4

2.1.3 Limestone Characteristics

The characteristics of the limestone used in the wet FGD are presented in Exhibit 2-7. The limestone properties are from the April 2016 revision of "QGESS: Specification for Selected Feedstocks." [10]

Exhibit 2-7. Limestone composition

Name	Formula	Concentration
Calcium Carbonate	$CaCO_3$	80.40
Magnesium Carbonate	$MgCO_3$	3.50
Silica	SiO_2	10.32
Aluminum Oxide	Al_2O_3	3.16
Iron Oxide	Fe_2O_3	1.24
Sodium Oxide	Na_2O	0.23
Potassium Oxide	K_2O	0.72
Undetermined	N/A	0.43

2.1.4 Environmental Targets

2.1.4.1 Air Emissions

Environmental targets were established for the plant retrofit with wet FGD wastewater treatment as follows:

- Sulfur dioxide (SO_2), filterable particulate matter (PM), mercury (Hg), and hydrochloric acid (HCl) limits were set according to the emission limits for existing coal-fired units by the April 2016 update to the Utility Mercury and Air Toxics Standards for PC technologies. [11]
- The nitrogen oxides (NOx) emission limit was set equal to the air quality permit for Duke Energy's Cliffside Steam Station. [12]

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 air emission limits established as applicable to this study are provided in Exhibit 2-8.

Exhibit 2-8. Emission limits for SO_2, NOx, PM, Hg, and HCl at existing plants [11], [12]

Pollutant	(lb/MWh-gross)
SO_2	1.50
NOx	1.00
PM (Filterable)	0.30
Hg	$1.3x10^{-5}$
HCl	0.02

Other regulations that could affect emissions limits from an existing plant include the New Source Review (NSR) permitting process and Prevention of Significant Deterioration (PSD). The NSR process requires installation of emission control technology, meeting either the Best Available Control Technology (BACT) determinations for sources being in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) 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 EPA's Green Book Non-attainment Area Map, relatively few areas in the midwestern United States are classified as "non-attainment," so the plant site for this study was assumed to be in an attainment area. [13]

It was assumed that low-NOx burners and staged overfire air (OFA) would limit NOx production to 0.35 lb/MMBtu and that selective catalytic reduction (SCR) technology would be approximately 64 percent efficient. By adjusting the ammonia flow rate and/or catalyst bed depth in the SCR unit, the NOx emissions limit was able to be met exactly.

To meet the SO_2 emission limit exactly, the wet FGD was assumed to be 95.3 percent efficient. Current technology allows wet FGD removal efficiencies in excess of 99 percent. However, based on the assumed existing source air emission limits, such high removal efficiency is not necessary.

While fabric filters are commonly capable of achieving removal efficiencies of greater than 99.9 percent, the efficiency was varied to meet the PM emission limit exactly, which required a removal rate of 99.5 percent.

It was assumed that the total mercury removal rate resulting from the combination of pollution control technologies used (SCR, dry sorbent injection (DSI), activated carbon injection (ACI), fabric filters, and wet FGD) would meet the applicable limit. DSI is required to limit the effects of sulfur trioxide (SO_3) on Hg capture due to the high sulfur content of the coal in this study.

2.1.4.2 Water Emissions

The Effluent Limitation Guidelines are national technology-based standards derived from data collected from industry. [14] They are intended to provide flexibility in implementation through use of technologies already installed and operating in the power industry. The federal standards established are the minimum discharge standards. As the guidelines are enforced under the National Pollutant Discharge Elimination System (NPDES) [15], more stringent water quality-

based standards may be established by the local permitting authority. These additional requirements were not considered in this assessment. The applicable wet FGD wastewater discharge limits for an existing source are shown in Exhibit 2-9. [14]

Exhibit 2-9. Discharge limits for wet FGD wastewater from existing sources

Effluent Characteristic	Long-Term Average	Daily Maximum Limit	Monthly Average Limit[A]
Arsenic, ppb	5.98	11	8
Mercury, ppt	159	788	356
Selenium, ppb	7.5	23	12
Nitrate/nitrite as N, ppm	1.3	17	4.4

Note: The 2019 updated limits released by the EPA are not considered in this study.
[A]Monthly Average Limit refers to the highest allowable average of daily discharges over 30 consecutive days.

For the FGD wastewater treatment systems, the limits are applied at the discharge, prior to mixing with other plant water systems.

2.1.5 Existing Plant Basis

For the purposes of this study, the existing fleet is represented by a modified version of the non-capture, supercritical PC plant from the Revision 4 Bituminous Baseline. [1] The modifications consisted of removing the spray dryer evaporator to allow the wet FGD wastewater to be discharged to surface water and updating the air and water emission standards to better reflect emission limits for existing PC power plants. The modified reference plant is shown in Exhibit 2-10.

Exhibit 2-10. Summary description of the existing reference plant

General Characteristics	
Net Capacity, MWe	650
Steam Cycle	Supercritical
Steam Conditions, psig/°F/°F	3,500/1,100/1,100
Capacity Factor, %	85
Wastewater Characteristics	
FGD Wastewater Flow Rate, gpm	54.5
Wet FGD Chloride Concentration, ppmw	20,000
As Concentration, ppb	1,400
Hg Concentration, ppb	700
Se Concentration, ppb	5,000
Nitrate/Nitrite Concentration, ppb	30,000

The steam generator is a once-through, spiral-wound, Benson-boiler, wall-fired, balanced draft type unit with a water-cooled dry bottom furnace, with superheater, reheater, economizer, and air preheater. It is assumed for the purposes of this study that the power plant is designed for operation as a base-load unit.

While the capacity factor assumed for the plant retrofit with wet FGD wastewater treatment is achievable for a supercritical PC plant, according to the Energy Information Administration (EIA), the average capacity factor for a plant in the existing coal fleet was 54 percent in 2018. [16] It was assumed that plants with relatively high capacity factors, compared to the fleet average, would be more likely to undertake a retrofit to achieve effluent limitation guideline (ELG) compliance. As the availability of the biological system is expected to be high, with supplier guarantees being provided above 85 percent, the capacity factor was assumed to be 85 percent.

A detailed description of the BOP systems (e.g., air emission control systems, ash handling systems) is available in the reference study. [1]

2.1.5.1 FGD Wastewater Quality

The design wastewater composition for the wet FGD blowdown is provided in Exhibit 2-11. The design water quality is based on a survey of plants burning bituminous, high-sulfur coal [17], [18] and on internal information from Black & Veatch projects. Exhibit 2-11 includes a range of values, an average, and the design basis.

Exhibit 2-11. Design basis FGD wastewater quality

Parameter	Range	Average	Design Basis
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, µS/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

Parameter	Range	Average	Design Basis
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
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

[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.

2.1.6 Wastewater Treatment System Configuration

For compliance with the ELG regulations, the reference plant is retrofit with chemical precipitation and biological treatment processes, described in Section 2.1.6.1 and Section 2.1.6.2.

2.1.6.1 Chemical Precipitation

The biological treatment process requires pretreatment with a chemical precipitation process. Pretreatment is required to meet existing source mercury and arsenic limits, as well as to

remove solids to prevent fouling of downstream equipment and to reduce required backwash rates.

Mercury and arsenic removal are achieved by the addition of organosulfide, which converts soluble forms of mercury and arsenic to insoluble sulfide precipitates, resulting in high removal rates (over 99 percent).

For the plant retrofit with wet FGD wastewater treatment, it is assumed that mercury and arsenic are reduced through the following reactions:

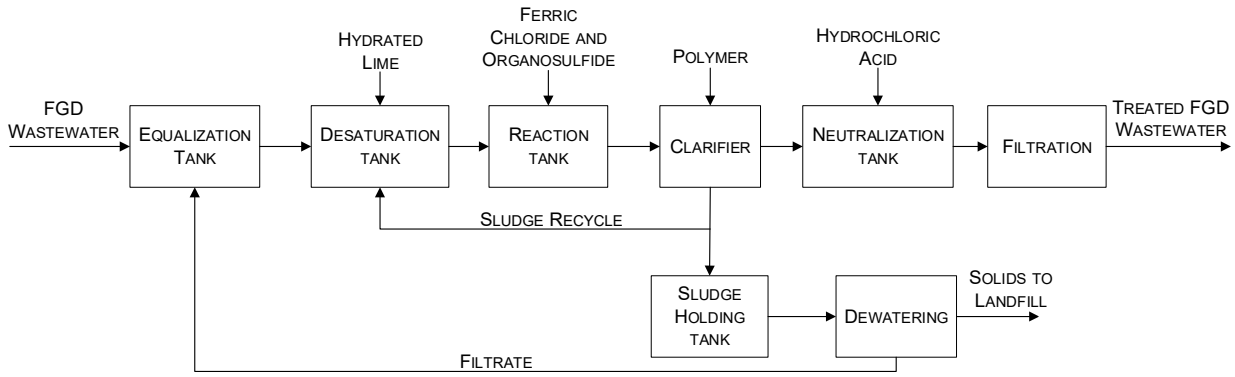
$$2As^{3+} + 3S^{2-} \xrightarrow{yields} As_2S_3$$

$$Hg^{2+} + S^{2-} \xrightarrow{yields} HgS$$

There may be other reactions involving mercury and arsenic within the chemical precipitation process, but the considerations of this study were limited to the two provided above. The feed rate is controlled so that organosulfide is present in significant excess, ensuring the desired removal rates are consistently achieved.

As shown in Exhibit 2-12, the wet FGD wastewater is pumped to a continuously mixed equalization tank, which buffers the treatment system against variations in wastewater quality and flow. The wastewater flows to a desaturation tank where the pH is raised with lime to approximately 8.5 in order to precipitate saturated gypsum, which decreases the potential for scaling in downstream equipment. [4] One continuously mixed reaction tank is located downstream of the desaturation tank to allow for addition of ferric chloride (a coagulant) and organosulfide, which is sized to allow sufficient reaction time for the chemical precipitation reactions to occur. [4], [19] The reaction tank feeds a clarifier where polymer is added to increase the particle size of the insoluble particles to allow settling within the clarifier. Suspended solids from the wet FGD system such as gypsum, inerts, unreacted limestone, heavy metals, and fly ash are removed with traditional clarification techniques. Settled solids from clarification are directed to dewatering equipment.

Exhibit 2-12. Chemical precipitation process configuration



The pH of the clarified water is adjusted with hydrochloric acid to approximately 6.5 to prevent scaling in the downstream filters used to polish the clarifier effluent to achieve low residual solids. Filtration can reduce effluent suspended solids to <10 ppm and significantly reduce the

concentration of heavy metals such as mercury. The most common type of filter used for wet FGD wastewater treatment is a continuously backwashed sand filter, which has a continuous backwash stream recycled to the equalization tank.

The sludge produced in the clarifying process contains between 10 and 15 wt% solids and will be dewatered to approximately 50 wt% solids using plate and frame filter presses prior to being sent to the landfill for disposal. The filtrate is collected and recycled back to the front end of the chemical precipitation process. A portion of the sludge is recycled to the desaturation tank at a rate between 5 and 10 percent of the FGD blowdown flow rate.

There is typically up to 12 hours of residence time in the equalization tank and a few additional hours of residence time through the reaction tanks, clarifiers, and filters. As a result, the effluent from the chemical precipitation system will be close to ambient temperature and pressure conditions.

2.1.6.2 Biological Treatment

The purpose of biological treatment is to reduce nitrate/nitrite and selenium, which are not removed by the chemical precipitation system described in the previous section. Anoxic/anaerobic biological treatment is an industry-proven technology for selenium and nitrate/nitrite removal from wet FGD wastewater. Biological treatment involves the growth of two types of naturally occurring microorganisms: denitrifiers and selenium-reducing bacteria. A food source (nutrient) is oxidized by both microorganisms, which in turn reduces the different oxyanions. The denitrifiers reduce nitrate/nitrite to nitrogenous gas, and the selenium-reducing bacteria reduce both selenate and selenite and precipitate solid elemental selenium. The order of oxyanions favored in biological reaction kinetics is dissolved oxygen, followed by nitrate and selenate. Biological treatment typically consists of a series of reaction vessels to accomplish the desired removals. A controlled environment is required for the proper reactions to occur. The denitrification process requires an anoxic (absent of oxygen) environment, and the selenium is then reduced in an anaerobic environment (absent of oxygen and nitrate/nitrite).

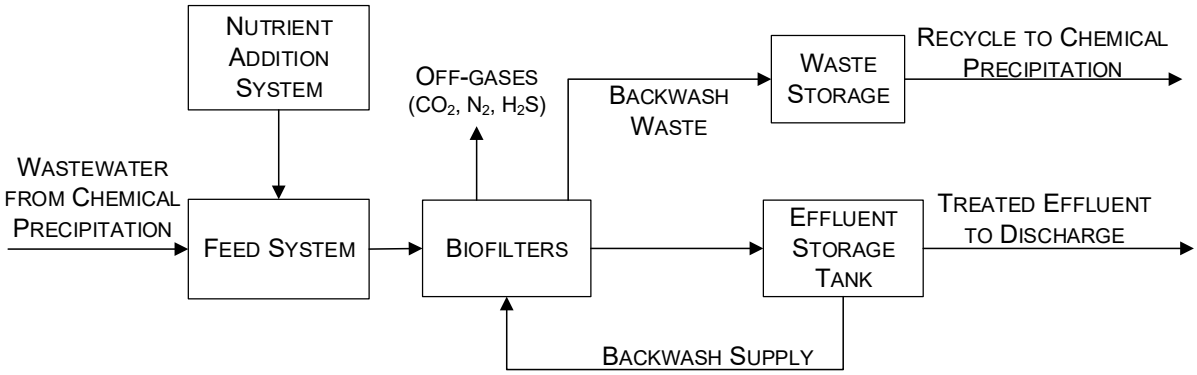
Biomass and elemental selenium are either backwashed from the reactors or removed utilizing downstream filtration. Ultrafiltration is typically used for downstream filtration in order to increase removal efficiency. The periodic backwash waste stream from either the reactors or filters requires further thickening and dewatering prior to disposal. This is accomplished by sending the backwash to the equalization tank of the upstream pretreatment system.

The two types of biological reactors are attached growth and suspended growth (activated sludge type) systems. Attached growth is composed of a biofilm, or layer of microorganisms, that grows on the surface of a solid-phase media such as rock, granular activated carbon, sand, or other substrate. Attached growth technologies include GE's ABMet® process, Envirogen Technologies' fluidized bed reactor system and Frontier's SeHAWK® process that have been developed specifically for removal of selenium and other oxyanions from wastewaters. Suspended growth systems are not being used to treat wet FGD wastewater and were not further considered in this study.

The biological treatment system consists of a series of fixed film biofilters in a packed bed reactor design and dual-stage arrangement. Each packed bed reactor contains a bed of granular activated carbon on which specifically selected microbes grow, develop a biofilm, and are retained.

As shown in Exhibit 2-13, wet FGD wastewater from the chemical precipitation pretreatment system is fed to the first stage storage tank and is pumped to the first stage of biofilters. Wastewater flows downward by gravity through the biofilters to a second stage feed tank. Wastewater from the tank is pumped to the second stage of biofilters for additional treatment and collected in an effluent tank.

Exhibit 2-13. Biological treatment process configuration



Wet FGD wastewater entering the system will typically have a positive redox level.[a] As the wastewater passes downward through the biofilter, the redox potential gradually decreases as a result of microbial activity. A nutrient (carbon source) solution is added to the system to control the degree of redox gradient of each biofilter within the range that is ideal for nitrate/nitrite and selenium removal. Within the first stage packed bed reactor, nitrate and nitrite are reduced to nitrogen gas (denitrification) followed by the second stage packed bed where selenate and selenite are reduced to elemental selenium.

Entrained solids and gases need to be periodically removed with a backwash process, which may occur between 1 and 4 times per month. To backwash, treated effluent is used as a counter-flow wash to remove entrained solids and gases from the biofilter substrate. Backwash wastewater is allowed to degas and is then recycled to the equalization tank of the chemical precipitation treatment system where the solids are settled in the clarifier and dewatered with the pretreatment sludge. Waste testing of existing installations has shown that the solids produced can be disposed of as non-hazardous waste per the Toxicity Characteristic Leaching Procedure test.

[a] Redox level refers to the oxidation-reduction potential (ORP) of the wastewater. As the ORP reaches 0, denitrification occurs, and as ORP decreases further into the negative range, selenate and/or selenite is reduced to an elemental state.

2.1.7 Cost Estimating Methodology

For the plant retrofit with wet FGD wastewater treatment, it was assumed that all capital costs of the existing plant were paid off, such that capital costs reflect only the cost of the wastewater treatment system and plant upgrades required to accommodate the retrofit. The reference supercritical PC plant is utilized as a reference for all costs not associated with the wastewater treatment system. [1] The methodology used in developing the costs for the non-capture, supercritical PC plant is consistent with "QGESS: Cost Estimation Methodology for NETL Assessments of Power Plant Performance." [20]

For the wet FGD wastewater treatment configurations reviewed in this study, order-of-magnitude (±50 percent) capital and operation and maintenance (O&M) cost estimates, were prepared based on in-house information (provided by Black & Veatch), supplemented with budgetary vendor quotes.

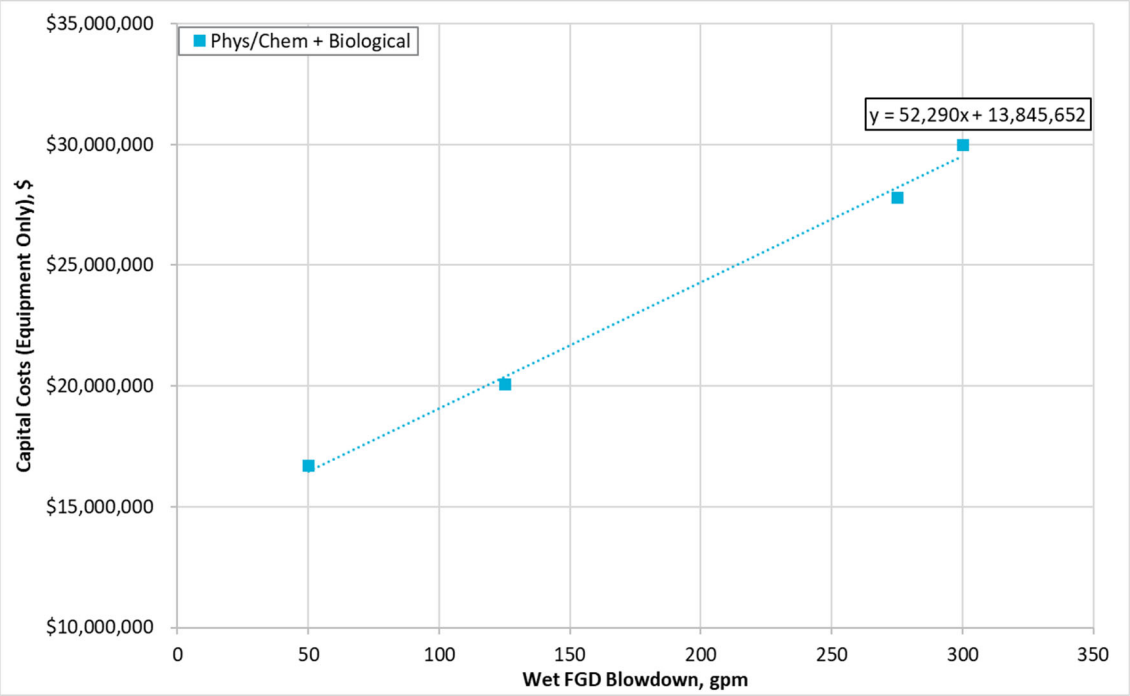
Using cost estimates from in-house projects, Black & Veatch provided the data shown in Exhibit 2-14 for chemical precipitation and biological treatment of wet FGD wastewater. These data were used to develop the cost correlation shown in Exhibit 2-15, which allowed the equipment costs associated with the wet FGD wastewater treatment system to be estimated using the influent feed rate.

The BOP capital costs were scaled based on the methodology described in "QGESS: Capital Cost Scaling Methodology." [21]

Exhibit 2-14. Wet FGD wastewater treatment reference costs

	Capital Costs, $/1,000,000
Flow Rate, gpm	Chemical Precipitation + Biological Treatment
50	16.7
125	20.1
140	N/A
275	27.8
300	30.0

Exhibit 2-15. Wet FGD wastewater treatment cost correlations



While the trendline in Exhibit 2-15 shows a linear relationship between flow and cost, this is likely due to the limited number of available data points.

The estimated capital costs are for equipment only and do not include plant interconnects, labor, or indirect costs such as engineering, process/project contingencies, or owner's costs. These additional costs were estimated based on similar equipment from the non-capture, subcritical pulverized coal (PC) plant of "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 4" (Bituminous Baseline). Direct labor costs were scaled as follows:

$$DL = RF * EC * \frac{RL}{RC}$$

where:

- DL – direct labor cost
- RF – retrofit factor (labor)
- EC – equipment cost (priced for a greenfield site)
- RL – reference labor cost
- RC – reference equipment cost

For the wastewater treatment system, the engineering, construction management, home office and fees were assumed to be 15 percent of the bare erected costs (BEC). The BEC is the sum of the equipment cost and the direct labor cost. Project contingencies were assumed to be 30 percent of the sum of BEC, engineering, construction management, home office and fees, and process contingency.

The process contingencies applied for each technology vary depending on the availability and maturity of technologies. For technologies that have full-scale operating experience but are not yet widely commercially used, "QGESS: Cost Estimating Methodology" [20] suggests a process contingency between 5 and 20 percent. Given this range and the reliability rating of medium-high provided by Black & Veatch for this treatment configuration, the process contingency assumed for the wastewater treatment system is 5 percent. The BOP is assumed to have no process contingency.

Retrofit difficulty factors were applied to the equivalent capital and labor costs at the sub-account level according to "QGESS: Estimating Plant Costs Using Retrofit Difficulty Factors." [22] Equipment retrofit factors varied from 5 to 10 percent and labor retrofit factors varied from 15 to 30 percent; the retrofit factors applied at the sub-account level in each case are available in Exhibit 2-16.

The list of sub-accounts in Exhibit 2-16 represents all sub-accounts impacted by the installation of a wet FGD wastewater treatment system. Since there is no specific guidance in the retrofit QGESS documentation for wastewater treatment systems, the retrofit difficulty factors applied to this sub-account were assumed to be the same as the retrofit difficulty factors applied to a CO_2 removal system.

Exhibit 2-16. Retrofit difficulty factors

Sub-Account[A]	Description	Retrofit Difficulty Factor, %[B]	
		Equipment	Direct Labor
3.8	Wet FGD Wastewater Treatment Processes	5	15
11.2	Station Service Equipment	5	15
11.3	Switchgear & Motor Control	5	15
11.4	Conduit & Cable Tray	10	15
11.5	Wire & Cable	10	15
11.6	Protective Equipment	5	15
12.5	Signal Processing Equipment	0	0
12.6	Control Boards, Panels, & Racks	5	15
12.7	Distributed Control System Equipment	5	30
12.8	Instrument Wiring & Tubing	5	20
12.9	Other Instrumentation & Controls Equipment	5	20
13.1	Site Preparation	5	20
13.2	Site Improvements	5	20
13.3	Site Facilities	5	20

[A]Sub-accounts correspond to the capital cost code of accounts provided in Appendix: Cost and Performance Results.
[B]Retrofit costs are calculated by multiplying the estimated equipment and direct labor greenfield costs by 1 plus the associated retrofit difficulty factor for each sub-account.

The LCOE is reported on $/MWh basis and consists of contributions from the O&M costs (fixed, variable, and fuel), and the annualized capital over the assumed 30-year lifetime of the plant. Additional details on the cost estimating methodology and other economic assumptions can be found in "QGESS: Capital Cost Scaling Methodology." [23]

2.1.8 Selected FGD Wastewater Treatment Parameters

A goal of this study is to identify potential R&D improvements for FGD wastewater treatment systems and the overall impact those improvements might have on plant efficiency and LCOE. To explore the impact of potential R&D improvements, sensitivity analyses with respect to the selected parameters were conducted.

A review of several NETL-funded, extramural projects determined that project developers were focusing on reducing the footprint of the wastewater treatment system, recovering wastewater for reuse, reducing chemical consumption, and reducing energy demand.

Due to the proprietary nature of wastewater treatment systems, insufficient data were available to assess parameters that would impact the footprint of the wastewater treatment system. However, this effect can be approximated by using the system capital cost as an analog for footprint, assuming that the footprint is reduced with decreasing costs.

The chemical precipitation and biological treatment system have an auxiliary load of 51 kW, or 0.15 percent of the total auxiliary load of the plant (see Section 3.1.1). As this does not represent an area of significant potential improvement, no parameters were assessed specifically to determine the impact on power requirement. Exhibit 2-17 presents a list of the parameters that were selected for the sensitivity analyses.

Exhibit 2-17. Selected FGD wastewater parameters for sensitivity analyses

Parameter	Minimum	Current Status	Maximum
Chloride Concentration, ppm	5,000	20,000	40,000
Retrofit Difficulty Factor	Varies*	Varies*	Varies*
Maintenance Material, $/yr	249,996	499,992	749,987
Maintenance Labor, $/yr	166,664	333,328	499,992
Operating Labor, $/yr	53,343	106,687	160,030
Waste Disposal Costs, $/yr	58,612	117,225	175,837
Consumables, $/yr	51,330	102,697	154,046
Chemical Precipitation Equipment Costs, $	1,534,081	3,068,162	4,602,243
Biological Treatment Equipment Costs, $	1,210,562	2,421,124	3,631,686
Equipment Fabrication Costs, $	5,854,520	11,709,039	17,563,559
Water Building, $	166,974	333,948	500,923
Labor of Installation Cost, $	5,559,509	11,119,019	16,678,528
Water Reuse, %	0	0	80

*The retrofit difficulty factors vary by cost account. The values assumed for the current status were presented in Exhibit 2-14. The sensitivity minimum was set at a reduction of 50 percent below the current status for each of the factors and the sensitivity maximum was set at an increase of 50 percent above the current status for each of the factors.

The current status values for all the parameters listed in Exhibit 2-17 are based on data from the reference NETL study "Techno-Economic Analysis and Evaluation of Wet FGD Wastewater Treatment Processes at Existing Plants." [3]

The sensitivity value for chloride concentration is based on wet FGD wastewater compositions reported by the Environmental Protection Agency [24] and the water reuse percentage is based on stated goals of NETL-funded, extramural projects.

As the wastewater treatment systems are proprietary and little information is publicly available, the sensitivity values of the remaining parameters were set at a 50 percent reduction from the current status.

2.1.9 Study Assumptions

In addition to those noted above, the following assumptions were also made:

- No plant upgrades were required to accommodate the addition of wet FGD wastewater treatment processes.
- The capacity factor would not be negatively impacted by the addition of a wet FGD wastewater treatment system.
- There are no impacts to plant emissions from installing any of the wet FGD wastewater treatment configurations assessed in this study.
- Plants with relatively high capacity factors, compared to the fleet average, would be more likely to undertake a retrofit to achieve compliance. Therefore, the capacity factor was set to 85 percent in all cases.
- The wet FGD, SCR, and fabric filter of an existing plant would be less efficient and, therefore, achieve lower removal rates for equivalent energy demands to those of the non-capture, supercritical PC Baseline plant. Therefore, no adjustments to the performance or operation were made beyond reducing the air quality control equipment's removal efficiencies.
- The mercury emission limit is achieved exactly with no changes to account for the reduction in the mercury emission limit from what the reference supercritical PC plant was designed to achieve. The exact mercury removal rate achieved in the non-capture, supercritical PC reference plant is unknown. Rather, vendors indicated that the DSI and ACI systems, in combination with co-benefit removal of downstream equipment, would be capable of achieving emissions in compliance with applicable regulations. While the mercury emission limit in this study is less stringent than what the reference supercritical PC plant was designed to achieve, the limit is achieved exactly with no changes to the removal system to account for the less stringent limit.
- No specific considerations were made for deconstruction, modification, disposal, or other specific costs associated with retrofitting an existing plant with wet FGD wastewater treatment processes.

- All capital costs of the existing plant are paid off, such that capital costs reflect only the cost of the wastewater treatment system and plant upgrades required to accommodate the retrofit.

2.2 DRY COOLING SYSTEMS AND STEAM CONDENSERS

This section discusses the design basis and cost assumptions used for the assessment of a greenfield plant with an ACC. An Aspen model was developed and used to generate material and energy balances, which provided a design basis for the major equipment items. The equipment list and material balances were used to generate the capital and operating cost estimates. The ACC performance and cost estimates were obtained using a combination of an Excel-based ACC rating tool and STEAMPRO/PEACE software package. Balance-of-plant (BOP) capital and operating costs were estimated using data from other relevant NETL studies [8] and appropriate scaling methodology. [2]

2.2.1 Site Characteristics

The plant used for assessment of the ACCs in this study is assumed to be located at a generic greenfield site in the midwestern U.S. The site characteristics and ambient conditions can be found in Exhibit 2-1 and Exhibit 2-2, respectively (Section 2.1.1).

The land area assumes that 30 acres are required for the plant proper and the balance provides a buffer of approximately 0.25 miles to the fence line.

It was assumed that the steam turbine and boiler are enclosed in a building.

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
- Coal characteristics
- Local code height requirements
- Noise regulations – Impact on site and surrounding area
- Other localized environmental concerns
- Weather delays

The design coal used is Illinois No. 6 with characteristics presented in Exhibit 2-18. The coal properties are from the 2013 version of “Quality Guidelines for Energy System Studies (QGESS): Detailed Coal Specifications.” [25]

Exhibit 2-18. Design coal characteristics

Rank	Bituminous	
Seam	**Illinois No. 6 (Herrin)**	
Source	Old Ben Mine	
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
Sulfur	2.51	2.82
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, Btu/lb (Btu/lb)	26,151 (11,252)	29,544 (12,712)
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	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen[B]	6.88	7.75
Total	100.00	100.00

[A]The proximate analysis assumes sulfur as volatile matter.
[B]By difference

2.2.2 Environmental Targets

Environmental targets were established as follows:

- Hg and hydrochloric acid (HCl) limits were set by the March 2013 update to the Mercury and Air Toxics Standards (MATS) for PC technologies. [26], [27], [28]
- Particulate matter (PM), sulfur dioxide (SO_2), and nitrogen oxide (NOx) limits were set by the February 2013 update to the New Source Performance Standards (NSPS) for PC and NGCC technologies. [28], [29]

As mentioned in Section 2.1.4, Illinois No. 6 coal is considered to be non-low rank.

The emission limits imposed by MATS and NSPS that apply to plants used to assess dry cooling systems and steam condensers are provided in Exhibit 2-19.

Exhibit 2-19. MATS and NSPS emission limits for SO_2, NOx, PM, Hg, and HCl

Pollutant	PC (lb/MWh-gross)
SO_2	1.00
NOx	0.70
PM (Filterable)	0.09
Hg	$3x10^{-6}$
HCl	0.010

Other regulations that could affect emissions limits from a new plant include the New Source Review (NSR) permitting process and Prevention of Significant Deterioration (PSD). The NSR process requires installation of emission control technology, meeting either best available control technology (BACT) determinations for new sources located in areas meeting ambient air quality standards (attainment areas), or Lowest Achievable Emission Rate (LAER) technology for sources located 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 EPA's Green Book Non-Attainment Area Map, relatively few areas in the midwestern United States are classified as "non-attainment," so the plant site for this report was assumed to be in an attainment area. [29]

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.

It was assumed that low-NOx burners and staged overfire air (OFA) would limit NOx emissions to 0.5 lb/MMBtu and that SCR technology would be 83 percent efficient. By adjusting the ammonia flow rate in the SCR, the NOx emissions limits were met exactly.

The wet limestone scrubber was assumed to be 98 percent efficient, which results in SO_2 emissions below the NSPS SO_2 limit. Current technology allows wet flue gas desulfurization (FGD) removal efficiencies greater than 99 percent, but based on NSPS requirements, such high removal efficiency is not necessary.

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

It was assumed that the total Hg removal rate resulting from the combination of pollution control technologies used (SCR, dry sorbent injection [DSI], activated carbon injection [ACI],

fabric filters, and FGD) would meet the limit exactly. DSI is required to limit the effects of sulfur trioxide (SO_3) on Hg capture due to the high sulfur content of the coal in this study.

EPA issued updated ELGs and standards for the steam electric power generation point source category in November 2015 to strengthen controls on wastewater discharges. [30] For the plant configuration considered, FGD wastewater discharged by the PC plant arrangement is the only wastewater stream that is applicable to ELG regulations. The objective of the assessment for greenfield plants with an ACC is to explore R&D opportunities for ACCs rather than meeting the stringent ELGs. So, the plant configuration used for analyzing ACCs does not consider wastewater treatment options suggested by the 2015 rule.

2.2.3 Reference Plant Basis

The non-capture, supercritical PC plant configuration from the previous NETL study "Cost and Performance Impact of Dry and Hybrid Cooling on Fossil Energy Power Systems" is used as the reference for a greenfield plant with an ACC. [31] The reference plant design is shown in Exhibit 2-20, along with the reference condenser operating conditions. The only modification made for this study includes replacement of the existing ACC design with the ACC design from an Excel-based ACC rating tool, described in subsequent sections. The plant was assumed to have a capacity factor of 85 percent and is designed for operation as a base-load unit.

Exhibit 2-20. Reference plant design used for analysis of ACCs

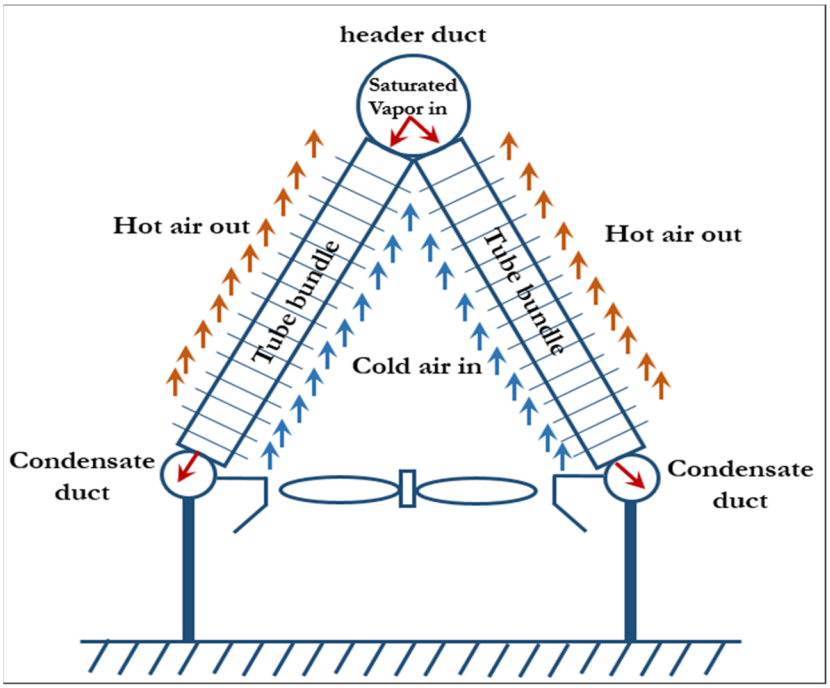
General Characteristics	
Net Capacity, MWe	547
Steam Cycle	Supercritical
Steam Conditions, psig/°F/°F	3,500/1,100/1,100
Capacity Factor, %	85
Wet FGD Wastewater Treatment	None
Condenser Operating Conditions	
Condenser Inlet Temperature, °F	105
Condenser Inlet Pressure, psig	1.104
Condenser Inlet Vapor Quality	0.76
Steam Flow Rate, lb/hr	2,658,775
Condenser Duty, MMBtu/h	2,088

The steam generator is a once-through, spiral-wound, Benson-boiler, wall-fired, balanced draft type unit with a water-cooled dry bottom furnace, with superheater, reheater, economizer, and air preheater. It is assumed for the purposes of this study that the power plant is designed for operation as a base-load unit.

2.2.4 Air Cooled Condenser Configuration

The schematic of an ACC bay is presented in Exhibit 2-21.

Exhibit 2-21. Schematic of ACC bay



As depicted in the schematic, low-pressure (LP) turbine, exhaust steam is distributed to the tube bundles via a header duct. The saturated steam flows through the finned tube heat exchanger bundles with multiple rows of tubes. The forced draft fan located at the bottom of the ACC draws cold air over the tube bundles in a crossflow arrangement to the steam flow. The cooled steam condensate is collected at the bottom in the condensate ducts. To meet the required condenser duty, several such bays are employed.

2.2.5 Performance Estimation Methodology

The performance model of the ACC bay is developed in Excel, based on an example problem (Example 8.1.4) from the air-cooled heat exchangers and cooling towers textbook by Kröger. [7]. The adjustable inputs in the spreadsheet are the condenser duty, steam operating conditions (inlet quality and temperature), and ambient dry bulb temperature. The model iteratively calculates the steam condensation rate, air flow rate, number of required bays, and total auxiliary fan power consumption. Exhibit 2-22 summarizes the adjustable input parameters and key model outputs.

Exhibit 2-22. Adjustable input parameters and key performance model outputs in the ACC spreadsheet model

Inputs	Outputs
Steam quality	Steam condensation rate
Steam temperature	Air flow rate
ACC heat duty	ACC fan power consumption
Ambient-air dry bulb temperature	Number of ACC bays

The geometrical parameters of the modeled tube bundles are listed in Exhibit 2-23. [7]

Exhibit 2-23. ACC tube bundle parameters

Parameter	Value
Number of tube rows	2
Number of tube bundles	8
Vertical tube spacing (P_l), mm	120.0
Horizontal tube spacing (P_t), mm	50.0
Tube outer minor axis, mm	17
Major axis/minor axis	5.7
Tube wall thickness, mm	1.5
Fin thickness, mm	Unknown
Fin height, mm	Unknown
Length of finned tube (L_t), m	9.5
Apex angle of A-frame, 2θ	60
Number of fans	1
Fan diameter, m	9.145

Each tube bundle contains two rows of tubes. For each tube row, the following set of equations are solved iteratively to calculate the heat duty of each tube row and consequently the total heat transfer rate of each bay.

$$Q = m_{steam} i_{fg} \qquad \textit{Equation (1)}$$

$$Q = m_a C_{p,a} (T_{a,out} - T_{a,in}) \qquad \textit{Equation (2)}$$

$$UA = \left(\frac{1}{htc_{steam} A_{steam}} + \frac{1}{htc_a A_a} \right)^{-1} \qquad \textit{Equation (3)}$$

$$\varepsilon = 1 - e^{\frac{-UA}{m_a C_{p,a}}} \quad \textit{Equation (4)}$$

$$Q = \varepsilon m_a C_{p,a}(T_{steam} - T_{a,in}) \quad \textit{Equation (5)}$$

where Q is the heat duty; m_{steam} and m_a are the steam and air mass flow rates respectively; $C_{p,a}$ is the specific heat of air, $T_{a,out}$ and $T_{a,in}$ are the air outlet and inlet temperatures respectively; i_{fg} is the steam latent heat; A_{steam} and A_a are the steam-side and air-side heat transfer areas respectively; ε is the effectiveness of tube row; T_{steam} is the temperature of steam entering the tube bundle.

To calculate the overall conductance (UA) in Equation (3), the air-side heat transfer coefficient (HTC) (htc_a) and steam-side HTC (htc_{steam}) are needed. The steam-side HTC is calculated using a correlation based on experimental data for an A-frame ACC with elliptical/flattened tubes as shown in Equation (6). [7]

$$htc_{steam} = 0.9245 \left[\frac{k^3 \rho^2 g_{acc} \cos(\theta) i_{fg} L_t}{\mu m_a C_{p,a}(T_{steam} - T_{a,in})\left[1 - \exp\left\{-\frac{UL_t H_t}{m_a C_{p,a}}\right\}\right]} \right] \quad \textit{Equation (6)}$$

where k is the thermal conductivity; ρ is the density; μ is the dynamic viscosity of steam; g_{acc} is the acceleration due to gravity; U is the overall HTC.

The air-side HTC is calculated using experimentally determined empirical correlations for the characteristic heat transfer parameter (N_y). A separate set of correlations are applied to each tube row:

$$N_y = 366.007945\ R_y^{0.433256} \text{ – For first tube row} \quad \textit{Equation (7)}$$

$$N_y = 360.58807\ R_y^{0.470373} \text{ – For second tube row} \quad \textit{Equation (8)}$$

where R_y is the air-side characteristic flow parameter and is calculated as follows:

$$R_y = \frac{m_a}{\mu_a A_{fr}} \quad \textit{Equation (9)}$$

A_{fr} is the frontal area of the tube bundle. The air-side HTC and characteristic heat transfer parameter are related as follows:

$$htc_a A_a = k_a Pr_a A_{fr} N_y \quad \textit{Equation (10)}$$

where k_a is the thermal conductivity; Pr_a is the Prandtl number; μ_a is the dynamic viscosity of air. The differences in the air-side HTC between the two tube rows is due to the variation in $(T_{steam} - T_{a,i})$ since both the tube rows use an identical tube bundle design. The second row of tubes experiences relatively hotter air than the first row of tubes. Therefore, the steam condensation rate in the second tube row is significantly lower than the first tube row.

The air-side pressure losses can be represented as follows:

$$\Delta P_a = \Delta P_{a,ts} + \Delta P_{a,fan} + \Delta P_{a,FSI} + \Delta P_{a,\theta t} \quad \textit{Equation (11)}$$

$$\Delta P_{a,ts} = K_{ts} \frac{(G_a \sigma)^2}{2\rho_a} \quad \textit{Equation (12)}$$

$$\Delta P_{a,fan} = \left(K_{up} + K_{do}\right). \frac{\left(\frac{m_a}{A_e}\right)^2}{2\rho_a} \quad \textit{Equation (13)}$$

$$\Delta P_{a,FSI} = K_{FSI}. \frac{\left(\frac{m_a}{A_c}\right)^2}{2\rho_a} \quad \textit{Equation (14)}$$

$$\Delta P_{a,\theta t} = K_{\theta t} \frac{(G_a \sigma)^2}{2\rho_a} \quad \textit{Equation (15)}$$

where $\Delta P_{a,ts}$ is the pressure loss of air due to cooler bay support structures; $\Delta P_{a,fan}$ is the fan upstream and downstream pressure losses; $\Delta P_{a,FSI}$ is the pressure loss of air across the fan inlet shroud and $\Delta P_{a,\theta t}$ is the pressure loss of air due to the oblique flow across the tube bundles. The loss coefficients K_{ts}, K_{up}, K_{do}, K_{FSI}, and $K_{\theta t}$ are calculated from Example 8.1.1 of the Kröger textbook. [7]

2.2.6 Cost Estimating Methodology

ACC capital costs were determined using STEAMPRO and PEACE software packages. The geometrical parameters listed in Exhibit 2-23 were reproduced in STEAMPRO for the reference condenser operating conditions from Exhibit 2-20 to obtain an equivalent ACC cost. Exhibit 2-24 compares the outputs from the ACC Excel model and STEAMPRO software package.

The minimum possible vertical tube spacing in STEAMPRO is 130.6 mm. Therefore, there is a slight difference in P_l value used in the Excel model and STEAMPRO.

Also, the fin thickness and height are unknown from the Kröger textbook. Therefore, these values were selected to match the performance results of the ACC bay from the Excel model.

Other than these differences, the model inputs used in STEAMPRO match exactly with the values listed in Exhibit 2-23.

As can be seen from Exhibit 2-24, the number of ACC bays and ACC fan power consumption calculated by the ACC Excel model and STEAMPRO match very closely for the reference condenser operating conditions.

PEACE software estimated the ACC bare erected cost (BEC) to be around $65MM for 54 bays. So, the cost per bay is around $1.2MM.

The STEAMPRO software package contains several other ACC designs offering significantly lower capital cost and fan power consumption. However, these designs didn't match the tube bundle geometrical parameters from the Kröger textbook.

Most of the modern ACCs only have a single tube row rather than two tube rows. Despite using older ACC design, the Excel model is appropriate to assess the relative impacts of various ACC-related parameters.

Exhibit 2-24. Comparison between ACC Excel model and STEAMPRO outputs

	Parameter	ACC Excel model	STEAMPRO
Inputs	Vertical tube spacing (P_l), mm	120.0	130.6
	Fin thickness, mm	Unknown	0.15
	Fin height, mm	Unknown	6.125
Outputs	Number of ACC bays	54	54
	ACC fan power consumption	13,024	13,059
	ACC BEC (2018$)	$65,045,000	

For the sensitivity analyses presented in this study, the ACC costs are scaled linearly based on the number of bays estimated by the ACC model.

BOP capital costs were estimated using data from other relevant NETL studies and appropriate scaling methodology. [2] These costs were obtained in June 2011 dollar basis and then adjusted to December 2018 dollars using the Chemical Engineering Plant Cost Index (CEPCI). Engineering, procurement, construction fees, and process contingencies were included prior to incorporating these adjusted costs into the overall plant-level, greenfield total overnight cost (TOC) estimate. Additionally, fixed and variable O&M cost estimates were developed. The LCOE is reported on $/MWh basis and consists of contributions from the O&M costs (fixed, variable, and fuel), and the annualized capital over the assumed 30-year lifetime of the plant. Additional details on the cost estimating methodology and other economic assumptions can be found in "QGESS: Capital Cost Scaling Methodology." [23]

2.2.7 Selected ACC Parameters

A goal of this study is to identify potential R&D improvements for ACCs and the overall impact those improvements might have on overall plant efficiency and LCOE. To explore the impact of potential R&D improvements, sensitivity analyses with respect to the selected ACC parameters were conducted. Exhibit 2-25 presents a list of the ACC parameters that were selected for the sensitivity analyses. Any R&D improvements to enhance the air-side and steam-side HTCs, and/or reduce the air-side loss coefficient will likely have a positive impact on the ACC performance. The steam temperature (or LP turbine exhaust pressure) is a design choice that depends on the ambient design conditions and the selected ACC design. Any potential improvements to the ACC design could also enable reduction in the turbine back pressure by reducing steam temperature approach to the ambient dry bulb temperature.

The base case values for all the parameters listed in Exhibit 2-25 are the values within the Excel model for the reference ACC operating conditions from Exhibit 2-20. For the sensitivity analyses, the HTCs and air-side loss coefficient ($k_{\theta t}$) are hardwired rather than using the correlations presented in Section 2.2.5. Also, each of these parameters are varied individually while holding the other ACC parameters at their respective base case values. Therefore, further improvements can be realized if simultaneous R&D improvements can be achieved for multiple ACC parameters.

Exhibit 2-25. Selected ACC parameters for sensitivity analyses

ACC Parameter	Base Case	Minimum	Maximum
Air-side HTC Row 1 (W/K)	350,254	220,000	480,000
Air-side HTC Row 2 (W/K)	553,754	347,822	758,884
Steam-side HTC Row 1 (W/m^2-K)	15,210	9,000	21,000
Steam-side HTC Row 2 (W/m^2-K)	15,889	9,450	22,050
Loss coefficient for tube bundle at inclination angle, $k_{\theta t}$	33	15	50
Steam temperature, °F	105	68	140

2.2.8 Study Assumptions

In addition to those noted above, the following assumptions were also made:

- The steam-side and air-side HTCs for the second tube row are proportional to the first tube row. For example, increasing the first tube row air-side HTC from base case value of 350,254 W/K to 480,000 W/K (37 percent increase) leads to a corresponding 37 percent increase for the second tube row air-side HTC. This is fairly realistic assumption since any R&D improvements will be applied to both the tube rows.
- Design changes needed to achieve R&D improvements don't have a big impact on individual ACC bay capital cost. For example, enhancing air-side HTC or reducing loss coefficient might require a change in tube bundle design, construction materials, etc. However, these changes are assumed to not have an impact on the ACC bay capital cost ($1.2MM). This is one of the major drawbacks of this study since these economic impacts are not captured in the sensitivity analyses presented. Nevertheless, the sensitivities are useful to assess the overall potential benefits.

3 RESULTS, ANALYSIS, AND DISCUSSION

3.1 FLUE GAS DESULFURIZATION WASTEWATER TREATMENT COMPLIANCE TECHNOLOGY

3.1.1 Performance Results

A summary of the performance results for the supercritical PC plant retrofitted with chemical precipitation and biological treatment for wet FGD wastewater is provided in Exhibit 3-1. Additional performance data are available in the Appendix: Cost and Performance Results.

Exhibit 3-1. Performance results summary

Case	Chemical Precipitation + Biological Treatment
HHV Heat Rate, Btu/kWh	**8,418**
HHV Net Plant Efficiency, %	**40.5**
Total Gross Power, MWe	**685**
Total Auxiliaries, MWe	**35**
Wastewater Treatment Auxiliary Load, kWe	51
BOP Auxiliary Load, kWe	34,620
Total Net Power, MWe	**650**
As Received Coal Feed Rate, lb/hr	469,257
Wastewater Solids Handling and Disposal, TPD	10.4
Treated Water Flow Rate, gpm	53.8
Raw Water Withdrawal, gpm/MW-net	9.3
Raw Water Consumption, gpm/MW-net	7.3

3.1.2 Cost Results

A summary of the cost results (given the study assumptions provided in Section 2.1.7) for the supercritical PC plant retrofitted with chemical precipitation and biological treatment for wet FGD wastewater is shown in Exhibit 3-2. Additional cost data are available in the Appendix: Cost and Performance Results.

Exhibit 3-2. Cost results summary

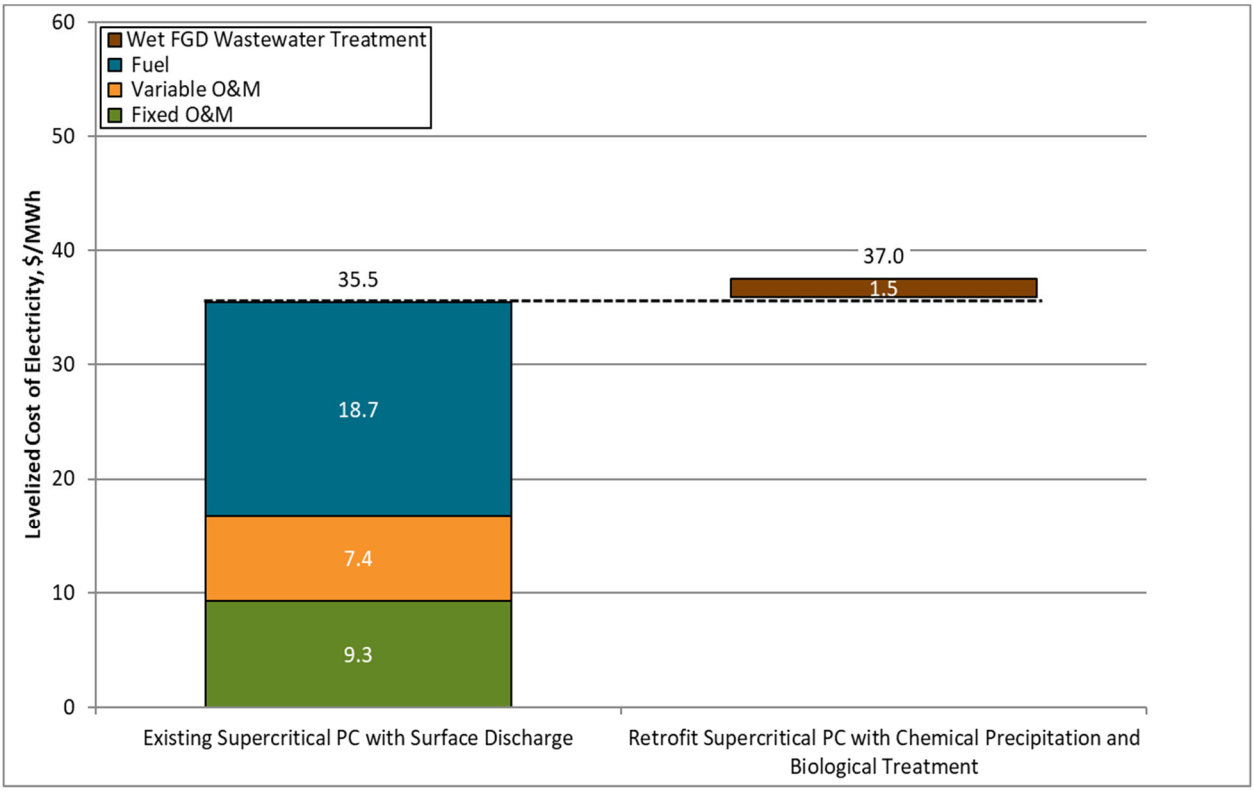
Case	Chemical Precipitation + Biological Treatment
Total Plant Cost, $/kW	80
Total Plant Cost of Wastewater Treatment, $/kW	69
Total Plant Cost of BOP, $/kW	11
Total Plant Cost, $/1,000	52,082

Case	Chemical Precipitation + Biological Treatment
Total Plant Cost Wastewater Treatment, $/1,000	44,696
Total Overnight Cost, $/kW	97
Total As-Spent Cost, $/kW	112
LCOE, [A] $/MWh	37.0
Capital, $/MWh	1.1
Fixed O&M, $/MWh	9.6
Variable O&M, $/MWh	7.6
Fuel, $/MWh	18.7

[A] Assumes a capacity factor of 85 percent

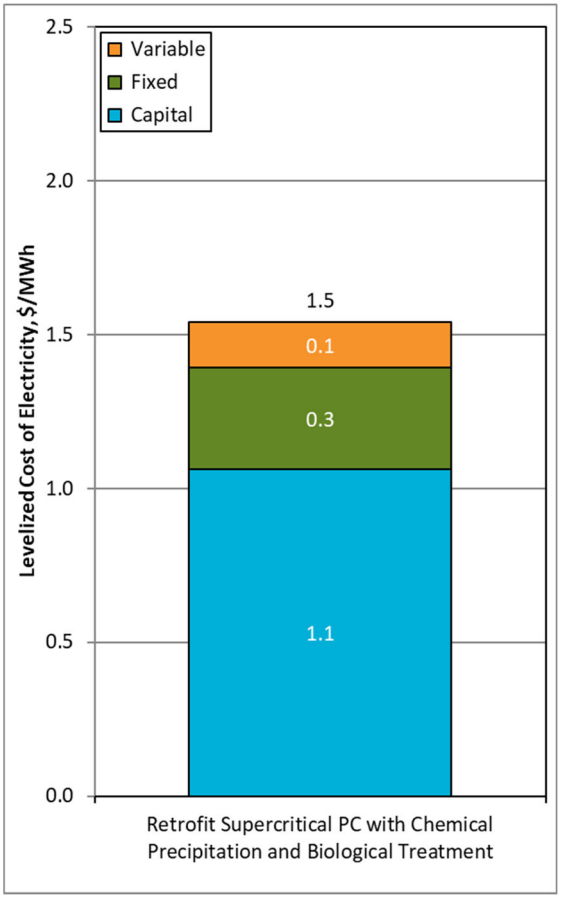
As shown in Exhibit 3-3, the addition of wet FGD wastewater treatment to an existing supercritical PC plant—using the assumptions and design basis established in this study—results in an increase in LCOE of approximately 4 percent.

Exhibit 3-3. Retrofit incremental and total LCOE impact



A stacked bar chart showing the breakdown of the incremental costs is provided in Exhibit 3-4.

Exhibit 3-4. Retrofit incremental LCOE breakdown

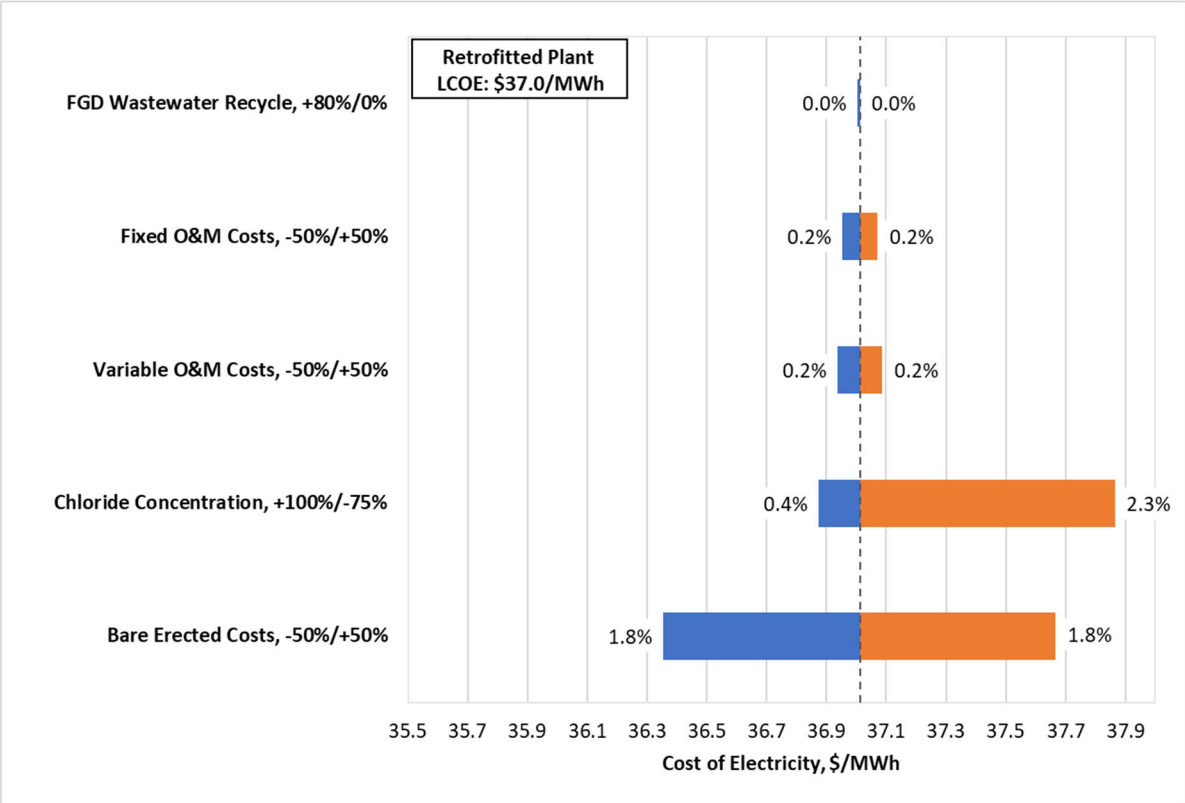


As shown, the capital costs constitute over 73 percent of the increase in LCOE, with the majority of the remainder associated with the fixed O&M (20 percent). It was assumed that the coal feed rate would be held constant, therefore there is no impact to the fuel component of the LCOE.

3.1.3 Sensitivity Analyses

Exhibit 3-5 presents the results of high-level sensitivity analyses conducted to assess the potential benefits that can be realized from improvements in wet FGD wastewater treatment system cost (BEC, variable O&M, and fixed O&M), water reuse, and tolerance to chloride. Breakdowns of the various cost categories are provided in subsequent figures.

Exhibit 3-5. LCOE Sensitivity



Due to the capital costs representing the majority of the increase in LCOE (Exhibit 3-4), a reduction in the BEC presents the greatest opportunity for reducing the LCOE. As shown in Exhibit 3-5, a 50 percent reduction in BEC is associated with a 1.8 percent reduction in LCOE ($37.0/MWh to $36.4/MWh). The impact of BEC on LCOE is further broken down in Exhibit 3-7.

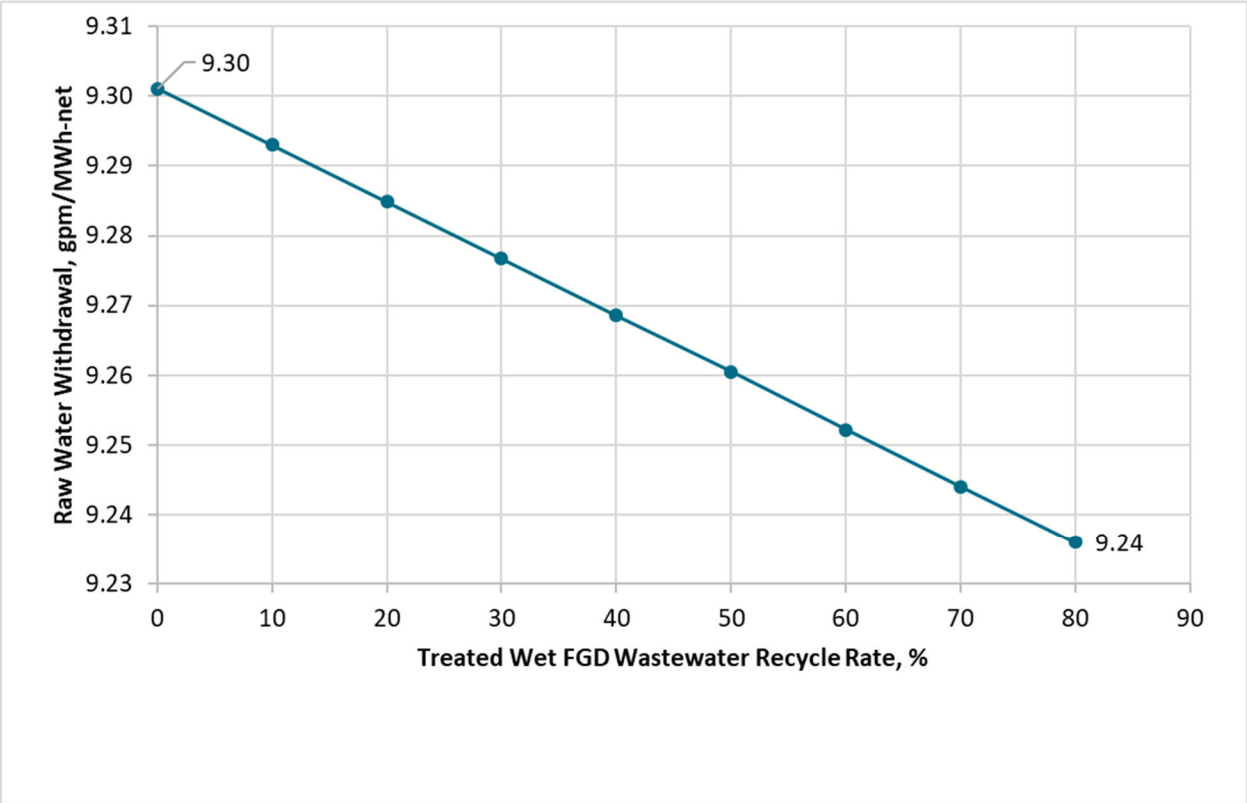
As shown in Exhibit 3-5, doubling the chloride tolerance from 20,000 ppm to 40,000 ppm results in a 0.4 percent reduction in LCOE ($37.0/MWh to $36.9/MWh). It is estimated that up to $1,851,000 could be expended in additional equipment costs (e.g., exotic materials) to achieve the higher chloride tolerance (40,000 ppm) before the capital cost expenditure outweighs the benefit realized by lower wet FGD wastewater volumes.

Reducing either the fixed O&M or variable O&M costs associated with the wet FGD wastewater treatment system by 50 percent could potentially reduce the LCOE by 0.2 percent (Exhibit 3-5), resulting in an LCOE of $37.0/MWh or $36.9/MWh, respectively. The impact of fixed and variable O&M costs on LCOE is further broken down in Exhibit 3-8 and Exhibit 3-9, respectively.

Treated wastewater from the wet FGD is assumed to be discharged from the plant. However, this water could be reused within the plant (e.g., makeup to the wet FGD, makeup to the cooling tower), reducing raw water withdrawal. However, even if 80 percent of the treated wet FGD wastewater were reused, there would be no observable impact to the LCOE (Exhibit 3-5). Furthermore, the wastewater discharged from the wet FGD wastewater treatment system (~54 gpm) represents only 0.9 percent of the total plant water demand. Therefore, reusing 80

percent of the treated wet FGD wastewater only reduces the raw water withdrawal by 0.6 percent (0.06 gpm/MWh).

Exhibit 3-6. Water recycle impact on withdrawal rate



The breakdown of BEC constituents on LCOE is provided in Exhibit 3-7. As shown, the factors within the BEC that have the greatest impact on LCOE are the equipment fabrication, labor of installation, and retrofit difficulty. For a 50 percent reduction in the costs associated with the equipment fabrication, labor of installation, and retrofit difficult, the total potential LCOE reduction is 1.5 percent (LCOE reduction from $37.0/MWh to $36.5/MWh), which is less than the sum of the individual reductions (1.7 percent) due to the interdependencies of these three parameters.

Reducing the chemical precipitation and biological treatment equipment cost by 50 percent can potentially reduce the LCOE by 0.2 percent and 0.1 percent, respectively. As the water building represents less than 2 percent of the total equipment costs, a 50 percent reduction in the building cost has no observable impact on the LCOE..

Exhibit 3-7. Sensitivity of LCOE to bare erected costs

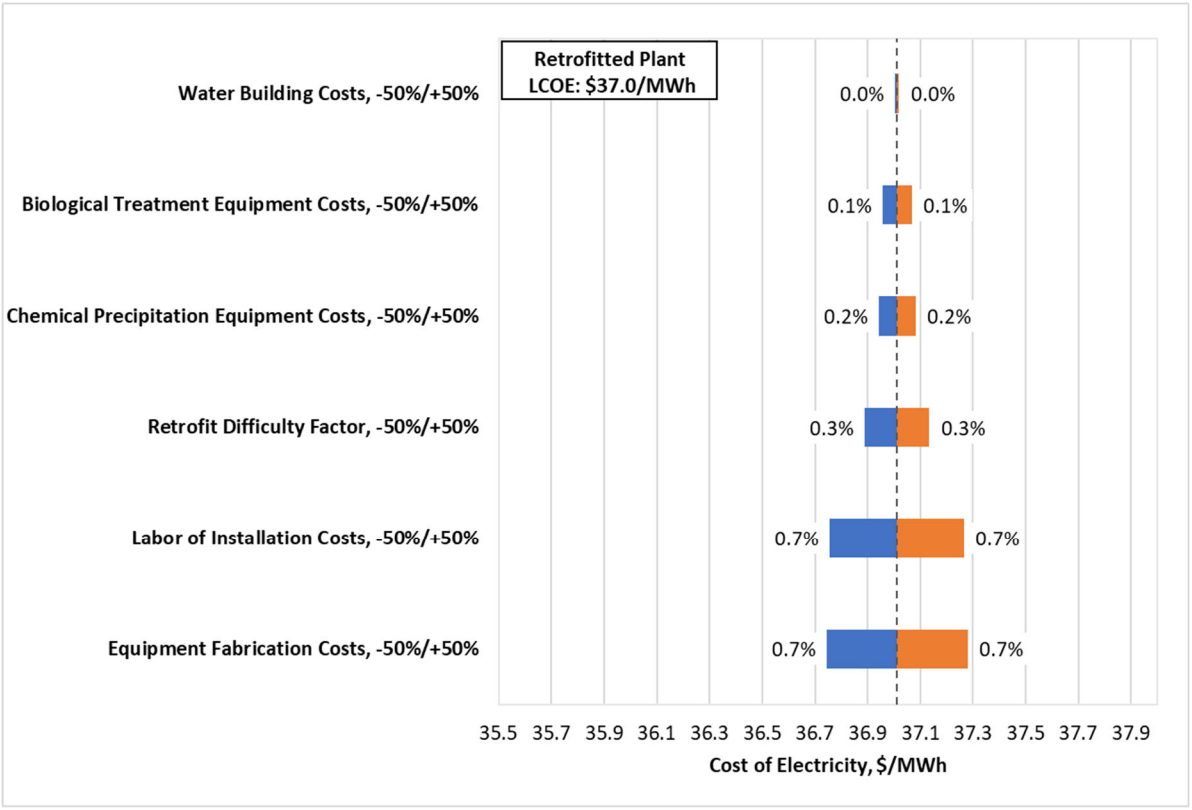


Exhibit 3-8 and Exhibit 3-9 demonstrate that there is no observable impact to the LCOE for a 50 percent reduction in costs associated with the wet FGD wastewater treatment system's operating labor, consumables, or waste disposal. Whereas a 50 percent reduction in the costs associated with maintaining the wet FGD wastewater treatment system, either labor or material, results in a 0.1 percent reduction in LCOE.

Exhibit 3-8. Sensitivity of LCOE to fixed O&M

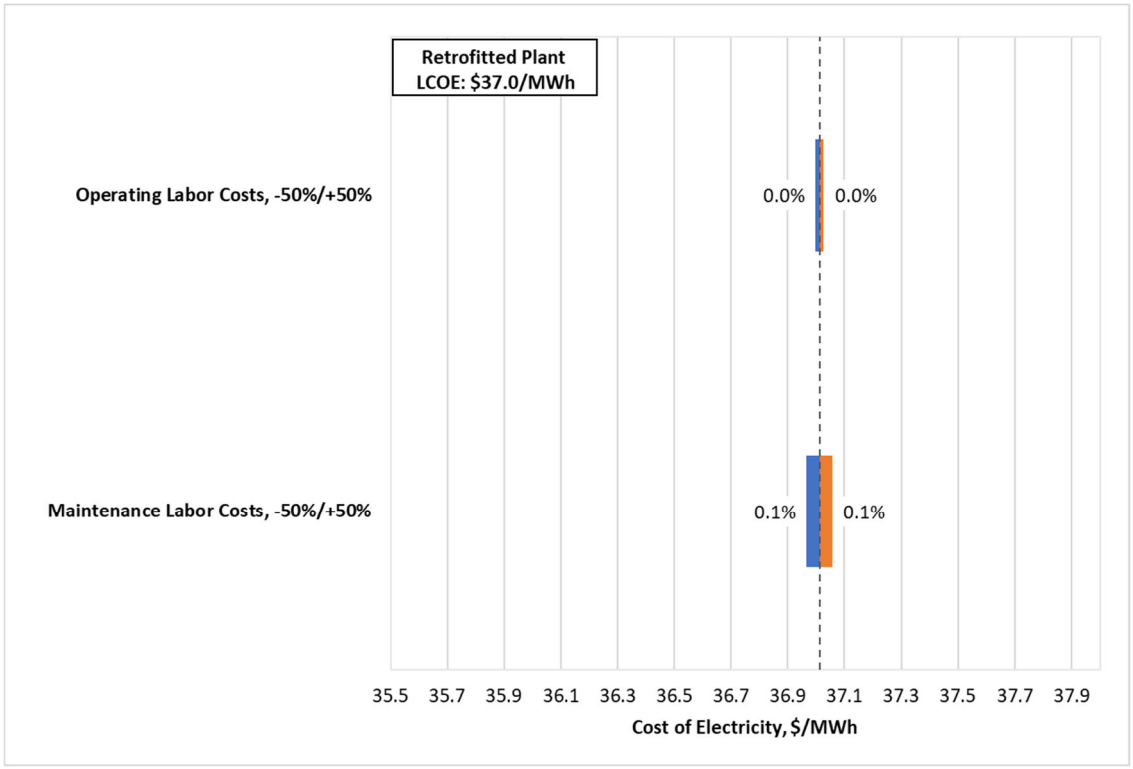
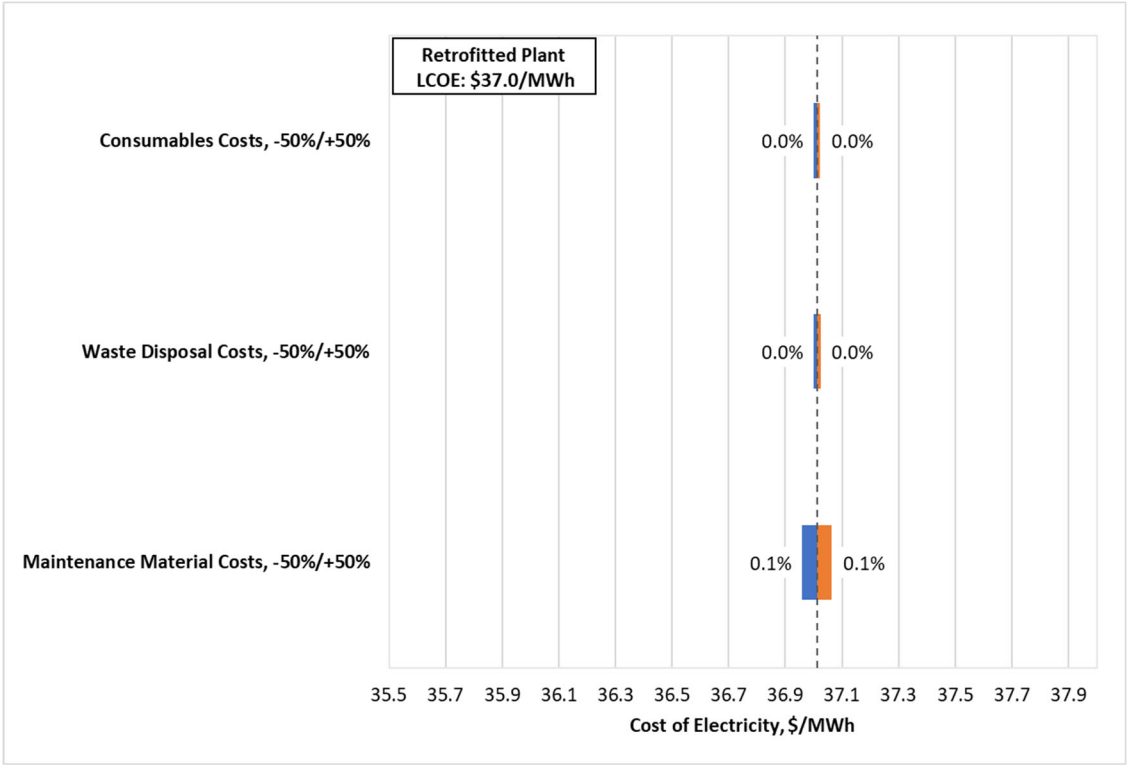


Exhibit 3-9. Sensitivity of LCOE to variable O&M



3.2 Dry Cooling Systems and Steam Condensers

3.2.1 Performance Results

Exhibit 3-10 presents a summary of the performance results for the greenfield plant with ACC (performance estimation methodology is described in Section 2.2.5). Additional performance data are available in the Appendix: Cost and Performance Results

Exhibit 3-10. Performance results summary for reference plant design with updated ACC design

Parameter	Value
HHV Heat Rate, Btu/kWh	**8,536**
HHV Net Plant Efficiency, %	**40.0**
Total Gross Power, MWe	**577**
Total Auxiliaries, MWe	**37**
ACC Auxiliary Load, kWe	13,024
BOP Auxiliary Load, kWe	23,576
Total Net Power, MWe	**540**
As Received Coal Feed Rate, lb/hr	395,053
Raw Water Withdrawal, gpm/MW-net	1.7
Raw Water Consumption, gpm/MW-net	1.7

3.2.2 Cost Results

Exhibit 3-11 presents a summary of the cost results (given the study assumptions provided in Section 2.2.4) for the greenfield plant with ACC (cost estimating methodology is described in Section 2.2.6). Additional cost data are available in the Appendix: Cost and Performance Results

Exhibit 3-11. Cost results summary for reference plant design with updated ACC design

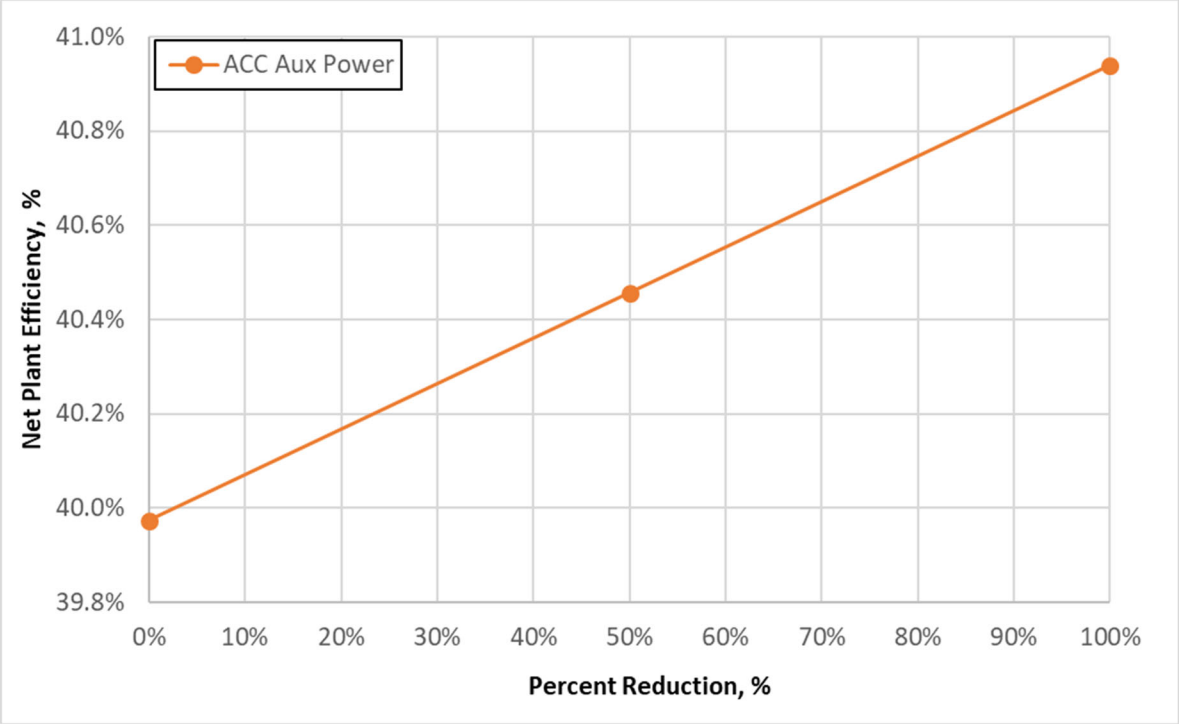
Parameter	Value
Total Plant Cost, $/kW	2,161
Total Plant Cost ACC, $/kW	152
Total Plant Cost, $/1,000	1,182,448
Total Plant Cost ACC, $/1,000	82,282
Total Overnight Cost, $/kW	2,545
Total As-Spent Cost, $/kW	3,068
LCOE, $/MWh	67.6
Capital, $/MWh	29.5
Fixed O&M, $/MWh	10.1
Variable O&M, $/MWh	8.9
Fuel, $/MWh	19.0

3.2.3 Sensitivity Analyses

High-level sensitivity analyses were conducted to assess the maximum potential benefits that can be realized from reducing the ACC auxiliary power, capital cost, and maintenance costs.[b]

Exhibit 3-12 shows the impact of reducing ACC auxiliary fan power consumption on the net plant efficiency (HHV basis). Reducing the ACC fan power consumption by 50 percent improves the plant efficiency by about 0.5 percentage points and eliminating the ACC fan power consumption altogether improves the efficiency by about 1 percentage point.

Exhibit 3-12. Impact of ACC auxiliary power on plant efficiency



Likewise, Exhibit 3-13 shows the impact of reducing ACC-related capital costs, auxiliary fan power consumption, and maintenance costs on the LCOE. A 50 percent reduction in the ACC BEC translates to 2.1 percent LCOE reduction and a 50 percent reduction in ACC fan power consumption reduces the LCOE by 1.6 percent. As can be seen from Exhibit 3-13, a reduction in ACC-related maintenance costs don't have a significant impact on LCOE.

For the selected plant, an LCOE reduction of 3.7 percent can be achieved by simultaneously reducing the ACC fan power consumption and the BEC by 50 percent.

[b] These high-level sensitivity analyses aren't associated with specific changes to parameters associated with the ACC (e.g., transfer coefficients, air pressure losses) and how the reduction in ACC auxiliary power and/or costs can be achieved

Exhibit 3-13. Impact of ACC BEC, auxiliary power, and maintenance costs on LCOE

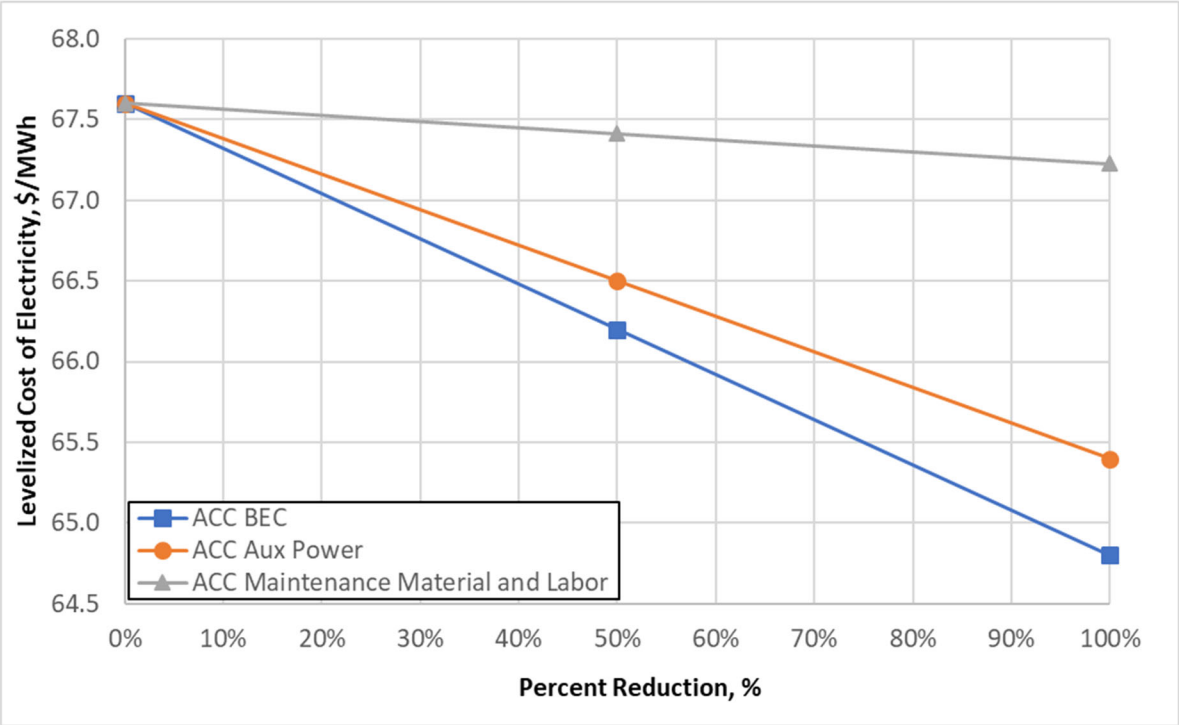


Exhibit 3-14 and Exhibit 3-15 shows the impact of different ACC parameters (listed in Exhibit 2-25) on the ACC auxiliary fan power consumption and net plant efficiency (HHV basis), respectively. As mentioned earlier, the air-side and steam-side HTCs for both the tube rows are varied simultaneously in a proportional manner.

Out of the selected parameters, the air-side HTC has the largest impact on both the ACC fan power and plant efficiency, followed by air loss coefficient ($k_{\theta t}$). Improving the air-side HTC by 37 percent leads to a 9 percent reduction in the ACC fan power, translating to about a 0.1 percentage point improvement in the plant efficiency. Likewise, a 54 percent reduction in the air loss coefficient results in a 9 percent reduction in the ACC fan power and a 0.1 percentage point improvement in the plant efficiency. Steam-side HTC doesn't have a significant impact on either the ACC fan power or plant efficiency. For ACCs, air-side HTC is the limiting parameter for heat transfer. Therefore, any improvements for steam-side HTC will have relatively minor impacts.

Exhibit 3-14. Impact of ACC-related parameters on the ACC auxiliary fan power

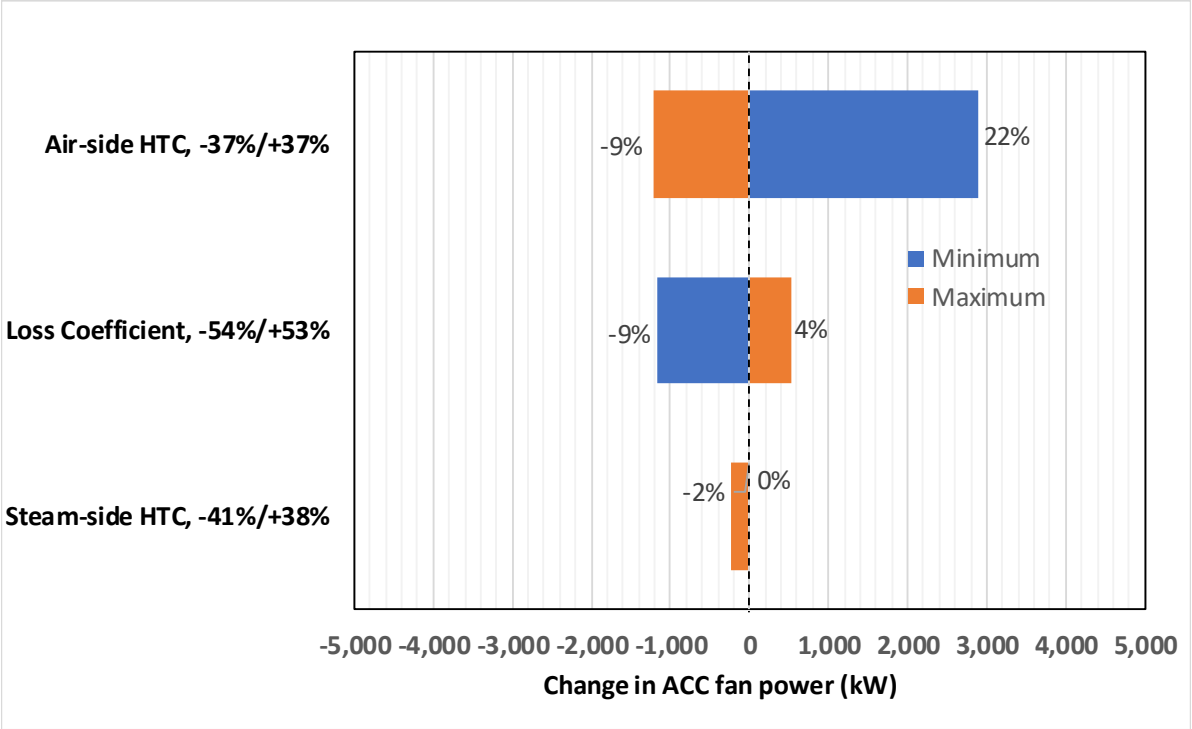


Exhibit 3-15. Impact of ACC-related parameters on the plant efficiency

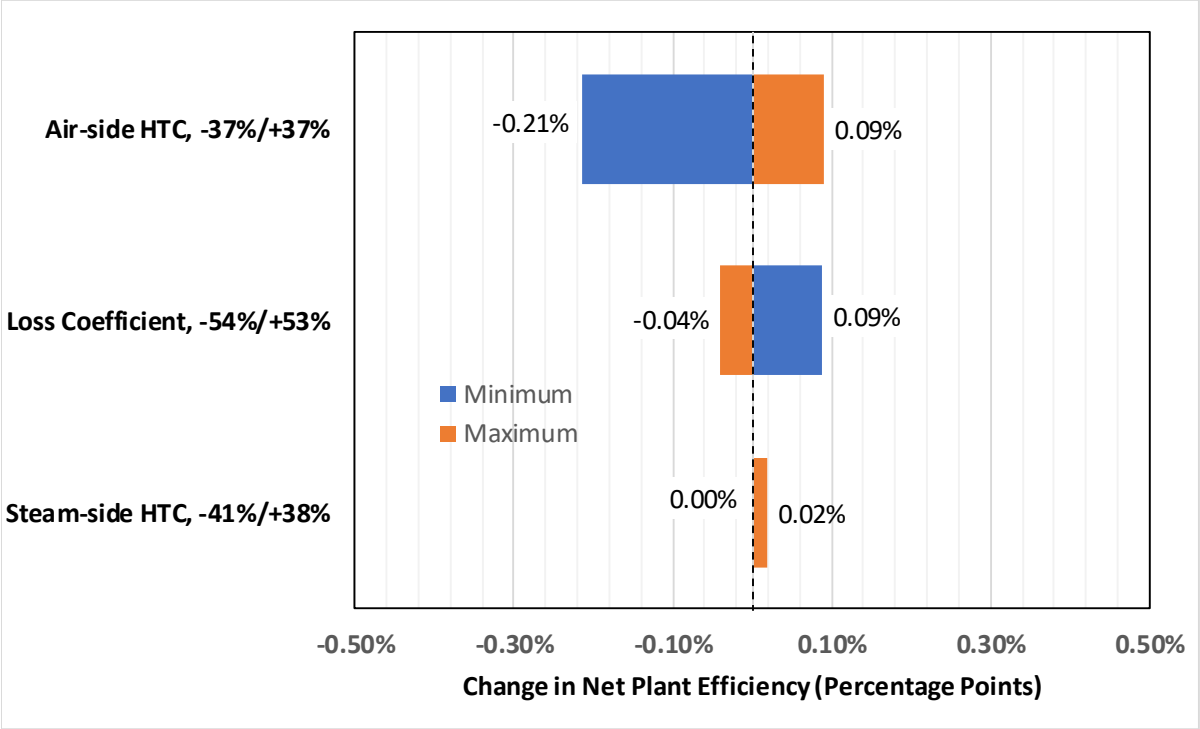


Exhibit 3-16 and Exhibit 3-17 show the impact of different ACC parameters (listed in Exhibit 2-25) on the number of ACC bays and LCOE, respectively.

Again, the air-side HTC has the largest impact on both the number of ACC bays, followed by the air loss coefficient ($k_{\theta t}$). Assuming that the ACC capital costs scale linearly with the number of ACC bays, and ignoring the economic impacts of ACC design changes needed to achieve R&D improvements, air-side HTC and $k_{\theta t}$ have the biggest impact on LCOE as well.

Improving the air-side HTC by 37 percent leads to a 9 percent reduction in the number of ACC bays (and correspondingly, ACC capital costs), translating to about 0.7 percent reduction in the LCOE. Likewise, a 54 percent reduction in the air loss coefficient results in a 6 percent reduction in the number of bays and a 0.5 percent reduction in the LCOE. Therefore, simultaneously improving the air-side HTC by 37 percent and reducing the air loss coefficient by 54 percent can result in up to a 1.2 percent LCOE reduction.

Again, the steam-side HTC doesn't have a significant impact on either the number of ACC bays or LCOE.

Exhibit 3-16. Impact of ACC-related parameters on the number of ACC bays

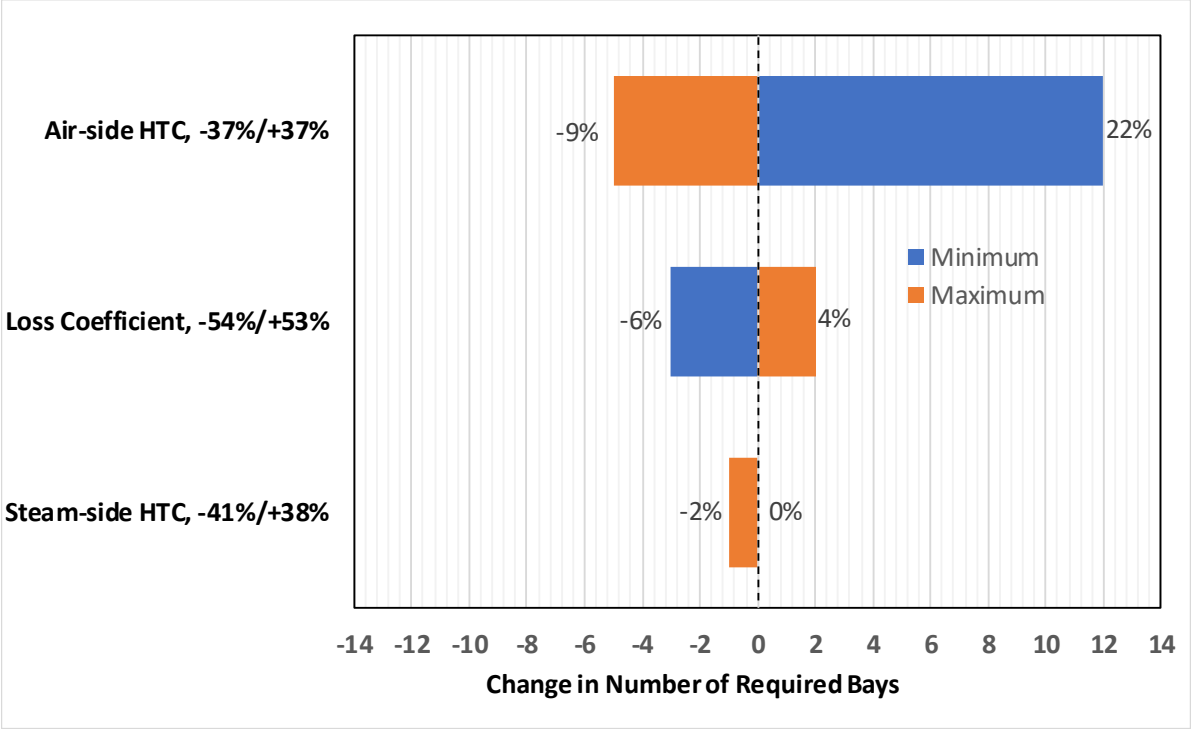
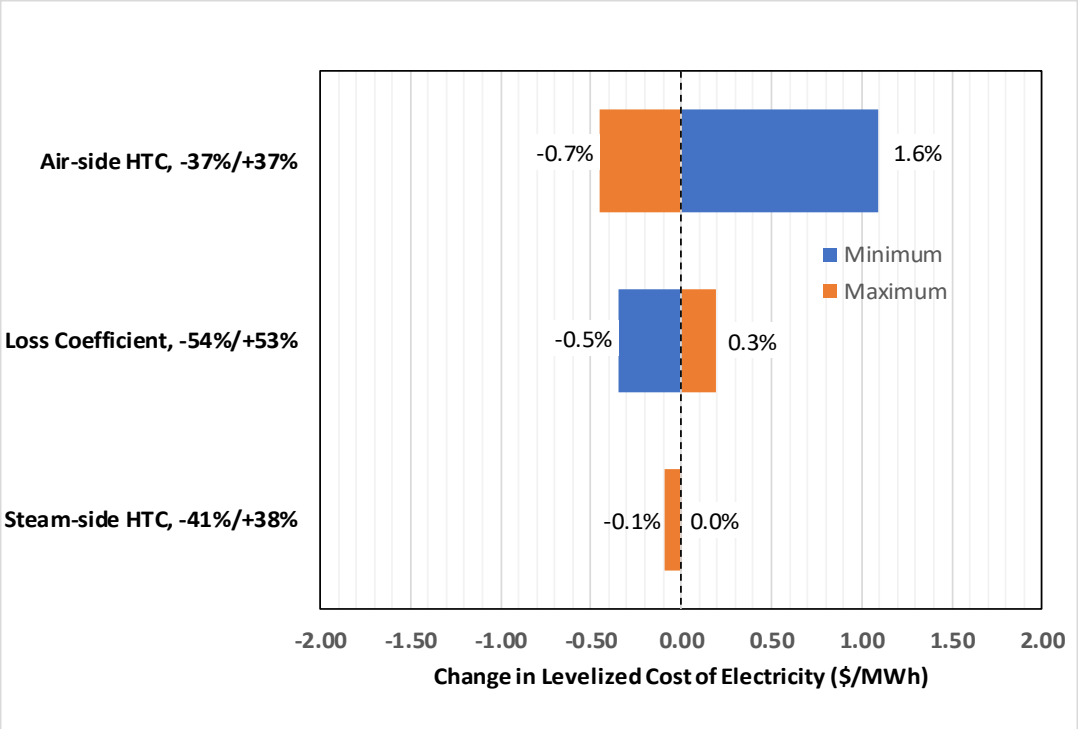


Exhibit 3-17. Impact of ACC-related parameters on the LCOE

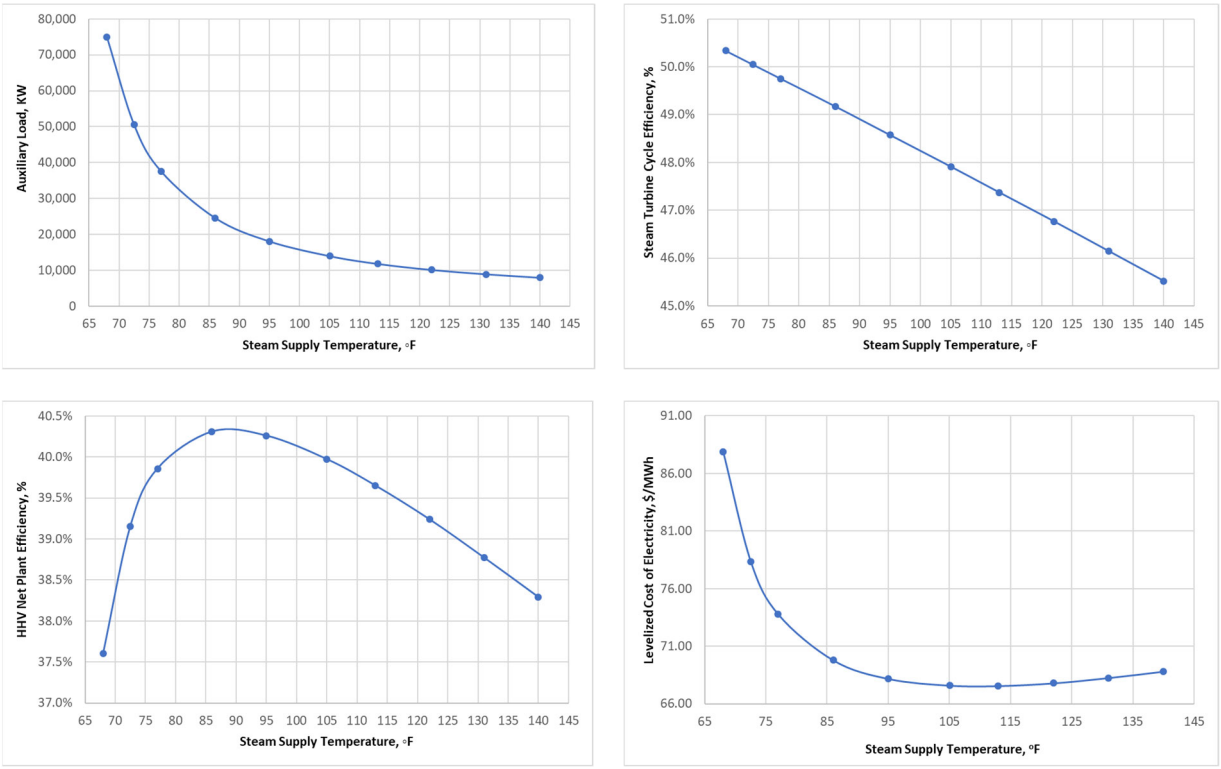


As mentioned earlier, a sensitivity analysis was conducted to investigate the impact of steam supply temperature (or LP turbine exhaust pressure) on the plant efficiency and LCOE. Exhibit 3-18 shows the impact of steam supply temperature on the ACC auxiliary power, steam cycle efficiency, plant efficiency, and LCOE.

As the steam supply temperature decreases, the ACC auxiliary power increases almost exponentially as the steam temperature approaches the ambient dry bulb temperature (59°F in this case). At the same time, reducing steam supply temperature reduces the LP turbine exhaust pressure (turbine back pressure), thereby increasing the steam turbine cycle efficiency as can be seen from Exhibit 3-18.

Due to these opposing trends, the plant efficiency achieves a maximum value around a steam supply temperature of 90°F. The base case has a steam supply temperature of 105°F. Therefore, reducing the steam supply temperature by 15°F offers an additional 0.3 percentage point improvement in the plant efficiency. However, the peak in plant efficiency didn't translate to LCOE reduction since the ACC capital cost increases as the steam supply temperature decreases due to lower approach to the ambient temperature (increases the required heat transfer area). In fact, the LCOE minimum is very close to the base case of 105°F. Therefore, the design choice for steam supply temperature is already close to the economic optimum, at least for the ACC design selected in this study. As noted earlier, the optimum design choice for the steam supply temperature will depend on the ambient design conditions as well as the selected ACC design.

Exhibit 3-18. Impact of steam supply temperature on the ACC auxiliary power (top left), steam cycle efficiency (top right), plant efficiency (bottom left), and LCOE (bottom right)



Since air-side HTC and pressure loss have the biggest impact on LCOE, additional sensitivity analyses were conducted to identify the parameters impacting them. Exhibit 3-19 shows the impact of tube bundle frontal area on the air-side HTC. Obviously, the most straight forward way to improve the air-side HTC is to increase the frontal area of tube bundle. However, this will result in higher capital costs. Developing new tube-fin geometries presents a better way to improve the air-side HTC and reduce capital costs.

Air-side pressure loss is impacted by several parameters due to the oblique flow of air to the tube bundles. The loss coefficient ($k_{\theta t}$) is impacted by the ACC apex angle, tube bundle downstream loss coefficient, entrance contraction loss coefficient, and pressure drop across the tube bundle. [7] Decreasing the pressure drop across the tube bundle using improved tube-fin geometries has a direct benefit on the air loss coefficient. In addition, Exhibit 3-20 presents the impact of ACC apex angle, downstream loss coefficient, and entrance contraction loss coefficient on the overall loss coefficient ($k_{\theta t}$). As can be seen, increasing the ACC apex angle offers significant reduction in air loss coefficient followed by the downstream loss coefficient. Entrance contraction losses have a fairly minor impact on the overall loss coefficient.

Exhibit 3-19. Impact of tube bundle frontal area on the air-side HTC

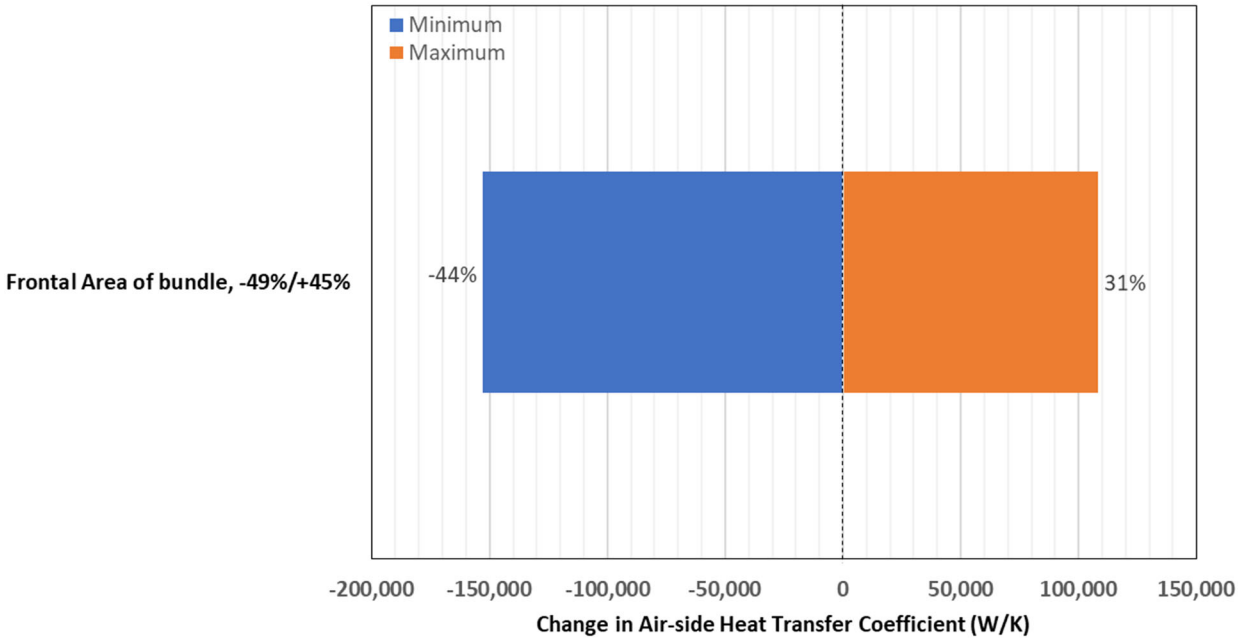
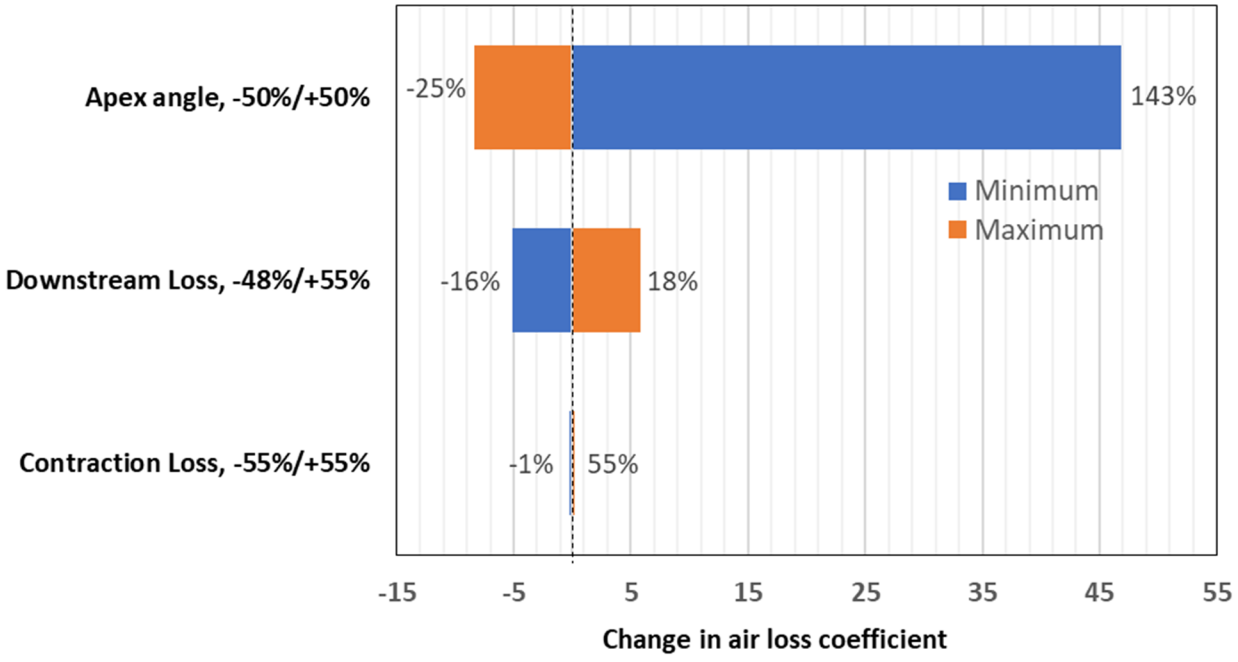


Exhibit 3-20. Impact of different parameters on the air loss coefficient ($k_{\theta t}$)



4 RECOMMENDED R&D AREAS OF IMPROVEMENT

4.1 FLUE GAS DESULFURIZATION WASTEWATER TREATMENT COMPLIANCE TECHNOLOGY

Based on the results of this study, the aspects of the FGD wastewater treatment system that provide the most potential for improvement to the LCOE are 1) improving the chloride tolerance of microorganisms and low-cost materials or coatings and 2) reducing the equipment fabrication and labor of installation costs.

4.1.1 Chloride Concentration

Increasing the maximum chloride concentration allows for higher recycle rates within the wet FGD, resulting in wastewater that is lower in volume and higher in contaminant concentration. The lower volume of wastewater requires smaller quantities of consumables, reduces equipment size, reduces system footprint, and reduces auxiliary loads.

Currently, the available materials of construction that can tolerate chloride concentrations greater than 20,000 ppm come at a cost premium. Furthermore, the microorganisms used in the biological treatment system limit the chloride concentration to 25,000 ppm.

It is recommended that the R&D goal be set at 40,000 ppm, which would be sufficiently high to allow direct application to the majority of wet FGD wastewaters. [4]

Achieving this goal could potentially reduce the LCOE by up to 0.4 percent (LCOE reduced from $37.0/MWh to $36.9/MWh). It is estimated that up to $1.9 million could be expended in additional equipment costs (e.g., exotic materials) to achieve the higher chloride tolerance (40,000 ppm) before the capital cost expenditure outweighs the benefit realized by lower wet FGD wastewater volumes.

4.1.2 Equipment Fabrication and Labor of Installation Costs

The total plant cost associated with retrofitting an existing supercritical pulverized coal boiler is approximately $52 million, including retrofit difficulty factors applied to both equipment and labor costs, and the BOP costs incurred in the accessory electric plant, instrumentation and control, and improvements to site (cost accounts are provided in Appendix: Cost and Performance Results).

Of the $52 million, the labor associated with the installation of the wastewater treatment system accounts for approximately $11 million (21 percent), and the equipment fabrication of the wastewater treatment system accounts for approximately $12 million (22 percent).

Much of the wastewater treatment system is currently field fabricated, leading to high construction costs in both retrofit and greenfield applications, with increased costs due to the difficulty associated with construction at an existing site.

Modularization of equipment at power plants can significantly reduce the cost associated with the labor of installation, equipment fabrication, and materials. For example, the modularization of fossil fuel power plants has been estimated to reduce the cost of materials by 30 to 40

percent [5] and the modularization of nuclear power plants has been estimated to reduce the capital cost by up to 15 percent. [6]

It is recommended that R&D pursue the modularization of FGD wastewater treatment equipment with the goal of reducing the costs associated with equipment fabrication and labor of installation of the wastewater treatment system ($23 million) by 25 percent.

Achieving this goal could potentially reduce the LCOE by up to 0.7 percent (LCOE reduced from $37.0/MWh to $36.7/MWh).

4.2 Dry Cooling Systems and Steam Condensers

Based on the results of this study, the aspects of the ACC that provide the most potential for improvement to the LCOE are: 1) improving the air-side HTC and 2) reducing the air-side pressure loss.

4.2.1 Air-Side Heat Transfer Coefficient

The absolute value of the air-side HTC varies depending on ACC operating conditions and the tube bundle design. For the selected reference operating conditions and tube bank design, the air-side HTC ranged from 350,000 – 550,000 W/K (depending on the tube row). Increasing the air-side HTC by 37 percent increased the plant efficiency by 0.1 percentage points and reduced the LCOE by $0.5/MWh (0.7 percent reduction).

4.2.2 Air-Side Pressure Loss Coefficient

The absolute value of air-side pressure loss coefficient depends on the operating conditions and ACC design. For the selected ACC design and operating conditions, the air-side pressure loss coefficient is 30. Reducing the pressure loss coefficient by 54 percent increased the plant efficiency by 0.1 percentage points and reduced the LCOE by $0.35/MWh (0.5 percent reduction).

It is recommended that R&D should seek design, modeling, and testing of advanced tube-fin geometries which can improve the air-side HTC while minimizing the air-side pressure drop across the tube bundle. The oblique flow of air to the tube bundles due to A-frame design is also a large contributor to the air-side pressure loss. Advanced ACC designs which can reduce the ACC A-frame apex angle can also mitigate the air-side pressure loss. It is important to note that any advanced ACC designs developed via R&D shouldn't increase either the ACC capital or maintenance costs to realize the benefits projected in this study.

Improving the steam-side HTC will likely have a minimal impact on the plant efficiency and LCOE since airside HTC is the limiting factor in case of ACCs. Sensitivity analysis to the ACC steam supply temperature (or LP turbine back pressure) indicated that there is an optimum ACC steam supply temperature that minimize LCOE due to approach to the ambient dry bulb temperature. However, this optimum is likely going to depend on the ambient design conditions and the ACC design. Therefore, any potential improvements to the ACC design could also enable reduction in the turbine back pressure by reducing steam temperature approach to the ambient dry bulb temperature.

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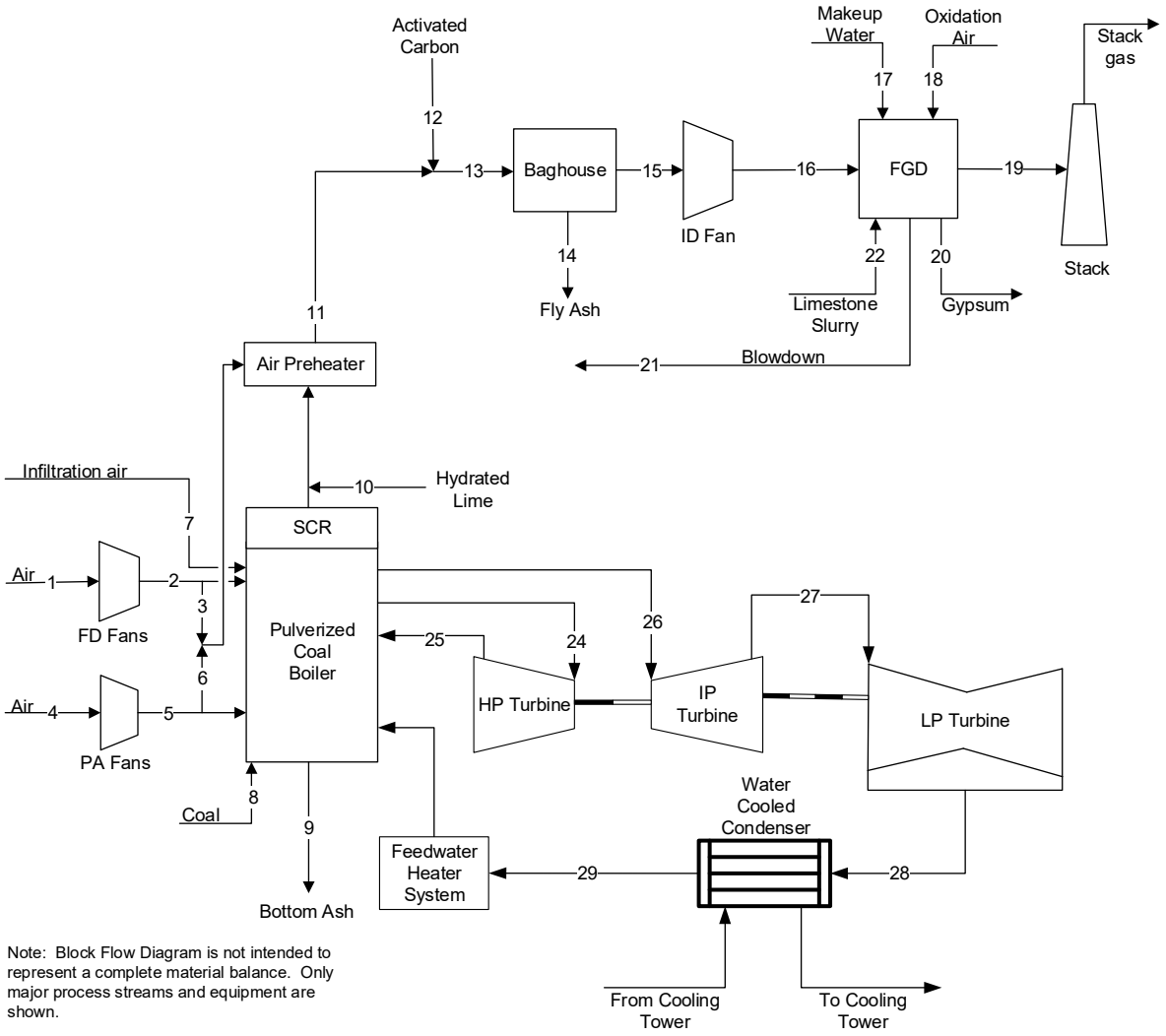
APPENDIX: COST AND PERFORMANCE RESULTS

The cost and performance results of each case produced in this study are presented in this section.

A.1 FLUE GAS DESULFURIZATION WASTEWATER TREATMENT COMPLIANCE TECHNOLOGY

The plants used to assess flue gas desulfurization (FGD) wastewater treatment systems are supercritical pulverized coal (PC) plants that are based on the non-capture, supercritical PC plant from "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 4" (Bituminous Baseline). The block flow diagram and associated stream tables are provided in Exhibit A-1 and Exhibit A-2 respectively.

Exhibit A-1. Block flow diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit A-2. Stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
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	0.0088	0.0000	0.0088	0.0000	0.0092
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1383	0.0000	0.1383	0.0000	0.0003
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	1.0000	0.0839	0.0000	0.0839	0.0000	0.0099
HCl	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001	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	0.7339	0.0000	0.7339	0.0000	0.7732
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0331	0.0000	0.0331	0.0000	0.2074
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000	0.0020	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	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	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	0.0000	0.0000	0.0000	1.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	1.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flow Rate (kg_{mole}/hr)	58,030	58,030	1,719	17,826	17,826	2,453	1,283	0	0	1	81,395	0	81,395	1	58,030
V-L Flow Rate (kg/hr)	1,674,558	1,674,558	49,598	514,407	514,407	70,795	37,014	0	0	12	2,417,160	0	2,417,160	148	1,674,558
Solids Flow Rate (kg/hr)	0	0	0	0	0	0	0	212,851	4,291	1,160	18,550	45	18,596	18,608	0
Temperature (°C)	15	19	19	15	25	25	15	15	1,316	15	143	15	143	143	15
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.23	34.36	34.36	30.23	40.78	40.78	30.23	---	---	---	---	---	---	---	30.23
AspenPlus Enthalpy (kJ/kg)[B]	-97.58	-93.45	-93.45	-97.58	-87.03	-87.03	-97.58	-2,119.02	1,267.06	-13,402.95	-2,400.40	-6.79	-2,400.36	-842.64	-97.58
Density (kg/m³)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	1,003.6	0.9	---	0.9	2,151.6	1.2
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	18.015	29.697	---	29.697	110.983	28.857
V-L Flow Rate (lb_{mole}/hr)	127,933	127,933	3,789	39,300	39,300	5,409	2,828	0	0	1	179,446	0	179,446	3	127,933
V-L Flow Rate (lb/hr)	3,691,768	3,691,768	109,344	1,134,073	1,134,073	156,077	81,601	0	0	26	5,328,926	0	5,328,926	327	3,691,768
Solids Flow Rate (lb/hr)	0	0	0	0	0	0	0	469,257	9,460	2,558	40,896	100	40,997	41,024	0
Temperature (°F)	59	66	66	59	78	78	59	59	2,400	59	289	59	289	289	59
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.6	14.7	14.4	14.7	14.4	14.4	14.7
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---	---	---	---	---	---	13.0
AspenPlus Enthalpy (Btu/lb)[B]	-42.0	-40.2	-40.2	-42.0	-37.4	-37.4	-42.0	-911.0	544.7	-5,762.2	-1,032.0	-2.9	-1,032.0	-362.3	-42.0
Density (lb/ft³)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	62.650	0.053	---	0.053	134.322	0.076

[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

Exhibit A-2. Stream table (cont'd)

	16	17	18	19	20	21	22	23	24	25	26	27	28	29
V-L Mole Fraction														
Ar	0.0088	0.0088	0.0000	0.0092	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1383	0.1383	0.0000	0.0003	0.1255	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	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0839	0.0839	0.9967	0.0099	0.1436	0.9998	0.9943	0.9999	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
HCl	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N_2	0.7339	0.7339	0.0000	0.7732	0.6860	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0331	0.0331	0.0000	0.2074	0.0366	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0020	0.0020	0.0000	0.0000	0.0001	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	0.0000	0.0000	0.0000	0.0000
NaCl	0.0000	0.0000	0.0005	0.0000	0.0000	0.0001	0.0009	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
$CaCl_2$	0.0000	0.0000	0.0028	0.0000	0.0000	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	1.0000	1.0000	1.0000	1.0000	1.0000
V-L Flow Rate (kg_{mole}/hr)	81,394	81,394	11,189	3,434	90,942	191	647	2,669	104,712	87,540	87,540	75,438	57,177	75,649
V-L Flow Rate (kg/hr)	2,416,999	2,416,999	204,733	99,100	2,622,069	3,446	11,963	48,098	1,886,415	1,577,053	1,577,053	1,359,039	1,030,068	1,362,835
Solids Flow Rate (kg/hr)	0	0	1,841	0	0	30,997	182	20,590	0	0	0	0	0	0
Temperature (°C)	143	154	27	15	56	15	56	15	593	342	593	270	38	39
Pressure (MPa, abs)	0.10	0.11	0.10	0.10	0.10	0.10	0.10	0.10	24.23	4.90	4.80	0.52	0.01	1.32
Steam Table Enthalpy (kJ/kg) [A]	275.83	287.47	---	30.23	283.68	---	---	---	3,477.96	3,049.81	3,652.36	3,000.14	2,343.61	162.43
AspenPlus Enthalpy (kJ/kg)[B]	-2,412.44	-2,400.80	-15,763.85	-97.58	-2,884.74	-12,520.29	-15,500.14	-14,994.25	-12,502.33	-12,930.48	-12,327.93	-12,980.15	-13,636.69	-15,817.87
Density (kg/m^3)	0.8	0.9	1,002.4	1.2	1.1	881.8	980.5	1,003.7	69.2	19.2	12.3	2.1	0.1	993.3
V-L Molecular Weight	29.695	29.695	18.297	28.857	28.832	18.021	18.495	18.019	18.015	18.015	18.015	18.015	18.015	18.015
V-L Flow Rate (lb_{mole}/hr)	179,443	179,443	24,669	7,571	200,494	422	1,426	5,885	230,850	192,992	192,992	166,313	126,055	166,777
V-L Flow Rate (lb/hr)	5,328,571	5,328,571	451,360	218,478	5,780,673	7,597	26,373	106,038	4,158,834	3,476,806	3,476,806	2,996,169	2,270,910	3,004,537
Solids Flow Rate (lb/hr)	0	0	4,058	0	0	68,337	402	45,393	0	0	0	0	0	0
Temperature (°F)	289	309	80	59	133	59	133	59	1,100	648	1,100	517	101	101
Pressure (psia)	14.2	15.3	14.7	14.7	14.8	14.7	14.7	14.7	3,514.7	710.8	696.6	75.0	1.0	190.7
Steam Table Enthalpy (Btu/lb)[A]	118.6	123.6	---	13.0	122.0	---	---	---	1,495.3	1,311.2	1,570.2	1,289.8	1,007.6	69.8
AspenPlus Enthalpy (Btu/lb)[B]	-1,037.2	-1,032.2	-6,777.2	-42.0	-1,240.2	-5,382.8	-6,663.9	-6,446.4	-5,375.0	-5,559.1	-5,300.1	-5,580.5	-5,862.7	-6,800.5
Density (lb/ft^3)	0.052	0.055	62.580	0.076	0.067	55.048	61.209	62.658	4.319	1.197	0.768	0.131	0.003	62.010

[A]Steam table reference conditions are 32.02°F & 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

A.1.1 Performance Results

Exhibit A-3. Plant performance summary

Performance Summary	
Total Gross Power, MWe	**685**
CO_2 Capture/Removal Auxiliaries, kWe	0
CO_2 Compression, kWe	0
Balance of Plant, kWe	34,671
Total Auxiliaries, MWe	**35**
Net Power, MWe	**650**
HHV Net Plant Efficiency, %	40.5%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,881 (8,418)
LHV Net Plant Efficiency, %	42.0%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,566 (8,119)
HHV Boiler Efficiency, %	88.6%
LHV Boiler Efficiency, %	91.9%
Steam Turbine Cycle Efficiency, %	48.2%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,471 (7,082)
Condenser Duty, GJ/hr (MMBtu/hr)	2,589 (2,454)
As-Received Coal Feed, kg/hr (lb/hr)	212,851 (469,257)
Limestone Sorbent Feed, kg/hr (lb/hr)	20,590 (45,393)
HHV Thermal Input, kWt	1,604,373
LHV Thermal Input, kWt	1,547,438
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.035 (9.3)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.028 (7.3)
Excess Air, %	20.3%

Exhibit A-4. Plant power summary

Power Summary	
Steam Turbine Power, MWe	685
Total Gross Power, MWe	**685**
Auxiliary Load Summary	
Activated Carbon Injection, kWe	30
Air Cooled Condenser Fans	0
Ash Handling, kWe	680
Baghouse, kWe	90
Circulating Water Pumps, kWe	5,300
Coal Handling and Conveying, kWe	470
Condensate Pumps, kWe	660
Cooling Tower Fans, kWe	2,740
Dry Sorbent Injection, kWe	60
Flue Gas Desulfurizer, kWe	3,290
Forced Draft Fans, kWe	1,990
Ground Water Pumps, kWe	550
Induced Draft Fans, kWe	8,100
Miscellaneous Balance of Plant[A,B], kWe	2,250
Primary Air Fans, kWe	1,560
Pulverizers, kWe	3,190
SCR, kWe	30
Sorbent Handling & Reagent Preparation, kWe	990
Wet FGD Wastewater Treatment, kWe	51
Steam Turbine Auxiliaries, kWe	500
Transformer Losses, kWe	2,140
Total Auxiliaries, MWe	**35**
Net Power, MWe	**650**

[A]Boiler feed pumps are turbine driven
[B]Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

Exhibit A-5. Air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year)[A]	kg/MWh (lb/MWh)[B]
SO_2	0.081 (0.188)	3,471 (3,826)	0.680 (1.500)
NOx	0.054 (0.125)	2,314 (2,550)	0.454 (1.000)
Particulate	0.016 (0.038)	694 (765)	0.136 (0.300)
Hg	6.99E-7 (1.63E-6)	0.030 (0.033)	5.90E-6 (1.30E-5)
CO_2	87 (202)	3,739,476 (4,122,066)	733 (1,616)
CO_2[C]	-	-	772 (1,703)
	mg/Nm^3		
Particulate Concentration[D,E]	51.11		

[A]Calculations based on an 85 percent capacity factor
[B]Emissions based on gross power except where otherwise noted
[C]CO_2 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

Exhibit A-6. Carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	135,681 (299,126)	Stack Gas	137,062 (302,170)
Air (CO_2)	316 (697)	FGD Product	211 (465)
PAC	45 (100)	Baghouse	697 (1,536)
FGD Reagent	2,089 (4,606)	Bottom Ash	163 (359)
Total	**138,132 (304,530)**	**Total**	**138,132 (304,530)**

Exhibit A-7. Sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	5,335 (11,762)	Desulfurizer Product	4,883 (10,765)
		Stack Gas	237 (523)
		Baghouse	181 (399)
		FGD Blowdown	34 (75)
		Bottom Ash	–
Total	**5,335 (11,762)**	**Total**	**5,335 (11,762)**

Exhibit A-8. 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	2.2 (582)	–	2.2 (582)	–	2.2 (582)
Desulfurizer Blowdown	–	–	–	0.2 (53)	-0.2 (-53)
Deaerator Vent	–	–	–	0.1 (17)	-0.1 (-17)
Condenser Makeup	**0.1 (17)**	**–**	**0.1 (17)**	**–**	**0.1 (17)**
BFW Makeup	0.1 (17)	–	0.1 (17)	–	0.1 (17)
Cooling Tower	**21 (5,450)**	**–**	**21 (5,450)**	**4.6 (1,226)**	**16 (4,225)**
Total	**23 (6,049)**	**–**	**23 (6,049)**	**4.9 (1,295)**	**18 (4,754)**

Exhibit A-9. Energy balance

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	5,776 (5,474)	4.8 (4.6)	–	5,781 (5,479)
Air	–	67 (64)	–	67 (64)
Raw Water Makeup	–	86 (82)	–	86 (82)
Limestone	–	0.4 (0.4)	–	0.4 (0.4)
Auxiliary Power	–	–	125 (118)	125 (118)
TOTAL	**5,776 (5,474)**	**159 (150)**	**125 (118)**	**6,059 (5,743)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	5.5 (5.2)	–	5.5 (5.2)
Fly Ash	–	1.9 (1.8)	–	1.9 (1.8)
Stack Gas	–	744 (705)	–	744 (705)
Sulfur	0.0 (0.0)	0.0 (0.0)	–	0.0 (0.0)
Gypsum	–	2.0 (1.9)	–	2.0 (1.9)
FGD Blowdown	0.0 (0.0)	2.8 (2.7)	0.0 (0.0)	2.8 (2.7)
Motor Losses and Design Allowances	–	–	40 (38)	40 (38)
Cooling Tower Load[A]	–	2,694 (2,554)	–	2,694 (2,554)
Blowdown Streams and Deaerator Vent	–	2.4 (2.3)	–	2.4 (2.3)
Ambient Losses[B]	–	136 (129)	–	136 (129)
Power	–	–	2,466 (2,337)	2,466 (2,337)
TOTAL	**0.0 (0.0)**	**3,588 (3,401)**	**2,506 (2,375)**	**6,094 (5,776)**
Unaccounted Energy[C]	–	–	–	-35 (-33)

[A]Includes condenser, AGR, and miscellaneous cooling loads
[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

A.1.2 Cost Results

Exhibit A-10. Total plant cost details

Case:		-Supercritical PC, No Capture, Chemical Precipitation + Biological Treatment					Estimate Type:	Conceptual			
Plant Size (MW, net):		650					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	$/kW
3	Feedwater & Miscellaneous BOP Systems										
3.8	Spray Dryer Evaporator	$17,532	$0	$11,119	$0	$28,651	$4,298	$1,433	$10,314	$44,696	$69
	Subtotal	**$17,532**	**$0**	**$11,119**	**$0**	**$28,651**	**$4,298**	**$1,433**	**$10,314**	**$44,696**	**$69**
11	Accessory Electric Plant										
11.2	Station Service Equipment	$229	$0	$58	$0	$288	$50	$0	$51	$389	$1
11.3	Switchgear & Motor Control	$356	$0	$184	$0	$539	$94	$0	$95	$728	$1
11.4	Conduit & Cable Tray	$0	$1	$396	$0	$397	$69	$0	$70	$536	$1
11.5	Wire & Cable	$0	$2	$651	$0	$653	$114	$0	$115	$882	$1
11.6	Protective Equipment	$3	$0	$29	$0	$31	$5	$0	$6	$42	$0
	Subtotal	**$587**	**$2**	**$1,318**	**$0**	**$1,907**	**$334**	**$0**	**$336**	**$2,577**	**$4**
12	Instrumentation & Control										
12.6	Control Boards, Panels & Racks	$12	$0	$22	$0	$34	$6	$0	$6	$46	$0
12.7	Distributed Control System Equipment	$339	$0	$361	$0	$700	$122	$0	$123	$946	$1
12.8	Instrument Wiring & Tubing	$24	$0	$303	$0	$326	$57	$0	$58	$441	$1
12.9	Other Instrumentation & Controls Equipment	$29	$0	$269	$0	$298	$52	$0	$53	$403	$1
	Subtotal	**$404**	**$0**	**$955**	**$0**	**$1,359**	**$238**	**$0**	**$239**	**$1,836**	**$3**
13	Improvements to Site										
13.1	Site Preparation	$0	$40	$1,027	$0	$1,067	$187	$0	$251	$1,505	$2
13.2	Site Improvements	$0	$199	$316	$0	$515	$90	$0	$121	$727	$1
13.3	Site Facilities	$239	$0	$287	$0	$526	$92	$0	$124	$741	$1
	Subtotal	**$239**	**$240**	**$1,630**	**$0**	**$2,109**	**$369**	**$0**	**$496**	**$2,973**	**$5**
	Total	**$18,762**	**$242**	**$15,022**	**$0**	**$34,026**	**$5,238**	**$1,433**	**$11,386**	**$52,082**	**$80**

Exhibit A-11. Owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$275	$0
1 Month Maintenance Materials	$49	$0
1 Month Non-Fuel Consumables	$10	$0
1 Month Waste Disposal	$11	$0
25% of 1 Months Fuel Cost at 100% CF	$0	$0
2% of Total Plant Cost	$1,042	$2
Total	**$1,387**	**$2**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$20	$0
0.5% of Total Plant Cost (spare parts)	$260	$0
Total	**$281**	**$0**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$0	$0
Other Owner's Costs	$7,812	$12
Financing Costs	$1,406	$2
Total Overnight Costs (TOC)	**$62,969**	**$97**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$72,692**	**$112**

Exhibit A-12. Initial and annual operating and maintenance costs

Case:	-Supercritical PC, No Capture, Chemical Precipitation + Biological Treatment				Cost Base:	Dec 2018
Plant Size (MW, net):	650	Heat Rate-net (Btu/kWh):		8,418	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:		2.0
Operating Labor Burden:		30.00	**% of base**	Operator:		9.2
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:		1.0
				Lab Techs, etc.:		2.0
				Total:		**14.2**
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$6,244,819	$9.603
Maintenance Labor:					$8,850,733	$13.610
Administrative & Support Labor:					$3,773,888	$5.803
Property Taxes and Insurance:					$27,658,542	$42.530
Total:					**$46,527,981**	**$71.545**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$13,276,100	$2.74166
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (gal/1000):	0	4,355	$1.90	$0	$2,567,239	$0.53016
Makeup and Wastewater Treatment Chemicals (ton):	0	13.0	$550.00	$0	$2,213,733	$0.45716
Brominated Activated Carbon (ton):	0	1.20	$1,600.00	$0	$596,365	$0.12316
Enhanced Hydrated Lime (ton):	0	31.0	$240.00	$0	$2,308,309	$0.47669
Limestone (ton):	0	545	$22.00	$0	$3,717,961	$0.76780
Ammonia (19 wt%, ton):	0	44.1	$300.00	$0	$4,107,201	$0.84818
SCR Catalyst (ft^3):	13,546	12.4	$150.00	$2,031,932	$575,714	$0.11889
Ferric Chloride (lb)	0	81.6	$0.21	$0	$5,318	$0.00110
Polymer (lb)	0	26.3	$2.12	$0	$17,289	$0.00357
Hydrated Lime (lb)	0	654.9	$0.10	$0	$20,320	$0.00420
Hydrochloric Acid (lb)	0	177.1	$0.07	$0	$3,846	$0.00079
Organosulfide (lb)	0	64.6	$2.58	$0	$51,694	$0.01068
Nutrient (lb)	0	31.7	$0.43	$0	$4,230	$0.00087
Subtotal:				**$2,031,932**	**$16,189,218**	**$3.34326**
Waste Disposal						
Fly Ash (ton)	0	496	$38.00	$0	$5,850,169	$1.20813
Bottom Ash (ton)	0	114	$38.00	$0	$1,338,278	$0.27637
SCR Catalyst (ft^3):	0	12.4	$2.50	$0	$9,595	$0.00198
Chemical Precipitation Solids (ton):	0	9.9	$38.00	$0	$117,225	$0.02421
Subtotal:				**$0**	**$7,315,267**	**$1.51068**
By-Products						
Gypsum (ton)	0	820	$0.00	$0	$0	$0.00000
Subtotal:				$0	$0	$0.00000
Variable Operating Costs Total:				**$2,031,932**	**$36,780,586**	**$7.59560**
Fuel Cost						
Illinois Number 6 (ton):	0	5,631	$51.96	$0	$90,772,901	$18.74562
Total:				**$0**	**$90,772,901**	**$18.74562**

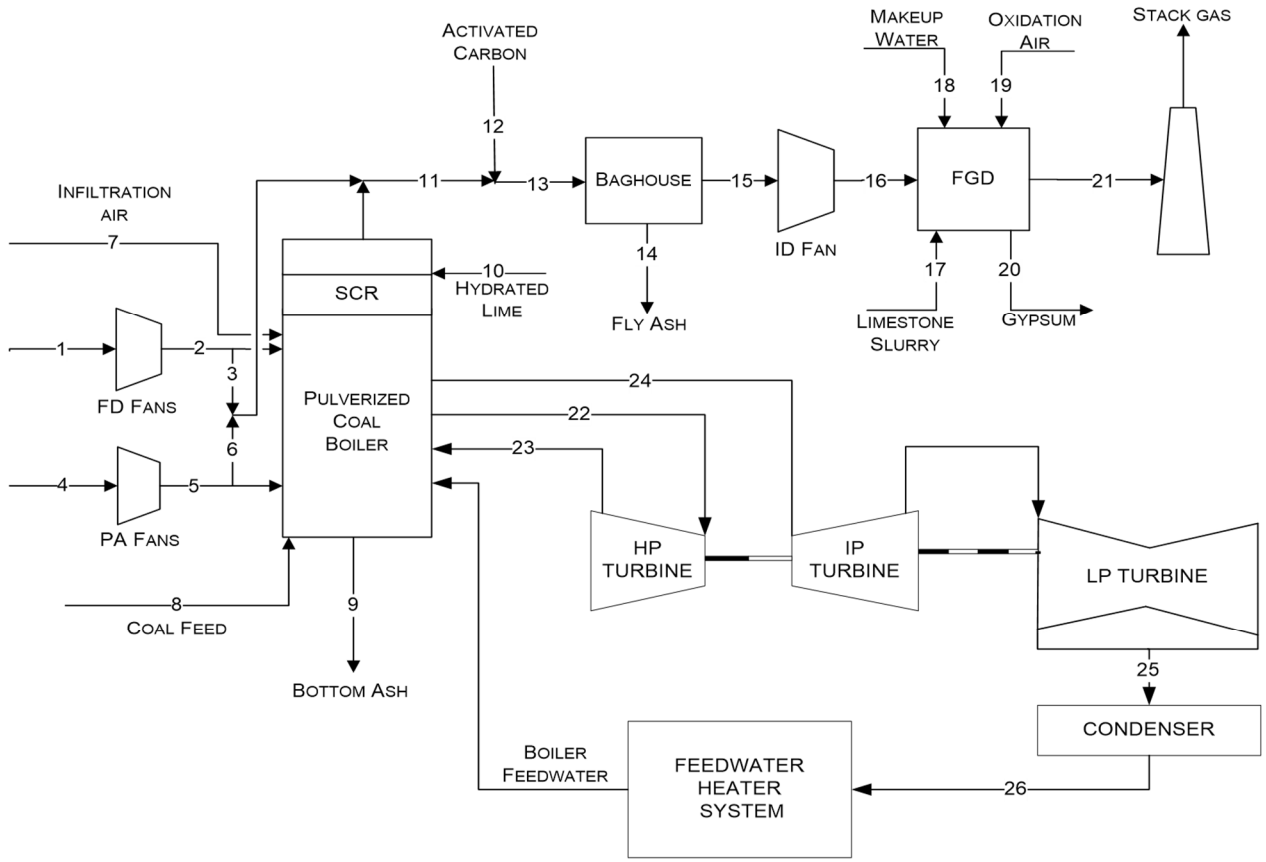
Exhibit A-13. Cost of electricity breakdown

Component	Value, $/MWh	Percentage
Capital	1.1	3%
Fixed	9.6	26%
Variable	7.6	21%
Fuel	18.7	51%
Total (Excluding T&S)	**37.0**	**N/A**
CO_2 T&S	0.0	0%
Total (Including T&S)	**37.0**	**N/A**

A.2 Dry Cooling Systems and Steam Condensers

The plants used to assess dry cooling systems and steam condensers are supercritical pulverized coal (PC) plants that are based on the non-capture, supercritical PC plant from "Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, Revision 3" (Bituminous Baseline). The block flow diagram and associated stream tables are provided in Exhibit A-14 and Exhibit A-15 respectively.

Exhibit A-14. Block flow diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Exhibit A-15. Stream table

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
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	0.0088	0.0000	0.0088	0.0000	0.0088
CO_2	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0000	0.0000	0.0000	0.1376	0.0000	0.1376	0.0000	0.1376
H_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H_2O	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0099	0.0000	0.0000	0.0000	0.0831	0.0000	0.0831	0.0000	0.0831
N_2	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.7732	0.0000	0.0000	0.0000	0.7345	0.0000	0.7345	0.0000	0.7345
O_2	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.2074	0.0000	0.0000	0.0000	0.0340	0.0000	0.0340	0.3333	0.0340
SO_2	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0020	0.0000	0.0020	0.6667	0.0020
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.0000	0.0000	0.0000	1.0000	0.0000	1.0000	1.0000	1.0000
V-L Flow Rate (kg_{mole}/hr)	49,407	49,407	1,463	15,177	15,177	2,089	1,079	0	0	0	69,254	0	69,254	3	69,251
V-L Flow Rate (kg/hr)	1,425,748	1,425,748	42,228	437,975	437,975	60,277	31,143	0	0	0	2,056,682	0	2,056,682	158	2,056,525
Solids Flow Rate (kg/hr)	0	0	0	0	0	0	0	179,193	3,475	3,611	17,512	104	17,616	17,616	0
Temperature (°C)	15	19	19	15	25	25	15	15	149	15	143	15	143	143	143
Pressure (MPa, abs)	0.10	0.11	0.11	0.10	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Steam Table Enthalpy (kJ/kg) [A]	30.22	34.36	34.36	30.22	40.78	40.78	30.22	---	---	0.00	0.00	0.00	---	---	274.33
AspenPlus Enthalpy (kJ/kg)[B]	-97.57	-93.43	-93.43	-97.57	-87.02	-87.02	-97.57	-2,114.05	97.18	-13,320.61	-2,399.61	-20.43	-2,399.49	-2,631.96	-2,397.47
Density (kg/m^3)	1.2	1.2	1.2	1.2	1.3	1.3	1.2	---	---	---	0.9	---	0.9	1.5	0.8
V-L Molecular Weight	28.857	28.857	28.857	28.857	28.857	28.857	28.857	---	---	---	29.698	---	29.698	53.376	29.697
V-L Flow Rate (lb_{mole}/hr)	108,924	108,924	3,226	33,460	33,460	4,605	2,379	0	0	0	152,678	0	152,678	7	152,671
V-L Flow Rate (lb/hr)	3,143,235	3,143,235	93,097	965,569	965,569	132,888	68,659	0	0	0	4,534,209	0	4,534,209	347	4,533,861
Solids Flow Rate (lb/hr)	0	0	0	0	0	0	0	395,053	7,662	7,961	38,607	230	38,837	38,837	0
Temperature (°F)	59	66	66	59	78	78	59	59	300	59	289	59	289	289	289
Pressure (psia)	14.7	15.3	15.3	14.7	16.1	16.1	14.7	14.7	14.4	14.7	14.4	14.7	14.4	14.4	14.2
Steam Table Enthalpy (Btu/lb)[A]	13.0	14.8	14.8	13.0	17.5	17.5	13.0	---	---				---	---	117.9
AspenPlus Enthalpy (Btu/lb)[B]	-41.9	-40.2	-40.2	-41.9	-37.4	-37.4	-41.9	-908.9	41.8	-5,726.8	-1,031.6	-8.8	-1,031.6	-1,131.5	-1,030.7
Density (lb/ft^3)	0.076	0.078	0.078	0.076	0.081	0.081	0.076	---	---	---	0.053	---	0.053	0.096	0.052

[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

Exhibit A-15. Stream table (cont'd)

	16	17	18	19	20	21	22	23	24	25	26
V-L Mole Fraction											
Ar	0.0088	0.0000	0.0000	0.0092	0.0000	0.0082	0.0000	0.0000	0.0000	0.0000	0.0000
CO_2	0.1376	0.0000	0.0000	0.0003	0.0001	0.1288	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	0.0000	0.0000
H_2O	0.0831	1.0000	1.0000	0.0099	0.9999	0.1451	1.0000	1.0000	1.0000	1.0000	1.0000
N_2	0.7345	0.0000	0.0000	0.7732	0.0000	0.6854	0.0000	0.0000	0.0000	0.0000	0.0000
O_2	0.0340	0.0000	0.0000	0.2074	0.0000	0.0325	0.0000	0.0000	0.0000	0.0000	0.0000
SO_2	0.0020	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	1.0000	1.0000	1.0000	1.0000
V-L Flow Rate (kg_{mole}/hr)	69,251	2,296	9,200	732	169	75,042	88,630	74,095	74,095	66,938	67,115
V-L Flow Rate (kg/hr)	2,056,525	41,356	165,741	21,135	3,052	2,165,147	1,596,691	1,334,844	1,334,844	1,205,909	1,209,103
Solids Flow Rate (kg/hr)	0	17,707	0	0	27,462	0	0	0	0	0	0
Temperature (°C)	153	15	27	167	56	56	593	342	593	41	41
Pressure (MPa, abs)	0.11	0.10	0.11	0.31	0.10	0.10	24.23	4.90	4.80	0.01	1.80
Steam Table Enthalpy (kJ/kg) [A]	285.58	---	111.65	184.48	---	286.08	3,477.96	3,049.83	3,652.36	1,997.61	172.18
AspenPlus Enthalpy (kJ/kg) [B]	-2,386.23	-14,995.75	-15,964.53	56.68	-12,481.92	-2,940.30	-12,502.33	-12,930.47	-12,327.94	-13,982.68	-15,808.12
Density (kg/m^3)	0.9	1,003.6	992.3	2.4	833.1	1.1	69.2	19.2	12.3	0.1	992.7
V-L Molecular Weight	29.697	18.015	18.015	28.857	18.018	28.852	18.015	18.015	18.015	18.015	18.015
V-L Flow Rate (lb_{mole}/hr)	152,671	5,061	20,283	1,615	373	165,440	195,395	163,352	163,352	147,573	147,964
V-L Flow Rate (lb/hr)	4,533,861	91,174	365,396	46,594	6,729	4,773,332	3,520,102	2,942,827	2,942,827	2,658,575	2,665,615
Solids Flow Rate (lb/hr)	0	39,037	0	0	60,544	0	0	0	0	0	0
Temperature (°F)	308	59	80	332	133	133	1,100	648	1,100	105	105
Pressure (psia)	15.2	15.0	15.7	45.0	14.7	14.7	3,514.7	710.8	696.6	1.1	261.6
Steam Table Enthalpy (Btu/lb) [A]	122.8	---	48.0	79.3	---	123.0	1,495.3	1,311.2	1,570.2	858.8	74.0
AspenPlus Enthalpy (Btu/lb) [B]	-1,025.9	-6,447.0	-6,863.5	24.4	-5,366.3	-1,264.1	-5,375.0	-5,559.1	-5,300.1	-6,011.5	-6,796.3
Density (lb/ft^3)	0.055	62.650	61.950	0.153	52.011	0.067	4.319	1.197	0.768	0.004	61.970

[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

A.2.1 Performance Results

Exhibit A-16. Plant performance summary

Performance Summary	
Total Gross Power, MWe	**577**
BOP, kWe	36,600
Total Auxiliaries, MWe	**37**
Net Power, MWe	**540**
HHV Net Plant Efficiency, %	40.0%
HHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	9,006 (8,536)
LHV Net Plant Efficiency, %	41.4%
LHV Net Plant Heat Rate, kJ/kWh (Btu/kWh)	8,687 (8,233)
HHV Boiler Efficiency, %	89.1%
LHV Boiler Efficiency, %	92.4%
Steam Turbine Cycle Efficiency, %	47.9%
Steam Turbine Heat Rate, kJ/kWh (Btu/kWh)	7,514 (7,122)
Condenser Duty, GJ/hr (MMBtu/hr)	2,204 (2,089)
As-Received Coal Feed, kg/hr (lb/hr)	179,193 (395,053)
Limestone Sorbent Feed, kg/hr (lb/hr)	17,707 (39,037)
HHV Thermal Input, kWt	1,350,673
LHV Thermal Input, kWt	1,302,741
Raw Water Withdrawal, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.007 (1.7)
Raw Water Consumption, $(m^3/min)/MW_{net}$ (gpm/MW_{net})	0.006 (1.7)
Excess Air, %	20.9%

Exhibit A-17. Plant power summary

Power Summary	
Steam Turbine Power, MWe	577
Total Gross Power, MWe	**577**
Auxiliary Load Summary	
Coal Handling and Conveying, kWe	430
Pulverizers, kWe	2,690
Sorbent Handling & Reagent Preparation, kWe	850
Ash Handling, kWe	620
Primary Air Fans, kWe	1,330
Forced Draft Fans, kWe	1,700
Induced Draft Fans, kWe	6,660
SCR, kWe	40
Activated Carbon Injection, kWe	22
Dry Sorbent Injection, kWe	86
Baghouse, kWe	90
Wet FGD, kWe	2,830
Miscellaneous BOP,[A,B] kWe	2,000
Steam Turbine Auxiliaries, kWe	400
Condensate Pumps, kWe	800
Miscellaneous CW Circulating Water Pumps, kWe	210
Ground Water Pumps, kWe	84
Cooling Tower Fans and Circulating Pumps, kWe	13,928
Transformer Losses, kWe	1,830
Total Auxiliaries, MWe	**37**
Net Power, MWe	**540**

[A]Boiler feed pumps are turbine driven
[B]Includes plant control systems, lighting, HVAC, and miscellaneous low-voltage loads

Exhibit A-18. Air emissions

	kg/GJ (lb/MMBtu)	Tonne/year (ton/year)[A]	kg/MWh (lb/MWh)[B]
SO_2	0.036 (0.085)	1,317 (1,452)	0.307 (0.677)
NOx	0.038 (0.088)	1,363 (1,502)	0.318 (0.700)
Particulate	0.005 (0.011)	175 (193)	0.041 (0.090)
Hg	1.61E-7 (3.75E-7)	0.006 (0.006)	1.36E-6 (3.00E-6)
CO_2	87 (204)	3,167,916 (3,492,030)	738 (1,627)
CO_2[C]	-	-	788 (1,737)
	mg/Nm^3		
Particulate Concentration[D,E]	15.17		

[A]Calculations based on an 85 percent capacity factor
[B]Emissions based on gross power except where otherwise noted
[C]CO_2 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

Exhibit A-19. Carbon balance

Carbon In		Carbon Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	114,226 (251,825)	Stack Gas	116,113 (255,985)
Air (CO_2)	261 (576)	FGD Product	171 (378)
PAC	104 (230)	Baghouse	104 (230)
FGD Reagent	1,797 (3,961)		
Total	**116,389 (256,593)**	**Total**	**116,389 (256,593)**

Exhibit A-20. Sulfur balance

Sulfur In		Sulfur Out	
	kg/hr (lb/hr)		kg/hr (lb/hr)
Coal	4,491 (9,902)	Desulfurizer Product	4,340 (9,567)
		Stack Gas	89 (195)
		Baghouse	63 (139)
Total	**4,491 (9,902)**	**Total**	**4,491 (9,902)**

Exhibit A-21. 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)
FGD Makeup	3.46 (913)	–	3.46 (913)	–	3.46 (913)
Deaerator Vent	–	–	–	0.05 (14)	-0.05 (-14)
Condenser Makeup	**0.05 (14)**	**–**	**0.05 (14)**	**–**	**0.05 (14)**
BFW Makeup	0.05 (14)	–	0.05 (14)	–	0.05 (14)
FGD Dewatering	–	–	–	1.78 (471)	-1.78 (-471)
Total	**3.51 (927)**	**–**	**3.51 (927)**	**0.05 (14)**	**3.46 (913)**

Exhibit A-22. Energy balance

	HHV	Sensible + Latent	Power	Total
Heat In GJ/hr (MMBtu/hr)				
Coal	4,862 (4,609)	4.1 (3.9)	–	4,866 (4,613)
Air	–	57.3 (54.3)	–	57.3 (54.3)
Raw Water Makeup	–	13.2 (12.5)	–	13.2 (12.5)
Limestone	–	0.38 (0.36)	–	0.38 (0.36)
Auxiliary Power	–	–	132 (125)	132 (125)
TOTAL	**4,862 (4,609)**	**74.9 (71.0)**	**132 (125)**	**5,069 (4,805)**
Heat Out GJ/hr (MMBtu/hr)				
Bottom Ash	–	0.4 (0.3)	–	0.4 (0.3)
Fly Ash + FGD Ash	–	2.0 (1.9)	–	2.0 (1.9)
Stack Gas	–	619 (587)	–	619 (587)
Sulfur	–	–	–	–
Motor Losses and Design Allowances	–	–	33 (32)	33 (32)
Condenser	–	2,204 (2,089)	–	2,204 (2,089)
Non-Condenser Cooling Tower Loads	–	106 (100)	–	106 (100)
Cooling Tower Blowdown	–	0.0 (0.0)	–	0.0 (0.0)
CO_2 Capture Losses	–	–	–	–
Ambient Losses[A]	–	146.4 (138.8)	–	146.4 (138.8)
Power	–	–	2,075 (1,967)	2,075 (1,967)
TOTAL	**–**	**3,077 (2,917)**	**2,109 (1,999)**	**5,186 (4,916)**
Unaccounted Energy[B]	–	-117 (-111)	–	-117 (-111)

[A]Includes condenser, AGR, and miscellaneous cooling loads
[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

A.2.2 Cost Results

Exhibit A-23. Total plant cost details

Case:			– Supercritical PC w/o CO_2				Estimate Type:			Conceptual	
Plant Size (MW, net):		540					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	$/kW
1	Coal & Sorbent Handling										
1.1	Coal Receive & Unload	$4,181	$0	$1,884	$0	$6,065	$606	$0	$1,001	$7,672	$14
1.2	Coal Stackout & Reclaim	$5,404	$0	$1,207	$0	$6,611	$661	$0	$1,091	$8,363	$15
1.3	Coal Conveyors	$5,024	$0	$1,195	$0	$6,219	$622	$0	$1,026	$7,867	$15
1.4	Other Coal Handling	$1,314	$0	$276	$0	$1,591	$159	$0	$262	$2,012	$4
1.5	Sorbent Receive & Unload	$167	$0	$50	$0	$216	$22	$0	$36	$274	$1
1.6	Sorbent Stackout & Reclaim	$2,692	$0	$486	$0	$3,178	$318	$0	$524	$4,020	$7
1.7	Sorbent Conveyors	$960	$209	$232	$0	$1,401	$140	$0	$231	$1,773	$3
1.8	Other Sorbent Handling	$580	$137	$300	$0	$1,017	$102	$0	$168	$1,286	$2
1.9	Coal & Sorbent Hnd. Foundations	$0	$4,846	$6,389	$0	$11,235	$1,124	$0	$1,854	$14,213	$26
	Subtotal	**$20,322**	**$5,191**	**$12,020**	**$0**	**$37,533**	**$3,753**	**$0**	**$6,193**	**$47,480**	**$88**
2	Coal & Sorbent Preparation & Feed										
2.1	Coal Crushing & Drying	$2,391	$0	$460	$0	$2,851	$285	$0	$470	$3,606	$7
2.2	Coal Conveyor to Storage	$6,123	$0	$1,318	$0	$7,441	$744	$0	$1,228	$9,413	$17
2.5	Sorbent Prep Equipment	$4,570	$198	$936	$0	$5,704	$570	$0	$941	$7,215	$13
2.6	Sorbent Storage & Feed	$551	$0	$208	$0	$759	$76	$0	$125	$960	$2
2.9	Coal & Sorbent Feed Foundation	$0	$558	$489	$0	$1,047	$105	$0	$173	$1,324	$2
	Subtotal	**$13,635**	**$756**	**$3,411**	**$0**	**$17,801**	**$1,780**	**$0**	**$2,937**	**$22,519**	**$42**
3	Feedwater & Miscellaneous BOP Systems										
3.1	Feedwater System	$22,704	$0	$7,320	$0	$30,024	$3,002	$0	$4,954	$37,981	$70
3.2	Water Makeup & Pretreating	$1,628	$0	$515	$0	$2,143	$214	$0	$471	$2,829	$5
3.3	Other Feedwater Subsystems	$7,142	$0	$2,932	$0	$10,074	$1,007	$0	$1,662	$12,744	$24
3.4	Service Water Systems	$326	$0	$171	$0	$497	$50	$0	$109	$656	$1
3.5	Other Boiler Plant Systems	$8,664	$0	$8,191	$0	$16,855	$1,686	$0	$2,781	$21,322	$39
3.6	FO Supply Sys & Nat Gas	$342	$0	$399	$0	$741	$74	$0	$122	$937	$2
3.7	Waste Treatment Equipment	$167	$0	$97	$0	$264	$26	$0	$58	$348	$1
3.8	Misc. Equip. (Cranes, Air Comp., Comm.)	$3,348	$0	$1,035	$0	$4,383	$438	$0	$964	$5,786	$11
	Subtotal	**$44,320**	**$0**	**$20,660**	**$0**	**$64,981**	**$6,498**	**$0**	**$11,123**	**$82,602**	**$153**
4	Pulverized Coal Boiler & Accessories										
4.1	PC Boiler & Accessories	$188,154	$0	$107,209	$0	$295,363	$29,536	$0	$32,490	$357,390	$662
4.2	SCR	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.5	Primary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.6	Secondary Air System	w/4.1	$0	w/4.1	$0	$0	$0	$0	$0	$0	$0

Case:			– Supercritical PC w/o CO_2					Estimate Type:		Conceptual	
Plant Size (MW, net):		540						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	$/kW
4.8	Major Component Rigging	$0	w/4.1	w/4.1	$0	$0	$0	$0	$0	$0	$0
4.9	Boiler Foundations	$0	w/14.1	w/14.1	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$188,154**	**$0**	**$107,209**	**$0**	**$295,363**	**$29,536**	**$0**	**$32,490**	**$357,390**	**$662**
5A	**Gas Cleanup and Piping**										
5A.1	Absorber Vessels & Accessories	$70,430	$0	$15,058	$0	$85,488	$8,549	$0	$9,404	$103,441	$192
5A.2	Other FGD	$3,675	$0	$4,136	$0	$7,812	$781	$0	$859	$9,452	$18
5A.3	Bag House & Accessories	$19,911	$0	$12,550	$0	$32,461	$3,246	$0	$3,571	$39,278	$73
5A.4	Other Particulate Removal Materials	$1,347	$0	$1,432	$0	$2,780	$278	$0	$306	$3,363	$6
5A.5	Gypsum Dewatering System	$5,646	$0	$952	$0	$6,599	$660	$0	$726	$7,984	$15
5A.6	Mercury Removal System	$4,280	$942	$4,209	$0	$9,430	$943	$0	$1,037	$11,411	$21
	Subtotal	**$105,291**	**$942**	**$38,338**	**$0**	**$144,570**	**$14,457**	**$0**	**$15,903**	**$174,930**	**$324**
7	**Ductwork & Stack**										
7.3	Ductwork	$11,152	$0	$7,040	$0	$18,192	$1,819	$0	$3,002	$23,013	$43
7.4	Stack	$11,090	$0	$6,445	$0	$17,535	$1,754	$0	$1,929	$21,217	$39
7.9	Duct & Stack Foundations	$0	$1,209	$1,435	$0	$2,644	$264	$0	$582	$3,491	$6
	Subtotal	**$22,242**	**$1,209**	**$14,920**	**$0**	**$38,371**	**$3,837**	**$0**	**$5,512**	**$47,721**	**$88**
8	**Steam Turbine & Accessories**										
8.1	Steam TG & Accessories	$78,448	$0	$8,555	$0	$87,002	$8,700	$0	$9,570	$105,273	$195
8.2	Turbine Plant Auxiliaries	$436	$0	$927	$0	$1,362	$136	$0	$150	$1,648	$3
8.3b	ACC	w/BEC	$0	$0	$0	$65,045	$6,504	$0	$10,732	$82,282	$152
8.4	Steam Piping	$26,525	$0	$10,751	$0	$37,276	$3,728	$0	$6,151	$47,154	$87
8.9	TG Foundations	$0	$1,299	$2,144	$0	$3,443	$344	$0	$758	$4,545	$8
	Subtotal	**$105,409**	**$1,299**	**$22,376**	**$0**	**$194,129**	**$19,413**	**$0**	**$27,361**	**$240,903**	**$446**
9	**Cooling Water System**										
9.1	Cooling Towers	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9.2	Circulating Water Pumps	$121	$0	$3	$0	$123	$12	$0	$14	$149	$0
9.3	Circ. Water System Auxiliaries	w/9.6	w/9.6	w/9.6	$0	$0	$0	$0	$0	$0	$0
9.4	Circ. Water Piping	$0	$422	$543	$0	$965	$96	$0	$159	$1,220	$2
9.5	Make-up Water System	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
9.6	Component Cooling Water Sys.	$3,692	$157	$872	$0	$4,721	$472	$0	$779	$5,973	$11
9.9	Circ. Water Foundations & Structures	w/9.6	w/9.6	w/9.6	$0	$0	$0	$0	$0	$0	$0
	Subtotal	**$3,813**	**$579**	**$1,417**	**$0**	**$5,810**	**$581**	**$0**	**$952**	**$7,342**	**$14**
10	**Ash & Spent Sorbent Handling Systems**										
10.6	Ash Storage Silos	$813	$0	$2,488	$0	$3,301	$330	$0	$363	$3,994	$7
10.7	Ash Transport & Feed Equipment	$5,401	$0	$5,354	$0	$10,755	$1,075	$0	$1,183	$13,013	$24
10.9	Ash/Spent Sorbent Foundation	$0	$184	$226	$0	$410	$41	$0	$90	$541	$1
	Subtotal	**$6,214**	**$184**	**$8,068**	**$0**	**$14,465**	**$1,446**	**$0**	**$1,636**	**$17,548**	**$33**
11	**Accessory Electric Plant**										
11.1	Generator Equipment	$2,025	$0	$324	$0	$2,348	$235	$0	$194	$2,777	$5

Case:			– Supercritical PC w/o CO_2					Estimate Type:		Conceptual	
Plant Size (MW, net):		540						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	$/kW
11.2	Station Service Equipment	$3,757	$0	$1,260	$0	$5,017	$502	$0	$414	$5,932	$11
11.3	Switchgear & Motor Control	$5,007	$0	$824	$0	$5,831	$583	$0	$641	$7,056	$13
11.4	Conduit & Cable Tray	$0	$2,956	$9,630	$0	$12,585	$1,259	$0	$2,077	$15,920	$29
11.5	Wire & Cable	$0	$5,630	$10,140	$0	$15,770	$1,577	$0	$2,602	$19,949	$37
11.6	Protective Equipment	$321	$0	$1,112	$0	$1,433	$143	$0	$158	$1,734	$3
11.7	Standby Equipment	$1,562	$0	$36	$0	$1,598	$160	$0	$176	$1,934	$4
11.8	Main Power Transformers	$10,270	$0	$214	$0	$10,485	$1,048	$0	$1,153	$12,687	$23
11.9	Electrical Foundations	$0	$374	$951	$0	$1,325	$132	$0	$291	$1,748	$3
	Subtotal	**$22,942**	**$8,959**	**$24,491**	**$0**	**$56,393**	**$5,639**	**$0**	**$7,706**	**$69,738**	**$129**
12	**Instrumentation & Control**										
12.1	PC Control Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.3	Steam Turbine Control	w/8.1	$0	w/8.1	$0	$0	$0	$0	$0	$0	$0
12.5	Signal Processing Equipment	w/12.7	$0	w/12.7	$0	$0	$0	$0	$0	$0	$0
12.6	Control Boards, Panels & Racks	$570	$0	$349	$0	$919	$92	$0	$152	$1,162	$2
12.7	Distributed Control Sys. Equipment	$5,758	$0	$1,027	$0	$6,784	$678	$0	$746	$8,209	$15
12.8	Instrument Wiring & Tubing	$3,472	$0	$6,317	$0	$9,789	$979	$0	$1,615	$12,383	$23
12.9	Other I & C Equipment	$1,582	$0	$3,760	$0	$5,342	$534	$0	$588	$6,464	$12
	Subtotal	**$11,381**	**$0**	**$11,453**	**$0**	**$22,834**	**$2,283**	**$0**	**$3,101**	**$28,219**	**$52**
13	**Improvements to Site**										
13.1	Site Preparation	$0	$60	$1,264	$0	$1,324	$132	$0	$291	$1,747	$3
13.2	Site Improvements	$0	$1,855	$2,451	$0	$4,307	$431	$0	$947	$5,685	$11
13.3	Site Facilities	$3,536	$0	$3,709	$0	$7,245	$724	$0	$1,594	$9,563	$18
	Subtotal	**$3,536**	**$1,915**	**$7,425**	**$0**	**$12,875**	**$1,287**	**$0**	**$2,832**	**$16,995**	**$31**
14	**Buildings & Structures**										
14.1	Boiler Building	$0	$10,427	$9,163	$0	$19,590	$1,959	$0	$3,232	$24,781	$46
14.2	Turbine Building	$0	$14,918	$13,894	$0	$28,812	$2,881	$0	$4,754	$36,447	$68
14.3	Administration Building	$0	$739	$781	$0	$1,520	$152	$0	$251	$1,923	$4
14.4	Circulation Water Pumphouse	$0	$210	$167	$0	$378	$38	$0	$62	$478	$1
14.5	Water Treatment Buildings	$0	$225	$205	$0	$430	$43	$0	$71	$544	$1
14.6	Machine Shop	$0	$494	$332	$0	$826	$83	$0	$136	$1,045	$2
14.7	Warehouse	$0	$335	$336	$0	$671	$67	$0	$111	$848	$2
14.8	Other Buildings & Structures	$0	$274	$233	$0	$506	$51	$0	$84	$641	$1
14.9	Waste Treating Building & Str.	$0	$462	$1,402	$0	$1,864	$186	$0	$308	$2,358	$4
	Subtotal	**$0**	**$28,084**	**$26,512**	**$0**	**$54,596**	**$5,460**	**$0**	**$9,008**	**$69,064**	**$128**
	Total	**$547,259**	**$49,117**	**$298,301**	**$0**	**$959,722**	**$95,972**	**$0**	**$126,754**	**$1,182,448**	**$2,190**

Exhibit A-24. Owner's costs

Description	$/1,000	$/kW
Pre-Production Costs		
6 Months All Labor	$8,566	$15.87
1 Month Maintenance Materials	$1,113	$2
1 Month Non-Fuel Consumables	$1,743	$3
1 Month Waste Disposal	$650	$1
25% of 1 Months Fuel Cost at 100% CF	$1,873	$3
2% of Total Plant Cost	$23,649	$44
Total	**$37,594**	**$70**
Inventory Capital		
60-day supply of fuel and consumables at 100% CF	$18,392	$34
0.5% of Total Plant Cost (spare parts)	$5,912	$11
Total	**$24,305**	**$45**
Other Costs		
Initial Cost for Catalyst and Chemicals	$0	$0
Land	$900	$2
Other Owner's Costs	$177,367	$329
Financing Costs	$31,926	$59
Total Overnight Costs (TOC)	**$1,454,540**	**$2,694**
TASC Multiplier (IOU, 35 year)	1.154	
Total As-Spent Cost (TASC)	**$1,679,138**	**$3,110**

Exhibit A-25. Initial and annual operating and maintenance costs

Case:	-Supercritical PC, No Capture				Cost Base:	Dec 2018
Plant Size (MW, net):	540	Heat Rate-net (Btu/kWh):		8,536	Capacity Factor (%):	85
Operating & Maintenance Labor						
Operating Labor				**Operating Labor Requirements per Shift**		
Operating Labor Rate (base):		38.50	**$/hour**	Skilled Operator:	2.0	
Operating Labor Burden:		30.00	**% of base**	Operator:	9.0	
Labor O-H Charge Rate:		25.00	**% of labor**	Foreman:	1.0	
				Lab Techs, etc.:	2.0	
				Total:	**14.0**	
Fixed Operating Costs						
					Annual Cost	
					($)	**($/kW-net)**
Annual Operating Labor:					$6,138,132	$11.369
Maintenance Labor:					$7,567,667	$14.017
Administrative & Support Labor:					$3,426,450	$6.346
Property Taxes and Insurance:					$23,648,960	$43.802
Total:					**$40,781,209**	**$75.535**
Variable Operating Costs						
					($)	**($/MWh-net)**
Maintenance Material:					$11,351,501	$2.82369
Consumables						
	Initial Fill	**Per Day**	**Per Unit**	**Initial Fill**		
Water (gal/1000):	0	668	$1.90	$0	$393,540	$0.09789
Makeup and Wastewater Treatment Chemicals (ton):	0	3,232	$0.28	$0	$275,722	$0.06859
Brominated Activated Carbon (ton):	0	468	$22.00	$0	$3,197,364	$0.79535
Enhanced Hydrated Lime (ton):	0	96	$200.00	$0	$5,927,990	$1.47459
Limestone (ton):	0	3	$1,312.54	$0	$1,123,506	$0.27947
Ammonia (19 wt%, ton):	0	68	$300.00	$0	$6,341,838	$1.57753
SCR Catalyst (ft^3):	0	0.31	$5,297.21	$0	$516,285	$0.12843
Subtotal:				**$0**	**$17,776,244**	**$4.42185**
Waste Disposal						
Fly Ash (ton)	0	470	$38.00	$0	$5,538,121	$1.37761
Bottom Ash (ton)	0	92	$38.00	$0	$1,089,402	$0.27099
Subtotal:				**$0**	**$6,627,523**	**$1.64860**
By-Products						
Gypsum (ton)	0	727	$0.00	$0	$0	$0.00000
Subtotal:				$0	$0	$0.00000
Variable Operating Costs Total:				**$0**	**$35,755,268**	**$8.89413**
Fuel Cost						
Illinois Number 6 (ton):	0	4,741	$51.96	$0	$76,418,953	$19.00924
Total:				**$0**	**$76,418,953**	**$19.00924**

Exhibit A-26. Cost of electricity breakdown

Component	Value, $/MWh	Percentage
Capital	29.5	44%
Fixed	10.1	15%
Variable	8.9	13%
Fuel	19.0	28%
Total (Excluding T&S)	**67.6**	**N/A**
CO_2 T&S	29.5	0%
Total (Including T&S)	**10.1**	**N/A**

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