SOUTHERN INDIANA GAS AND ELECTRIC COMPANY
d/b/a CENTERPOINT ENERGY INDIANA SOUTH
(CEI SOUTH)

IURC CAUSE NO. 45564

DIRECT TESTIMONY
OF
JASON A. ZOLLER
CHIEF ENGINEER, BLACK & VEATCH

ON

BLACK & VEATCH'S ENGINEERING WORK IN SUPPORT OF PETITIONER'S REQUEST

SPONSORING PETITIONER'S EXHIBIT NO. 7

ATTACHMENTS JAZ-1 THROUGH JAZ-4

DIRECT TESTIMONY OF JASON A. ZOLLER

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jason A. Zoller. My business address is Black & Veatch Corporation ("Black & Veatch"), 11401 Lamar Ave., Overland Park, Kansas, 66211.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting testimony on behalf of Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("Petitioner", "CenterPoint Indiana South", "CEIS" or "Company"), which is an indirect subsidiary of CenterPoint Energy, Inc.

Q. What is your role with respect to Petitioner?

A. I am the Chief Engineer for Black & Veatch Power (Conventional Generation, Renewables, Distributed Energy and Transmission & Distribution), and Oil & Gas. Black & Veatch was the Owner's Engineer in supporting the work activities associated with evaluating the Flue Gas Desulfurization ("FGD") system upgrades, Gas Conversion, and Simple Cycle Plant. Separate studies were developed for each of these work activities and are referenced in my testimony below as sponsoring attachments or workpapers.

Q. Please describe your educational background.

A. I received a Bachelor of Science Degree in Mechanical Engineering from North Dakota State University in 1989. I am currently licensed as a Professional Engineer in the state of Missouri.

Q. Please describe your professional experience.

I have over 31 years of power and/or oil & gas industry experience (27 years as a licensed Professional Engineer).

My expertise includes a broad spectrum of technical areas including the following specialty areas of power plant engineering:

- Air Quality Control

- Coal
- Simple Cycle
- Combined Cycle
- Combustion Turbine
- Steam Turbine
- Thermal Cycle Design
- Consulting Engineering
- Oil & Gas

Q. What are your present duties and responsibilities as Chief Engineer?

A. My responsibilities as Black & Veatch Chief Engineer include managing all engineering discipline processes, standards, and guides, incorporating continuous improvement and lessons learned, and resolution of project engineering issues for Black & Veatch Power and Oil & Gas Businesses. I have global authority over all technical aspects of projects that Black & Veatch executes. This includes all projects from the feasibility and conceptual design phase through detailed design execution, construction support, startup and testing.

Q. Have you previously testified before the Indiana Utility Regulatory Commission (the "Commission")?

A. No.

Q. Are you sponsoring any attachments to your direct testimony in this proceeding?

A. Yes. I sponsor the following attachments:

- <u>Petitioner's Exhibit No. 7</u>, **Attachment JAZ-1:** A.B. Brown Scrubber Assessment and Estimate
- <u>Petitioner's Exhibit No. 7</u>, **Attachment JAZ-2 (CONFIDENTIAL)**: EPC Basis of Estimate for the F-Class Configuration
- <u>Petitioner's Exhibit No. 7</u>, **Attachment JAZ-3 (CONFIDENTIAL):** Petitioner's Natural Gas Conversion Independent Assessment Report
- <u>Petitioner's Exhibit No. 7</u>, **Attachment JAZ-4 (CONFIDENTIAL):** Petitioner's OEM F Class 2x0 Simple Cycle Preliminary Bid Evaluation Combustion Turbine-Generators Report

Q. Did you provide oversight for the engineering attachments and workpapers?

A. Yes, as the Chief Engineer for Black & Veatch I provide oversight of the organization and manage the process to develop all engineering deliverables. The engineering work is regulated in accordance with the technical processes and procedures that I supervise.

II. PURPOSE & SCOPE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide information regarding the engineering work completed by Black & Veatch in support of the CenterPoint Indiana South application for a Certificate of Public Convenience and Necessity ("CPCN"). Black & Veatch performed an independent review of the FGD project proposal, Gas Conversion of coal firing units, and obtained market cost to install two Combustion Turbines ("CTs") for a new simple cycle power plant ("SCPP") on the A.B. Brown site. The testimony will include a discussion of cost with technical supporting documents. I will discuss each separately because we handled these activities as separate projects.

III. OVERVIEW

Q. What work has Black & Veatch performed to support this CPCN application?

A. As discussed above, Black & Veatch performed an independent review of the FGD conceptual project offering, Gas Conversion of coal firing units, and obtained market cost to install two CTs.

Q. Why is Black & Veatch qualified to perform this work?

A. Black & Veatch is an engineering and construction company with experience in power plant design for coal power plants, natural gas fired plants, simple cycle plants, and combined cycle plants. Through the large number of studies performed and projects built, Black & Veatch has developed a large in-house database of costs for the various types of boilers, conversion alternatives, equipment, and construction activities, which gives us the ability to perform the studies with technical competency. Besides providing engineering, consulting, and Owner's Engineer services, Black & Veatch is a global Engineering, Procurement, Construction ("EPC") Contractor designing and building power stations. We can draw on our extensive EPC experience to help execute these engineering services by understanding what will be needed to take this project through design, procurement, construction, and commissioning.

IV. FGD DISCUSSION

Q. Please describe the FGD work Black & Veatch performed for the Petitioner.

A. Units 1 and 2 at Petitioner's A. B. Brown Generating Station are each nominally 265 megawatt (MW) gross, coal-fired electric generating units ("EGUs"). The units were built in the late 1970s to the mid-1980s. Each of the existing units is outfitted with an originally supplied, dual alkali ("DA") wet FGD system for the control of acid gases such as sulfur dioxide (SO_2).

Black & Veatch provided an order of magnitude conceptual design cost estimate, technology support, and review and consolidation of third-party conceptual design as well as cost estimates for the inputs into financial modeling of the current and available air quality control ("AQC") scrubber technologies that could be employed at Petitioner's A.B. Brown Generating Station for continued operation of both Unit 1 and Unit 2. Black & Veatch, in addition to other architectural engineering consultants hired by CenterPoint Indiana South, performed technology reviews and assessments to develop construction and ongoing operations and maintenance ("O&M") costs of these various technologies.

Black & Veatch served as the lead engineer in the FGD evaluation effort. Black & Veatch, AECOM, and Burns & McDonnell all provided technical data and cost information for individual FGD upgrade options, as requested by CenterPoint Indiana South. Those reports which served to support the technology data and costs are attached to this testimony as Petitioner's Exhibit No. 7, Attachment JAZ-1.

Q. What was the purpose of your evaluation for the FGD system?

A. The purpose in evaluating the FGD system was to indicate the applicability, reliability, and estimated costs of the AQC technology options that could be utilized at A.B. Brown Generating Station to support continued operation of Unit 1 and Unit 2 which use high-sulfur coal. The assessment considered interfaces to the existing equipment and ductwork at the A.B. Brown Units and included evaluation of the reuse and/or removal of the existing auxiliary support equipment (mechanical tanks, pumps, fans, electrical switchgear, etc.).

The evaluation was performed to assist CenterPoint Indiana South in determining a preliminary selection of the preferred FGD equipment for evaluation in the Petitioner's 2019/2020 IRP. Black & Veatch has assumed that the installation of a new FGD system will be subject to Federal and Indiana Department of Environmental Management ("IDEM") air regulations as a modification to an existing major source, and, therefore, an air construction permit will have to be obtained to authorize construction. However, because of the nature of the project (where the existing air emissions limits are the baseline), it is assumed that the emissions increase as a result of this project, if any, would be less than the Prevention of Significant Deterioration ("PSD") significance thresholds. Thus, according to these assumptions, the project would be considered a minor modification and would, therefore, not be subject to PSD Best Available Control Technology ("BACT") requirements. Black & Veatch notes that confirmation of air permitting applicability of a given technology cannot be accomplished until a New Source Review ("NSR") applicability analysis is conducted. Should PSD BACT ultimately be applicable, the results of a BACT analysis could alter the required technology because emissions targets lower than the current emissions limits may be required. An operating change, such as an expected increase in the unit capacity factor, could result in making BACT applicable.

Q. Please summarize your findings.

A. The technologies evaluated, responsible lead engineering company that performed the work, and outcomes are indicated in Table JAZ-1 below.

TABLE JAZ-1: SCRUBBER TECHNOLOGIES				
Technology	**Lead**	**Expected Outcome**	**Water Treatment Impacts**	**Other Impacts**
Wet Limestone Forced Oxidation Scrubber	Burns & McDonnell	Feasible	Yes	Lime Injection FGD Gypsum Market
Limestone Forced Oxidation (Conversion from DA Scrubber)	AECOM	Not Feasible	Yes	Lime Injection
Limestone Inhibited Oxidation (Conversion from DA Scrubber)	AECOM	Not Feasible	Yes	Lime Injection
Inhibited Wet Lime Scrubber	Black & Veatch	Feasible	Yes	Lime Injection Powdered Activated Carbon (PAC) Injection
Spray Dryer Absorber	Black & Veatch	Not Feasible	No	Not Applicable
Circulating Dry Scrubber	Black & Veatch	Feasible	No	PAC Injection
Flash Dryer Absorber	Black & Veatch	Not Feasible	No	Lime Injection
Ammonia Scrubber	Black & Veatch	Feasible	Yes	Lime Injection PAC Injection Fertilizer Market

Q. After the results were established what were your next steps and how was cost considered?

A. The technologies were reviewed to determine those that merited further analysis on the basis of their ability to meet emissions criteria for the full range of boiler design fuel. The feasible technologies were then evaluated to assess the cost to purchase and operate the control technology. Table JAZ-2 presents the capital cost estimates and Table JAZ-3 presents the operations and maintenance cost estimates.

The capital cost presented for the Wet Limestone Forced Oxidation ("LSFO") technology includes cost for wastewater treatment but does not include costs for water treatment or landfill. The LSFO technology produces two streams; a bleed stream requiring wastewater treatment prior to discharge and a wall-board quality gypsum product which does not require landfill. The LSFO technology does not require water treatment for process water needs.

The capital cost presented for Wet Lime Inhibited Oxidation ("WLIO") is for the FGD systems only and does not include the need for or costs for water/wastewater treatment ("WWT") The WWT costs for WILO system are negligible. Minor water and wastewater costs have been included in the balance of plant cost for upgrades. Any wastewater created would be mixed with the byproduct or fly ash and disposed of in a landfill.

The capital costs presented for the Circulating Dry Scrubber ("CDS") do not include the need, or costs, for WWT or landfill as this is a semi-dry system with no wastewater handling requirements. The Ammonia (NH_3) system includes costs for wastewater treatment of water used for the wet electrostatic precipitator ("ESP").

TABLE JAZ-2: CAPITAL COST ESTIMATES

(2019 Dollars x 1000)	Wet Lime Inhibited	Ammonia Scrubber (NH_3)	Circulating Dry Scrubber	Limestone Forced Oxidation Scrubber
Installation Cost (2020 - 2024)	$318,079	$284,835	$269,550	$424,878
Capitalized Cost (2024 - 2039)	$34,313	$30,727	$29,078	$45,834

The O&M costs, which start in 2024 assuming the FGD system installation will be completed in 2023, are in 2019 dollars; and no escalation has been applied. O&M costs for labor are not included in the estimates below. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table JAZ-3 represents the O&M costs for the FGD systems only and does not include the balance-of-plant O&M costs.

TABLE JAZ-3: O&M – 20 YEAR TOTALS 2020 TO 2039				
(2019 Dollars x 1000)	Wet Lime Inhibited Oxidation Scrubber	Ammonia Scrubber (NH_3)	Circulating Dry Scrubber	Limestone Forced Oxidation Scrubber
O&M Schedule Outage	$21,510	$19,262	$18,228	$28,732
O&M – Base Non-Labor	$11,148	$9,983	$9,448	$14,892
Total	$32,659	$29,245	$29,078	$43,624

Those reports which served to support the technology data and costs are attached to this testimony as Petitioner's Exhibit No. 7, Attachment JAZ-1.

V. GAS CONVERSION DISCUSSION

Q. Please describe the Gas Conversion work Black & Veatch performed for the Petitioner.

A. Black & Veatch performed a study for CenterPoint Indiana South to assess the cost and performance impacts associated with the conversion of coal-fired power generating units to natural gas at A.B. Brown Unit 1 and Unit 2. The study summarized and compiled numerous cost and equipment modification estimates from Burns & McDonnell, Babcock & Wilcox, Bowen Engineering, and other evaluations performed in recent years to assess the capital cost of a potential natural gas conversion.

Q. What was the outcome of your evaluation for a Gas Conversion?

A. Black & Veatch conducted a review for the concept of converting Petitioner's A.B. Brown Unit 1 and Unit 2 from firing coal to firing 100 percent natural gas. Converting to 100 percent natural gas firing involves the replacement of the existing bituminous coal-fired burners with natural gas burners; the existing natural gas igniters will not be replaced. The new natural gas burners would lower emissions during startups and during normal operations by providing up to 100 percent of boiler maximum continuous rated ("MCR") heat input. The existing flue gas cleaning equipment (scrubbers, baghouse/precipitator) would be removed from service. The natural gas pipeline supply to the A.B. Brown site boundary was excluded from the scope of this assessment.

The typical project schedule is 30 months (including 10 months for permitting activities), with a 10-month construction period that includes a 12-week outage for A.B. Brown Unit 1 and a 14-week outage for A.B. Brown Unit 2. Replacement burner/igniter manufacture and delivery time is 13 months from award of a purchase order.

A summary of the A.B. Brown Unit 1 and Unit 2 boiler impacts when converting to natural gas are listed below:

- When converted to natural gas, the heat rate impact will be higher (poorer performance) for A.B. Brown Units 1 and 2 due to the decreased boiler efficiency.
- Boiler efficiency can decrease due to the level of latent heat of vaporization of water in the flue gas. Flue gas moisture derives from moisture in the fuel and from combustion of H_2 in the fuel. Since natural gas is about 25% H_2 by weight, latent heat losses can be high.
- At high gas utilization levels, some boilers can suffer from heat transfer imbalances. Reduction in superheat and reheat temperatures is also a concern.
- Other limitations include start-up time and ramp rate of the unit since it would still be limited by the heating surface and steam turbine cycle.

When burning natural gas, flue gas emissions reductions from the boilers for particulate matter ("PM"), sulfur dioxide ("SO_2"), and mercury ("Hg") would be reduced almost directly proportional to the reduction in coal combustion. Boiler flue gas emissions of nitrogen oxides ("NO_X") and carbon monoxide ("CO") while firing natural gas would also be reduced compared to firing coal. Options assessed to reduce NO_X and CO emissions include the design and installation of an overfire air ("OFA") system, flue gas recirculation ("FGR") system, CO catalyst system (required for higher capacity factor operation), and continued operation of the Selective Catalytic Reduction ("SCR") catalysts. For this assessment, all options have been evaluated and costs estimated; final selection will be dependent on final air permitting.

Q. What does Black & Veatch estimate the Gas Conversion Project will cost?

A. The capital cost estimate for the Gas Conversion Project is estimated at approximately $56,000,000 for A.B. Brown Unit 1 and $62,000,000 for A.B. Brown Unit 2. This estimate excludes the Petitioner's cost which must be added to determine the Total Project Cost.

The Natural Gas Conversion Evaluation is consistent with the Association for the Advancement of Cost Engineering ("AACE") Class 4 estimate based on Black & Veatch's review of the third-party reports, deliverables, and the level of effort. In addition, Black & Veatch provided the preliminary environmental approach and recommendations, including estimating the cost for SCR and CO catalyst requirements for the units. These estimates are also consistent with an AACE Class 4 estimate.

The scope of these projects would be inclusive of the following items:

- Materials; burner replacements, ducting metering/regulating station, balance-of-plant ("BOP") modifications, etc.
- Installation; burner replacements, ducting metering/regulating station, BOP modifications, etc.
- Bowen gas line from T10 to Tee
- FGD demo and bypass duct
- CO catalyst layer (materials)
- CO catalyst layer (installation)
- SCR catalyst (materials)
- SCR catalyst (installation)
- OFA (materials and installation)
- Flue gas recirculation system (materials and installation)
- General boiler/plant modifications

Those reports which served to support the technology data and costs are attached to this testimony as Petitioner's Exhibit No. 7, Attachment JAZ-3.

Q. Why would a conversion to gas negatively impact the boiler efficiency?

A. Natural gas combustion results in a lower boiler efficiency than coal due to differences in the chemical composition between gas and coal. The boiler's performance will also be lowered. This is because there is a shift in heat transfer within the boiler from radiant heat when burning coal to more convective heat transfer when burning natural gas when converting a unit from coal firing to natural gas firing. This is due to the natural gas flame having a lower emissivity that results in less radiant heat output. Additionally, there is more heat transfer in the convective pass of the boiler because there is less ash content produced with firing natural gas.

VI. DESCRIPTION OF COMBUSTION TURBINES ("CTs")

Q. How has Black & Veatch assisted in CenterPoint Indiana South's assessment of installing a new simple cycle power plant at the AB Brown Generating Station?

A. Black & Veatch assisted CenterPoint Indiana South by developing conceptual designs and detailed cost estimates for installing a new simple cycle power plant on the AB Brown site.

Q. Please describe the team that performed the work discussed in your testimony.

A. Steven Williams is the Project Manager leading the engineering project for Black & Veatch. He is licensed as a Professional Engineer in the state of Indiana and is the responsible engineer. Nathan Mentzer is the Engineering Manager and is a licensed Professional Mechanical Engineer working under the direct supervision of Steven Williams. As Chief Engineer, they are working under the engineering processes that I own.

Q. Describe the work performed by Black & Veatch to develop the description of the SCPP.

A. Black & Veatch's work included the following key activities:

- Development of a design basis
- Development of a conceptual design

Q. What technologies were evaluated by Black & Veatch?

A. Black & Veatch evaluated the following plant configuration:

- 2 x 0 F-Class CT

Q. How did Black & Veatch decide which technologies and plant configurations to consider?

A. CenterPoint Indiana South specified the technologies. A detailed discussion of how CenterPoint Indiana South determined their need can be found in the direct testimony of Petitioner's Witnesses Wayne D. Games and Matthew A. Rice. The selected 2x0 plant configuration was identified as best suiting CenterPoint Indiana South's generation need. Determination of CenterPoint Indiana South's generation need is outside the scope of Black & Veatch's work.

Q. Describe the work performed by Black & Veatch to develop a design basis for the new CT plant.

A. Black & Veatch performed various design evaluations to provide CenterPoint Indiana South with the information needed to make decisions on the plant design and features. Some of the evaluations performed are as follows:

- **Re-Used Equipment Study** – This study analyzed the potential for existing equipment to be reused for the new simple cycle.
- **Switchyard Interconnect Study** – This study evaluated the suitability of the existing A.B. Brown 138 kilovolt ("kV") switchyard for interconnection of two new combustion turbine generators operating as a 2x0 SCPP.
- **Environmental Regulatory and Permitting Assessment** – This assessment of environmental permitting requirements is based on the proposed shut-down of A.B. Brown Units 1 and 2 and the installation of a new 2x0 natural gas-fired SCPP.
- **Simultaneous vs. Sequential Starting** – This evaluation studied auxiliary electrical system design impacts due to pushing the start button to start operating the CTs at the same time versus staggered operating start of the CTs one after the other.
- **Black Start Analysis** – This study evaluated using new diesel gensets as a means of black starting one of the CTs of the new SCPP versus utilizing the existing Unit 3 as a means of black starting one of the CTs of the new SCPP.
- **Existing Fire Water System Review** – The purpose of this evaluation was to review the existing fire water system with respect to implementing the new simple cycle.

- **Level 1 Schedule** – Black & Veatch developed a Level 1 project schedule outlining the design, procurement, construction, and commissioning phases of the Project.

There are individual reports in my workpapers supporting and describing each of these evaluations.

- **Original Equipment Manufacturer ("OEM") for Combustion Turbine-Generators Evaluation** – Black & Veatch developed a specification for the combustion-turbine-generator equipment, which defined requirements for furnishing two CTs along with their associated electric generator(s), auxiliaries, stacks, and control systems. CenterPoint Indiana South sent a Request for Information ("RFI") to CT OEMs requesting information on their turbines. The CT OEMs who received the RFI included General Electric ("GE"), Mitsubishi Power Americas ("MPA"), and Siemens Energy ("Siemens"). The RFI also included specification requirements for a long-term service agreement ("LTSA") for the combustion turbine generators. Responses were received from GE and Siemens for the GE 7F.05 and the Siemens 5000F CTs, respectively. Black & Veatch supported the technical evaluation of the responses. Those reports which served to support the technology data and costs are attached to this testimony as Petitioner's Exhibit No. 7, Attachment JAZ-4 .

Q. Describe the work performed by Black & Veatch to develop a conceptual design for the new CTs.

A. In order to support the project cost estimate, conceptual designs for the new SCPP were developed. Black & Veatch developed the following design documents:

- Design Basis Document
- General Arrangement
- Electrical One Lines
- Water Mass Balance
- Equipment Lists
- Technical Specifications for Combustion Turbines
- Technical Specifications for Engineering, Procurement, and Construction of the SCPP

These documents are included in my workpapers.

VII. DESCRIPTION OF COST ESTIMATE OF CTs

Q. Describe the work performed by Black & Veatch to develop the cost estimate of the SCPP.

A. Black & Veatch's work included the following key activities:

- AACE Class 3 (+/- 30 percent) total installed cost ("TIC") estimate
- Preparation, Issue, and Technical Evaluation of Request for Proposal ("RFP")
- Development of an AACE Class 2 (+/- 10 percent) estimate

Q. Describe the work performed by Black & Veatch to develop the AACE Class 3 cost estimate.

A. Black & Veatch developed an AACE Class 3 (+/- 30 percent) TIC estimate for the Project based on the preliminary conceptual design by Black & Veatch. The Turnkey Contractors scope of work includes the design, engineering, procurement, construction, construction management, commissioning, operator training, demonstration, and testing of the project. The cost estimate was based upon a lump-sum turnkey approach where the Turnkey contractor will purchase the combustion turbine equipment and maintain performance responsibilities. The Turnkey structure used for the estimate is based upon the contractor self-performing the work and utilizing subcontractors for appropriate work.

The cost estimate was based on pricing obtained during previous works and comparing with recent Black & Veatch proposals and projects. Material takeoffs were based on the preliminary design of the A.B. Brown simple cycle plant with reference to similar sized plants that Black & Veatch has designed, constructed, and/or estimated on an EPC/Turnkey basis.

Q. Describe the work performed by Black & Veatch to issue and evaluate the RFPs.

A. Black & Veatch developed technical specifications encompassing all applicable responsibilities, activities, equipment, codes, and standards required to bid an EPC scope for a 2x0 F-class simple cycle project at the A.B. Brown site. The EPC specification focused on scope, plant performance and system descriptions; EPC contractors were to utilize their standard engineering procedures and construction methods. The EPC specification included a CT specification as well. The RFP was sent to contractors as well as CT OEMs. All bidders were given the opportunity to bid the full scope, however the CT OEMs elected to bid only furnishing the CT equipment. Contractor bids included the full scope including supplying the CTs.

Black & Veatch supported the RFP bidding process from a technical standpoint; prepared responses and clarifications to the bidders' questions on the RFP documents, created bid tabulations to compare offerings, evaluated Bill of Quantity ("BOQ") document submittals, and examined bid data for scope and completeness. Black & Veatch also conducted technical evaluations, prepared questions for bidders to ensure complete scope, identified gaps between Turnkey contractor scope and Owner's scope, and recommended technical adjustments as required to fill gaps in scope with the specification and submitted technical assessments with supporting documentation and analysis.

Black & Veatch worked with PowerAdvocate and CenterPoint Indiana South throughout this process. PowerAdvocate liaised with the bidders, CenterPoint Indiana South and Black & Veatch. PowerAdvocate performed the commercial evaluation as well as scored and ranked the bids whereas Black & Veatch provided input to the technical ranking of the bids.

Q. Describe the technical evaluation work performed by Black & Veatch to evaluate the EPC Contractors.

A. As noted, CenterPoint Indiana South issued an RFP specification for the engineering, procurement, and construction of the 2x0 SCPP. The bidders were asked to base their proposals on their standard technical specifications and procedures. Technical specifications for the CTs were included within the RFP. The RFP was issued to, and bids were received from, LSTK Bidder 1, Kiewit, and LSTK Bidder 3. Black & Veatch performed a technical review of the bids. Commercial items such as pricing, terms, and conditions were not a part of Black & Veatch's technical evaluation.

Bids received were for the complete engineering, procurement, construction, and commissioning of the 2x0 SCPP, including the procurement of the combustion turbines by the Turnkey contractor. Each bidder submitted bids with plants designed for both the GE 7F.05 and the Siemens 5000F CTs. Bids were evaluated for technical compliance with the

RFP as well as responses to RFIs. Technical cost adjustments as required to be in line with the specification were included.

There are individual reports in my workpapers describing these evaluations.

Q. Describe the work performed by Black & Veatch to develop the AACE Class 2 cost estimate.

A. The evaluation of the EPC bids was utilized as the basis of the AACE Class 2 (+/- 10 percent) estimate. Black & Veatch developed an AACE Class 2 (+/- 10 percent) estimate which is driven by the project execution plan, turnkey bids, and schedule. The cost estimate is based on the competitive bids received in response to the RFP. Design documents and material takeoffs were provided by contractors as part of their preliminary design of the A.B. Brown SCPP. Quantities are based on the RFP package that included plant specifications, design basis, system descriptions, and specific site conditions.

Adjustments identified in the EPC evaluation were added to fill any scope gaps to determine the project cost. Owner's cost was added as provided by CenterPoint Indiana South. The AACE Class 2 (+/- 10 percent) estimate was compared against the +/- 30% estimate provided by Black & Veatch as well as recent market pricing.

Black & Veatch developed an updated project schedule for basis of the +/-10 percent estimate outlining the design, procurement, construction, and commissioning phases of the Project based on feedback from the EPC bids.

Q. Explain the components of the AACE Class 2 (+/- 10 percent) estimate.

A. Capital cost estimates include items in the following cost categories:

- **Direct Costs** – Costs for equipment, commodities, labor, transportation, and services associated with building the new facility.
- **Construction Management and Construction Indirects** – Includes construction cost other than direct labor including management, startup, QA/QC, safety, warehousing, equipment, temporary utilities, trailers, tools, consumables, and scaffolding.

- **Engineering** – Includes engineering, project controls, procurement, and project management.
- **Project Indirects** – Includes Taxes, Insurance, Bonds and Letters of Credit, Warranty; and Includes Builders Risk Insurance.
- **EPC Contractor Contingency** – This is the EPC contractor's allocation to account for the unknown costs associated with the project.
- **Overhead and Profit** – Overhead and profit for the contractor to complete the project is included based on bids received.
- **Escalation** – The Turnkey price includes escalation.

Those reports which served to describe the basis of estimate are attached to this testimony as Petitioner's Exhibit No. 7, Attachment JAZ-2.

Q. Indiana Code § 8-1-8.5-6(e) requires that for a proposal to construct a generating facility of this size, the estimated costs must, to the extent commercially practicable, be the result of competitively bid engineering, procurement or construction contracts, as applicable. Does your estimate satisfy this?

A. Yes. First, I would note that engineering, procurement "or" construction contracts is not the same thing as an EPC contract. An EPC contract is engineering, procurement "and" construction. With that said, Black & Veatch's cost estimate is based on competitively bid pricing for engineering, procurement and construction contracts.

Q. What level of accuracy would you estimate these cost estimates represent?

A. The cost estimate for the project represents an AACE Class 2 (+/- 10 percent).

Q. What was the design basis for the cost estimates?

A. Table JAZ-4 includes items from the design basis for our conceptual design.

TABLE JAZ-4: DESIGN BASIS	
Item	**Description**
Nominal Plant Capacity	~460 MW net
Configuration	2x0 Simple Cycle
Project Location	Posey County Coordinates (Google Earth): 37°54'18.17"N; 87°42'55.54"W
Unit Number	Unit 5 (South CTG), Unit 6 (North CTG)
Design Life	30 years
Operation Philosophy	Daily Cycling
Operating Range	Minimum Emissions Compliance Load to Full Load
Fuel	
Primary Fuel	Natural Gas
General Design Data:	
Building Code	2014 Indiana Building Code (IBC 2012)
Risk Category	III
Site Elevation (Mean Sea Level), ft	415
Wind Design Data:	
Ultimate Design Wind Speed, Vult, Nominal 3 second gust wind speed at 33 ft above ground for Exposure C category, mph	120
Exposure Category	C
Topographic Factor, Kzt	1.0
Snow Design Data:	
Ground Snow Load, Pg, lb/ft2	20
Importance Factor (Snow Loads), I	1.1
Seismic Design Data:	
Short Period Mapped Spectral Acceleration, Ss	0.616g
One Second Period Mapped Spectral Acceleration, S1	0.213g
Site Class	D
Design Spectral Response Acceleration Parameter, SDS	0.537g
Design Spectral Response Acceleration Parameter, SD1	0.280g
Seismic Design Category	D
Importance Factor (Seismic Loads), I	1.25

Q. How does Black & Veatch's estimate for the cost of the simple cycle project relate to the Total Project Cost presented by Witness Games?

A. The EPC/Turnkey AACE Class 2 (+/- 10 percent) cost estimate for the new combustion turbine simple cycle project supports and aligns with the cost breakdown of the Total Project Cost presented by Witness Games. The details of our estimate are set forth in my confidential workpapers. Because that breakdown is used by Mr. Games to estimate the remaining issues being negotiated with the winning EPC bidder, that breakdown is being kept confidential.

Q. Did Black & Veatch include escalation in your estimate?

A. Yes, Black & Veatch included escalation based upon criteria submitted with the EPC bids.

VIII. COMPARISON OF COSTS

Q. What are the cost impacts if the second CT installation were delayed?

A. For a postulated five (5) year delay between the construction of the first combustion turbine and the second turbine, the costs incurred were estimated to be approximately 25 percent higher overall. This estimate was derived from the competitive bids received by Black & Veatch for the 2x0 SCPP for both units constructed at the same time, but a detailed review was not conducted.

IX. CONCLUSION

Q. Does this conclude your direct testimony?

A. Yes, at the present time.

VERIFICATION

I, Jason A. Zoller, Chief Engineer, Black & Veatch, under the penalty of perjury, affirm that the answers in the foregoing Direct Testimony are true to the best of my knowledge, information and belief.

Zoller, Jason A.

Digitally signed by Zoller, Jason A
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Jason A. Zoller

Chief Engineer, Black & Veatch

Dated: June 15, 2021

FINAL - REV 1

A.B. BROWN SCRUBBER ASSESSMENT AND ESTIMATE

B&V PROJECT NO. 400278
B&V FILE NO. 40.0001

PREPARED FOR

Vectren Corporation

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BLACK & VEATCH

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1.2 INTRODUCTION/BACKGROUND

Units 1 and 2 at Vectren's A. B. Brown Power Station are each nominally 265 megawatt (MW) gross, coal-fired electric generating units (EGUs). The units were built in the late 1970s to the mid-1980s. Each of the existing units is outfitted with an originally supplied, dual alkali (DA) wet flue gas desulfurization (FGD) system for the control of acid gases such as sulfur dioxide (SO_2).

Vectren has contracted with Black & Veatch Corporation (Black & Veatch) to provide order of magnitude conceptual design cost estimating, technology support, and review and consolidation of third-party conceptual design and cost estimates for the inputs into financial modeling of the current and available air quality control (AQC) scrubber technologies that could be employed at Vectren's A.B. Brown Station, for continued operation of both Unit 1 and Unit 2. Black & Veatch, in addition to other architectural engineering consultants hired by Vectren, has performed technology reviews and assessments to develop construction and ongoing operations and maintenance (O&M) costs of these various technologies.

This document presents AQC technologies evaluated for the A. B. Brown coal fired power plant for evaluation in Vectren's 2019 Integrated Resource Plan (IRP) for continued coal operation of A.B. Brown Units 1 and 2. Black & Veatch served as the lead engineer in the FGD evaluation effort. Black & Veatch, AECOM, and Burns & McDonnell all provided technical data and cost information for individual FGD upgrade options, as requested by Vectren. Those reports served to support the technology and costs presented in this report.

- Burns & McDonnell – A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate
- AECOM – Wet FGD Limestone Conversion Study for A.B. Brown Station.

1.3 PURPOSE

The purpose in developing this compiled report is to indicate the applicability, reliability, and estimated costs of the AQC technology options that could be utilized at A.B. Brown Station to support continued operation of Unit 1 and Unit 2 on the full range of current coal fuel. The assessment will consider interfaces to the existing equipment and ductwork at the A.B. Brown Units and include evaluation of the reuse and/or removal of the existing auxiliary support equipment (mechanical tanks, pumps, fans, electrical switchgear, etc.).

The technologies evaluated and the responsible lead engineering company performing the work are indicated in Table 1-1.

Table 1-1 Scrubber Technologies

Technology	Lead	Expected Outcome	Water Treatment Impacts	Other Impacts
Wet Limestone Forced Oxidation Scrubber	Burns & McDonnell	Feasible	Yes	Lime Injection FGD Gypsum Market
Limestone Forced Oxidation (Conversion from DA Scrubber)	AECOM	Not Feasible	Yes	Lime Injection
Limestone Inhibited Oxidation (Conversion from DA Scrubber)	AECOM	Not Feasible	Yes	Lime Injection
Inhibited Wet Lime Scrubber	Black & Veatch	Feasible	Yes	Lime Injection Powdered Activated Carbon (PAC) Injection
Spray Dryer Absorber	Black & Veatch	Not Feasible	No	Not Applicable
Circulating Dry Scrubber	Black & Veatch	Feasible	No	PAC Injection
Ammonia Scrubber	Black & Veatch	Feasible	Yes	Lime Injection PAC Injection Fertilizer Market

1.4 SUMMARY TABLE OF RESULTS

1.3.1 Capital Costs Summary

The technologies were reviewed to determine those that merited further analysis on the basis of their ability to meet emissions criteria for the full range of boiler design fuel. The selected technologies were then evaluated to assess the cost to purchase and operate the control technology. Table 1-2 presents the capital cost estimates. The capital cost presented for the LSFO technology includes cost for wastewater treatment but does not include costs for water treatment or landfill. The capital cost presented for Wet Lime Inhibited Oxidation (WLIO) and Circulating Dry Scrubber (CDS) are for the FGD systems only and do not include the need for or costs for water/wastewater treatment (WWT) or landfill. Waste water treatment costs for the Wet Limestone Forced Oxidation (LSFO) and Ammonia (NH_{3}) FGD system have been included. The LSFO system includes waste water treatment. The NH_3 system includes costs for wastewater treatment of water used for the wet ESP. Refer to Appendix A at the end of the report.

Table 1-2 Capital Cost Estimates

(2019 Dollars x 1000)	Wet Lime Inhibited Oxidation Scrubber (WLIO)	Ammonia Scrubber (NH_3)	Circulating Dry Scrubber (CDS)	Limestone Forced Oxidation Scrubber (LSFO)
Installation Cost (2020 - 2024)	$318,079	$284,835	$269,550	$424,878
Capitalized Cost (2024 - 2039)	$34,313	$30,727	$29,078	$45,834

1.3.2 20 Year Totals 2020 to 2039

The O&M costs start in 2024 assuming the FGD system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied; O&M costs for labor are not included in the estimates below. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 1-3 represents the O&M costs for the FGD systems only and does not include the balance-of-plant O&M costs. Refer to Appendix A at the end of the report.

Table 1-3 Operations and Maintenance – 20 Year Totals 2020 to 2039

(2019 Dollars x 1000)	WLIO	NH_3	CDS	LSFO
O&M Schedule Outage	$21,510	$19,262	$18,228	$28,732
O&M – Base Non-Labor	$11,148	$9,983	$9,448	$14,892
Total	$32,659	$29,245	$29,078	$43,624

2.0 List of Abbreviations

acfm	Actual Cubic Foot per Minute
AFUDC	Allowance for Funds Used During Construction
AQC	Air Quality Control
BACT	Best Available Control Technology
BPT	Balance-of-Plant Treatment
$Ca(OH)_2$	Calcium Hydroxide
CaO	Quicklime
$CaSO_3$	Calcium Sulfite
$CaSO_3 \bullet 1/2H_2O$	Calcium Sulfite Hemihydrate
$CaSO_4 \bullet 2H_2O$	Calcium Sulfate Dihydrate
CDS	Circulating Dry Scrubber
CEMS	Continuous Emissions Monitoring System
DA	Dual Alkali
DBA	Dibasic Acid
DCS	Distributed Control System
DESP	Dry Electrostatic Precipitator
ECO	Electrocatalytic Oxidation
EPA	Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ESP	Electrostatic Precipitator
FDA	Flash Dryer Absorber
FGD	Flue Gas Desulfurization
H_2SO_4	Sulfuric Acid Mist
Hg	Mercury
ID	Induced Draft
IDEM	Indiana Department of Environmental Management
IRP	Integrated Resource Plan
JET	Jiangnan Environmental Technology, Inc.
L/G	Liquid-To-Gas
lb/Btu	Pound per British Thermal Unit
Lb/h	Pound per Hour
LIFAC	Limestone Injection into the Furnace and Activation of Calcium
LSFO	Limestone Forced Oxidation
LSIO	Limestone Inhibited Oxidation
MBtu	Million British Thermal Unit

MW	Megawatt
NH_3	Ammonia
NIPSCO	Northern Indiana Public Service Company
NO_X	Nitrogen Oxides
NSR	New Source Review
O&M	Operations and Maintenance
PAC	Powdered Activated Carbon
PGLS	Pre-Ground Limestone
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
PM_{10}	Particulate Matter Less than 10 Microns
PSD	Prevention of Significant Deterioration
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SO_X	Sulfur Oxides
TBtu	Trillion British Thermal Units
WESP	Wet Electrostatic Precipitator
WLIO	Wet Lime Inhibited Oxidation
WWT	Wastewater Treatment

3.1 Conceptual Design Basis

3.2 ENVIRONMENTAL REGULATIONS

Black & Veatch anticipates that the installation of a new FGD system or major modification of the existing system will be subject to Federal and Indiana Department of Environmental Management (IDEM) air regulations as a modification to an existing major source. An air construction permit would, therefore, need to be obtained to authorize construction. However, Black & Veatch anticipates that the permit could be obtained as a minor modification and would not be subject to Prevention of Significant Deterioration (PSD) review and Best Available Control Technology (BACT) requirements. Black & Veatch notes that confirmation of air permitting applicability of a given technology cannot be accomplished until a New Source Review (NSR) applicability analysis is conducted. Should PSD BACT ultimately be applicable, the results of a BACT analysis could alter the required technology because emissions targets lower than the current emissions limits may be required. An operating change, such as an expected increase in the unit capacity factor, could cause BACT to be applicable. The conceptual design basis used to screen the scrubber technologies must be able to meet, as a minimum, the minor modification to permit (~98 percent removal).

3.3 BOILER PERFORMANCE

Characteristics for boiler performance parameters used by Black & Veatch were based on a previous study performed in 2013 for A.B. Brown Unit 1. The same information was utilized for A.B. Brown Unit 2 for this high-level assessment.

Table 3-1 Combustion Performance

Parameters	Typical Coal Exhaust Gas Flow (Typical Sulfur)	Maximum Design Exhaust Gas Flow (Maximum Sulfur)	Typical Coal Minimum Exhaust Gas Flow (Typical Sulfur)	Design Maximum Values	Minimum Design Values
Unit Characteristics					
Unit Rating, Gross MW	268	268	~115	268	~115
Unit has an SCR	Yes	Yes	Yes		
Boiler Heat Input, MBtu/h (HHV)	2,690	2,714	1,015	2,714	1,015
Boiler Heat to Steam, MBtu/h	2,351	2,351	893		
Coal Flow Rate, lb/h	241,000	261,000	94,000	241,000	94,000
LOI, % of fly ash	1.79	1.79	1.79	1.79	1.79
Boiler Misc. Heat Losses, %	1.50	1.50	1.50	1.50	1.50
Excess Air at Economizer, %	3.60	3.60	6.80	6.80	3.60
Excess Air, %	22.81	22.82	53.21		
Air Heater Leakage, %	10.84	10.83	28.99		
Fly Ash Portion of Total Ash, %	85	85	85		
Altitude, ft above MSL	415	415	415	415	415
Barometric Pressure, in. Hg Abs	29.496	29.496	29.496		
Ambient Pressure, in. H_2O	401	401	401	401	401
Ambient Temperature, °F	85	85	85	105	-23
Relative Humidity, %	60	60	60		
SO_2 to SO_3 Oxidation Rate by Boiler, percent	0.8	0.8	0.8		
SO_2 to SO_3 Oxidation Rate by SCR, percent	0.5	0.5	0.5		
Total SO_2 to SO_3 Oxidation Rate, percent	1.3	1.3	1.3		
PJFF Inlet Conditions					
Actual flow, acfm	1,040,000	1,080,000	540,000		
Flue Gas Temperature, °F	305	330	285	330	285
Flue Gas Pressure, in. w.g.	-24.0	-24.0	-5.5	-24.0	-5.5
Flue Gas Composition					
O_2, % Vol wet basis	5.29	5.29	9.92		
N_2,% Vol wet basis	73.62	73.61	74.69		
CO_2, % Vol wet basis	11.98	11.84	8.32		
SO_2 , % Vol wet basis	0.27	0.43	0.19		
HCl, % Vol wet basis	0.0013	0.0035	0.0009		

Parameters	Typical Coal Exhaust Gas Flow (Typical Sulfur)	Maximum Design Exhaust Gas Flow (Maximum Sulfur)	Typical Coal Minimum Exhaust Gas Flow (Typical Sulfur)	Design Maximum Values	Minimum Design Values
H_2O, % Vol wet basis	8.83	8.83	6.88		
Sulfur Dioxide Concentration, lb/MBtu	6.72	10.54	6.92		
H_2SO_4 ppmvd	22.1	34.9	15.0		
H_2SO_4, lb/MBtu	0.076	0.120	0.079		
Oxidized Hg, lb/TBtu	4.75	4.75	4.35	4.80	
Elemental Hg, lb/TBtu	0.53	0.53	0.67	1.20	
Total Hg, lb/TBtu	5.28	5.28	5.02	6.00	
Particulate Concentration, lb/MBtu	7.54	12.23	7.76		
Particulate Mass Rate, gr/acf	2.28	3.59	1.70		
PJFF Outlet/ID Fan Inlet Conditions					
Actual flow, acfm	1,340,000	1,350,000	550,000		
Actual flow per duct total of two ducts per boiler, acfm	670,000	675,000	275,000		
Flue Gas Temperature, °F	305	330	285	330	285
Flue Gas Pressure, in. w.g.	-32.0	-32.0	-13.5		
Flue Gas Composition					
O_2, % Vol wet basis	5.29	5.29	9.92		
N_2,% Vol wet basis	73.62	73.61	74.69		
CO_2, % Vol wet basis	11.98	11.84	8.32		
SO_2 , % Vol wet basis	0.27	0.43	0.19		
HCl, % Vol wet basis	0.0013	0.0035	0.0009		
H_2O, % Vol wet basis	8.83	8.83	6.88		
H_2SO_4 ppmvd	19.9	31.4	13.5		
H_2SO_4, lb/MBtu	0.069	0.108	0.071		
Oxidized Hg, lb/TBtu	4.72		4.80	4.80	
Elemental Hg, lb/TBtu	0.13		0.38	1.20	
Total Hg, lb/TBtu	4.85	0.00	5.18	6.00	
PM (Filterable), lb/MBtu	0.010	0.010	0.010		
Ref: Boiler performance from A.B. Brown Unit 1 Environmental Study 2013 Design Basis – Exhaust Flow Information.					

3.4 DESIGN COAL

Table 3-2 Design Coal

Parameters	Design Cases - Bituminous Design Coal	Range - Bituminous Minimum	Range - Bituminous Maximum
Ultimate Coal Analysis, wet basis			
Carbon, %	62.02	50.80	75.38
Hydrogen, %	4.23	3.50	5.30
Sulfur, %	3.75	0.86	5.48
Nitrogen, %	1.02	0.86	2.20
Oxygen, %	6.91	5.00	11.11
Chlorine, %	0.04	0.01	0.17
Ash, %	9.71	7.00	14.68
Moisture, %	12.32	2.70	16.50
Total, %	100	71	131
Higher Heating Value, Btu/lb	11,143	10,400	12,493
Ref: A.B. Brown Unit 1 Environmental Study 2013 Design Basis – Fuel Information. Installation Scope.			

4.1 Potential Air Quality Control Technologies

The evaluation is being performed to assist Vectren in determining a preliminary selection of the preferred FGD equipment for evaluation in Vectren's 2019 IRP. Black & Veatch has assumed that the installation of a new FGD system will be subject to Federal and IDEM air regulations as a modification to an existing major source, and, therefore, an air construction permit will have to be obtained to authorize construction. However, because of the nature of the project (where the existing air emissions limits are the baseline), it is assumed that the emissions increase as a result of this project, if any, would be less than the PSD significance thresholds. Thus, according to these assumptions, the project would be considered a minor modification and would, therefore, not be subject to PSD BACT requirements. Black & Veatch notes that confirmation of air permitting applicability of a given technology cannot be accomplished until an NSR applicability analysis is conducted. Should PSD BACT ultimately be applicable, the results of a BACT analysis could alter the required technology because emissions targets lower than the current emissions limits may be required. An operating change, such as an expected increase in the unit capacity factor, could result in making BACT applicable.

4.2 REVIEW OF POTENTIAL TECHNOLOGIES

This section identifies, summarizes, and evaluates potential SO_2 control technologies for feasibility of use at the A.B. Brown Station. The current generation of FGD system design represents improvements and advances to previous generations of FGD systems that were first installed in the United States in the 1970s.

Many of the FGD system vendors offer both semi-dry systems (i.e., CDS or spray dryer absorber [SDA] systems) and wet systems (lime- and limestone-based spray/tray towers absorbers) and will offer whichever best meets the utility's particular requirements on a site-by-site basis. Improvements to the wet FGD technologies have also been realized through better process chemistry and the use of chemical additives such as dibasic acid (DBA). The following subsections identify and describe the potential technologies that were evaluated for use at A.B. Brown Station.

4.1.1 Conversion of the Current FGD System to a Limestone-Based Scrubber

Conversion of the existing DA FGD systems to a limestone-based FGD system has been completed on similar type units in industry and was examined in this study. The detailed study of this option was provided in a report completed by AECOM, an engineering firm under separate contract with Vectren. This report is provided as Appendix C at the end of this report. In this report, AECOM presents the option of converting the existing A.B. Brown FGD systems to a limestone-based reagent scrubber using either of two options: limestone inhibited oxidation (LSIO), producing calcium sulfite solids for landfill disposal, or LSFO operations, producing wallboard-quality gypsum that allows for the potential marketing and selling of the byproduct to avoid the landfill costs. AECOM previously converted DA scrubbers at Northern Indiana Public Service Company's (NIPSCO's) Schahfer Station to limestone-based reagent, along with in situ oxidation to produce wallboard-quality gypsum. Both options were assessed with the intention to repurpose and/or reuse as much existing equipment as possible. For this preliminary report, only the use of pre-ground limestone (PGLS) was evaluated. A description of the proposed process configurations, scope of work, capital requirements, and operating cost impacts are presented in the AECOM report. Vectren indicates that additional equipment and construction items that were not included in the AECOM report have been addressed by a local Evansville, Indiana, engineering firm, Three I Design, that has assisted Vectren over the years in the evaluation of the FGD equipment.

4.1.2 Wet Limestone Process

Numerous suppliers offer FGD processes using a limestone slurry as the scrubbing agent. A detailed evaluation of this technology option was provided in a report completed by Burns & McDonnell, an engineering firm under separate contract with Vectren. This report is provided in Appendix B at the end of this report. In this report, Burns & McDonnell presents the option of installing new limestone reagent-based scrubbers using LSFO operations to produce wallboard-quality gypsum that can be landfilled or marketed and sold.

The Wet Limestone process utilizes a ball mill to create a limestone slurry which is fed into the absorber reaction tank to maintain the appropriate pH. Recirculation pumps feed limestone slurry from the reaction tank to the spray lances at the top of the absorber tower. The flue gas flows countercurrent to the sprayed slurry where the SO_2 reacts and is removed from the flue gas stream. The flue gas continues through a set of mist eliminators before leaving the absorber. The SO_2 which reacts with the lime in the system is oxidized to form gypsum. A bleed stream is removed from the absorber reaction tank and sent to the dewatering system where water is removed from the gypsum byproduct.

4.1.3 Wet Lime Process

Wet lime FGD is the generic term for processes using slaked lime as the scrubbing reagent in a spray tower FGD module. Wet lime processes are offered by a number of FGD suppliers. The reagent preparation system equipment is the only significant difference between the equipment used in the wet lime and wet limestone systems. The higher reactivity of the lime allows the equipment to be smaller than with a wet limestone scrubber.

Inhibited oxidation producing a calcium sulfite material is used or forced oxidation is used to promote formation of a fully oxidized gypsum byproduct. For this study, an inhibited oxidation process is assumed that produces a material for landfill disposal.

The primary difference in the wet lime and wet limestone processes is the preparation of scrubbing reagent slurry. In wet lime processes, quicklime (CaO) is slaked to produce a calcium hydroxide [Ca $(OH)_2$] slurry.

4.1.4 Semi-Dry Lime-Based FGD Systems

Semi-dry FGD processes have been extensively used in the United States, where utilities have installed numerous semi-dry FGD systems on boilers using low sulfur fuels. The semi-dry FGD process uses $Ca(OH)_2$ produced from the lime reagent as either a slurry or as a dry powder added to the flue gas in a reactor designed to provide good flue gas-reagent contact. The SO_2 in the flue gas reacts with the calcium in the reagent to produce primarily calcium sulfite hemihydrate ($CaSO_3 \bullet 1/2H_2O$) and a smaller amount of calcium sulfate dihydrate ($CaSO_4 \bullet 2H_2O$) through the following reactions:

$$SO_2 + Ca(OH)_2 \rightarrow CaSO_3 \bullet ½H_2O + ½H_2O$$

$$SO_2 + Ca(OH)_2 + ½O_2 \rightarrow CaSO_4 \bullet 2H_2O$$

Water is also added to the reactor (either as part of the reagent slurry or as a separate stream) to cool and humidify the flue gas, which promotes the reaction and reagent utilization. The amount of water added is typically sufficient to cool the flue gas to within 30° to 40° F of the flue gas adiabatic saturation temperature. Significantly less water is used in these semi-dry FGD processes than in wet FGD processes.

The reaction byproducts and excess reagent are dried by the flue gas and removed from the flue gas by a downstream particulate control device (either fabric filter or dry electrostatic precipitator [DESP]). Fabric filters are preferred for most systems because the additional contact of the flue gas with the particulate on the filter bags provides additional SO_2 removal and higher reagent utilization. A portion of the reaction byproducts collected is recycled to the reagent preparation system to increase the utilization of the lime.

Because of the large amount of excess lime present in the FGD byproducts, the byproducts (and fly ash, if present) will experience pozzolanic (cementitious) reactions when wetted. When wetted and compacted, the byproduct makes a fill material with low permeability (low lengthening characteristics) and high bearing strength. However, other than as structural fill, this byproduct has limited commercial value and typically must be disposed of as a waste material.

The semi-dry FGD processes offer benefits in addition to SO_2 removal, including the lack of a visible vapor plume and sulfur trioxide (SO_3) removal. Because the semi-dry FGD systems do not saturate the flue gas with water, there is no visible plume from the stack under most weather conditions. Environmental concerns with SO_3 emissions are also reduced with the semi-dry scrubber. SO_3 is formed during combustion and will react with the moisture in the flue gas to form sulfuric acid (H_2SO_4) mist in the atmosphere. An increase in H_2SO_4 emissions will increase PM_{10} emissions. The gas temperature leaving the reactor is lowered below the sulfuric acid dew point, and significant SO_3 removal will be attained as the condensed acid reacts with the alkaline reagent. By removing SO_3 in the flue gas, the condensable particulate matter emissions can be reduced. This will reduce the potential for any SO_3 plume that may cause opacity in stacks. Similar type SO_3 removal is not achievable with a wet scrubber.

The following four variants of semi-dry FGD processes are described further in this analysis:

- Spray Dryer Absorber (SDA).
- Circulating Dry Scrubber (CDS).
- Flash Dryer Absorber (FDA).
- Turbosorp.

4.1.4.1 Spray Dryer Absorber

All current SDA designs use a vertical gas flow absorber. These absorbers are designed for co-current or a combination of co-current and countercurrent gas flow. In co-current applications, gas enters the cylindrical vessel near the top of the absorber and flows downward and outward. In combination-flow absorbers, a gas disperser located near the middle of the absorber directs a fraction of the total flue gas flow upward toward the slurry atomizers.

The atomizer produces an umbrella of atomized reagent slurry through which the flue gas passes. The SO_2 in the flue gas is absorbed into the atomized droplets and reacts with the calcium to form calcium sulfite and calcium sulfate. Before the slurry droplet can reach the absorber wall, the water in the droplet evaporates and a dry particulate is formed.

The flue gas, then containing fly ash and FGD byproduct solids, leaves the absorber and is directed to a fabric filter. The fly ash and byproduct solids collected in the fabric filter are pneumatically transferred to a silo for disposal. To improve both reagent utilization and spray solids drying efficiency, a large portion of the collected solids is directed to a recycle system, where it is slurried and re-injected into the spray dryer along with the fresh lime reagent.

SDA installations, primarily located in the western United States, use either lignite or subbituminous coals, such as Powder River Basin, as the boiler fuel and generally have spray dryer systems designed for a maximum fuel sulfur content of less than 2 percent. The semi-dry lime-based FGD system has inherent removal efficiency limitations on higher sulfur fuels with higher SO_2 inlet concentration. This limitation varies with flue gas inlet temperature because the amount of slurry that can be injected into the absorber is limited by how close the flue gas temperature can approach its water saturation temperatures.

4.1.4.2 Circulating Dry Scrubber

The CDS FGD, also known as a circulating fluid bed scrubber, process is a semi-dry, hydrated lime-based FGD process that uses a circulating fluid bed contactor. The CDS absorber module is a vertical solid/gas reactor upstream of a particulate control device. The particulate control device is elevated to allow the recycle of the byproduct back to the fluidized bed in the absorber vessel. Water is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of SO_2 with the reagent. Hydrated lime [$Ca(OH)_2$] and recirculated dry solids from the particulate control device are injected concurrently with the flue gas into the base of the absorber module. One or more venturi should be at the bottom of the absorber module to accelerate the flue gas to maintain the fluidized bed in the absorber. The gas velocity in the reactor is reduced, and a suspended bed of reagent and fly ash is developed. The SO_2 in the flue gas reacts with the hydrated lime reagent to form predominantly calcium sulfite ($CaSO_3$).

4.1.4.3 Flash Dryer Absorber

The FDA is a variation of CDS technology. In this system, the fly ash is mixed with lime and water in a mixer/hydrator prior to being injected into the flash dryer. The flue gas is evaporatively cooled and humidified by the water being absorbed onto the dry particulate. Furthermore, SO_2 is removed from the flue gas stream by the reaction with the lime or limestone. The dry particulate is then removed in a fabric filter. A portion of the dry particulate from the fabric filter is collected for disposal, while a significant amount is recirculated to the mixer for conditioning and reuse in the absorber to achieve better reagent use and performance.

4.1.4.4 Limestone Injection into Furnace and Reactivation of Calcium

In the early 1980’s, Tampella Power Inc. of Finland began the development of a humidification process that would enhance the effectiveness of the furnace-injection FGD process by humidifying the flue gas and installing a solid/gas contact reactor upstream of the particulate control device. This process is referred to by the acronym LIFAC (limestone injection into the furnace and activation of calcium). The two major differences between the LIFAC process and the furnace-injection process are the use of a reactor to enhance reagent contact with the flue gas and the recirculation of a portion of the fly ash and byproduct solids collected in the particulate control device to the reactor.

This process is offered only by Tampella Power or one of its affiliated companies and has been applied to full-scale, coal fired utility boilers in Finland, Russia, Canada, and the United States.

4.1.4.5 Turbosorp

The Turbosorp circulating fluidized bed scrubber is a multi-pollutant control technology that removes SO_2, SO_3, hydrochloric acid, and mercury (Hg) from flue gas for coal fired applications. Turbosorp was originally developed by Austrian Energy & Environment and is now offered by Andritz and Babcock Power Environmental Inc.

4.1.5 Ammonia Scrubber

Anhydrous ammonia is used in the ammonia scrubber as the desulfurization absorbent to capture the SO_2, and the byproduct of the process is ammonium sulfate, a known fertilizer material. The only large FGD system of this type in the United States was installed at Dakota Gasification in North Dakota. This site is not a coal burning power plant. At this plant synthetic natural gas is produced by oxidizing lignite coal. The ammonia solution contacts the flue gas in a spray tower type absorber similar to a wet limestone or lime system.

4.1.6 Powerspan Electrocatalytic Oxidation Process

The Powerspan Electrocatalytic Oxidation (ECO) process is a multi-pollutant control technology that oxidizes and removes nitrogen oxides (NO_X), sulfur oxides (SO_X), and Hg from flue gas. The ECO process consists of the following steps:

- Fabric Filter or Electrostatic Precipitator (ESP)--Removes fly ash.
- ECO Reactor--Oxidizes pollutants.
- Absorber Vessel--Removes SO_2 and NO_2.
- Wet Electrostatic Precipitator (WESP)--Removes acid aerosols, fine PM, and oxidized Hg.

4.2 TECHNOLOGY PERFORMANCE EVALUATION CRITERIA (SO_2 AND PM)

An analysis was performed to identify the technical feasibility of the control options identified in Section 4.1, considering source-specific factors. A control option that was determined to be technically infeasible was eliminated. “Technically infeasible” in this case was defined as a control option that has not been proven to meet the emissions limits currently required at the plant for the defined range of potential operating conditions.

The performance requirements are as follows:

- 98 percent SO_2 removal efficiency for all coals.
- Particulate matter (PM) emissions at or below current baseline emissions.

Technologies are also considered infeasible if performance restrictions preclude the technology from achieving the primary emissions target or secondary emissions targets because of physical, chemical, or engineering issues. Secondary emissions targets would include other air or water emissions limits, such as Hg, not necessarily directly controlled by the technology but for which the technology cannot prevent control of the secondary emissions through other means. After completion of this step, technically infeasible options were then eliminated from the review process.

Control options that are not eliminated are considered technically feasible. A "technically feasible" control option is defined as a control technology that has been installed and operated successfully at a similar type of source of comparable size to the proposed facility under review (i.e., "demonstrated"). If the control option cannot be demonstrated, the analysis considers two key concepts: availability and applicability. "Availability" is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. An "available" technology does not mean that it does not have technical or commercial risks that differ from other available technologies. These risks are identified and evaluated during the analysis and considered in later analysis steps.

4.3 ELIMINATED TECHNOLOGIES

In order to eliminate technologies, an evaluation of all the available control technologies identified in Step 1 of the analysis was completed to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar type of source of comparable size, or there is technical agreement that the technology can be applied to the source. Available and applicable are the two terms used to define the technical feasibility of a control technology. Table 4-1 identifies what technologies are considered technically feasible SO_2 options for the A. B. Brown application.

Table 4-1 Summary – Eliminate Technically Infeasible Options

Technology Alternative	Technically Feasible (Yes/No) Available	Applicable
Wet FGD		
Limestone Conversion of Existing DA FGD - Forced Oxidation	Yes	No –would not meet expected emissions requirements when operating over the high sulfur range of the coals used at A.B. Brown.
Limestone Conversion of Existing DA FGD - Inhibited Oxidation	Yes	No –would not meet expected emissions requirements when operating over the high sulfur range of the coals used at A.B. Brown.
Wet Limestone FGD - Forced Oxidation(1)	Yes	Yes
Wet Lime FGD - Inhibited Oxidation(1)	Yes	Yes
Limestone Injection into the Furnace	Yes	No – would not meet expected emissions requirements when operating over the high sulfur range of the coals used at A.B. Brown.
Dry and Semi-Dry Lime FGD		
SDA	Yes	No – SDA has limited SO_2 removal efficiency over the project range of fuels, which are higher sulfur contents.
CDS or Turbosorp	Yes	Yes – Installations comparable in size are in operation. However, no full-scale operational experience is available in the United States over the high sulfur range of the coals used at A.B. Brown.
FDA	Yes	No – FDA has limited SO_2 removal efficiency over the high range of sulfur in the fuels.
Ammonia Scrubber	Yes	Yes – However, only one US application in operation and current interest limited to one Chinese supplier with no US experience.
Powerspan ECO Process	No	No – Only pilot size experience.

(1) Alternate absorber designs in wet lime or limestone FGD (spray tower, double contact spray tower, trays, etc.) are equal for comparison purposes.

On the basis of the initial selection of candidate technologies to address Vectren's objectives, the control technologies identified in Table 4-2 were selected for further evaluation; the firm responsible for the evaluation is also identified.

Table 4-2 Selected Technologies

Option	Acronym	Data Source
Wet Lime Inhibited Oxidation	WLIO	Black & Veatch
Circulating Dry Scrubber	CDS	Black & Veatch
Ammonia	NH_3	Black & Veatch
Limestone Forced Oxidation	LSFO	Burns & McDonnell

4.4 POTENTIAL TO MEET FUTURE REGULATIONS

It should be noted that this analysis is focused on meeting current emissions requirements and meeting Vectren's current objectives. It is possible that future environmental regulations will be promulgated that require A.B. Brown to reduce air emissions beyond the current requirements. If this occurs in the future, additional study will be needed to determine what additional modifications and capital expenditures would be needed for each technology.

5.1 Limestone Forced Oxidation Scrubber (LSFO)

The LSFO study was completed by Burns & McDonnell and is attached in Appendix B.

5.2 DESCRIPTION OF TECHNOLOGY

5.1.1 Basic Process Description

Limestone FGD utilizes crushed limestone ($CaCO_3$) ground and mixed with water to be used as a scrubber reagent that is pumped to a scrubber vessel reaction tank and the slurry in the reaction tank is recirculated by large pumps to the spray headers at the top of the spray tower vessel. The spray headers discharge the slurry into the spray towers with flue gas passing through the spray stream in a countercurrent direction and the removes SO_2 from the gas stream. Oxidation air blowers are provided to push oxygen to the reaction tank to create a gypsum byproduct.

$$CaCO_3 + SO_2 \rightarrow CaSO_3 + CO_2$$

$$CaSO_3 + \tfrac{1}{2} O_2 + 2H_2O \rightarrow CaSO_4 \bullet 2(H_2O)$$

The gypsum byproduct bleed stream is pumped from the reaction tank through a hydroclone as an initial step to separate solids from liquid. Liquids are returned to the reaction tank and solids are separated and sent to the vacuum filter to further remove liquids before being loaded and shipped to a purchaser or disposed of in a landfill.

For a detailed description of the limestone forced oxidation scrubber technology as provided by Burns & McDonnell, refer to Section 3.2 of the Burns & McDonnell Wet Limestone Forced Oxidation FGD Cost Estimate report included as Appendix B.

5.1.2 Flow Diagram

Figure 5-1 is a typical process flow diagram for an LSFO.

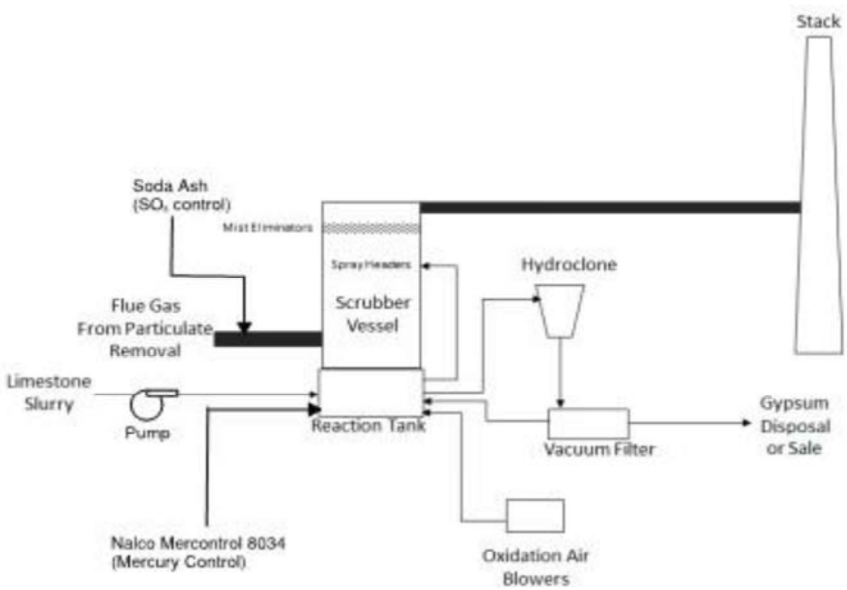

Figure 5-1 Limestone Forced Oxidation Scrubber

5.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

Control of SO_3 will be with use of a soda ash injection system (such as AECOM SBS Injection system). The current soda ash injection point is located after the fabric filter on Unit 1 and after the ESP on Unit 2 both locations are upstream of the scrubber vessels.

The LSFO system will use the existing mercury control systems (Nalco Mercontrol 8034) for mercury control. Mercontrol 8034 chemical is injected into the scrubber limestone slurry recirculation piping for mixing and dispersion.

The LSFO scrubber system removes the HCl from the flue gas steam.

Table 5-1 Environmental Controls LSFO

Pollutant	Hg	SO_3	SO_2	PM
Control Technologies	LSFO + Nalco Mercontrol 8034	Existing SBS Injection System	LSFO	Existing PM control: Unit 1 – Fabric Filter Unit 2 - ESP

5.2 ESTIMATING METHODOLOGY

Burns & McDonnell requested budgetary bids from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi. An average of the budgetary quotes was assumed for the FGD supply cost.

Direct costs were factored based on costs from past FGD projects. Factored costs were used for Indirect costs which include engineering and start-up. Burns & McDonnell developed an estimate of the following balance of plant direct costs:

- Equipment installation.
- Civil and foundation work.
- New chimney for Unit 1.
- Demolition of Unit 1 thickener.
- Concrete.
- Steel.
- Ductwork and insulation.
- Buildings.
- Limestone and gypsum pile canopies.
- Wastewater treatment equipment (falling film evaporator and crystallizer).
- Piping.

- Electrical (new transformers, PCM, switchgear, MCC's and miscellaneous panels).
- Instrumentation and controls.

Refer to Section 3.5 of the Burns & McDonnell report in Appendix B.

5.3 ESTIMATE ASSUMPTION

Burns & McDonnell made the following assumptions in preparation of the cost estimate:

- All estimates aide screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes.
- Assumes contracting philosophy is Engineer, Procure, Construction (EPC) approach.
- All information is preliminary and should not be used foil construction purposes.
- Assumes project engineering starts January 1, 2020 with both scrubbers in operation by January 2024.
- All capital cost and O&M estimates are stated in 2019 US dollars (USD). Escalation is excluded.
- Fuel and power consumed during construction, startup, and/or testing are included.
- Piling is included under heavily loaded foundations.
- All foundations are new; no re-use of existing foundations.
- Adequate water supply is assumed to be available from existing raw water supplies.
- This estimate assumes that the integrity of the tie-in points is sufficient.
- This estimate assumes that there are no significant underground utilities that would have to be re-routed.
- Removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.
- No new induced draft (ID) fans or booster fans ate included in the capital cost estimate. Burns & McDonnell reviewed the fan curves provided by Vectren and determined there was sufficient capacity to handle the pressure drop through the new FGD system.
- This estimate does not include provisions for either Mercury control or SO_3 control. Vectren can continue using the existing system for each following conversion to the wet LSFO technology.

Refer to Subsection 3.5.1 of the Burns & McDonnell report in Appendix B.

5.4 PROJECT INDIRECT COSTS

Burns & McDonnell included the following indirect costs in the capital cost estimate:

- Performance testing and CEMS/stack emissions testing.
- Pre-operational testing, startup, start-up management and calibration.
- Construction/start-up technical serv ice.
- Engineering.
- Freight.
- Start-up spare parts.

Refer to Section 3.6 of the Burns & McDonnell report in Appendix B.

5.5 OWNER COSTS

Burns & McDonnell did not include the following Owner's costs in the estimates:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.
- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- Political concessions.
- Builder's risk insurance.
- Owner's contingency.
- Allowance for funds used during construction (AFUDC).

Refer to Section 3.7 of the Burns & McDonnell report in Appendix B.

5.6 COST ESTIMATE EXCLUSIONS

The following costs were excluded from Burns & McDonnell's estimate:

- Escalation.
- Sales tax.
- Property tax and property insurance.
- Utility demand costs.
- Salvage values.

Refer to Section 3.8 of the Burns & McDonnell report in Appendix B.

5.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement LSFO system is summarized in Table 5-2. The direct cost includes the cost of the absorber, limestone preparation system, gypsum dewatering system, gypsum canopy for 3 days of gypsum storage, WWT equipment, electrical upgrades, boiler reinforcement, new stack for Unit 1, and installation.

Table 5-2 LSFO Capital Costs

Category	Cost
Total Direct Cost	$265,287,000
Indirect Cost	$66,480,000
Contingency	$65,571,000
Engineering, Procurement, and Construction (EPC) Fee	$27,540,000
Total Project Cost	**$424,878,000**

5.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the LSFO system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied; labor costs are not included in the O&M estimates in Table 5-3. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 5-3 represents the O&M costs for the LSFO system only and does not include the balance-of-plant O&M costs.

Table 5-3 LSFO Operation and Maintenance Costs

Category	Cost
O&M Schedule Outage	$28,732,000
O&M – Base Non-Labor	$14,892,000
20 Year Total	$43,624,000

5.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

The cost estimates developed for this FGD technology includes the assumption that the LSFO process will produce a saleable gypsum product. The chloride content is limited in saleable gypsum, therefore a gypsum cake washing process is required. The estimate includes water treatment and wastewater treatment equipment sized and developed for this process only. The LSFO water and wastewater treatment equipment is not sized to handle or treat flow streams from or to support other parts of the project site.

5.10 RISKS

The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.

There are a large number of LSFO systems operating in the United States which have a proven record of achieving the required emissions rates. The limestone reagent required for this system is readily available in the US. The gypsum byproduct will need to be landfilled if a buyer(s) for this material is not found or contracted with to take this material for recycling and re-use.

6.1 Wet Lime Inhibited Oxidation Scrubber (WLIO)

6.2 DESCRIPTION OF TECHNOLOGY

WLIO is one replacement technology with the capability to achieve the SO_2 removal required for A.B. Brown. The technology uses slaked lime in a spray tower scrubber to remove SO_2 from the flue gas producing.

6.1.1 Basic Process Description

Wet lime FGD is the generic term for processes using slaked lime as the scrubbing reagent in a spray tower FGD module. Wet lime processes are offered by a number of FGD suppliers. The reagent preparation system equipment is the only significant difference between the equipment used in the wet lime and wet limestone systems. However, the higher reactivity of the lime allows the equipment to be smaller than with a wet limestone scrubber.

Inhibited oxidation producing a calcium sulfite material is used or forced oxidation is used to promote formation of a fully oxidized gypsum byproduct. For this study, an inhibited oxidation process is assumed that produces a material for landfill disposal.

The primary difference in the wet lime and wet limestone processes is the preparation of scrubbing reagent slurry. In wet lime processes, CaO is slaked to produce a Ca $(OH)_2$ slurry.

$$CaO + H_2O \rightarrow Ca\,(OH)_2$$

For a wet lime FGD process, the chemical reactions are as follows:

$$SO_2 + Ca(OH)_2 \rightarrow CaSO_3 \bullet 1\ 1/2\ H_2O + 1/2\ H_2O$$
$$SO_2 + Ca(OH)_2 + 1/2\ O_2 + H_2O \rightarrow CaSO_4 \bullet 2\ \ H_2O$$

The reactivity of Ca $(OH)_2$ in the lime slurry is significantly greater than that of limestone. Since lime is typically manufactured by calcination of limestone, the cost of lime is significantly greater than that of limestone.

The lime slurry may be prepared in detention, paste, or ball mill slakers. An inventory of prepared slurry is stored in a slurry feed tank, ready for automatic injection into the FGD module's reaction tank as required to maintain the pH of the reaction tank slurry.

Spray towers for wet lime processes are essentially identical to those used in wet limestone FGD processes, except the absorber can be slightly shorter. Slurry from the FGD module reaction tank is sprayed into the flue gas flow stream; the SO_2 is absorbed from the flue gas by the lime slurry. The height of the tower and the liquid to gas ratio (L/G) may be lower than for limestone systems because of the reactivity of the lime slurry.

The solubility of Ca $(OH)_2$ in the slurry results in a pH in the reaction tank that is higher than in a wet limestone FGD process. The higher pH limits the natural oxidation of sulfites to sulfates to less than that achieved in a wet limestone process, but an oxidation inhibitor additive is required to keep oxidation levels low enough to prevent potential scaling issues.

6.1.2 Flow Diagram

The WLIO system utilizes pebble lime as the reagent, which is slaked producing a 20 percent solids slurry. The slaked lime slurry is fed into a spray tower absorber. The resulting calcium sulfite solids are removed and sent to thickeners and rotary drum filters for dewatering. The byproduct has a high moisture content and must be fixated with fly ash or Portland cement prior to disposal in the landfill. There is no market for the byproduct from a WLIO.

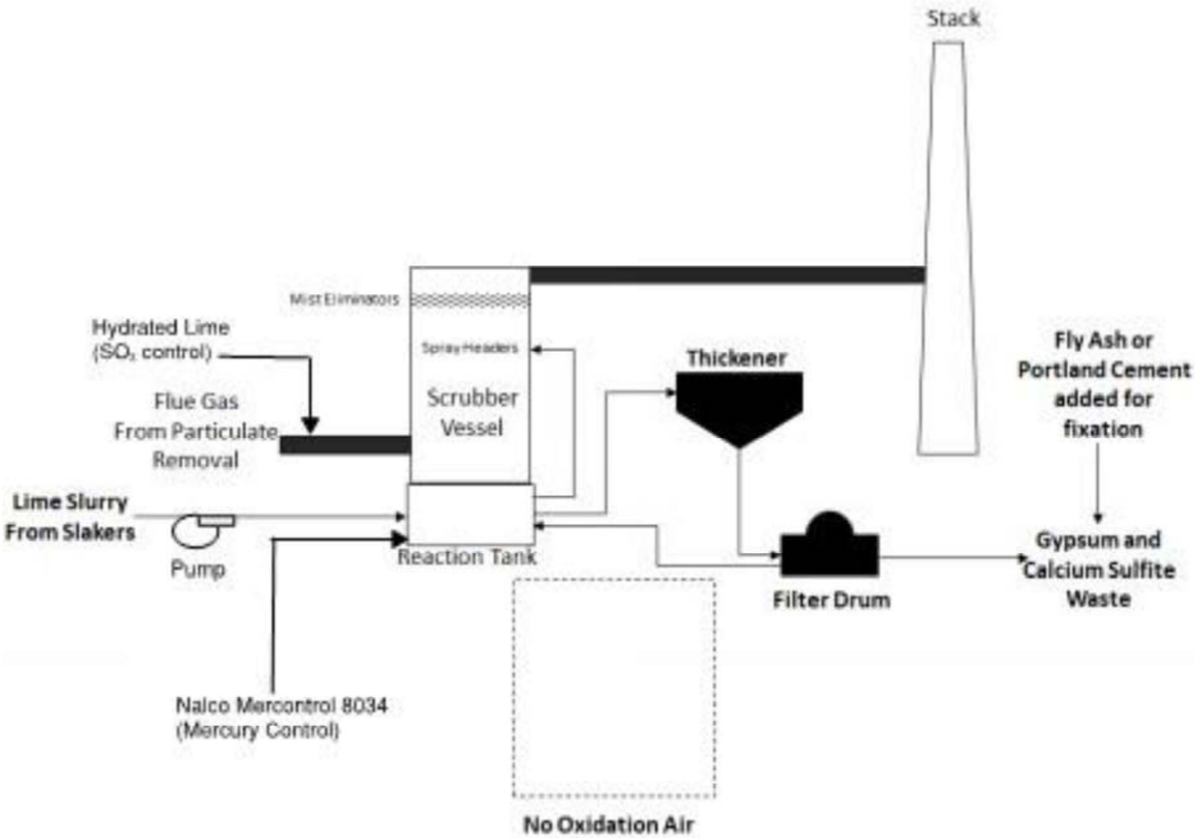

Figure 6-1 Wet Lime Inhibited Oxidation Scrubber

6.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

The WLIO system will use the existing mercury control systems (Nalco Mercontrol 8034) for mercury control. Mercontrol 8034 chemical is injected into the scrubber lime slurry recirculation piping for mixing and dispersion. Mercury is captured in the scrubber slurry as it is circulated through the scrubber vessel.

Hydrated lime is pneumatically injected into the duct (DSI) upstream of the scrubber to control SO_3 emissions.

HCl is removed through a combination of hydrated lime injection and the WLIO scrubber system.

Table 6-1 Environmental Controls WLIO

Pollutant	Hg	SO_3	SO_2	PM
Control Technologies	WLIO + Nalco Mercontrol 8034	Hydrated Lime Injection	WLIO	Existing PM control: Unit 1 – Fabric Filter Unit 2 - ESP

6.1.4 Reagent Type, Storage, and Preparation

Pebble lime is utilized as the reagent in a WLIO scrubber. The pebble lime would be shipped to the site by pneumatic truck or railcar and stored in silos. The silos would be designed to store 7 to 14 days of pebble lime on the basis of full load operation. The pebble lime would be fed into a slaker that mixes the pebble lime with water. The exothermic reaction produces a $Ca(OH)_2$ slurry containing about 20 percent solids, which is stored in an agitated slurry tank. Pumps are used to supply the slurry to the absorber based on the demand signal from the control system.

6.1.5 Byproduct Type, Storage, and Handling

The byproduct produced by the WLIO system is a combination of calcium sulfite and calcium sulfate. The high pH in the absorber system naturally inhibits oxidation so the resulting byproduct is mostly calcium sulfite. Dewatering of calcium sulfite is difficult so the resulting byproduct will contain 20 to 30 percent free moisture. The byproduct would be mixed with fly ash or Portland cement in a pug mill before being transported via truck to dispose of in a landfill.

6.1.6 Description of Basic Equipment in Process

The WLIO system includes the following basic equipment:

- Absorber Module, including spray headers, mist eliminators, and recirculation pumps.
- Reagent Preparation System, including fluidized storage system, feeders, lime slakers, slaked lime slurry storage tanks, and reagent feed pumps.
- Dewatering System, including thickeners and rotary drum filters.
- Byproduct Fixation System, including Portland cement silo and pug mill.

6.1.7 Description of Basic Sizing Criteria for Major Equipment

The major equipment was scaled from other projects based on the size of the units (MW), sulfur content of the fuel, and the amount of reagent required to meet the emissions targets.

6.2 ESTIMATING METHODOLOGY

Black & Veatch developed order of magnitude estimates for the feasible SO_2 control technologies. This section details the basis of these estimates, including scope and assumptions used in the estimate development.

6.2.1 Original Equipment Manufacturer Equipment

The capital cost estimate is based on previous EPC bids Black & Veatch received for another project. The costs were adjusted for the size of the units (on a MW basis) and differences in the fuel being burned. The cost was escalated using the Chemical Engineering Plant Cost Index factor to 2019 dollars. To allow for continued operation of the existing units, the location for new FGD equipment installation has been preliminarily selected to be due East of the existing Unit 1 fabric filter. Installation of a new concrete stack for Unit 1 is included in the estimate.

A cost of $18,650,000 was included for the demolition of the existing Unit 1 and Unit 2 scrubbers based on estimated costs for demolition of building and equipment at grade and costs obtained from similar projects for stack demolition. Demolition will occur in two stages to enable continued operation of the units during the construction periods for the new FGD equipment. Demolition includes removal of Unit 1 scrubber equipment, ducts, piping, electrical, and buildings to enable construction of Unit 2 scrubber equipment and reuse of Unit 1 stack for Unit 2 operation. Upon Unit 2 new FGD tie-in and operation, the Unit 2 existing scrubber equipment, ducts, piping, electrical, buildings, sludge handling equipment, and Unit 2 stack will be demolished and removed from the site.

6.2.2 Balance-of-Plant Equipment Needed to Make the Estimate Complete

The balance-of-plant modification costs were also based on the recent projects completed by Black & Veatch for WLIO system additions.

The project costs included the following modifications to the balance-of-plant equipment:

- Induced Draft (ID) Fan Upgrades.
- Auxiliary Electrical Equipment.
- Ductwork.
- Structural Steel.
- Foundations.
- Continuous Emissions Monitoring System (CEMS) System.
- Boiler Reinforcement.
- Service Water System.
- Service and Instrument Air Systems.
- Unit 1 Stack Demolition and New Stack Installation.

6.3 ESTIMATE ASSUMPTIONS

6.3.1 General Assumptions

- No costs associated with existing ash pond were considered.
- Existing soil will have sufficient strength to support the new basins and building.
- No costs were included for existing gravel road repair or new roads.

- A liner was assumed to be needed under the collection basin and settling basins. A liner was not assumed to be needed under new piping.
- No site leveling or raising were included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- No provisions for future expansion of the new WWT equipment were included.
- Equipment sizing was based on two operating units.
- Costs associated with changes to the current FGD wastewater mercury treatment equipment, or any upstream piping or devices from either unit will be made for any options that will reuse the equipment, are included.
- Required instrumentation is included in cost of treatment system.
- Existing excavated dirt is assumed to be suitable for backfill material. No imported fill is included.

6.3.2 Direct Cost Assumptions

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation was included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs are based on an EPC construction approach.
- Total capital costs are AACE Class 5 ±50 percent for concept screening, and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Separate FGD absorber systems are provided for each unit with some common equipment for both units, including reagent preparation and byproduct handling.

6.3.3 Indirect Cost Assumptions

The following indirect costs are included in the base construction cost estimate:

- General indirect costs include all necessary services required for checkouts, testing services, and commissioning.
- Insurance, including builder's risk and general liability.
- Field construction management services, including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond and liability insurance for equipment and tools.
- Startup/commissioning spare parts.

- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Reagent usage rates provided for variable O&M component.

The following additional items of cost are not included in the construction estimate. These costs shall be determined by Vectren and included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes.
- Major equipment spare parts.
- Land.
- Interest during construction.
- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Emissions credits.
- Environmental mitigation.

6.4 PROJECT INDIRECT COSTS

The following project indirect costs are included in the capital cost estimate:

- Engineering.
- Construction and field expenses.
- Startup costs.
- Contingencies.
- Freight.
- Performance testing.

6.5 OWNER COSTS

The Owner's costs are not included in the capital cost estimate:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.

- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- O&M base non-labor cost for the plant as provided by Vectren.
- O&M base labor cost for the plant as provided by Vectren.
- Political concessions.
- AFUDC.

6.6 COST ESTIMATE EXCLUSIONS

In addition to the Owner's costs, the following costs were also excluded from the capital cost estimate:

- Escalation.
- Sales tax.
- Property tax.
- Salvage values.
- Utility demand costs.

6.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement WLIO system is summarized in Table 6-2. The direct cost includes the cost of the absorber, reagent preparation system, PAC system, electrical upgrades, ID fan upgrades, boiler reinforcement, silo and pug mill, Unit 1 chimney, and installation. The costs were based on recent projects completed by Black & Veatch.

Table 6-2 WLIO Capital Costs

Category	Cost
Total Direct Cost	$318,079,000
Indirect Cost	Included Above
Contingency	Included Above
EPC Fee	Included Above
Total Project Cost	**$318,079,000**

6.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the WLIO system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied. Labor costs are not included in the estimates in Table 6-3. The O&M costs are total cost for 20 years from 2020 to 2039 and are rounded to the nearest $1,000. The O&M costs in Table 6-3 only represent the O&M costs for the WLIO system only and do not include the balance-of-plant O&M costs.

Table 6-3 WLIO Operation and Maintenance Costs

Category	Cost
O&M Schedule Outage	$21,510,000
O&M – Base Non-Labor	$11,159,000
20 Year Total	$32,659,000

6.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

Water and Wastewater treatment system costs for the WLIO system are negligible. Minor water and wastewater treatment system costs have been included with the balance of plant (BOP) costs for upgrade of those systems. Any water used or wastewater created by the WLIO would effectively be managed by mixing with the byproduct and fixating material (either fly ash or Portland Cement) at a pug mill on the discharge of the filter drum to mix these materials. The discharge waste material is then taken to a designated waste disposal area.

6.10 RISKS

The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.

Below is a list of potential risks A.B. Brown may encounter when implementing WLIO technology:

- WLIO scrubbers have the potential to scale which would impact scrubber operation and performance.

7.1 Circulating Dry Scrubber (CDS)

7.2 DESCRIPTION OF TECHNOLOGY

The CDS FGD, also known as a circulating fluid bed scrubber, process is a semi-dry, lime-based FGD process that uses a circulating fluid bed contactor rather than an SDA. The CDS absorber module shown on Figure 7-1 is a vertical solid/gas reactor between the unit's air heater and its particulate control device. The CDS system consists of an absorber module, particulate control device (fabric filter or ESP), air slides, reagent storage silo, water storage tank, water inject lances, and water pumps. The reagent can be either hydrated lime or pebble lime. If pebble lime is utilized, an on-site hydrator is required to hydrate the pebble lime (CaO) to hydrated lime [$Ca(OH)_2$] prior to injection into the absorber module.

7.1.1 Basic Process Description

Water (humidification) is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of SO_2 with the reagent. Hydrated lime [$Ca(OH)_2$] and recirculated dry solids from the particulate control device are injected concurrently with the flue gas into the base of the reactor just above the water sprays. The gas velocity in the reactor is reduced, and a suspended bed of reagent and fly ash is developed. The SO_2, SO_3, and HCl in the flue gas reacts with the reagent to form predominantly $CaSO_3$ with some CaCl and $CaSO_4$. Fine particles of byproduct solids, excess reagent, and fly ash are carried out of the reactor and removed by the particulate removal device (either a fabric filter or dry ESP). More than 90 percent of these solids are returned to the reactor to improve reagent utilization and increase the surface area for SO_2/reagent contact.

The CDS FGD system produces an extremely high solids load on the particulate removal device as a result of recycling the byproduct/fly ash mixture. Air slides are used to recycle the large amounts of byproduct to the absorber. Air slides are capable of moving large amounts of solids with less energy consumption. The use of air slides require the particulate control device to be elevated to allow the material to flow down to the absorber vessel.

The byproducts from this process are similar to that produced in the lime SDA discussed previously. No dewatering is required, but the wastes must be wetted for control of fugitive dust emissions during transportation and for compaction at the landfill. When wetted, unreacted lime in the wastes should cause a fixation reaction, decreasing waste permeability and increasing unconfined compressive strength.

The process is controlled through three variables: SO_2 emissions, reactor exit temperature, and reactor differential pressure. SO_2 outlet concentration is monitored, and fresh hydrated lime reagent is introduced at the venturi as required to maintain the desired SO_2 removal efficiency. The reactor outlet temperature is maintained between 160° and 180° F, and an approach temperature of 35° to 40° F is maintained by controlling the quantity of water introduced at the venturi. The pressure drop across the reactor is regulated by the rate of return of recycled material to the reactor. One advantage of the CDS system over the SDA system is the addition of water and reagent is separate, allowing the system to inject more reagent to reach higher emissions removal.

These circulating fluid bed SO_2 absorber systems have been in operation in Europe since 1980. Since 1987, they have recorded an average of 97 percent SO_2 removal rate on a 100 MW lignite fueled plant. The technology has rapidly gained favor with many units as large as 250 to 300 MW on a single absorber. The largest unit operating overseas is 300 MW.

7.1.2 Process Flow Diagram

Figure 7-1 is a flow diagram of the CDS system. The CDS system shown below utilizes hydrated lime as it does not include a hydrator system to convert pebble lime to hydrated lime. The CDS system also includes a dedicated water supply system for the humidification of the flue gas, including a water tank and 2 x 100 percent pumps.

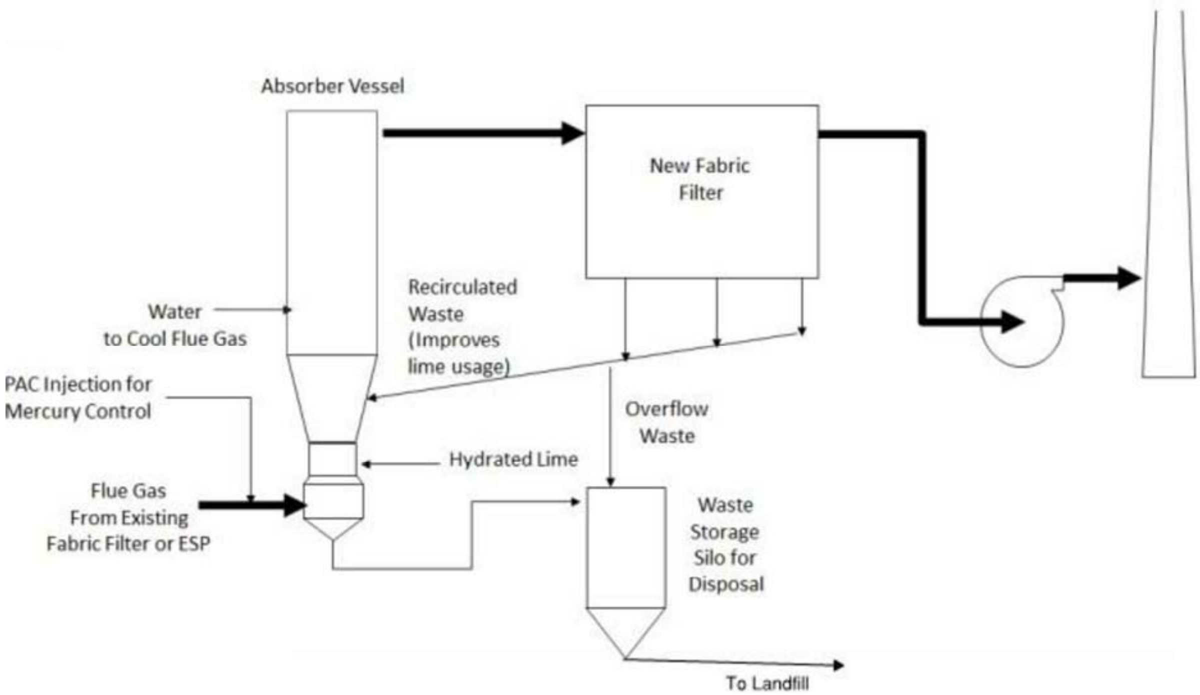

Figure 7-1 Circulating Dry Scrubber

7.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

Powdered activated carbon (PAC) is injected upstream of the CDS vessel to control mercury emissions. The PAC material is circulated in the CDS absorber vessel and collects on the fabric filter media bags.

The hydrated lime reagent in the CDS system removes SO_3, HCl, as well as SO_2. The fabric filter located downstream of the CDS absorber vessel collects the hydrated lime and ash (including PAC) particulate and returns the majority of the particulate back to be recirculated in the CDS vessel. A portion of this collected particulate is taken and sent to the waste storage silo for safe disposal.

Table 7-1 Environmental Controls CDS

Pollutant	Hg	SO_3	SO_2	PM
Control Technologies	Powdered Activated Carbon (PAC) Injection	CDS System	CDS System	Existing PM control: Unit 1 – Fabric Filter Unit 2 – ESP Post CDS - Fabric Filter

7.1.4 Reagent Type, Storage, and Preparation

CDS systems utilize either hydrated lime or pebble lime reagent. Hydrated lime is brought in with pneumatic trucks or railcars and pneumatically conveyed into storage silo(s), which typically have 7 to 14 days of storage.

Pebble lime can also be utilized as the reagent for the CDS. The pebble lime is pneumatically conveyed into a storage silo from a pneumatic truck or railcar. Pebble lime (CaO) must be reacted with water in a hydrator to produce hydrated lime [$Ca(OH)_2$]. The hydrator mixes a stoichiometric amount of water with the pebble lime to produce a hydrated lime product with less than 1 percent free moisture. The hydrated lime product is conveyed to the hydrated lime silo where it is stored for use in the CDS absorber.

7.1.5 Byproduct Type, Storage, and Handling

The hydrated lime reagent injected into the CDS module will react with acid gas, including SO_2, SO_3, and HCl. The resulting byproducts are mostly calcium sulfite ($CaSO_3$) with some calcium sulfate ($CaSO_4$) and calcium chloride (CaCl). The byproducts are mixed with fly ash and activated carbon for mercury removal.

The byproduct is pneumatically conveyed to the byproduct silo where it would be conditioned for dust control before being hauled to the landfill. The byproduct has limited reuse potential but can be used for soil stabilization. In most cases the byproduct is sent to a landfill.

7.1.6 Description of Basic Equipment in Process

The CDS system includes the following basic equipment:

- CDS Scrubber Module, including venturi.
- Humidification System, including water tank, pumps, valves, and water injection lances (3 to 4).
- Reagent System, including fluidized storage system, de-aeration bin, weigh belt feeder, rotary valves, and air slide.
- Particulate Collection System, including fabric filter.
- Byproduct Recirculation and Removal System, including air slides and dosing valves.

7.1.7 Description of Basic Sizing Criteria for Major Equipment

The major equipment was scaled from other projects based on the size of the units (MW), sulfur content of the fuel, and the amount of reagent required to meet the emissions targets.

7.2 ESTIMATING METHODOLOGY

Black & Veatch developed order of magnitude estimates for the feasible SO_2 control technologies. This section details the basis of these estimates, including scope and assumptions used in the estimate development.

7.2.1 Original Equipment Manufacturer Equipment Estimate

For the CDS System Black & Veatch used actual pricing from recent projects completed in the last 5 years. The project scope was evaluated and modified as needed to compare to the A.B. Brown requirements. The project costs were scaled based on unit size and sulfur removal. The costs were also escalated to 2019 dollars.

7.2.2 Balance-of-Plant Equipment Needed to Make the Estimate Complete

The balance-of-plant modification costs were also based on the recent projects completed by Black & Veatch for CDS system additions.

The project costs included modifications to the balance-of-plant equipment:

- ID Fan Upgrades.
- Auxiliary Electrical Equipment.
- Ductwork.
- Structural Steel.
- Foundations.
- CEMS System.
- PAC Injection System.
- Boiler Reinforcement.
- Service Water System.
- Service and Instrument Air Systems.

PAC Injection

Activated carbon (PAC) injection was added to the train to control mercury emissions. Hydrated lime is injected in the CDS module, which will control sulfuric acid (SO_3) emissions. Additional hydrated lime injection for SO_3 control would not be necessary. The PAC will be recirculated in the CDS system and coat the fabric filter bags, allowing for a significant residence time in the flue gas.

ID Fan

The existing ID fans do not have the capacity required for the new air quality control train. Due to the added pressure drop of the new fabric filter and CDS module, the ID fans on each unit will need to be replaced. For the purposes of this study, new ID fans have been included in the scope of work.

Balance-of-Plant Modification

The scope of work includes modifications to balance-of-plant equipment like distributed control system (DCS), electrical equipment, CEMS, foundations, service and instrument air systems, boiler reinforcement, ductwork, and structural steel, which would be required to support the addition of the new air quality control system.

7.3 ESTIMATE ASSUMPTIONS

7.3.1 General Assumptions

- No costs associated with existing ash pond were considered.
- Existing soil will have sufficient strength to support the new basins and building.
- No cost was included for existing gravel road repair or new roads.
- A liner was assumed to be needed under the collection basin and settling basins. A liner was not assumed to be needed under new piping.
- No site leveling or raising was included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- No provisions for future expansion of the new WWT equipment were included.
- Equipment sizing was based on two operating units.
- Required instrumentation was included in the cost of the treatment system.
- Existing excavated dirt was assumed to be suitable for backfill material. No imported fill was included.

7.3.2 Direct Cost Assumptions

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation was included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs were based on an EPC construction approach.
- Total capital costs are AACE Class 5 ±50 percent for concept screening, and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Separate FGD absorber systems were provided for each unit with some common equipment for both units, including reagent preparation, and byproduct handling.

7.3.3 Indirect Cost Assumptions

The following indirect costs were included in the base construction cost estimate:

- General indirect costs for checkouts, testing services, and commissioning.
- Insurance, including builder's risk and general liability.
- Field construction management services including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Startup/commissioning spare parts.
- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Reagent usage rates provided for variable O&M component.

The following additional items of cost were not included in the construction estimate. These costs shall be determined by Vectren and included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes.
- Major equipment spare parts.
- Land.
- Interest during construction.
- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Emissions credits.
- Environmental mitigation.

7.4 PROJECT INDIRECT COSTS

The following project indirect costs are included in the capital cost estimate:

- Engineering.
- Construction and field expenses.
- Startup costs.

- Contingencies.
- Freight.
- Performance testing.

7.5 OWNER COSTS

The Owner's costs are not included in the capital cost estimate:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.
- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- O&M base non-labor cost for the plant as provided by Vectren.
- O&M base labor cost for the plant as provided by Vectren.
- Political concessions.
- AFUDC.

7.6 COST ESTIMATE EXCLUSIONS

In addition to the Owner's costs, the following costs were also excluded from the capital cost estimate:

- Escalation.
- Sales tax.
- Property tax.
- Salvage values.
- Utility demand costs.

7.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement CDS system is summarized in Table 7-2. The direct cost includes the cost of the absorber, fabric filter, PAC system, electrical upgrades, ID fan upgrades, boiler reinforcement, and installation. The costs were based on recent projects completed by Black & Veatch.

Table 7-2 CDS Capital Costs

Category	Cost
Total Direct Cost	$269,550,000
Indirect Cost	Included Above
Contingency	Included Above
EPC Fee	Included Above
Total Project Cost	**$269,550,000**

7.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the CDS system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied; labor costs are not included in the estimates in Table 7-3. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 7-3 represents the O&M costs for the CDS system only and does not include the balance-of-plant O&M costs.

Table 7-3 CDS Operations and Maintenance Costs

Category	Cost
O&M Schedule Outage	$18,228,000
O&M – Base Non-Labor	$9,448,000
20 Year Total	$27,676,000

7.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

Water and Wastewater treatment system costs for the CDS system are negligible. Minor water and wastewater treatment system costs have been included with the balance of plant (BOP) costs for upgrade of those systems. Any water used or wastewater created by the CDS would effectively be used in the CDS as water to cool the flue gas and control flue gas temperature. Solids in the water/wastewater would be removed from the gas stream using the new fabric filter.

7.10 RISKS

The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.

Below is a potential risk A.B. Brown may encounter when implementing CDS scrubber technology.

- Lime Consumption - Large quantities of hydrated lime are required to achieve the removal levels required for these units. The shipping logistics are significant and a delivery interruption could impact unit operation due to material availability to control emissions. The estimated lime consumption would require approximately one pneumatic truck load of pebble lime per hour.

8.1 Ammonia (NH_3) Scrubber

8.2 DESCRIPTION OF TECHNOLOGY

The ammonia (NH_3) scrubber technology uses a spray tower absorber with ammonia reagent to remove SO_2 from the flue gas. Ammonia combines with SO_2 to form ammonium sulfate. The ammonium sulfate is dewatered, crystalized, and dried to form a solid ammonium sulfate byproduct that can be used for fertilizer.

8.1.1 Basic Process Description

In the ammonia scrubber, anhydrous ammonia is used as the desulfurization absorbent to capture SO_2, and the byproduct of the process is a marketable fertilizer material. The only large FGD system of this type in the United States was installed at Dakota Gasification in North Dakota. At this facility, the ammonia solution contacts the flue gas in a spray tower type absorber similar to a wet limestone or lime system. The ammonia solution absorbs the SO_2 to form an ammonium sulfite solution. Air is fed into the absorber to oxidize the ammonium sulfite to an ammonium sulfate solution. The ammonium sulfate solution is concentrated and crystallized into a slurry, which is then transferred to an area where the ammonium sulfate is separated from the solution, and dried. The dried ammonium sulfate can be sold as fertilizer.

Currently one equipment supplier, based in China but with offices in the United States, has expressed interest in the A. B. Brown application. A second potential equipment supplier has indicated that it is currently focusing on industrial applications because of the uncertain operating status of many coal fired power plants. Jiangnan Environmental Technology, Inc. (JET), has completed ammonia scrubbers in China and other overseas countries but has no United States applications to date. The ammonia scrubber technology is similar to the United States application of ammonia scrubbing that currently is in operation in North Dakota; however, JET did not supply the unit in North Dakota.

Dakota Gasification Company's Great Plains Synfuels Plant is the only large U.S. based industrial plant with an ammonia scrubber installed. Emissions limits and the potential for a visible plume produced by the plant were addressed by the addition of a WESP. The plant also has ammonia discharge emissions limits. For the purpose of this study, a WESP has been included in the scope of work to mitigate emissions.

The quality of the ammonium sulfate byproduct produced or purity for the coal analysis specific to this site was not provided.

8.1.2 Flow Diagram

Figure 8-1 is a flow diagram of the ammonia scrubber. The typical ammonia scrubber uses anhydrous or aqueous ammonia reagent. The scrubber is a spray tower design using recycle pumps to inject the reagent into the flue gas. A bleed stream is removed from the reaction tank to be dewatered prior to drying the final ammonium sulfate byproduct.

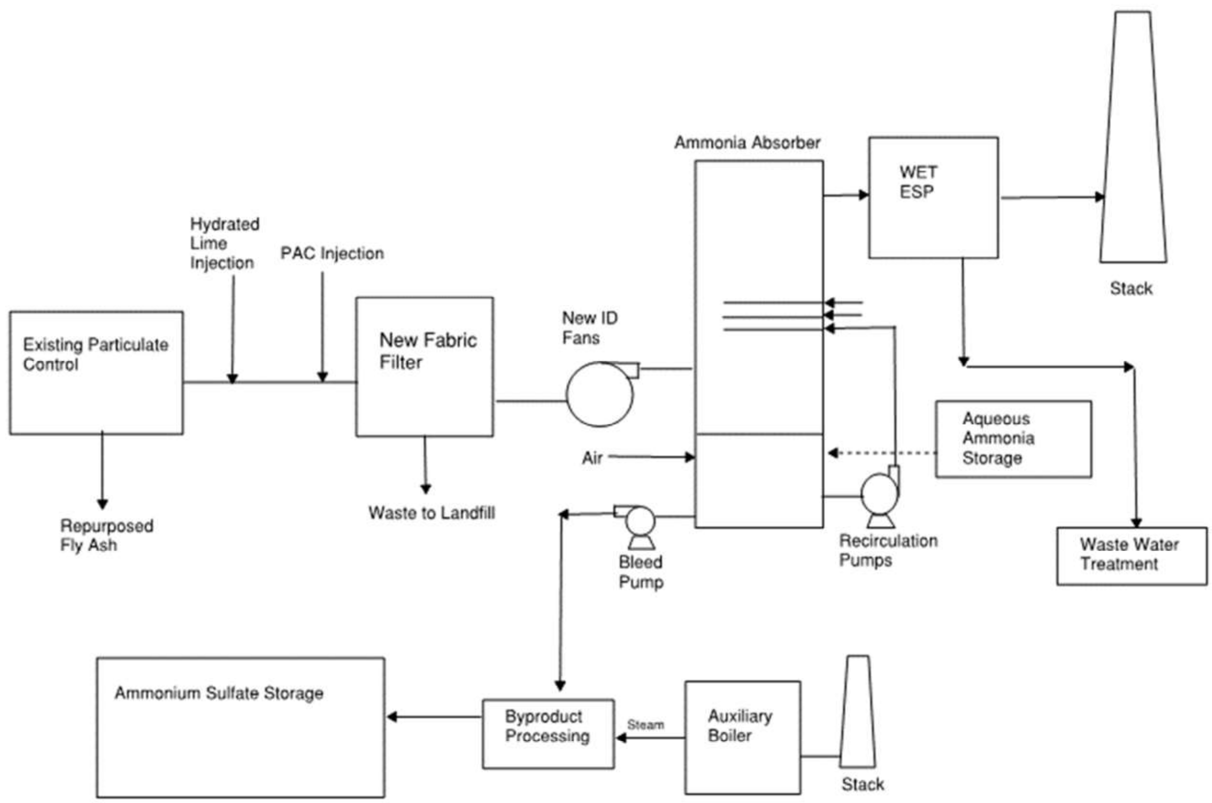

Figure 8-1 Ammonia Scrubber

8.1.3 Environmental Controls

The existing particulate control systems (fabric filter on Unit 1 and electrostatic precipitator (ESP) on Unit 2) and ash collection systems remain in service with the fly ash continuing to be available for recycle.

A dry sorbent injection system (DSI) system utilizing hydrated lime injection downstream of the existing particulate control system is used to control HCl and SO_3 emissions.

Powdered activated carbon (PAC) is injected downstream of the DSI injection to control mercury emissions. A new fabric filter is added to collect the particulate from the PAC and DSI injection. The collected solids from this fabric filter are sent as waste to the landfill.

A wet electrostatic precipitator (ESP) has been included to control ammonia slip and fine particulate emissions.

Table 8-1 Environmental Controls NH_3

Pollutant	Hg	SO_3	SO_2	PM
Control Technologies	Powdered Activated Carbon (PAC) Injection	Hydrated Lime Injection	Ammonia FGD	Existing PM control: Unit 1 – Fabric Filter Unit 2 – ESP Fabric Filters downstream of DSI and PAC injection WESP downstream of NH_3 FGD

8.1.4 Reagent Type, Storage, and Preparation

The reagent is either anhydrous ammonia or aqueous ammonia. Due to concerns regarding the safe storage and handling of anhydrous ammonia Vectren will need to complete a detailed analysis of the risks of storing large quantities of anhydrous ammonia onsite looking at the impact to surrounding communities and public safety.

For the purposes of this study aqueous ammonia was assumed to be utilized at A.B. Brown. The aqueous ammonia would be shipped to the site by a tanker truck or railcar and would be stored in large tanks. Vectren has requested 14 days of storage, which would require about 3,050,000 gallons of storage. The aqueous ammonia would be pumped into the reaction tank based on the demand signal from the process controls.

8.1.5 Byproduct Type, Storage, and Handling

The ammonia reagent combines with the SO_2 to form ammonium sulfate. The ammonium sulfate solution is pumped via a bleed stream from the recirculation tank. The ammonium sulfate must be dewatered and dried. Once the material is dry, the ammonium sulfate can be packaged and stored or bulk stored and shipped to a fertilizer wholesaler for further processing or blending. Ammonium sulfate is water soluble so it must be stored indoors. No information was provided regarding the purity of the ammonium sulfate, contaminants in the ammonium sulfate, particulate size distribution or whether the product was granular or powder. Processed ammonium sulfate can be sold as a fertilizer for agriculture if a market is available.

8.1.6 Description of Basic Equipment in Process

The ammonium scrubber systems can vary from each supplier, however, generally the equipment consists of a spray tower absorber module. Oxidation blowers to help oxidize the byproduct to sulfate. A recirculation tank at or near the bottom of the spray tower stores the recirculation mixture. Recirculation pumps supply the reagent mixture to the spray headers at the top of the absorber so that the reagent is sprayed and falls downward to maximize contact with the up-flow of exhaust gas. A bleed stream from the absorber feeds a small stream of the reagent mixture solution to a liquid and solids separation system. The byproduct is then further concentrated and crystalized to the ammonium sulfate byproduct. A drying system using steam heat is then used to completely dry the ammonium sulfate crystals.

8.1.7 Description of Basic Sizing Criteria for Major Equipment

The auxiliary support equipment required for this technology was scaled from other projects based on the size required, steam heat requirements, and the amount of reagent required to be stored on site to meet the specified days of operation for the emissions targets established.

The ammonia scrubber is to be designed for an inlet SO2 concentration of 6.72 lb/MBtu. The ammonia system is designed to meet an outlet SO2 emission rate of 0.10 lb/MMBtu.

8.2 ESTIMATING METHODOLOGY

8.2.1 Original Equipment Manufacturer Equipment Estimate

Black & Veatch sent a request for quotation to Marsulex and JET. Marsulex declined to provide a bid; JET provided a budgetary quotation for the ammonia scrubber, including the scrubber modules, recirculation tank with pumps, oxidation air fans, ammonia storage, hydrocyclones, dryers, packing machine, and byproduct storage.

8.2.2 Balance-of-Plant Equipment Needed to Make the Estimate Complete

The balance-of-plant modification costs were estimated based on the requirements of the A.B. Brown plant and based on the recent projects completed by Black & Veatch.

The project costs included modifications to the balance-of-plant equipment:

- ID Fan Upgrades.
- Auxiliary Electrical Equipment.
- WESP.
- Auxiliary Boiler.
- Fabric Filters.
- Unit 1 Chimney.
- Ductwork.
- Structural Steel.
- Foundations.
- CEMS System.
- PAC Injection System.
- Boiler Reinforcement.
- Storage Building.
- DCS Upgrade.
- Service and Instrument Air Systems.

Wet ESP

The Dakota Gasification Company's Great Plains Synfuels Plant is the only large industrial plant with an ammonia scrubber installed in the United States. Emissions limits and concerns for a visible plume produced by the plant were mitigated by the addition of a WESP. A.B. Brown has an ammonia discharge emissions limit to comply with. For the purpose of this study, a WESP has been included in the scope of work to ensure emissions compliance and to eliminate the potential for a visible plume.

PAC Injection

Activated carbon (PAC) injection was added to the train to control mercury emissions. Hydrated lime will be injected upstream of the PAC injection to control sulfuric acid (SO_3) emissions. SO_3 impacts the mercury removal performance of the PAC and must be removed from the flue gas prior to the addition of the PAC. New fabric filters have been included to capture the hydrated lime and PAC particulate.

Fabric Filters

To allow A.B. Brown to continue existing operations, a fabric filter has been added to capture the injected activated carbon and hydrated lime reagents. The fabric filter will be located downstream of the existing particulate control device and upstream of the new ammonia scrubber on each unit. For the purpose of this study, a fabric filter has been included in the scope of work to ensure emissions compliance.

ID Fan

The existing ID fans do not have the capacity required for the new air quality control train. Due to the added pressure drop of the new fabric filter, ductwork modifications, and WESP, the ID fans on each unit will need to be replaced. For the purposes of this study, new ID fans have been included in the scope of work.

Auxiliary Boiler

To produce a saleable ammonium sulfate byproduct the bleed stream from the scrubber must be concentrated and dewatered. The resulting dewatered solids must be dried to form a dry granular product suitable for bulk bagging or bulk loading of raw product. Equipment to dewater, dry, and either bag the byproduct or to bulk load equipment into truck or rail containers will be required. A source of steam heat is required to dry the byproduct in preparation for storage and transportation. For the purpose of this study, an auxiliary boiler has been sized and included in the scope of work to provide the required steam to the ammonium sulfate drying system. This will also maintain plant steam supply from the main boiler to the steam turbine to maximize unit output. In addition, Unit 1 and Unit 2 are currently not operated continuously and cannot be depended on to provide a continuous source of steam for heat to the ammonium sulfate drying system.

Unit 1 Chimney

In order to minimize outage time, the conceptual design layout developed would include installing the new air quality control system to the east of the existing air quality control system. A new stack would be built east of the new Unit 1 air quality control system. The existing Unit 1 scrubber system would be demolished, allowing for installation of the Unit 2 system. The new Unit 2 scrubber system would reuse the Unit 1 stack. The existing Unit 2 scrubber and Unit 2 stack would be demolished once the new Unit 2 scrubber system had been placed in service.

Balance-of-Plant Modification

The scope of work includes modifications and additions to balance-of-plant equipment, like DCS, electrical equipment, CEMS, foundations, service and instrument air systems, piping for water and wastewater systems, storage building, ductwork, and structural steel, which would be required to support the addition of the new air quality control system. Boiler, ductwork, and existing particulate collection equipment will require additional reinforcement to comply with National Fire Protection Association (NFPA) 85 recommendations.

8.3 ESTIMATE ASSUMPTIONS

8.3.1 General Assumptions

- No costs associated with existing ash pond were considered.
- Existing soil will have sufficient strength to support the new basins and building.
- No cost was included for existing gravel road repair.
- A liner was assumed to be needed under the collection basin and settling basins. A liner was not assumed to be needed under new piping.
- No site leveling or raising was included in the estimate.
- The site has sufficient area available to accommodate construction activities including, but not limited to, construction offices (trailers), laydown, and staging.
- No provisions for future expansion of the new WWT equipment were included.
- Equipment sizing was based on two operating units.
- Changes to the current FGD wastewater mercury treatment equipment or any upstream piping or devices from either unit will be made for any options that will reuse the equipment.
- WWT for the FGD system was provided for those FGD technologies requiring such.
- Required instrumentation was included in cost of treatment system.
- Existing excavated dirt was assumed to be suitable for backfill material. No imported fill was included.

8.3.2 Direct Cost Assumptions

The following assumptions are included in the base construction cost estimate for direct costs:

- All costs are expressed in 2019 dollars. No escalation is included.
- Direct costs include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs were based on an EPC construction approach utilizing union craft labor.
- Total capital costs are AACE Class 5 ±50 percent for concept screening, and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Separate FGD absorber systems were provided for each unit with some common equipment for both units, including reagent preparation and byproduct handling.

8.3.3 Indirect Cost Assumptions

The following indirect costs are included in the base construction cost estimate:

- General indirect costs include all necessary services required for checkouts, testing services, and commissioning.
- Insurance, including builder's risk and general liability.
- Field construction management services including field management staff, supporting staff personnel, field contract administration, field inspection/quality assurance, and project controls.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Startup/commissioning spare parts.
- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Reagent usage rates provided for variable O&M component.

The following additional items of cost are not included in the construction estimate. These costs shall be determined by Vectren and included in Vectren's cost estimate:

- Owner's contingency costs.
- Federal, state, and local taxes except a 25 percent tariff has been placed on the equipment being exported from China.
- Major equipment spare parts.
- Land.
- Interest during construction.

- Cost and fees for electrical, gas, and other utility interconnections.
- Project development costs, legal, and community outreach.
- All operating plant vehicles.
- No permitting costs have been included.
- Emissions credits.
- Environmental mitigation.

8.4 PROJECT INDIRECT COSTS

The following project indirect costs are included in the capital cost estimate:

- Engineering.
- Construction and Field Expenses.
- Startup Costs.
- Contingencies.
- Freight.
- Performance Testing.

8.5 OWNER COSTS

The Owner's costs are not included in the capital cost estimate:

- Project development.
- Owner's operational personnel.
- Owner's project management.
- Owner's engineering.
- Owner's startup engineering and training.
- Legal fees.
- Permitting/licensing.
- Construction power, temporary utilities, startup consumables.
- Site security.
- Operating spare parts.
- O&M base non-labor cost for the plant as provided by Vectren.
- O&M base labor cost for the plant as provided by Vectren.
- Political concessions.
- AFUDC.

8.6 COST ESTIMATE EXCLUSIONS

In addition to the Owner's costs, the following costs were also excluded from the capital cost estimate:

- Escalation.
- Property tax.
- Salvage values.
- Utility demand costs.

8.7 PRESENTATION OF CAPITAL COSTS

The capital cost of the replacement CDS system is summarized in Table 8-2. The direct cost includes the cost of the absorber, ammonia storage, byproduct production, storage and bagging, fabric filters, PAC systems, electrical upgrades, Unit 1 chimney, boiler reinforcement, auxiliary boiler, and installation. The costs were based on recent projects completed by Black & Veatch.

Table 8-2 Ammonia (NH_3) Capital Costs

Category	Cost
Total Direct Cost	$284,835,000
Indirect Cost	Included Above
Contingency	Included Above
EPC Fee	Included Above
Total Project Cost	**$284,835,000**

8.8 OPERATIONS AND MAINTENANCE COSTS – PRESENT 20 YEAR TOTALS

The O&M costs start in 2024 assuming the NH_3 scrubber system installation was completed in 2023. The O&M costs are in 2019 dollars and no escalation has been applied. Labor costs are not included in the estimates in Table 8-3. The O&M costs are total cost for 20 years (from 2020 to 2039) and are rounded to the nearest $1,000. Table 8-3 represents the O&M costs for the NH_3 scrubber system only and does not include the balance-of-plant O&M costs.

Table 8-3 Ammonia (NH_3) Operation and Maintenance Costs

Category	Cost
O&M Schedule Outage	$19,262,000
O&M – Base Non-Labor	$9,983,000
20 Year Total	$29,245,000

8.9 WATER/WASTEWATER TREATMENT/WASTEWATER RECYCLE

Water treatment system costs for the NH3 scrubber system are negligible. Waste water treatment system costs have been included with the NH3 scrubber for treatment of waste water from the wet ESP equipment. Waste water produced from the wet ESP equipment process and intermittent floor drains from equipment washdown is expected. Drains from the cooling water system are considered intermittent and do not result in a continuous flow stream. Use of aqueous ammonia as the reagent will reduce the overall process water requirements, however, the overall water volume decrease has not been confirmed by the manufacturer.

8.10 RISKS

The normal risks associated with procurement of equipment (domestic or internationally sourced), construction of equipment on a large power project, and operations of the plant once completed are not included in this section. Shut down of the AB Brown coal fired units prior to 20 years of operation will economically impact the selection of scrubber technology.

Below is a list of potential risks A.B. Brown may encounter when implementing ammonia scrubber technology.

- Limited experience is found in the United States as there is only one Ammonia Scrubber System installation in the US which is on an industrial gasification plant in North Dakota that is similar to the scale proposed at AB Brown.
- The supplier providing a proposal for this equipment has not installed any equipment in the United States. This would also appear to be the first project that the supplier would perform work as an EPC Contractor on a construction project in the U.S. The supplier has proposed using U.S. craft labor with Chinese supervision on this project.
- Vectren is a power producer that is dispatched on an irregular basis. The amount of ammonium sulfate that would be produced will vary based on the load they are dispatched at. It will be difficult to enter into a contract to sell the ammonium sulfate when there is no guarantee of the amount of material that can be produced. In the event of a long-term outage, Vectren could be responsible and penalized for not providing the ammonium sulfate material as contracted to a manufacturer or distributor.
- The ammonium sulfate byproduct sales are primarily based on seasonal material usage. This will either require the ability to store a large volume on site or pay to store material at a fertilizer manufacturer’s or distributor’s facility when the demand for ammonium sulfate is low.
- The seasonal sale price of ammonium sulfate significantly impacts the economics of a power plant needing to operate year-round.
- Ammonium sulfate shipping and handling costs can limit the distribution area.
- Transportation required to remove the ammonium sulfate from the site requires loading of approximately 1.5 transport trucks per hour.
- There are limited disposal options if the ammonium sulfate byproduct cannot be sold (no demand) or is found to be out of specification quality required by the purchaser. Ammonium sulfate is water soluble and will necessitate extensive requirements to stabilize the material and enable it to be landfilled.

- Storage of large quantities of liquid anhydrous ammonia is a safety risk to personnel on the site and to the city of Evansville, Indiana. Vectren can mitigate this by the use of a 19% aqueous ammonia as the reagent, however, the trucks required for transportation and storage volume increase by approximately a factor of five. This requires delivery and unloading of more than two transport trucks of 19 percent aqueous ammonia per hour.
- There is a high variability of anhydrous ammonia and aqueous ammonia supply cost.
- No information was provided regarding the purity of the ammonium sulfate, contaminants in the ammonium sulfate, particulate size distribution or whether the product was granular or powder.
- The ammonium sulfate may require additional processing by a fertilizer manufacturer's or distributor's facility to meet the quality needed for a saleable material to the public or farming community. This would impact sale price received for this material.
- An auxiliary boiler is needed to provide steam for heating to be available on a 24/7 basis for the ammonium sulfate drying process. The emissions from the auxiliary boiler combined with emissions from the ammonia scrubber and ammonium sulfate dryer equipment may require Vectren to perform a PSD analysis.

Appendix A. 20 Year Capital and O&M Cost Inputs to the IRP

Ammonia Scrubber (NH3 FGD)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
O&M - Labor																				
O&M - Scheduled Outage	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,481,658	$ 1,481,658	$ -	$ 1,481,658	$ -	$ 2,963,316	$ -	$ 2,963,316	$ 1,481,658	$ -	$ 2,963,316	$ 1,481,658	$ -	$ 2,963,316
O&M - Base Non-Labor	$ -	$ -	$ -	$ -	$ 246,943	$ 246,943	$ 634,996	$ 634,996	$ 246,943	$ 634,996	$ 246,943	$ 1,269,992	$ 246,943	$ 1,269,992	$ 634,996	$ 246,943	$ 1,269,992	$ 634,996	$ 246,943	$ 1,269,992
Total O&M Costs	$ -	$ -	$ -	$ -	$ 246,943	$ 246,943	$ 2,116,654	$ 2,116,654	$ 246,943	$ 2,116,654	$ 246,943	$ 4,233,308	$ 246,943	$ 4,233,308	$ 2,116,654	$ 246,943	$ 4,233,308	$ 2,116,654	$ 246,943	$ 4,233,308
Capital - Direct Unit					$ 458,608	$ 458,608	$ 2,116,654	$ 2,116,654	$ 458,608	$ 2,116,654	$ 458,608	$ 4,233,308	$ 458,608	$ 4,233,308	$ 2,116,654	$ 458,608	$ 4,233,308	$ 2,116,654	$ 458,608	$ 4,233,308
Capital - Construction	$ 79,223,650	$ 68,296,250	$ 81,955,500	$ 43,709,600	$ 11,650,000															
Total Capital Costs	$ 79,223,650	$ 68,296,250	$ 81,955,500	$ 43,709,600	$ 12,108,608	$ 458,608	$ 2,116,654	$ 2,116,654	$ 458,608	$ 2,116,654	$ 458,608	$ 4,233,308	$ 458,608	$ 4,233,308	$ 2,116,654	$ 458,608	$ 4,233,308	$ 2,116,654	$ 458,608	$ 4,233,308
20 Yr Total	$ 79,223,650	$ 68,296,250	$ 81,955,500	$ 43,709,600	$ 12,355,551	$ 705,551	$ 4,233,308	$ 4,233,308	$ 705,551	$ 4,233,308	$ 705,551	$ 8,466,616	$ 705,551	$ 8,466,616	$ 4,233,308	$ 705,551	$ 8,466,616	$ 4,233,308	$ 705,551	$ 8,466,616

Limestone Forced Oxidation (LSFO)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
O&M - Labor																				
O&M - Scheduled Outage							$2,210,135	$2,210,135		$2,210,135		$4,420,270		$4,420,270	$2,210,135		$4,420,270	$2,210,135		$4,420,270
O&M - Base Non-Labor					$368,356	$368,356	$947,201	$947,201	$368,356	$947,201	$368,356	$1,894,402	$368,356	$1,894,402	$947,201	$368,356	$1,894,402	$947,201	$368,356	$1,894,402
Total O&M Costs	$0	$0	$0	$0	$368,356	$368,356	$3,157,336	$3,157,336	$368,356	$3,157,336	$368,356	$6,314,672	$368,356	$6,314,672	$3,157,336	$368,356	$6,314,672	$3,157,336	$368,356	$6,314,672
Capital - Direct Unit					$684,089	$684,089	$3,157,336	$3,157,336	$684,089	$3,157,336	$684,089	$6,314,672	$684,089	$6,314,672	$3,157,336	$684,089	$6,314,672	$3,157,336	$684,089	$6,314,672
Capital - Construction	$42,487,800	$84,975,600	$169,951,200	$127,463,400																
Total Capital Costs	$42,487,800	$84,975,600	$169,951,200	$127,463,400	$684,089	$684,089	$3,157,336	$3,157,336	$684,089	$3,157,336	$684,089	$6,314,672	$684,089	$6,314,672	$3,157,336	$684,089	$6,314,672	$3,157,336	$684,089	$6,314,672
20 Yr Total	$42,487,800	$84,975,600	$169,951,200	$127,463,400	$1,052,445	$1,052,445	$6,314,672	$6,314,672	$1,052,445	$6,314,672	$1,052,445	$12,629,344	$1,052,445	$12,629,344	$6,314,672	$1,052,445	$12,629,344	$6,314,672	$1,052,445	$12,629,344

Wet Lime Inhibited Oxidation (WLIO FGD)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
O&M - Labor																				
O&M - Scheduled Outage	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,654,587	$ 1,654,587	$ -	$ 1,654,587	$ -	$ 3,309,174	$ -	$ 3,309,174	$ 1,654,587	$ -	$ 3,309,174	$ 1,654,587	$ -	$ 3,309,174
O&M - Base Non-Labor	$ -	$ -	$ -	$ -	$ 275,764	$ 275,764	$ 709,109	$ 709,109	$ 275,764	$ 709,109	$ 275,764	$ 1,418,217	$ 275,764	$ 1,418,217	$ 709,109	$ 275,764	$ 1,418,217	$ 709,109	$ 275,764	$ 1,418,217
Total O&M Costs	$ -	$ -	$ -	$ -	$ 275,764	$ 275,764	$ 2,363,696	$ 2,363,696	$ 275,764	$ 2,363,696	$ 275,764	$ 4,727,391	$ 275,764	$ 4,727,391	$ 2,363,696	$ 275,764	$ 4,727,391	$ 2,363,696	$ 275,764	$ 4,727,391
Capital - Direct Unit					$ 512,134	$ 512,134	$ 2,363,696	$ 2,363,696	$ 512,134	$ 2,363,696	$ 512,134	$ 4,727,391	$ 512,134	$ 4,727,391	$ 2,363,696	$ 512,134	$ 4,727,391	$ 2,363,696	$ 512,134	$ 4,727,391
Capital - Construction	$ 44,892,339	$ 74,820,585	$ 108,832,641	$ 77,883,435	$ 11,650,000															
Total Capital Costs	$ 44,892,339	$ 74,820,585	$ 108,832,641	$ 77,883,435	$ 12,162,134	$ 512,134	$ 2,363,696	$ 2,363,696	$ 512,134	$ 2,363,696	$ 512,134	$ 4,727,391	$ 512,134	$ 4,727,391	$ 2,363,696	$ 512,134	$ 4,727,391	$ 2,363,696	$ 512,134	$ 4,727,391
20 Yr Total	$ 44,892,339	$ 74,820,585	$ 108,832,641	$ 77,883,435	$ 12,437,899	$ 787,899	$ 4,727,391	$ 4,727,391	$ 787,899	$ 4,727,391	$ 787,899	$ 9,454,782	$ 787,899	$ 9,454,782	$ 4,727,391	$ 787,899	$ 9,454,782	$ 4,727,391	$ 787,899	$ 9,454,782

Circulating Dry Scrubber (CDS FGD)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
O&M - Labor																				
O&M - Scheduled Outage	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,402,148	$ 1,402,148	$ -	$ 1,402,148	$ -	$ 2,804,296	$ -	$ 2,804,296	$ 1,402,148	$ -	$ 2,804,296	$ 1,402,148	$ -	$ 2,804,296
O&M - Base Non-Labor	$ -	$ -	$ -	$ -	$ 233,691	$ 233,691	$ 600,921	$ 600,921	$ 233,691	$ 600,921	$ 233,691	$ 1,201,841	$ 233,691	$ 1,201,841	$ 600,921	$ 233,691	$ 1,201,841	$ 600,921	$ 233,691	$ 1,201,841
Total O&M Costs	$ -	$ -	$ -	$ -	$ 233,691	$ 233,691	$ 2,003,069	$ 2,003,069	$ 233,691	$ 2,003,069	$ 233,691	$ 4,006,138	$ 233,691	$ 4,006,138	$ 2,003,069	$ 233,691	$ 4,006,138	$ 2,003,069	$ 233,691	$ 4,006,138
Capital - Direct Unit					$ 433,998	$ 433,998	$ 2,003,069	$ 2,003,069	$ 433,998	$ 2,003,069	$ 433,998	$ 4,006,138	$ 433,998	$ 4,006,138	$ 2,003,069	$ 433,998	$ 4,006,138	$ 2,003,069	$ 433,998	$ 4,006,138
Capital - Construction	$ 63,967,324	$ 70,059,438	$ 77,166,904	$ 46,706,335	$ 11,650,000															
Total Capital Costs	$ 63,967,324	$ 70,059,438	$ 77,166,904	$ 46,706,335	$ 12,083,998	$ 433,998	$ 2,003,069	$ 2,003,069	$ 433,998	$ 2,003,069	$ 433,998	$ 4,006,138	$ 433,998	$ 4,006,138	$ 2,003,069	$ 433,998	$ 4,006,138	$ 2,003,069	$ 433,998	$ 4,006,138
20 Yr Total	$ 63,967,324	$ 70,059,438	$ 77,166,904	$ 46,706,335	$ 12,317,690	$ 667,690	$ 4,006,138	$ 4,006,138	$ 667,690	$ 4,006,138	$ 667,690	$ 8,012,275	$ 667,690	$ 8,012,275	$ 4,006,138	$ 667,690	$ 8,012,275	$ 4,006,138	$ 667,690	$ 8,012,275

Appendix B. Limestone Based Wet FGD – Burns & McDonnell

A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate

A CenterPoint Energy Company

Vectren Energy Delivery

Vectren A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate
Project No. 116946

Revision 0
3/5/2020

A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate

prepared for

Vectren Energy Delivery
Vectren A.B. Brown Wet Limestone Forced Oxidation FGD Cost Estimate
Evansville, IN

Project No. 116946

Revision 0
3/5/2020

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, MO

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
ABB	A.B. Brown Generating Station
AFUDC	Allowance for funds used during construction
BACT	Best Available Control Technology
BMcD	Burns & McDonnell Engineering Company, Inc.
BOP	Balance of plant
FGD	Flue gas desulfurization
IRP	Integrated Resource Plan
LSFO	Limestone forced-oxidation
NAAQS	National Ambient Air Quality Standards
O&M	Operation and maintenance
PFD	Process flow diagram
PM	Particulate matter
PSD	Prevention of Significant Deterioration
SBS	Sodium bisulfite
SCR	Selective catalytic reduction
SER	Significant Emission Rate
tpy	Tons per year
WLSFO	Wet Limestone Forced Oxidation

1.0 EXECUTIVE SUMMARY

Vectren has retained Burns & McDonnell Engineering Company, Inc. (BMcD) to evaluate retrofitting new wet limestone forced oxidation (WLSFO) flue gas desulfurization (FGD) system scrubbers for the two coal units at the A.B. Brown Generating Station (ABB). BMcD was tasked with developing a screening level estimate of the cost to replace the existing scrubbers with new scrubbers that meet current emissions regulations and allow for potential new more restrictive emission limits. This sectional report (the "Report") has been prepared to present results and assumptions of the scrubber replacement cost estimate, as well as a high-level assessment of the environmental permitting impacts of replacing the existing scrubbers.

In 2019, Vectren has retained BMcD to provide an all-inclusive cost estimate in 2019 dollars including all ancillary equipment required for a retrofit of this type.

1.1 Replacement Cost Estimate

The FGD technology evaluated by BMcD as a potential replacement for the existing FGD system at A.B. Brown is the wet limestone, forced-oxidation (LSFO) technology. This technology uses limestone ($CaCO_3$) to remove sulfur dioxide (SO_2) from the flue gas. In the process, excess oxidation air is added to the absorber reaction tank to create a gypsum ($CaSO_4 \bullet 2H_2O$) byproduct.

The wet LSFO technology is an FGD technology that is commonly used to achieve high SO_2 removal rates on coal-fired boilers burning high-sulfur coal. It is available from several suppliers and has a long track record of high SO_2 removal rates. The LSFO technology is also reliable with low frequency of outages caused by the scrubber system.

Budgetary quotes for a new wet LSFO FGD system were received in 2017 from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi were escalated to 2019 dollars, averaged and included in the overall capital cost estimate.

The capital cost estimate for the replacement FGD system is summarized in Table 1-1. The total direct cost listed includes the absorber, limestone preparation equipment, and gypsum dewatering equipment included in the budgetary quotations received from various FGD system suppliers. BMcD developed an estimate of the balance of plant (BOP) costs based on costs from past projects.

Table 1-1: Capital Cost Estimate Summary (2019 Dollars)

Area	Cost
Total Direct Cost	$263,808,600
Indirect Cost	$67,095,900
Contingency	$66,178,000
EPC Fee	$27,795,500
Total Project Cost	$424,878,000

A high-level environmental evaluation was conducted to determine the potential air permitting requirements applicable to a scrubber replacement project. An important air permitting issue for this scrubber replacement project will be the potential for Prevention of Significant Deterioration (PSD) review. If PSD is triggered for any pollutant, then a Best Available Control Technology (BACT) analysis is required for all new project sources for pollutants that are subject to PSD. In addition, air dispersion modeling is required for PSD pollutants to show compliance with the National Ambient Air Quality Standards (NAAQS) and PSD Increments (Class I and Class II). Based on the preliminary emissions analyses for the scrubber replacement project, a minor source (state) air permit may be required to permit the new installation of the new emission sources required for the wet scrubbers. It is unlikely that a major PSD air permit would be required, therefore no BACT analysis or air dispersion modeling is required by federal requirements. A good assumption for the timeframe to obtain a state air construction permit for the project would be approximately 6 to 9 months.

1.2 Limitations and Qualifications

Estimates and projections prepared by BMcD relating to performance, construction costs, and operating and maintenance costs are based on experience, qualifications, and judgment as a professional consultant. BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractor's procedures and methods, unavoidable delays, construction contractor's method of determining prices, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding and market conditions or other factors affecting such estimates or projections. Actual rates, costs, performance, schedules, etc., may vary from the data provided.

2.0 INTRODUCTION

2.1 Background

The A. B. Brown Generating Station is a four-unit, 650 MW power generating facility located on the northern bank of the Ohio river in Posey County, Indiana, 5 miles southwest of Evansville. Units 1 and 2 are coal-fired each with a nominal capacity of 265 MW, while Units 3 and 4 are gas turbines. Bituminous coal with dry sulfur content around 3.5% is used as the primary fuel for Units 1 and 2. In 1979, Unit 1 initiated operation with a FGD scrubber to help reduce sulfur dioxide emissions. In 1986 Unit 2 was completed also with a FGD scrubber, both of which scrubbers are still in operation. From 2001 to 2005, Vectren installed selective catalytic reduction (SCR) devices on four of the five coal-fired units, to reduce nitrogen oxide emissions. In 2004, Vectren replaced an existing electrostatic precipitator at Unit 1 with a fabric filter. Sodium bisulfite (SBS) solution injection before the SCR was added in 2014 to remove SO_3 and enhance mercury removal.

Vectren retained Burns & McDonnell to develop a screening level FEP-1 (±50%) estimate of the cost to replace the existing scrubbers with new WLSFO scrubbers that meet current emissions regulations. For the new scrubbers, Burns & McDonnell performed a high level assessment of the potential environmental permitting impacts of the replacement.

3.0 REPLACEMENT COST ESTIMATE

3.1 Replacement Selection

BMcD and Vectren agreed that BMcD would estimate the wet LSFO technology as a potential replacement for the current FGD system at A.B. Brown. The wet LSFO technology uses limestone ($CaCO_3$) to remove sulfur dioxide (SO_2) from the flue gas. In the process, excess oxidation air is added to the absorber reaction tank to create a gypsum ($CaSO_4 \bullet 2H_2O$) byproduct.

The wet LSFO technology is available from several suppliers and has a long track record of high SO_2 removal rates on coal fired boilers burning high-sulfur coal. The LSFO technology is also reliable with low frequency of outages caused by the scrubber system. The gypsum is a byproduct that can be dewatered relatively easily, so it can be handled and disposed of in a dry state. The wet technology also has the benefit of removing mercury in the oxidized form, especially for boilers firing bituminous coal that use selective catalytic reduction (SCR) systems.

It is BMcD's understanding that Vectren is evaluating differences between wet LSFO and other scrubber technologies by conducting similar cost estimate efforts with others on alternative technologies.

3.2 Description of Replacement

The wet LSFO technology evaluated in this study consists of two absorber towers (one per unit). This study assumes that a single limestone preparation system and single gypsum dewatering system would be shared by both units. In order to minimize unit outage time, this evaluation assumes that the new absorber for Unit 1 would be built to the north of the unit. A new stack would be constructed for Unit 1. The Unit 1 thickener would be demolished, and the new absorber for Unit 2 would be built in that location. The outlet from the new Unit 2 absorber would then tie into the original Unit 1 stack. A general arrangement drawing of the new absorber layout has been provided in Appendix C.

In order to minimize the amount of absorber bleed, the Unit 1 and 2 absorbers are assumed to be constructed of flake-glass lined carbon steel or Stebbins tile lined, either of which can handle high chloride levels (up to 50,000 mg/L). The quotes originally received for the FGD equipment in 2017 varied on materials of construction with both flake-glass lined carbon steel and Stebbins tile proposed. Both materials are commonly used in FGD retrofit projects, though BMcD understands that Vectren has had issues with flake-glass lining systems failure in the past. Pricing varied as well with neither coating being a clearly higher cost choice; as such the cost estimate provided will accommodate either material choice.

The absorber inlet (interface of wet and dry flue gas) and outlet ducts would be constructed of C276 (Hastelloy) as this environment is very corrosive. Each absorber would include the following:

- Slurry recycle pumps, piping and spray headers
- Mist eliminators and a mist eliminator wash water tank and associated pumps
- Absorber bleed pumps
- Oxidation air blowers and injection lances
- Process water tank
- Piping, valves and instrumentation

The limestone storage and handling system to be shared by the new Unit 1 and 2 FGD systems would consist of a truck unloading system, a limestone bulk storage pile, a reclaim conveyor, and two limestone day bins with weigh feeders. The shared limestone preparation system would consist of two ball mills, a mill product tank, mill product pumps, a ball mill slurry classifier, a limestone slurry storage tank, and limestone feed pumps. A limestone pile canopy is included in the estimate. The canopy will allow for up to 7 days of covered limestone storage.

Each unit would have a dedicated primary dewatering system consisting of a hydroclone, hydroclone underflow tank, and hydroclone underflow pumps. The secondary gypsum dewatering system to be shared by the new Unit 1 and 2 FGD systems would consist of a vacuum filter feed tank, filter feed pumps, two rotary drum-type vacuum filters, a reclaim (filtrate) water tank, and reclaim pumps. A gypsum canopy is included in the estimate. The canopy will allow for up to 3 days of covered gypsum storage.

The estimate is based on producing saleable quality gypsum; typically that limits scrubber chloride concentrations to approximately 20,000 mg/L due to cake washing constraints. If chlorides are held to 20,000 mg/L within the scrubber loop a bleed stream of 55 gallons per minute (gpm) will be required for each Unit. The estimate included wastewater treatment equipment for this purge stream consisting of physical/chemical treatment, falling film evaporator and a crystallizer to comply with the current published version of the Effluent Limitation Guidelines (ELG) which require zero discharge for new FGD waste streams. As there is no discharge of FGD wastewater there is no need for specialized Selenium treatment over and above the thermal system. The wastewater treatment system is sized only for the FGD purge stream, it will not treat flow from general plant drains or leachate collection.

The estimate also includes a FGD outage storage tank. The tank is approximately the same size as the absorber reaction tank and will be constructed of similar materials of construction (Stebbins tile or flake glass lined carbon steel). The tank will allow Vectren to empty the reaction tank during a Unit outage for absorber inspection activities. The FGD bleed pumps will transfer slurry from the absorber to this tank. New transfer pumps are included in the estimate to transfer the slurry back to the FGD vessel once outage activities are complete.

A Process Flow Diagram (PFD) for the replacement FGD system is provided in Appendix B.

3.3 Electrical System Evaluation

BMcD evaluated the existing electrical distribution system for AB Brown Units 1 and 2 to determine if upgrades would be required for the additional loads from the new wet LSFO FGD system and its associated ancillary equipment. It was determined that the existing system does not have sufficient capacity for the new auxiliary loads associated with the FGD upgrade. Therefore the estimate includes the following new electrical equipment: two new transformers, new PCM building, new switchgear (4160V and 480V), new MCC's and additional miscellaneous panels.

3.4 Conceptual Design Basis

The design basis for the wet LSFO system is shown in Table 4-1. The design coal assumed for this study, based on 2014, 2015 and 2016 coal data provided by Vectren, is provided in Table 4-2.

Table 3-1: Design Basis

Parameter	Unit 1	Unit 2
Gross MW	265	265
Heat Rate (Btu/kWh)	10,500	10,400
Annual Capacity Factor	70%	70%
Excess Air	20%	20%
Air Heater Leakage	5%	5%
Air Heater Outlet Temperature (°F)	325	325
Air Heater Outlet Pressure (in$H_2$0)	-8.0	-8.0
Target SO_2 Removal	≥98%	≥98%
Coal HHV (Btu/lb)	11,143	11,143
Coal sulfur content (%S by weight)	3.75%	3.75%
Inlet SO_2 Loading (lb SO_2/mmBtu)	6.7	6.7
Flue Gas at Scrubber Inlet (lb/hr)	2,898,000	2,870,000
Flue Gas at Scrubber Inlet (afcm)	922,000	913,000
PM limit (lb PM/mmBtu)	0.03	0.03

Table 3-2: Design Coal Analysis

Proximate Analysis (wt%, as rec'd)	
Moisture	11.8
Volatile Matter	35.0
Fixed Carbon	45.0
Ash	8.1
Ultimate Analysis (wt%, as rec'd)	
Moisture	11.8
Carbon	62.8
Hydrogen	4.0
Nitrogen	1.1
Chlorine	0.1
Sulfur	3.8
Ash	8.1
Oxygen	7.7
HHV (Btu/lb)	11,143

3.5 Estimating Methodology

Budgetary quotes for a new wet LSFO FGD system were requested from seven FGD system suppliers: Amec Foster Wheeler, Andritz, Babcock & Wilcox, Babcock Power, GE Power, Marsulex and Mitsubishi Hitachi. Many of these quotes included the cost of the limestone preparation and gypsum dewatering equipment. For quotes that did not include this equipment, budgetary quotes on limestone preparation and gypsum dewatering equipment from other projects was added in. An average of the budgetary quotes provided by the system suppliers was assumed for the FGD supply cost.

Direct costs were factored based on costs from past, similar projects. Indirect costs, including engineering and start-up, were also factored based on past, similar projects.

BMcD developed an estimate of the following balance of plant (BOP) direct costs based:

- Equipment installation
- Civil and foundation work
- New chimney for Unit 1
- Demolition of the Unit 1 thickener
- Concrete
- Steel
- Ductwork and insulation
- Buildings (pump houses, limestone preparation enclosure and gypsum dewatering enclosure)

- Limestone and Gypsum pile canopies
- Wastewater Treatment Equipment (falling film evaporator and crystallizer)
- Piping outside of the absorber islands
- Electrical (new transformers, PCM, switchgear, MCC's and miscellaneous panels)
- Instrumentation and controls

3.5.1 Estimate Assumptions

The assumptions below govern the overall approach of the cost estimate:

- All estimates are screening-level in nature, do not reflect guaranteed costs, and are not intended for budgetary purposes.
- Assumes contracting philosophy is Engineer, Procure, Construct (EPC) approach.
- All information is preliminary and should not be used for construction purposes.
- Assumes project engineering starts January 1, 2020 with both scrubbers in operation by January 2024.
- All capital cost and O&M estimates are stated in 2019 US dollars (USD). Escalation is excluded.
- Fuel and power consumed during construction, startup, and/or testing are included.
- Piling is included under heavily loaded foundations.
- All foundations are new; no re-use of existing foundations.
- Adequate water supply is assumed to be available from existing raw water supplies.
- This estimate assumes that the integrity of the tie-in points is sufficient.
- This estimate assumes that there are no significant underground utilities that would have to be re-routed.
- Removal of hazardous materials is not included.
- Emissions estimates are based on a preliminary review of BACT requirements and provide a basis for the assumed air pollution control equipment included in the capital and O&M costs.
- No new induced draft (ID) fans or booster fans are included in the capital cost estimate. BMcD reviewed the fan curves provided by Vectren and determined there was sufficient capacity to handle the pressure drop through the new FGD system.
- ABB Unit 2 boiler structural improvements were included as this work would be completed during the scrubber tie-in outage.
- This estimate does not include provisions for either Mercury control or SO3 control. Vectren can continue using the existing system for each following conversion to the wet LSFO technology.

3.6 Project Indirect Costs

The following project indirect costs are included in capital cost estimates:

- Performance testing and CEMS/stack emissions testing
- Pre-operational testing, startup, startup management and calibration
- Construction/startup technical service
- Engineering
- Freight
- Startup spare parts

3.7 Owner Costs

Allowances for the following Owner's costs are not included in the pricing estimates:

- Project development
- Owner's operational personnel
- Owner's project management
- Owner's engineering
- Owner's startup engineering and training
- Legal fees
- Permitting/licensing
- Construction power, temporary utilities, startup consumables
- Site security
- Operating spare parts
- Political concessions
- Builder's risk insurance
- Owner's Contingency
- Allowance for Funds Used During Construction (AFUDC).

3.8 Cost Estimate Exclusions

In addition to Owner's costs noted above, the following costs are also excluded from all estimates:

- Escalation
- Sales tax
- Property tax and property insurance
- Utility demand costs
- Salvage values

3.8.1 Capital Costs

The FEP-1 capital cost estimate for the replacement FGD system is summarized in Table 4-3. The total direct cost listed includes the absorber, limestone preparation and gypsum dewatering equipment included in the budgetary quotations received from various FGD system suppliers, as well as BOP Direct Costs including material and installation labor.

Table 3-3: Capital Cost Estimate Summary (2019 Dollars)

Area	Cost
Total Direct Cost	$263,808,600
Indirect Cost	$67,095,900
Contingency	$66,178,000
EPC Fee	$27,795,500
Total Project Cost	$424,878,000

3.8.2 O&M Costs

The scrubber replacement evaluation included a qualitative estimate of the impact of replacing the FGD systems on O&M costs. The major O&M costs associated with FGD systems include reagent, power, waste disposal, and operating and maintenance labor. Auxiliary power loads for the new wet LSFO system are estimated to be 10.2 MW, note this does not include power associated with the existing ID fans. Given that the pressure drop between the existing FGD system and replacement FGD system is not expected to be significantly different the impact on ID fan operations should be minimal.

Both the existing and replacement FGD systems include FGD byproduct dewatering with the use of vacuum filters. Because both systems will handle the dry byproduct in a similar manner, there is not expected to be a significant difference in waste disposal costs. The gypsum cake at 90% solids (saleable quality) generated by the new Unit 1 and 2 FGD systems is estimated to be 0.1 ton/MWhrg.

The number of operators required to operate the replacement FGD system is expected to be similar to that of the existing FGD system. Additional operators and maintenance staff will likely be needed for the wastewater treatment equipment; up to 5 additional full-time equivalents. No significant impact to operating labor cost is expected as a result of replacing the FGD system.

The existing FGD system uses two reagents, lime and soda ash (sodium carbonate, Na_2CO_3). The replacement scrubber will use limestone as a reagent. A detailed evaluation of reagent usage and annual costs was not conducted as part of this evaluation, however, limestone is a less expensive commodity. Annual reagent costs are expected to be lower for the replacement FGD system compared to the existing FGD system. The limestone used in the new Unit 1 and 2 FGD systems is estimated to be consumed at 0.06 ton/MWhrg. Maintenance labor and material costs are expected to be lower for the replacement FGD system compared to the existing FGD system.

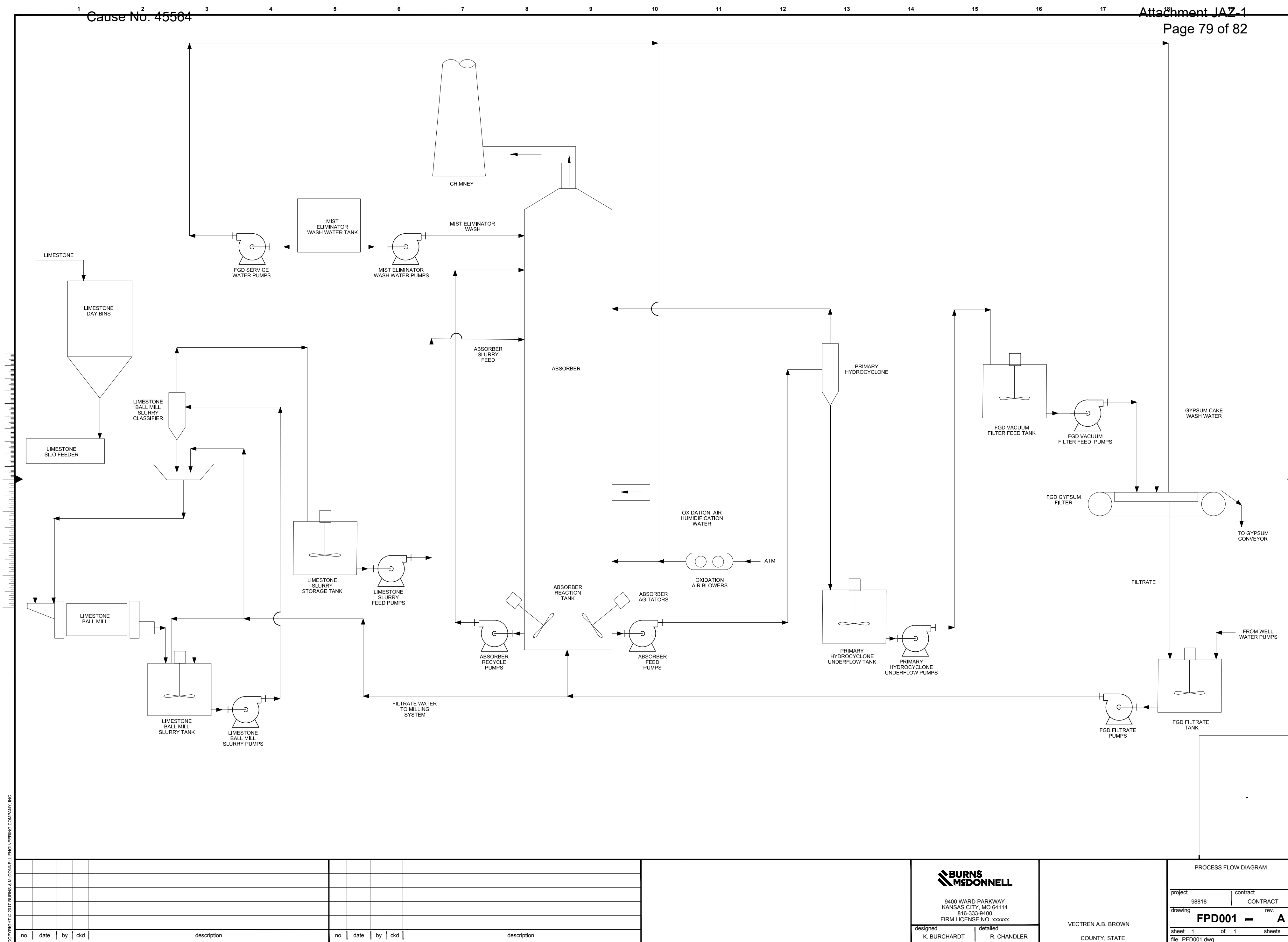
4.0 CONCLUSIONS AND RECOMMENDATIONS

Burns & McDonnell recommends that Vectren consider the information presented in this report when considering the economic viability of a new FGD system. Burns & McDonnell estimates that new scrubbers will cost an order-of-magnitude of $425 million (in 2019 dollars). This includes electrical system upgrades and all BOP considerations.

APPENDIX A – LIST OF DOCUMENTATION PROVIDED BY VECTREN

1. Capital & O&M Costs
2. Chimney Inspections
3. Coal Data
4. Drawings
    a. General Arrangement
    b. Lime System
    c. SBS Injection System
    d. Scrubber
    e. Soda Ash System
5. Emissions
6. FGD Power and Chemical Usage
7. ID Fan Info
8. Outage Cost Info – 2013
9. Scrubber Condition Reports
10. Scrubber Design Information
11. Service Water Information
12. Site Water Balance

APPENDIX B – PROCESS FLOW DIAGRAM


CHIMNEY
MIST ELIMINATOR WASH WATER TANK
MIST ELIMINATOR WASH
FGD SERVICE WATER PUMPS
MIST ELIMINATOR WASH WATER PUMPS
LIMESTONE
LIMESTONE DAY BINS
ABSORBER SLURRY FEED
ABSORBER
PRIMARY HYDROCYCLONE
LIMESTONE BALL MILL SLURRY CLASSIFIER
LIMESTONE SILO FEEDER
FGD VACUUM FILTER FEED TANK
FGD VACUUM FILTER FEED PUMPS
GYPSUM CAKE WASH WATER
FGD GYPSUM FILTER
TO GYPSUM CONVEYOR
OXIDATION AIR HUMIDIFICATION WATER
ATM
OXIDATION AIR BLOWERS
LIMESTONE SLURRY STORAGE TANK
LIMESTONE SLURRY FEED PUMPS
ABSORBER REACTION TANK
ABSORBER AGITATORS
LIMESTONE BALL MILL
ABSORBER RECYCLE PUMPS
ABSORBER FEED PUMPS
PRIMARY HYDROCYCLONE UNDERFLOW TANK
PRIMARY HYDROCYCLONE UNDERFLOW PUMPS
FILTRATE
FROM WELL WATER PUMPS
LIMESTONE BALL MILL SLURRY TANK
LIMESTONE BALL MILL SLURRY PUMPS
FILTRATE WATER TO MILLING SYSTEM
FGD FILTRATE PUMPS
FGD FILTRATE TANK
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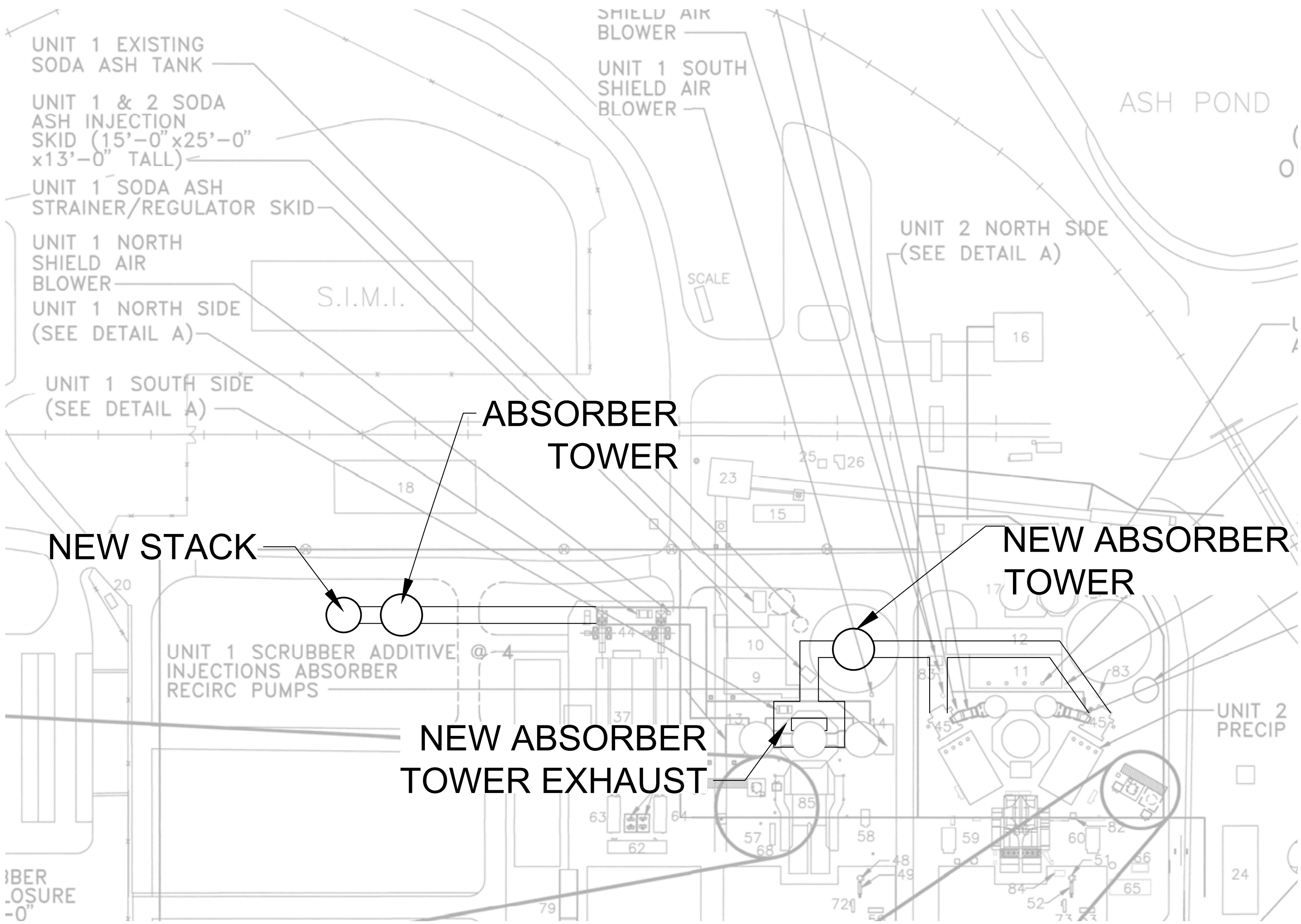
no. date by ckd description
no. date by ckd description
BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400
FIRM LICENSE NO. xxxxxx
designed K. BURCHARDT
detailed R. CHANDLER
VECTREN A.B. BROWN
COUNTY, STATE
PROCESS FLOW DIAGRAM
project 98818
contract CONTRACT
drawing FPD001 – rev. A
sheet 1 of 1 sheets
file PFD001.dwg

APPENDIX C – SKETCH OF ASSUMED LAYOUT



no.	date	by	ckd	description
A	5/12/17	KEB	KEB	ISSUED FOR OWNER REVIEW

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: K. BURCHARDT
detailed: R. CHANDLER

VECTREN
EVANSVILLE, IL

SKETCH OF ASSUMED LAYOUT

project: 98818
contract:
drawing: SKM001 – rev. A
sheet 1 of 1 sheets
file 98818SKM001.dwg

CREATE AMAZING.

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EPC COST - BASIS OF ESTIMATE AACE CLASS 2

A.B. Brown 2x0 Simple Cycle

B&V PROJECT NO. 406529
B&V FILE NO. 41.0001

PREPARED FOR

CenterPoint Energy

26 APRIL 2021

BLACK & VEATCH

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Executive Summary

The following is a progress report for the EPC capital cost AACE Class 2 (+/- 10 percent) estimate for the A.B. Brown 2X0 Simple Cycle Power Plant (2x0 SCPP). The cost estimates contained in this report are based on competitive bids received by Black & Veatch. These bids were obtained in response to the request for proposal (RFP) issued by CenterPoint Energy for the project, pursuant to the Black & Veatch conceptual design. Simple cycle configuration is representative of the combustion turbine, stack, and balance of plant equipment. Emission control for this cost estimate is based upon combustion controls only and does not include selective catalytic reduction (SCR) or oxidation catalyst.

The estimate has been included as Attachment A.

1.0 Estimate Basis

The cost estimate is based on an AACE Class 2 for engineering, equipment and construction costs.

The A. B. Brown Simple Cycle Plant will be located near Mount Vernon, Indiana, in Posey County and will be constructed on the existing A.B. Brown Plant site. The nominal 473 MW net natural gas fired simple-cycle power plant will consist of two F-Class Combustion Turbines in a 2x0 configuration. The EPC Contractors scope of work includes the design, engineering, procurement, construction, construction management, commissioning, operator training, demonstration, and testing of the project.

The cost estimate is based upon a lump-sum EPC approach. EPC contractor will purchase combustion turbine equipment and maintain performance responsibilities. The EPC structure used for the estimate is based upon the contractor self-performing the work and utilizing subcontractors for appropriate work.

The cost estimates are based on pricing obtained as a result of the RFP issued for the project. Material takeoffs were provided by contractors as part of their preliminary design of the A.B. Brown simple cycle.

The estimate provided herein is based on preliminary information, and as such is to be considered a non-binding price opinion and does not represent an offer to sell or a maximum price for the work scope. The estimate assumes moderate level of EPC commercial risk position and does not include specific pricing or schedule impacts for extensive site preparation. Other factors that can impact the price:

- Changes in labor market.
- Final site conditions.
- Noise requirements.
- Final project schedule.

1.1 PRELIMINARY DESIGN

In order to support the estimate, Black & Veatch prepared preliminary drawings and prepared a technical specification that was sent out for bid to EPC vendors. The following drawings were prepared and proposals received:

Description
Design Basis
Reuse Equipment Study
Switchyard Study
Level 1 Schedule
Kiewit Technical Proposal
Burns & McDonnell Technical Proposal
Phoenix Group Technical Proposal

1.2 QUANTITIES

Quantities that form the basis of the estimate were provided as part of the competitive proposal process. Quantities are based on the RFP package that included plant and equipment specifications, design basis, and specific site conditions. Competitive bids were reviewed for scope and completeness; technical adjustments were made as required to be in line with the specification.

1.2.1 Reused Equipment

Quantities based on reused existing equipment include:

- The existing fire water supply system including diesel and electric fire pumps.
- The existing compressed gas systems of carbon dioxide and hydrogen.
- The existing Demineralized water storage and transfer systems.
- The existing Raw/makeup water system.
- The existing Service, Potable and Waste water systems
- The existing Sanitary wastewater system.
- The existing Oily Waste System
- Reserve Auxiliary Transformers (RATs) will continue to support existing plant auxiliary electric system.
- The existing medium voltage switchgear.

1.3 DIRECT COSTS

EPC bid pricing will be segregated into two categories: direct and indirect. The direct project costs associated with the BOQs can then be developed by utilizing the unit costs provided during previous works.

- Unit manhour rates and wage rates provided in the bids are applied against the 2x0 SCPP quantities to develop labor cost.
- Unit material cost are applied against the updated quantities for commodities to develop material cost.
- Subcontract costs are based on rates provided in the bids.
- Cost for major equipment are based off bids received as part of the RFP process.

1.4 CONSTRUCTION MANAGEMENT AND CONSTRUCTION INDIRECTS AND ENGINEERING

Construction Management and Construction Indirects (CMCI) were based on a self-perform (direct-hire) approach as outlined in the bidder's proposals. As a result, the cost for management of the work as well as tools, scaffolding, cranes, warehousing, and laydown to support this work show as a CMCI expense.

Construction management and project indirects are based on the competitive EPC bids.

1.5 PROJECT INDIRECTS

Insurances, warranty, performance bonds, and a letters of credit costs are included, based on the bids received. Project indirects also includes Builder's All Risk Insurance.

1.6 EPC CONTINGENCY

EPC contingency rates were set based on the EPC bids received.

1.7 OVERHEAD AND PROFIT

Overhead and profit rates were based upon the EPC bids received.

1.8 ESCALATION

The EPC Contractor's price includes escalation. The escalation criteria utilized is based on the average escalation submitted with the EPC bids.

Attachment A – Engineer's Estimate REDACTED

FINAL

VECTREN NATURAL GAS CONVERSION INDEPENDENT ASSESSMENT REPORT

A.B. Brown Units 1, 2

F.B. Culley Unit 2

BLACK & VEATCH PROJECT NO. 403365
BLACK & VEATCH FILE NO. 40.4100

PREPARED FOR

Vectren

MARCH 17, 2020

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Foreword

For several years, Vectren, a CenterPoint Energy Company, has been updating their integrated resource plan (IRP) to forecast energy demands to ensure reliable service to their customers in the most cost-effective ways. To that end, Vectren has been engaged with several engineering consulting firms to evaluate the use of natural gas, in lieu of coal, for operations at A.B. Brown, Units 1 and 2 and F.B. Culley, Unit 2.

The evaluation covered by this report was undertaken to enable Vectren to assess all concepts and options for natural gas conversion. The following summarizes the steps that have been taken during the course of this Project:

- Burns & McDonnell provide a high level natural gas conversion conceptual design and budgetary cost estimate for A.B. Brown Units 1 & 2 in 2015 and provided an update in 2016.
- Early in 2019 to support the current IRP process, Burns & McDonnell provided an update to this previous study for coal to gas conversion of A.B. Brown Unit 2.
- Black & Veatch further developed the estimate by investigating details surrounding preliminary Prevention of Significant Deterioration (PSD) analysis, potential environmental control technologies, Bill of Quantities (BOQ) level construction estimates, and expected boiler performance.
- Babcock & Wilcox (B&W) provided updates to the Boiler Engineering Study (surface area assessment & expected performance) and budgetary cost estimate for boiler equipment.
- Bowen Engineering performed a site investigation developing BOQ of materials and provided a construction budgetary estimate.
- Black & Veatch reviewed and validated the information provided by B&W and Bowen and developed a Natural Gas Conversion cost estimate consistent with an AACE Class 4 (which has an expected accuracy range of +/- 30%).

Black & Veatch utilized prior assessments from the following firms to validate the project conceptual design and budget level cost estimates for the coal to natural gas conversion:

- Burns & McDonnell – Natural Gas Conversion Conceptual Design and Budgetary Cost Estimate for A.B. Brown, Unit 2.
- Bowen Engineering Corporation – Materials and construction budgetary cost estimate for A.B. Brown, Units 1 and 2; F.B. Culley, Unit 2.
- Babcock & Wilcox – Boiler Engineering Study and Budgetary Cost Estimate for A.B. Brown, Units 1 and 2; F.B. Culley, Unit 2.
- Cormetech, Inc. – Estimated costs for selective catalytic reduction (SCR)/carbon monoxide (CO) catalysts for A.B. Brown, Units 1 and 2; F.B. Culley, Unit 2.
- International Chimney Corporation – Estimated costs for chimney inspection and liner washdowns for A.B. Brown, Units 1 and 2.

1.0 Executive Summary

Vectren requested Black & Veatch to review the concept of converting Vectren's A.B. Brown, Unit 1 and 2 and F.B. Culley, Unit 2 from firing coal to firing 100 percent natural gas. Converting to 100 percent natural gas firing involves the replacement of the existing bituminous coal fired burners with natural gas burners; the existing natural gas igniters will not be replaced. The new natural gas burners would lower emissions during startups and during normal operations by providing up to 100 percent of boiler maximum continuous rated (MCR) heat input. The existing flue gas cleaning equipment (scrubbers, baghouse/precipitator) would be removed from service. The natural gas pipeline supply to the A.B. Brown site boundary was excluded from the scope of this assessment.

When converted to natural gas the heat rate impact will be approximately four percent less for A.B. Brown Units 1 and 2 and three percent less for F.B. Culley Unit 2 due to the decreased boiler efficiency. The typical project schedule is 30 months (including 10 months for permitting activities) with a 10-month construction period that includes a 12 week outage for A.B. Brown Unit 1, a 14 week outage for A.B. Brown Unit 2, and a 14 week outage for F.B. Culley Unit 2. Replacement burner/igniter manufacture and delivery time is 13 months from award of a purchase order. A summary of the A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 boiler impacts when converting to natural gas as assessed by Babcock & Wilcox is included in Table 1-1 and Table 1-2.

Table 1-1 Summary of the A.B. Brown Unit 1 and 2 Boiler Impacts (per Unit Basis)

COMPONENT	RESULTS	COMMENTS
Superheat (SH) and Reheat (RH) Attemperator Flows	SH and RH flow rate less than required for firing coal	Lower amounts of excess air required when firing natural gas as compared to firing coal
Air Heater Performance	The air and flue gas temperature profiles around the air heater were found to be acceptable for firing natural gas; flue gas and air flows and temperatures in/out of air heater were at or below original design values	No field data were available that indicated higher than original air heater leakage; therefore, original air heater leakage of 7.4% was assumed in evaluation
Boiler Performance	• Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal • RH steam outlet temperatures and pressure are slightly less when firing natural gas • Boiler efficiency as low as 84.16% compared to 87.92% when firing bituminous coal (because of moisture in losses due to H_2 and H_2O in the natural gas)	Boiler efficiency for coal fired based on original contract performance summary

COMPONENT	RESULTS	COMMENTS
Tube Metal Temperature Evaluation	• Existing tube metal metallurgies in the convection pass tubes do not exhibit any overstress issues; tubes predicted to operate below American Society of Mechanical Engineers (ASME) material code published limits • Header metal temperatures within Babcock & Wilcox standards	No surface modifications or surface removals are required when converting to firing 100% natural gas
Forced Draft (FD) Fans	Test block conditions for both units of the existing FD fans exceed the requirements for firing natural gas in capacity and static pressure rise	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise
Induced Draft (ID) Fans	Test block conditions of the existing ID fans far exceed the requirements in capacity and static pressure rise for firing natural gas	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

Table 1-2 Summary of the F.B. Culley Unit 2 Boiler Impacts

COMPONENT	RESULTS	COMMENTS
Pressure Parts	• Reduction in primary superheater surface is required in both cases where FGR is required to avoid exceeding the limits of the existing tube metallurgy • Twelve tube rows would be removed	Increased absorption through the convection pass components is due to FGR, which increases flue gas flow rates
Boiler Performance	• Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal • Superheater spray flows as high as 46% above firing bituminous coal • Boiler efficiency firing natural gas as low as 83.93% compared to 87.02% when firing bituminous coal (due to moisture in losses from H_2 and H_2O in the natural gas)	Boiler efficiency of 83.93% is based on primary superheater surface reduction without OFA ports
Attemperator Capacities	Attemperator flows firing natural gas increased compared to firing bituminous coal with/without FGR and/or boiler modifications	Existing spray water attemperator nozzle size would have to be modified by increasing the orifice diameter to meet the required flows; flows would be adequate with this modification at all boiler loads
Air Heater Performance	The air and gas side profiles were found to be acceptable for 100% natural gas firing	No field data were available to indicate amount of air heater leakage; original design value of 10% was used in the evaluation

COMPONENT	RESULTS	COMMENTS
Tube Metal Temperature Evaluation	• Existing tubes in convection pass tube had no overstress issues; tubes predicted to operate at temperatures below ASME material code published limit • Header metal temperatures within Babcock & Wilcox standards	Publishing design tube metal temperatures or unbalanced steam temperatures are not allowed by Babcock & Wilcox policy; available for review in Babcock & Wilcox's offices
Forced Draft (FD) Fans	Test block conditions of the existing fans exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction	These results are because the FD fans were originally designed for pressurized firing, which has been converted to balanced draft
Induced Draft (ID) Fans	Test block conditions of the existing ID fans far exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

When burning natural gas, flue gas emissions reductions from the boilers for particulate matter (PM), sulfur dioxide (SO_2), and mercury (Hg) would be reduced almost directly proportional to the reduction in coal combustion. Boiler flue gas emissions of nitrogen oxides (NO_X) and CO while firing natural gas would also be reduced compared to firing coal. Options assessed to reduce NO_X and CO emissions include the design and installation of an overfire air (OFA) system, flue gas recirculation (FGR) system, CO catalyst system, and continued operation of the SCRs (A.B. Brown Units 1 and 2 only). For this assessment, all options have been evaluated and costs estimated; final selection will be dependent on final air permitting.

The Natural Gas Conversion Evaluation is consistent with an AACE Class 4 estimate (which has an expected accuracy range of +/- 30%) based on Black & Veatch's review of the third part reports, deliverables, and the level of effort. In addition, Black & Veatch provided the preliminary environmental approach and recommendations, including estimated the cost for SCR and CO2 requirements for the units. These estimates are also consistent with an AACE Class 4 estimate.

2.0 Conceptual Design Basis

2.1 GENERAL

The project concept is to replace existing coal fired equipment with natural gas burners (natural gas igniters are currently in service) to use natural gas for startup and during normal operations at A.B. Brown, Units 1 and 2 and F.B. Culley, Unit 2. The natural gas burners would be sized so that 100 percent of each of the boilers' MCR heat input at full unit load could be supplied by firing 100 percent natural gas.

The implementation of the 100 percent natural gas firing option requires the replacement of the existing coal fired system (burners, pulverizers, coal and ash handling equipment, etc.) with a new low NO_X, natural gas fired burner system (burners, piping, valves, controls, and new burner management system [BMS], as a minimum). A new natural gas supply line from the A.B. Brown and F.B. Culley plant boundary to each of the units is included, along with branches to each of the units.

2.1.1 A.B. Brown Unit 1 and 2

A.B. Brown Units 1 and 2 are similar in design and are balanced draft, subcritical boilers, each with a secondary superheater, primary superheater, reheater, and economizer surfaces. Superheater and reheater temperatures are controlled by interstage spray attemperation and excess air/spray attemperation, respectively. The units are each front and rear wall fired with a total of twenty (24) Babcock & Wilcox 4Z low NO_X burners per unit. Each unit is equipped with six Babcock & Wilcox pulverizers and two Ljungstrom regenerative air heaters (refer to Figure 2-1). The gas conversion included a review of the boiler heating surfaces and adequacy of the existing forced draft (FD) fans and primary air (PA) fans. The differences in Unit 1 and Unit 2 are as follows:

- The furnace height of Unit 1 is 122'-0" compared to the furnace height of Unit 2, which is 124'-0."
- Unit 1 has a full furnace division wall; Unit 2 has six water-cooled furnace wing walls.
- Unit 1 was originally designed with flue gas recirculation (FGR), which has been removed from service; Unit 2 was designed to operate without FGR.

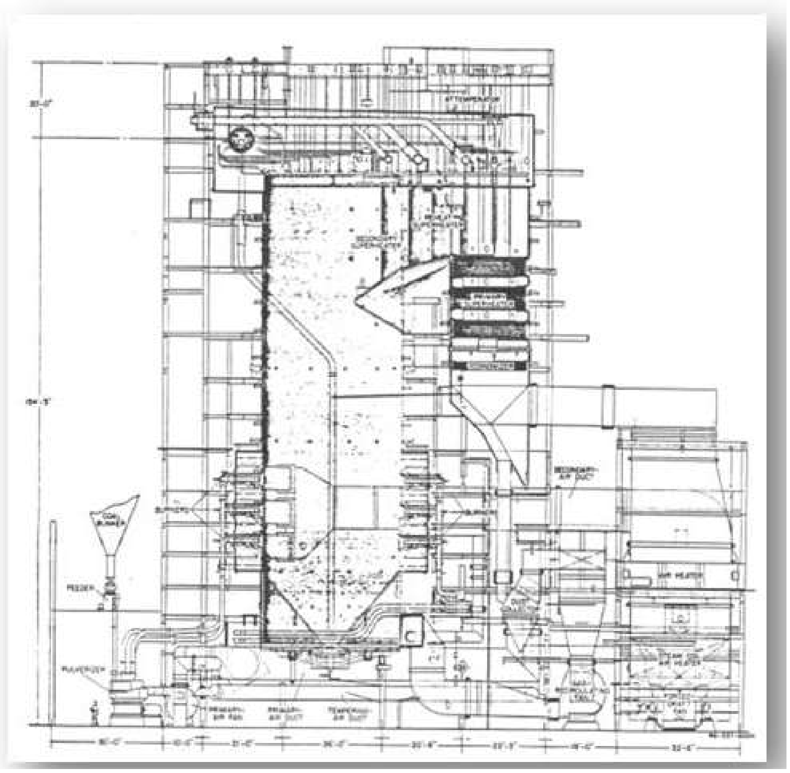

Figure 2-1 A.B. Brown Units 1 and 2 Typical Boiler Diagram

Table 2-1 A.B. Brown Units 1 and 2 Original Design As-Fired Fuel Analyses

CONSTITUENT	PERCENT BY WEIGHT
Carbon (C)	64.00
Hydrogen (H_2)	4.44
Nitrogen (N_2)	1.38
Oxygen (O_2)	6.51
Chlorine (Cl)	0.00
Sulfur (S)	3.52
Moisture (H_2O)	11.35
Ash	8.76
Total	**100.00**
HHV (Btu/lb)	11,533
HHV - higher heating value; Btu/lb - British thermal unit per pound	

2.1.2 F.B. Culley Unit 2

F.B. Culley Unit 2 is a subcritical El Paso type radiant boiler and was originally a pressurized fired design; it has been converted to a balanced draft design. The primary and secondary superheater and economizer surfaces are arranged in series (refer to Figure 2-2). Steam temperature is controlled via interstage attemperation. The unit is a front wall fired design and consists of 12 pulverized coal burners. F.B. Culley Unit 2 is different from A.B. Brown Units 1 and 2 in that it is not equipped with an SCR system for NO_X control.

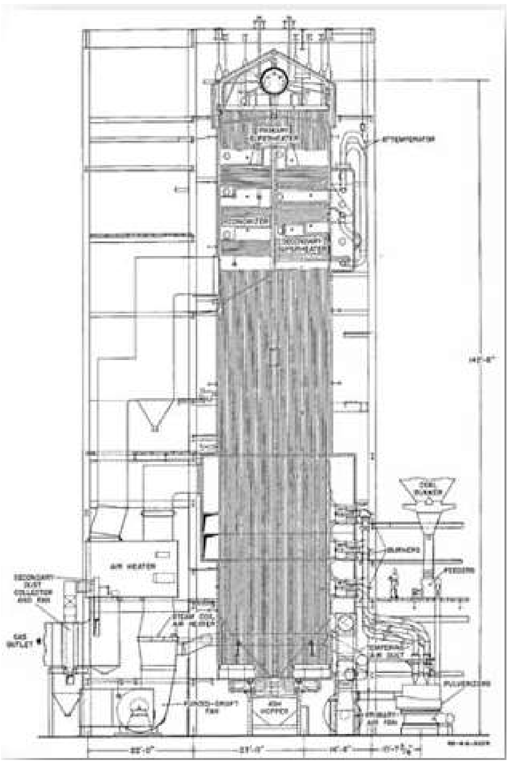

Figure 2-2 F.B. Culley Unit 2 Typical Boiler Diagram

Table 2-2 F.B. Culley Unit 2 Original Design Bituminous Coal Analysis

CONSTITUENT	PERCENT BY WEIGHT
Carbon (C)	55.27
Hydrogen (H_2)	3.70
Nitrogen (N_2)	1.05
Oxygen (O_2)	5.68
Chlorine (Cl)	0.00
Sulfur (S)	3.30
Moisture (H_2O)	19.00
Ash	12.00
Total	**100.00**
HHV (Btu/lb)	10,000

2.2 NATURAL GAS SYSTEM CONCEPTUAL DESIGN

For the conversion both A.B. Brown and F.B. Culley will require a new natural gas pipeline source. The natural gas pipeline supply to the A.B. Brown and F.B. Culley site boundaries were excluded from the scope of this assessment.

A conceptual design was developed for a natural gas supply piping, heating, and regulating system from the gas line tap to the boiler OEM's natural gas fuel controls, metering and pressure regulating skid.

Because of the Joule-Thomson effect, the temperature of natural gas can change during a pressure reduction operation, and its final temperature is related to the amount of pressure drop across the pressure regulating valve. Increasing the temperature of the natural gas may be required prior to pressure reduction to overcome the possibility of moisture condensation and freezing following the cooling effect of the pressure reduction operation. Insulation of the natural gas piping is included as required.

Natural gas heating can be accomplished with natural gas fired heaters, electrical resistance heaters, or using steam. For the purposes of this study, natural gas heating was assumed to be upstream of the site gas line connection by the gas supplier.

2.2.1 Codes and Standards

The conceptual design is based on meeting applicable national codes. The following are the most significant codes and standards applicable to this conceptual design:

- NFPA 85 will be the governing code used in determining the igniter and burner arrangement and operating principles based on a multiple burner boiler.

- ASME B31.1 Power Piping Code and other ASME codes will be used for mechanical design. It is not anticipated that any ASME Section I components will be affected unless boiler heating surfaces are modified.
- NFPA 497 and the National Electric Code (NFPA 70) will also be used in identifying electrical hazardous area classification issues that must be addressed.

2.2.2 A.B. Brown Units 1 and 2 Natural Gas Supply

For the conceptual design, natural gas for the project will be supplied at an assumed pressure at the main gas line connection point on the northwest corner of the site near the existing Unit 2 Cooling Tower at a pressure of approximately 500 psig.

The first stage pressure reduction, metering, and condition station which will reduce the main gas line pressure to around 200 psig will be located at the site gas line connection. From the first stage pressure reduction station a new underground natural gas line will supply the 200 psig natural gas to the southwest corner of Unit 2 where the gas will enter an intermediate regulating station to reduce the pressure to approximately 50 psig required by the boiler OEM. The outlet of the second stage reduction will connect to the Unit 1 and Unit 2 regulating skids provided by boiler OEM, which will further reduce the pressure to a level required for proper operation of the new natural gas burners., Dedicated lines will be routed aboveground to Units 1 and 2 following the second stage regulating stations. At the boilers on Unit 1 and 2, flow control valves and distribution headers will distribute and control the flow of natural gas to the burners located on each level. At each burner, a double block and vent valve arrangement will be furnished. Additional trip, isolation, and header vent valves will be included as part of the boiler OEM's piping internal to the boiler building

The natural gas analysis used in the evaluation was provided by Vectren for A.B. Brown is provided in Table 2-3.

Table 2-3 A.B. Brown Proximate Analysis for Natural Gas

CONSTITUENT	PERCENT BY VOLMUE
Nitrogen (N_2)	0.28
Methane (CH_4)	96.31
Ethane (C_2H_6)	1.46
Carbon Dioxide (CO_2)	1.89
Others	0.06
Total	**100.00**
HHV (Btu/ft^3)	1,037
Btu/ft^3 - British thermal unit per cubic foot	

2.2.3 F.B. Culley Unit 2 Natural Gas Supply

For the conceptual design, natural gas for the project will be supplied at an assumed pressure of approximately 500 psig at the main gas line connection point on the northwest corner of the site near the existing F.B. Culley site gas metering station.

The first stage pressure reduction, metering, and conditioning station which will reduce the main gas line pressure to around 200 psig will be located at the site gas line connection. From the first stage pressure reduction station a new underground natural gas line will supply the 200 psig natural gas to Unit 2 where the gas will enter an intermediate regulating station to reduce the pressure to approximately 50 psig required by the boiler OEM. The outlet of the second stage reduction will connect the regulating skids provided by the boiler OEM, which will further reduce the pressure to a level required for proper operation of the new natural gas burners. Following the second stage regulating stations, flow control valves and distribution headers will distribute and control the flow of natural gas to the burners located on each level. At each burner, a double block and vent valve arrangement will be furnished. Additional trip, isolation, and header vent valves will be included as part of the boiler OEM's piping internal to the boiler building.

The natural gas analysis used in this evaluation was provided by Vectren for F.B. Culley and is shown in Table 2-4.

Table 2-4 F.B. Culley Proximate Analysis for Natural Gas

CONSTITUENT	PERCENT BY VOLUME
Nitrogen (N_2)	1.79
Methane (CH_4)	91.88
Ethane (C_2H_6)	5.12
Others	1.21
Total	**100.00**
HHV (Btu/ft^3)	1,037

2.3 BOILER MODIFICATIONS

There is a shift in heat transfer within the boiler from radiant heat when burning coal to more convective heat transfer when burning natural gas when converting a unit from coal firing to natural gas firing. This is due to the natural gas flame having a lower emissivity that results in less radiant heat output. Additionally, there is more heat transfer in the convective pass of the boiler because there is less ash content produced with firing natural gas. Therefore, an assessment of the heat transfer surfaces, typically by the boiler OEM, is required to determine if any boiler heating surface modifications are required to maintain full load output. For this study, Babcock & Wilcox evaluated performance impacts and/or potential modifications to the boiler heating surfaces of converting the coal fired boilers at A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 to firing 100 percent natural gas.

2.3.1 A.B. Brown Unit 1 and 2 Boiler Modifications

A review of the heating surfaces was performed to assess the boiler pressure part metals at the boiler operating conditions shown in Table 2-5 using the original coal analysis (refer to Table 2-1) and the natural gas analysis provided by Vectren (refer to Table 2-3).

Table 2-5 A.B. Brown Units 1 and 2 Boiler Operating Conditions Used in Metals Evaluation

BOILER LOAD	MCR	60% MCR
Superheater (SH) Steam Flow (lb/h)	1,850,000	1,110,000
Steam Temperature at SH Outlet (°F)	1,005	933
Steam Pressure at SH Outlet (psig)	1,965	1,917
Reheater (RH) Steam Flow (lb/h) w/o attemperator flow	1,666,500	1,000,000
Steam Temperature at RH Outlet (°F)	992	835
Steam Pressure at RH Outlet (psig)	460	261
Feedwater Temperature (°F)	467	417
Excess Air Leaving Economizer (%)	10	18

A detailed boiler analysis for converting A.B. Brown Units 1 and 2 to natural gas was performed by Babcock & Wilcock the boiler OEM to determine possible equipment impacts and estimate performance. Table 2-6 provides a summary of Babcock & Wilcox boiler evaluation.

Table 2-6 Summary of the A.B. Brown Unit 1 and 2 Boiler Evaluation (per Unit Basis)

COMPONENT	RESULTS	COMMENTS
Superheat (SH) and Reheat (RH) Attemperator Flows	SH and RH flow rate less than required for firing coal	Lower amounts of excess air required when firing natural gas as compared to firing coal
Air Heater Performance	The air and flue gas temperature profiles around the air heater were found to be acceptable for firing natural gas; flue gas and air flows and temperatures in/out of air heater were at or below original design values	No field data were available that indicated higher than original air heater leakage; therefore, original air heater leakage of 7.4% was assumed in evaluation
Boiler Performance	• Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal • RH steam outlet temperatures and pressure are slightly less when firing natural gas • Boiler efficiency as low as 84.16% compared to 87.92% when firing bituminous coal (because of moisture in losses due to H_2 and H_2O in the natural gas)	Boiler efficiency for coal fired based on original contract performance summary
Tube Metal Temperature Evaluation	• Existing tube metal metallurgies in the convection pass tubes do not exhibit any overstress issues; tubes predicted to operate below American Society of Mechanical Engineers (ASME) material code published limits • Header metal temperatures within Babcock & Wilcox standards	No surface modifications or surface removals are required when converting to firing 100% natural gas

2.3.2 A.B. Brown Units 1 and 2 Combustion Equipment

For A.B. Brown Unit 1 and 2 two modifications were evaluated to convert the existing twenty-four (24) Babcock & Wilcox DRB-4Z® low NO_X coal fired burners to fire natural gas:[1]

The first option was to modify the existing coal burners by adding a "Super-Spud" to each burner configuration. This modification would allow firing natural gas with the ability to continue to fire coal. Refer to Figure 2-3. The Super-Spud is identified in the figure as "Gas Inlet."

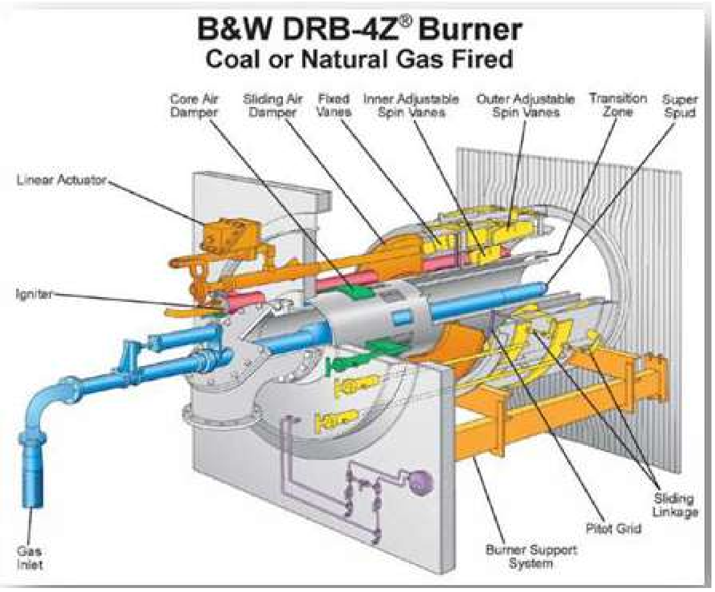

Figure 2-3 Babcock & Wilcox DRB-4Z® Burner (Coal or Gas Fired)

[1] Figures 2-3 and 2-4 were retrieved from Babcock & Wilcox's "Engineering Study for Natural Gas Firing," Contract 591-1048 (317A), June 13, 2019, Rev. 5.

The second option is to remove the existing coal nozzle and replace it with a hemi-spud cartridge. The modification will basically convert the Babcock & Wilcox 4Z low NO_X burners into a Babcock & Wilcox model XCL-S™ burners (refer to Figure 2-4). The XCL-S burner was developed by Babcock & Wilcox to achieve superior NO_X performance utilizing a burner only.

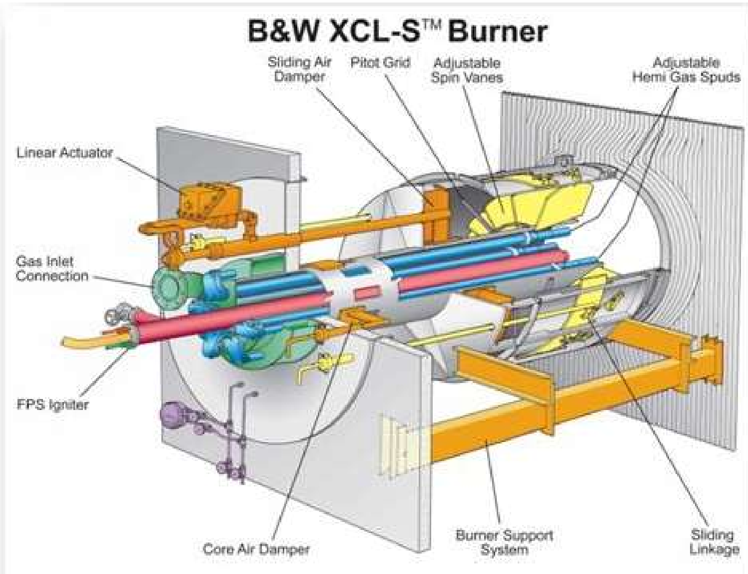

Figure 2-4 Babcock & Wilcox XCL-S™ Burner (Natural Gas Fired)

Additional upgrades to the ignitors and flame scanners are typically required to support the new burner design and control system upgrades.

The existing ignitors will be reused while the flame scanners will be replaced with new UV scanners capable of detecting flames from the new natural gas fuel.

2.3.3 F.B. Culley Unit 2 Boiler Modifications

A review of the heating surfaces was performed to assess the boiler pressure part metals at the boiler operating conditions shown in Table 2-7 using the original coal analysis (refer to Table 2-2) and the natural gas analysis provided by Vectren (refer to Table 2-4).

Table 2-7 F.B. Culley Unit 2 Boiler Operating Conditions Used in Metals Evaluation

BOILER LOAD	MCR	50% MCR
Superheater Steam Flow (lb/h)	840,000	420,000
Steam Temperature at SH Outlet (°F)	955	925
Steam Pressure at SH Outlet (psig)	1,290	1,260
Feedwater Temperature (°F)	425	360
Excess Air Leaving Economizer (%)	10	18

A detailed boiler analysis for converting F.B. Culley Unit 2 to natural gas was performed by Babcock & Wilcock the boiler OEM to determine possible equipment impacts and estimate performance. Table 2-8 provides a summary of Babcock & Wilcox boiler evaluation.

Table 2-8 Summary of the F.B. Culley Unit 2 Boiler Evaluation

COMPONENT	RESULTS	COMMENTS
Pressure Parts	• Reduction in primary superheater surface is required in both cases where FGR is required to avoid exceeding the limits of the existing tube metallurgy • Twelve tube rows would be removed	Increased absorption through the convection pass components is due to FGR, which increases flue gas flow rates
Boiler Performance	• Main steam outlet temperatures, pressures, and flow rates equal to firing bituminous coal • Superheater spray flows as high as 46% above firing bituminous coal • Boiler efficiency firing natural gas as low as 83.93% compared to 87.02% when firing bituminous coal (due to moisture in losses from H_2 and H_2O in the natural gas)	Boiler efficiency of 83.93% is based on primary superheater surface reduction without OFA ports
Attemperator Capacities	Attemperator flows firing natural gas increased compared to firing bituminous coal with/without FGR and/or boiler modifications	Existing spray water attemperator nozzle size would have to be modified by increasing the orifice diameter to meet the required flows; flows would be adequate with this modification at all boiler loads
Air Heater Performance	The air and gas side profiles were found to be acceptable for 100% natural gas firing	No field data were available to indicate amount of air heater leakage; original design value of 10% was used in the evaluation
Tube Metal Temperature Evaluation	• Existing tubes in convection pass tube had no overstress issues; tubes predicted to operate at temperatures below ASME material code published limit • Header metal temperatures within Babcock & Wilcox standards	Publishing design tube metal temperatures or unbalanced steam temperatures are not allowed by Babcock & Wilcox policy; available for review in Babcock & Wilcox's offices

2.3.4 F.B. Culley Unit 2 Combustion Equipment

The existing 12 coal fired burners for F.B. Culley Unit 2 will be replaced with new Babcock & Wilcox XCL-S™ burners which can be retrofitted into the existing burner openings in the furnace walls. Some adjustment to the existing burner throat diameter may be required, which will be dependent on the choice of NO_x reduction technologies: burners only, burners plus OFA, FGR, and any combination of these NO_x reduction technologies. Conical ceramic throat inserts for reducing the burner throat diameter may be installed, or refractory may be removed to increase the burner throat diameter. The chosen design will be based on the results of the engineering phase. It should be noted that all the combustion air will have to be supplied via the secondary air ducting system since PA (for pulverized coal transport) will no longer be available

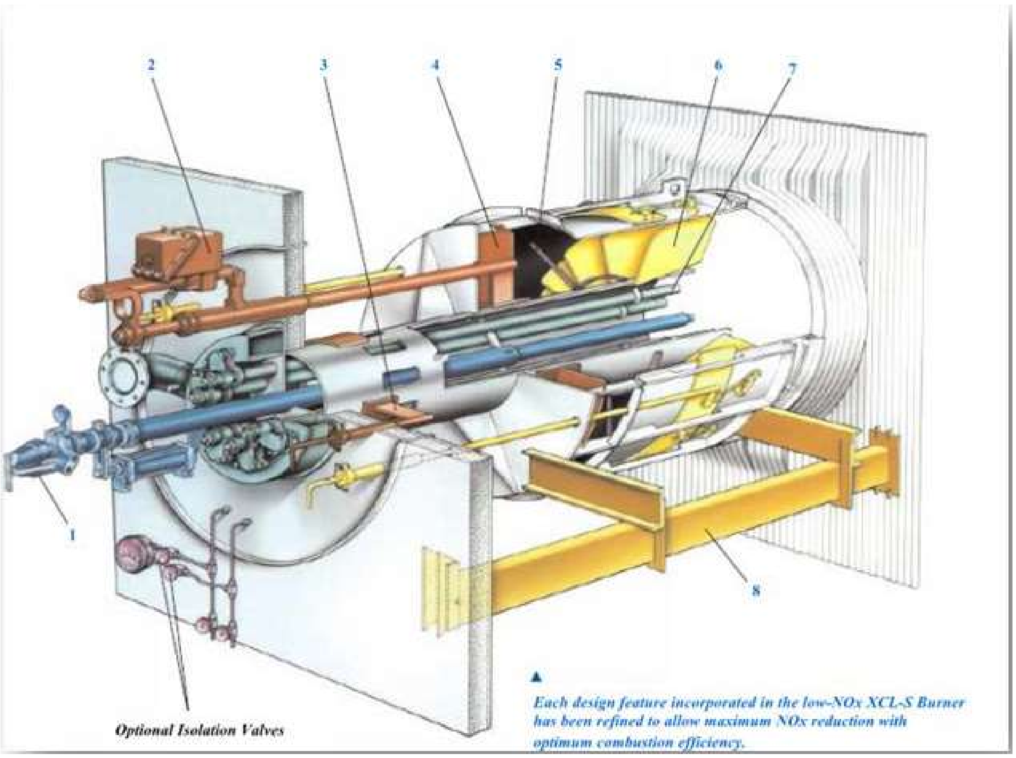

Figure 2-5 Babcock & Wilcox Low-NO_X XCL-S™ Burner[2]

The existing ignitors will be replaced with new high energy spark ignitors and the flame scanners will be replaced with new scanners capable of detecting flames from the new natural gas fuel.

[2] Figure 2-5 was retrieved from Babcock & Wilcox's "Engineering Study for Natural Gas Firing," Contract 591-1022 (293H), June 13, 2019, Rev. 2.

2.4 COMBUSTION AIR SYSTEM

For natural gas firing, the mills and PA fans can be taken out of service (abandoned in place). The portion of the combustion air traveling to the mills is blocked off such that all combustion air travels to the windbox. These changes are easily accomplished in the combustion air ductwork.

Changes to the windbox size to accommodate the additional combustion air may be required to facilitate installation of FGR and/or OFA based on final design. Typically, no changes are required to the air heaters to accommodate the removal of the PA system. If required, these combustion air system modifications for natural gas firing can easily be reversed for a future return to coal firing, if the plant determines to do so.

2.4.1 A.B. Brown Unit 1 and 2 Forced Draft Fan Analysis

The existing forced draft fans on Units 1 and 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-9. The predicated fan performance from the boiler OEM is can be found in Appendix A.

Table 2-9 A.B. Brown Unit 1 and 2 Fan Evaluation

COMPONENT	RESULTS	COMMENTS
Forced Draft (FD) Fans	Test block conditions for both units of the existing FD fans exceed the requirements for firing natural gas in capacity and static pressure rise	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

2.4.2 F.B. Culley Unit 2 Forced Draft Fan Analysis

The existing forced draft fans on Unit 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-10. The predicated fan performance from the boiler OEM is can be found in Appendix B.

Table 2-10 F.B. Culley Unit 2 Fan Evaluation

COMPONENT	RESULTS	COMMENTS
Forced Draft (FD) Fans	Test block conditions of the existing fans exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction	These results are because the FD fans were originally designed for pressurized firing, which has been converted to balanced draft

2.5 FLUE GAS SYSTEM

Since natural gas firing has no ash and negligible sulfur compared to firing coal, air quality control systems including fabric filters, electrostatic participators, and flue gas desulfurization (FGD) are generally no longer required post conversion. However, it is typical for fabric filters and electrostatic participators to remain in operation for a short period of time following the natural gas conversion to capture residual coal ash remaining in the equipment and ductwork before eventually being decommissioned in place and the internals removed. FGD systems are abandoned or demolished and new flue gas ductwork installed from the FGD inlet to the stack.

2.5.1 A.B. Brown Unit 1 and 2 Induced Draft Fan Analysis

The existing induced draft fans on Units 1 and 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-11. The predicated fan performance from the boiler OEM is can be found in Appendix A.

Table 2-11 A.B. Brown Unit 1 and 2 Fan Evaluation

COMPONENT	RESULTS	COMMENTS
Induced Draft (ID) Fans	Test block conditions of the existing ID fans far exceed the requirements in capacity and static pressure rise for firing natural gas	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

2.5.2 F.B. Culley Unit 2 Induced Draft Fan Analysis

The existing induced draft fans on Unit 2 were reviewed for the 100% natural gas firing and determined that no modifications are required to meet the new design conditions as summarized in Table 2-12. The predicated fan performance from the boiler OEM is can be found in Appendix B.

Table 2-12 F.B. Culley Unit 2 Fan Evaluation

COMPONENT	RESULTS	COMMENTS
Induced Draft (ID) Fans	Test block conditions of the existing ID fans far exceed the requirements for firing natural gas with new burners, with/without OFA ports, with/without primary superheater surface reduction	Flue gas and air flow requirements for firing natural gas are less than the requirements when firing coal, resulting in less static pressure rise

2.6 CONTROL SYSTEM MODIFICATIONS

The existing BMS and BCS I/O and control processors should be repurposed or replaced along with new control logic and DCS reprogramming to support the new natural gas fired equipment. New instrumentation is required to control the new natural gas supply and burner equipment. Flow transmitters on the natural gas supply to each unit will support boiler fuel input calculations while pressure instrumentation will provide both control and necessary interlocks in accordance with NFPA 85.

2.7 FIRE PROTECTION IMPACTS

In general, converting from coal burners to natural gas burner would not require additional fire protection. However, Black & Veatch recommends getting approval from the local Authority Having Jurisdiction (AHJ) during the project design stages.

2.8 AUXILIARY ELECTRICAL SYSTEM IMPACTS

No major additions to the existing auxiliary electrical system are needed. Burner block and vent valves will be air operated valves and existing ID and FD fans will remain so that no new major power requirements are foreseen.

All systems associated with coal firing (mills, coal and ash handling equipment, etc.) would be removed from service, resulting in a reduction in auxiliary power. Also removed from service will be the precipitator and the dual alkali scrubber which will further reduce the auxiliary load on the plant.

New natural gas pressure reducing stations will require power for control panels. Each reducing station power supply will be fed by existing plant equipment and will have negligible electrical power consumption.

2.9 PLANT WATER SYSTEM IMPACTS

Boiler demineralized water consumption can increase in natural gas conversions if the conversion leads to more cyclical operation. In addition, when the unit is shut down for prolonged periods of time the resulting boiler draining and filling will result in intermittent high demands of demineralized water usage. Wet scrubber technology for the reduction of acid gases from fuel bound nitrogen in the bituminous coal being fired requires a continuous supply of water to make up the continued blowdown system. Water is also utilized for sluicing bottom ash to an ash pond and for the hydroveyor to the barge used for transporting dry fly ash off-site. Water for these systems will no longer be needed with the conversion.

2.10 NFPA IMPACTS

2.10.1 Hazardous Classification Impacts

NFPA 497 defines hazardous area classifications involving flammable or combustible liquids, combustible gases, or combustible dusts. This classification is necessary for the proper selection and installation of electrical equipment. The National Electric Code (NEC), as defined by NFPA 70, defines the requirements for electrical equipment and associated installation methods within the boundaries of hazardous areas defined by NFPA 497. In many cases, this requires vendors to provide equipment in explosion proof enclosures, the installation of purge air systems, or the use of intrinsically safe barrier systems. Electrical installation methods include the use of raceway systems specifically rated for the hazardous area and the use of seal-offs in raceway that cross the hazardous area boundary.

Assuming that the existing powerhouse meets the definition of being well-ventilated, NFPA 497 requires that 15-foot spheres around each potential leakage point be classified as a Class I Division II hazardous area. Long sections of welded natural gas piping without any flanges, valves, or instruments will not require a hazardous area classification. The fuel gas piping to the burners includes flanged connections, stem packing on the control and shutoff valves, and fittings on instrument connections that represent potential leakage points. As a result, all existing electrical components and raceway within the 15-foot sphere of potential leak points not rated for a Class I Division II environment will require replacement with appropriately rated equipment and materials. Examples include lighting, receptacles, communications equipment, power distribution equipment, control panels, drives, and associated raceway. A detailed hazardous area impact study would need to be performed to identify equipment and materials that need to be upgraded or replaced.

2.10.2 NFPA 85 Implosion Control

Although no FD or ID fan modifications are anticipated at this time to enable natural gas firing on any of the units, there may be an increased implosion potential in each boiler due to the firing characteristics of natural gas compared with coal. Natural gas can "flame out" much more quickly than coal, and natural gas does not have residual heat remaining in pulverized fuel pipes like coal. The result is the potential for an immediate drop in boiler temperature, rapidly lowering the internal boiler pressure. To fully evaluate the impacts and required boiler pressure rating due to this operating scenario, a Furnace and Draft System Transient Pressure Analysis study should be completed prior to detailed design. To some extent, the boiler depressurization can be mitigated with controls optimization (damper and fan operation control); this will also need to be evaluated by the study.

2.11 EXISTING EMISSION CONTROL EQUIPMENT IMPACTS

When burning natural gas, flue gas emissions reductions from the boilers for PM, SO2, and Hg are reduced almost directly proportional to the reduction in coal combustion. Therefore, the precipitator and related equipment will not be required for firing 100 percent natural gas. The systems, however, will remain in service for a short time after the conversion to 100 percent natural gas to remove any residual ash remaining in the ducting after the conversion. The dual alkali scrubber has numerous maintenance issues and therefore would also be removed from service, demolished, and replaced with ducting from the precipitator outlet to the stack.

The existing SCRs on A.B. Brown Unit 1 and 2 have been considered as part of the NO_x reduction control technologies and continued operation would be confirmed as part of the final netting analysis and permitting strategy (refer to Section 4.0).

3.0 Performance Impacts Analysis

Compared to firing coal, firing natural gas will reduce the boiler efficiency which will result in an increase in the net plant heat rate. The main impact on boiler efficiency is due to the hydrogen losses from the higher hydrogen content of the natural gas. Water vapor is a byproduct of combusting hydrogen, which requires additional heat to remove the water vapor. This additional heat is a loss in the flue gas rather than being absorbed in the boiler walls to create steam. Babcock & Wilcox has estimated that the excess air requirements for firing natural gas is 10 percent, compared to 20 percent for firing coal. The lower excess air requirement results in less flue gas flow, which equates to smaller losses for heating the flue gas.

A reduction in auxiliary power requirements will be realized since the pulverizers, motors and electrical equipment associated with the scrubbers, coal handling equipment, will no longer be operated after the conversion.

3.1 A.B. BROWN UNITS 1 AND 2 BOILER STEAMING CAPABILITY

Based on an assessment by Babcock & Wilcox, at MCR the main steam temperature leaving the boiler is expected to be the same as with firing coal, however, the hot reheater (HRH) temperature after gas conversion is expected to be less than the HRH temperature from firing coal. A summary of the predicted performance results based on Babcock & Wilcox' evaluation is shown in Table 3-1.

At the 60% MCR flow condition, Table 3-1 shows a more significant reduction in steam temperatures for natural gas operation. Main steam temperature decreases from 1,005 °F to 955 °F and hot reheat temperature decreases from 1,005 °F to 835 °F. Reductions in main steam and reheat steam temperatures will reduce the net turbine heat rate at this operating condition.

In addition, the excess air requirements for firing natural gas are less than the excess requirements for firing coal. This equates to a reduction in the spray water requirements for the main steam and reheater attemperators.

Table 3-1 A.B Brown Units 1 and 2 Predicted Boiler Steam Conditions

LOAD CONDITION	UNITS	MCR	MCR	60%	60%
FUEL	**-**	**100% COAL**	**100% NATURAL GAS**	**100% COAL**	**100% NATURAL GAS**
Superheater Exit Steam Flow	kpph	1,850	1,850	1,110	1,110
CRH Steam Flow	kpph	1,667	1,667	1,000	1,000
Superheater Exit Steam Pressure	psig	1,965	1,965	1,917	1,917
Reheater Exit Steam Pressure	psig	460	460	261	261
Superheater Exit Steam Temperature	F	1,005	1,005	1,005	955
Reheater Exit Steam Temperature	F	1,005	992	1,005	835

One possible way to reduce the impact to the hot reheat steam temperature is to increase air flow through the boiler with the use of FGR and OFA. These systems are typically considered for NOx control but can also be utilized to improve boiler performance by increasing overall combustion air flow through the boiler. The result is more heat transfer in the convective pass of the boiler improving HRH temperatures. A detailed analysis would need to be performed by the OEM or a third-party boiler model developed to evaluate the potential for improved performance.

3.1.1 Steam Turbine Impacts

The increased temperature difference between main steam and hot reheat steam during natural gas firing can have an adverse impact on the steam turbine. Based on the 60% MCR flow conditions for natural gas operation, the temperature difference is estimated to be 120 °F (955 °F – 835 °F). The main steam and hot reheat steam admissions are adjacent to one another in the same turbine shell and thus the initial and reheat temperatures have an important influence on the axial temperature gradient in the turbine shell.

General Electric (GE), the steam turbine OEM, typically provides guidelines on the permissible temperature difference at various operating load points. A review of the A.B. Brown steam turbine operating manual and subsequent discussion with GE indicates that the guideline included by GE for allowable differences between main and reheat steam temperatures is for units with opposed flow HP-IP turbines similar to the A.B. Brown turbines, but with a separate control valve chest. The A.B. Brown turbines however have an integral valve chest (shell mounted). GE has confirmed the provided guideline is also applicable to the A.B. Brown turbines with integral valve chest. The GE provided data indicates the 120°F differential temperature is acceptable at 60% MCR flow. Predicted boiler performance on natural gas operation was not evaluated below 60% MCR flow, therefore this operating condition would need to be assessed to fully understand the possible impacts to the steam turbine at lower loads.

Additional measures to mitigate the reduction in steam temperatures and potentially reducing their temperature difference may include sliding pressure operation at part load (compared to constant main steam pressure at part load), and possible additional measures in the boiler operation. The degree of extension of the constant temperature range for variable pressure operation will vary with a particular steam generator, fuel and other station constraints and would require additional evaluation by Babcock & Wilcox.

Reduced hot reheat steam temperature can result in increased moisture at the low-pressure turbine exhaust. Increased moisture can increase the potential for erosion of the blading of the low-pressure turbine section. The steam turbine OEM should be requested to further evaluate the impact, if any, of this increased exhaust moisture as well as the impact of the changed conditions in the low-pressure turbine section where the onset of condensation will occur (known as the Wilson Line). Initial assessment indicates the exhaust moisture may increase on the order of 3% at the 60% of MCR flow operating conditions.

3.2 F.B. CULLEY UNIT 2 BOILER STEAMING CAPABILITY

It is predicted that the main steam output of the units will not be reduced following the conversion. The excess air requirements for firing natural gas are less than the excess requirements for firing coal. This equates to a reduction in the spray water requirements for the main steam attemperators – the orifice diameter in the spray water attemperator nozzle would have to be increased. The main steam temperature and pressure leaving the boiler is expected to be the same as with firing coal. To meet these conditions, a surface reduction in the primary superheater would be required in the case where flue gas recirculation is utilized. A summary of the predicted performance results based on Babcock & Wilcox' evaluation is shown in Table 3-3.

Table 3-3 F.B. Culley Unit 2 Predicted Boiler Steam Conditions

LOAD CONDITION	UNITS	MCR	MCR	50%	50%
FUEL	**-**	**100% COAL**	**100% NATURAL GAS**	**100% COAL**	**100% NATURAL GAS**
Superheater Exit Steam Flow	kpph	840	840	420	420
Superheater Exit Steam Pressure	psig	1,290	1,290	1,260	1,260
Superheater Exit Steam Temperature	F	955	955	955	955

3.2.1 Steam Turbine Impacts

As shown in Table 3-3 the superheat steam flow and temperature remain consistent between coal and natural gas fired scenarios. Therefore unlike A.B. Brown Units where they drop off at part load, there is not a concern of potential steam turbine impacts to F.B. Culley Unit 2 when firing natural gas.

4.0 NOx and CO Reduction Techniques

Converting the boilers to 100 percent natural gas combustion should significantly decrease the NO_x while increasing CO from the combustion process. Since there is nearly zero fuel-bound nitrogen in natural gas, NO_x production is a direct result of thermal NO_x formation during combustion. In addition, natural gas firing temperatures are typically lower, as less excess air is required to complete combustions compared to coal, reducing the potential for thermal NO_x to form. However, this limited oxygen environment that results in lower NO_x does increase CO from incomplete combustion. It should be noted that even though NOx production is lower for natural gas vs. coal due to less combustion air, the allowable permitting limits for burning natural gas can be much lower than coal. For instance, Unit 1 at A.B. Brown is currently subject to New Source Performance Standard (NSPS) Subpart D, which carries a NO_X limit of 0.70 lb/MBtu for coal-fired units. For natural gas-fired units, the rule prescribes a NO_X limit of 0.20 lb/MBtu. Unit 2 at A.B. Brown is subject to NSPS Subpart Da, which requires that the unit meet a NO_X emission limit of 0.50 lb/MBtu for coal-firing. Following a conversion to natural gas, the unit would be subject to a limit of 0.20 lb/MBtu. F.B. Culley Unit 2 is not subject to any NSPS NO_X limits given its age. Black & Veatch would not anticipate that this would change following a conversion to natural gas assuming that the project is not applicable to major modification permitting requirements.

To control NO_x and CO, additional controls are typically required and for this evaluation included assessment of selective catalytic reduction (SCR), flue gas recirculation (FGR), over-fire air (OFA), and CO Catalyst also referred to as Oxygen catalyst to limit emissions.

Specific reduction techniques considered for A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 are identified in Table 4-1 and Table 4-2. Calculated emission rates for the evaluated emission control technologies are identified in Section 5, Table 5-1.

Table 4-1 A.B. Brown Unit 1 and 2 Optional Methods for NOx Reduction

COMPONENT	RESULTS	COMMENTS
OPTIONAL METHODS FOR NO_X REDUCTION		
Staged Combustion (OFA Ports)	Addition of eight new OFA (aka NO_X ports) in the furnace walls; four in the front wall, four in the rear wall.	Will require windbox and duct work modifications. Since A.B. Brown units are currently equipped with SCR systems OFA may not be required
Flue Gas Recirculation (FGR)	Introduction of recirculated flue gas into the combustion air stream upstream of the burner windbox via new FGR fan pulling flue gas from ducting downstream of the air heater.	Mixing device to be added in the combustion air ductwork to adequately distribute the recirculated flue gas into the incoming combustion air. Since A.B. Brown units are currently equipped with SCR systems, FGR may not be required
Selective Catalytic Reduction (SCR)	Continued operation of existing SCRs including ammonia storage and feed systems.	Existing SCR catalyst would require analysis to determine if any or all layers require replacement to meet targeted NO_x reduction.

OPTIONAL METHODS FOR CO REDUCTION		
CO Catalyst	Addition of a CO (Oxygen) Catalyst to be located in the fourth layer of the existing SCR which is currently unused.	Multiple catalysis technologies are available and include duel SCR and CO catalysis which should be evaluated during detailed design.

Table 4-2 F.B. Culley Unit 2 Optional Methods for NO_x Reduction

COMPONENT	RESULTS	COMMENTS
OPTIONAL METHODS FOR NO_X REDUCTION		
Staged Combustion (OFA Ports)	Addition of eight new OFA (aka NO_X ports) in the furnace walls; four in the front wall, four in the rear wall, located approximately 8 feet above the top burner row	Will require windbox and duct work modifications
FGR	Introduction of recirculated flue gas into the combustion air stream upstream of the burner windbox via new FGR fan pulling flue gas from ducting downstream of the air heater	Mixing device to be added in the combustion air ductwork to adequately distribute the recirculated flue gas into the incoming combustion air
OPTIONAL METHODS FOR CO REDUCTION		
CO Catalyst	Addition of a new CO (Oxygen) Catalyst in the flue gas ductwork between the economizer outlet and air heater inlet.	Would require extensive modifications to the flue gas ductwork to facilitate installation.

4.1 OVER-FIRE AIR (OFA)

Two-staged combustion is a method of achieving a significant reduction in NO_x. Combustion air is directed to the burner zone in quantities (70 percent to 90 percent) that are less than that required to theoretically burn the fuel. The remainder of the combustion air (10 percent to 30 percent) is directed to OFA ports, which are located above the top row of burners. By reducing the excess air in the primary combustion (burner) zone, NO_x formation is stunted due to the limited amount of oxygen in the air. Furthermore, less oxygen means a decrease in the combustion reactions occurring and a decrease in the heat of reaction released, reducing the overall and peak temperatures in the burner zone (first stage). The additional air nozzles also spread the release of heat over a larger area in the furnace. Thermal NO_x formation increases with higher temperatures, so reducing the overall and peak temperatures represses thermal NO_x. Any residual unburned material, such as CO that inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

The expected NO_x reduction from a given OFA system depends on a number of factors. The stoichiometry in the burner zone decreases as the amount of OFA is increased, and a point is reached where CO emissions reach high levels and become uncontrollable. The point at which this occurs varies, depending on the balance of flows between individual burners. As the OFA amount approaches 10 to 15 percent, the probability for individual burners to be operating under fuel-rich conditions increases so that pockets of very high CO emissions would be formed.

The total estimated furnish and installed cost for an over-fire air system is shown in Table 4-3.

Table 4-3 Over-Fire Air System Estimated Cost

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY, UNIT 2
Materials and installation[1]	$1,000,000	$1,000,000	$975,000
Total furnish and installed cost for OFA system	$1,000,000	$1,000,000	$975,000

Note:
1. Includes OFA nozzles, ducting modifications, and dampers

4.2 FLUE GAS RECIRCULATION

FGR is useful in reducing NO_x when the contribution of fuel nitrogen to the total NO_x formation is a small fraction of the constituents, such as the case with natural gas. Typically, a portion of the flue gas is extracted from the discharge of the economizer (gas side) or discharge of the air heater and introduced into the combustion air flow stream, which lowers the burner peak flame temperatures.

The typical design of an FGR system requires the installation of an FGR fan, ducting, duct supports, and controls. The FGR system utilizes air foils to mix the recirculated flue gas with the combustion air downstream of the FD fan. This ensures that the flue gas and combustion air are thoroughly mixed before reaching the burners.

For retrofit applications, FGR sometimes needs to be provided with OFA ports, because the original burners are not capable of handling the significant increase in mass flow from the recirculated flue gas. The necessary FGR rates can result in throat velocities that exceed the burners' design, which will result in burner instability and potential pulsations while firing.

In general, a significant increase in flue gas recirculation to the burners would produce a large reduction in NO_x emissions. The amount of FGR would be dictated by the emissions levels that are targeted as well as limitations on equipment size and boiler components.

An additional benefit of FGR is that the additional flue gas flow with the combustion air can increase furnace velocities to push heat to the convective heating surfaces, which could increase steam temperatures on coal units that have been converted to gas.

The total estimated furnish and installed cost for a flue gas recirculation system is shown in Table 4-4.

Table 4-4 Flue Gas Recirculation System Estimated Cost

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY, UNIT 2
Materials and installation[1]	$3,880,000	$3,880,000	$1,560,000
Total furnish and installed cost for FGR system	$3,880,000	$3,880,000	$1,560,000

Notes:
1. Includes FGR fan/motor, ducting, instrumentation, and installation

4.3 SELECTIVE CATALYTIC REDUCTION

Selective catalytic reduction (SCR) reduces NO_x emissions by introducing ammonia (NH_3) into the flue gas upstream of a reaction chamber. Ammonia readily reduces the NO_x molecules into nitrogen and water at temperatures above 1600°F (870°C). The SCR reaction chamber, which is installed between the economizer and air preheater, is at temperatures much less than is optimal for NH_3-NO_x reactions, so catalysts are needed to promote the reactions. The reaction chamber contains one or multiple layers of catalyst that are made of metals and/or ceramics contained a highly porous structure.

Poisoning of the catalyst from alkali metals and trace elements (especially arsenic) is a steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. This means that the catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. For natural gas applications, significantly less catalyst poisoning is expected compared to coal burning facilities.

Since the existing SCR catalyst systems at A.B. Brown Unit 1 and Unit 2 have been in use for several years it was assumed for this study and cost estimate that multiple layers of SCR catalyst would need to be replaced to facilitate continued operation and NO_x reduction through the SCRs. The next step would be for Vectren to have a catalyst OEM assess the condition of the existing catalyst and make a recommendation for replacement or reuse for the natural gas conversion operation.

The total estimated furnish and installed cost for a selective catalytic reduction system is shown in Table 4-5.

Table 4-5 Selective Catalytic Reduction System Estimated Cost

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY, UNIT 2
Total materials	$1,060,000	$1,060,000	N/A
Total installation	$1,000,000	$1,000,000	N/A
Total furnish and installed cost for a SCR system[1] certification	$2,060,000	$2,060,000	NA
Notes: 1. SCR system includes replacement of catalyst, chemical disposal, SCR catalyst replacement, installation.			

4.4 OXGYEN CATALYTIC REDUCTION (CO CATALYST)

Catalytic oxidation is a post-combustion method for reduction of CO and VOC emissions. This control process utilizes a platinum/vanadium catalyst that oxidizes CO to CO2 and VOC to CO2 and water. The process is a straight catalytic oxidation/reduction reaction requiring no reagent. Catalytic CO and VOC emissions reduction methods have been proven for use on natural gas and oil fueled combustion turbine sources, but not coal fired boilers. It should be noted that none of the catalyst components are considered toxic.

The primary technical challenge for including an oxidation catalyst on a coal or natural gas fired boiler is the location of the catalyst in a high temperature regime, which would ideally be prior to the economizer as the optimum exhaust gas temperature range for CO and VOC catalyst operation is between 850°F and 1,110°F (1,560°C and 2,012°C). For the purpose of this study the CO catalyst is assumed to be located between the economizer and air heater.

The total estimated cost for a catalytic oxidation system is shown in Table 4-6.

Table 4-6 Catalytic Oxidation System Estimated Cost

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY, UNIT 2
Total materials	$3,500,000	$3,500,000	$2,000,000
Total installation	$1,500,000	$1,500,000	$3,000,000
Total furnish and installed cost for CO system[1]	$5,000,000	$5,000,000	$5,000,000
Notes: 1. Includes CO system materials,			

5.0 Emissions Netting

5.1 BACKGROUND

Converting A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 to fire natural gas would constitute a modification of an existing air emissions source and would, therefore, require an air construction permit to authorize construction. The first step in any air construction permit application process is to determine the proposed project's applicability to the federal New Source Review (NSR) pre-construction permitting program.

The Federal Clean Air Act (CAA) NSR provisions are implemented for major modifications at existing major sources under two programs: the Prevention of Significant Deterioration (PSD) program outlined in 40 CFR §52.21 for areas in attainment of the National Ambient Air Quality Standards (NAAQS), and the Non-Attainment NSR (NA-NSR) program outlined in 40 CFR §51 and §52 for areas classified as not in attainment of the NAAQS (i.e., non-attainment areas). Currently, both Posey County and Warrick County, Indiana, are designated as either attainment or unclassifiable for all criteria pollutants. Because of this, a determination of whether the proposed natural gas conversions would qualify as a major modification at an existing major source would need to be made in accordance with the procedures outlined in the PSD program. Projects that are subject to PSD permitting are required to undertake extensive analyses as part of the permit application process, including air dispersion modeling and the identification and application of best available control technology (BACT). Additionally, PSD permitting can take as long as 12-18 months. Non-PSD permitting, or minor source permitting, on the other hand does not typically require modeling or BACT and the associated timeline is typically 3-6 months.

For a project to be deemed a major PSD modification under the definition provided in 40 CFR §52.21, the project must result in both a significant emission increase and a significant net emission increase. The process of determining whether a significant emissions increase will result from the construction of a project is commonly referred to as "Step 1" of the PSD applicability test. Because both A.B. Brown and F.B. Culley are existing major sources under the PSD process, the Step 1 evaluation must be conducted on a pollutant-by-pollutant basis by comparing the emissions increase of each pollutant against the PSD significant emissions rates (SERs). If a project's emissions increase of a given pollutant are larger than the pollutant's respective SER, the project is considered to result in a significant emissions increase. Since the proposed natural gas conversions will involve existing emissions units, this Step 1 emissions increase, or project emissions increase (PEI), can be calculated as the difference between either the project actual emissions (PAE) or the potential to emit (PTE) and the baseline actual emissions (BAE). BAE is defined in the federal PSD regulations as the average rate, in tons per year (tpy), at which the emissions unit actually emitted a regulated NSR pollutant during any consecutive 24 month period selected by the owner or operator within the 5 year period immediately preceding when the owner or operator begins actual construction of the project. However, because air construction permit applications are required to be submitted several months prior to the start of construction, agencies will typically accept BAEs based on the 5-year period immediately preceding the submittal of the air construction permit application.

Because the proposed projects entail the conversion of coal fired boilers to natural gas firing, the PAE cannot easily be determined, as no past operation burning natural gas could be used to base a projection on. Therefore, the PTE would likely be used in conjunction with the BAE to determine the PEI of the proposed natural gas conversions in Step 1 of the PSD applicability determination. According to federal and state definitions, the PTE is "the maximum capacity of a source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type of/amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation is enforceable […]."

Vectren has determined that any air construction permitting strategy for the proposed natural gas conversions at A.B. Brown and F.B. Culley should try to mitigate the need for PSD. As previously noted, obtaining a PSD permit involves several rigorous requirements including the application of Best Available Control Technology (BACT) and the performance of an air dispersion modeling analysis examining the effects of the project's emissions on the ambient air quality. Thus, the PSD review process typically adds significant time in a project schedule to account for application preparation as well as Indiana Department of Environmental Management (IDEM) and Environmental Protection Agency (EPA) review.

5.2 PRELIMINARY PSD APPLICABILITY ANALYSIS

A high-level preliminary emissions analysis was conducted to determine the operational limits (i.e., limits on annual hours of operation) required to keep the Step 1 pollutant-by-pollutant PEI for the natural gas conversion at each facility less than the respective PSD SERs so that PSD permitting would not be required. The analysis examined the added hours of operation that could be achieved utilizing various air quality control technologies.

Assuming all other factors are held equal, because of the cleaner nature of natural gas combustion compared to coal, conversion of the A.B. Brown and F.B. Culley coal fired boilers to natural gas fueled units should result in emissions reductions when comparing the PTE to the BAE for those pollutants that are directly related to fuel makeup (i.e., PM and SO_2). On the other hand, for pollutants where emissions are associated with the combustion process (i.e., NO_X, CO, and VOC), emissions associated with natural gas combustion can yield emissions increases in the Step 1 PEI calculation. Because of this, the preliminary analysis was limited to examine only NO_X, CO, and VOC as the "limiting pollutants."

The NO_X, CO, and VOC BAE for A.B. Brown and F.B. Culley utilized a combination of industry standard emission factors from EPA's AP-42 database, continuous emissions monitoring system (CEMS) data, and fuel usage data. The A.B. Brown baseline includes monthly emissions through February 2019 whereas F.B. Culley's BAE was based on data through the end of 2018. The BAE for both A.B. Brown units and the F.B. Culley unit only considered data dating back to January 2015, which is not consistent with the definition above that specifies a lookback period of 5 years. Black & Veatch notes, however, that this approach is consistent with a decision by IDEM that dictated that operational data prior to January 2015 would not be able to be considered, as it was not representative of the current operating characteristics of the A.B. Brown units.

For the PTE calculations, natural gas fired emissions rates that were developed in previous coal to natural gas conversion study were utilized. These emission rates considered varying configurations of three combustion controls designed to reduce NO_X emissions:

- Low NO_X natural gas burners (XCL-S burners).
- OFA.
- FGR.

In addition to combustion controls, Vectren requested that Black & Veatch examine the impacts of catalyst based post-combustion controls for NO_X, CO, and VOC. Typical post-combustion catalyst-based controls include SCR to control NO_X emissions and oxidation catalyst (i.e., CO catalyst) to control emissions of CO and VOC. A.B. Brown Units 1 and 2 already employ an SCR to control NO_X emissions, and for the expanded analysis, it was assumed that these systems would be left in service following the natural gas conversion. For F.B. Culley, all additional control scenarios would require newly installed equipment. In addition to a separate catalyst system to control NO_X and CO/VOC, Black & Veatch also analyzed a scenario in which a dual catalyst designed to control both NO_X and CO would be used in addition to SCR to achieve the necessary pollutant controls.

The emissions calculation methodology first entailed calculating the threshold magnitude of NO_X, CO, and VOC emissions that could occur without triggering PSD (tpy) by adding the BAE of each unit to the respective SERs (i.e., 40 tpy for NO_X and VOC and 100 tpy for CO). Because the modification at A.B. Brown involves two units, an assumption was made that the threshold emissions increases for the project (the "project" would include the cumulative emissions increases for both unit conversions) would be distributed equally between Unit 1 and Unit 2. The emission rates were then combined with projected heat inputs rates (in million British thermal units per hour [MMBtu/h]) to determine the maximum number of hours that a particular unit could be operated without triggering PSD for at least one of the limiting pollutants. Heat inputs for natural gas-fired operation for all three units were assumed to be identical to heat inputs for coal fired operation.

The analysis examined three different load points: 100 percent load, 60 percent load, and 10 percent load. For each load point, the following air quality control configurations were examined:

- A.B. Brown Units 1 and 2:
  - XCL-S burners only.
  - XCL-S burners and OFA.
  - XCL-S burners, OFA, and FGR.
  - XCL-S burners and FGR.
  - XCL-S burners and CO catalyst.
  - XCL-S burners, existing SCR, and dual catalyst.
  - XCL-S burners, FGR, and CO catalyst.
- F.B. Culley Unit 2:
  - XCL-S burners only.
  - XCL-S burners and OFA.

- XCL-S burners, OFA, and FGR.
- XCL-S burners and FGR.
- XCL-S burners and CO catalyst.
- XCL-S burners, new SCR, and new dual catalyst.
- XCL-S burners, FGR, and CO catalyst.

Preliminary iterations of the analysis examining OFA indicated that the NO_x reduction from OFA is insignificant. As such, the analysis as presented below was refined to only include results from the scenarios that include XCL-S burners, FGR, and post combustion controls. The emission rates that were utilized to calculate the post-conversion PTE's are included in Table 5-1.

Table 5-1 Natural Gas Fired Emission Rates

UNIT	POLLUTANT	XCL-S BURNERS ONLY	XCL-S BURNERS & FGR	XCL-S BURNERS AND CO CATALYST[1]	XCL-S BURNERS, SCR, AND DUAL CATALYST[2]	XCL-S BURNERS, FGR, AND CO CATALYST[1]
A.B. Brown Unit 1	NO_X	0.17	0.07	0.17	0.01	0.07
	CO	0.15	0.15	0.015	0.015	0.015
	VOC	0.003	0.003	0.0017	0.0017	0.0017
A.B. Brown Unit 2	NO_X	0.19	0.07	0.19	0.01	0.07
	CO	0.15	0.15	0.015	0.015	0.015
	VOC	0.003	0.003	0.0017	0.0017	0.0017
F.B. Culley Unit 2	NO_X	0.16	0.07	0.16	0.01	0.07
	CO	0.15	0.15	0.015	0.015	0.015
	VOC	0.003	0.003	0.0017	0.0017	0.0017

Notes:

1. NO_X emissions rates for A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 were obtained from Babcock & Wilcox studies on converting the boilers from coal to natural gas. CO and VOC emissions rates are based on engineering estimate. Assumes 90% and 45% removal efficiency in the CO catalyst, respectively.
2. NO_X and CO emissions are based on Cormetech estimates. VOC emissions rates are based on engineering estimate. Assumes 45% removal efficiency in the dual catalyst.

Figures 5-1 through 5-3 illustrate the hours available to each unit while avoiding PSD permitting at 100 percent, 60 percent, and 10 percent load. Finally, in addition to the hours of operation achievable while not triggering PSD, the figures also include the installed cost estimates for each air quality control scenario.

As can be seen in the figures, the most affordable option available that also allows full operational flexibility for all three units is the addition of XCL-S burners and dual catalyst.

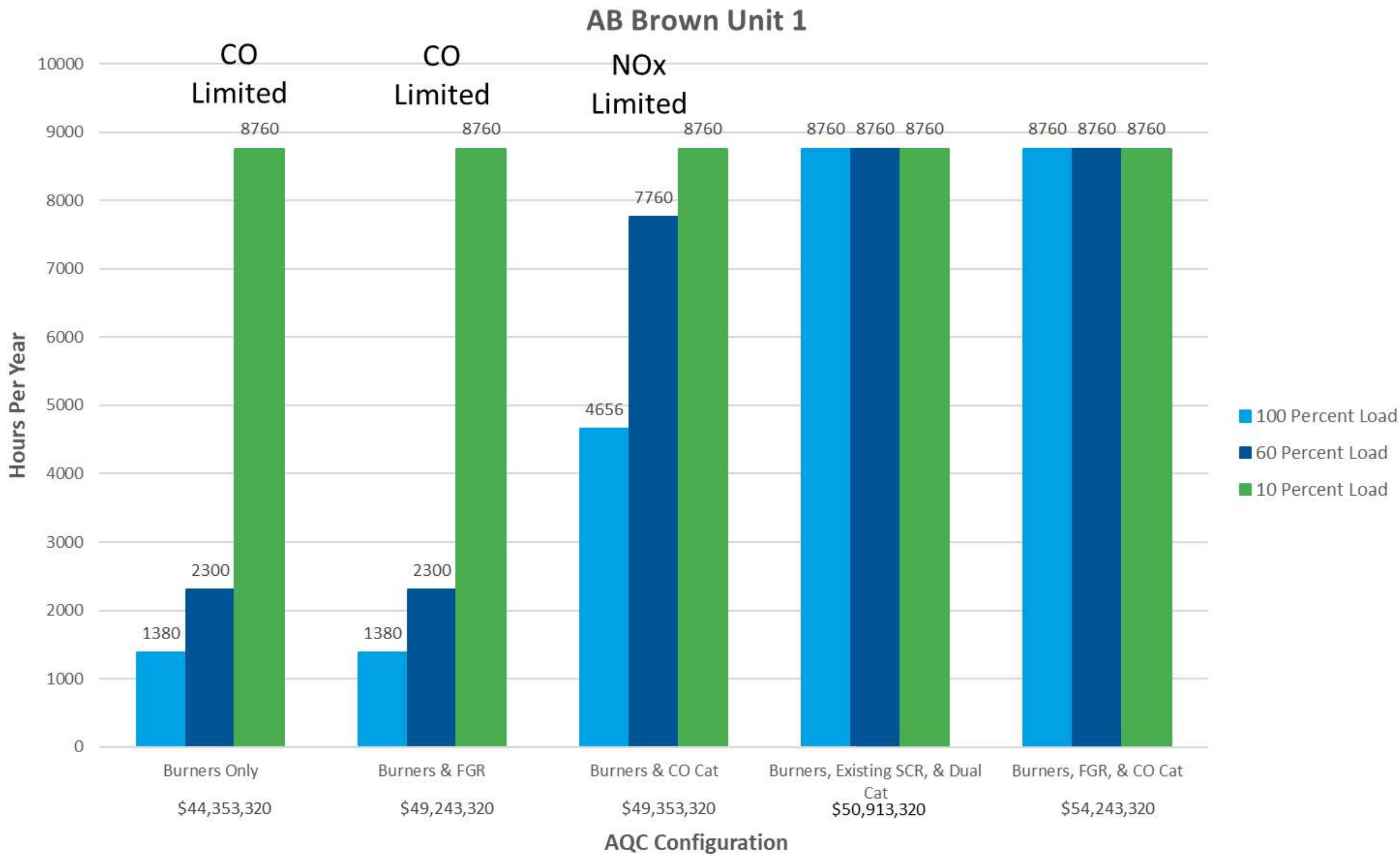

Figure 5-1 Hours of Operation Achievable without Triggering PSD – A.B. Brown Unit 1

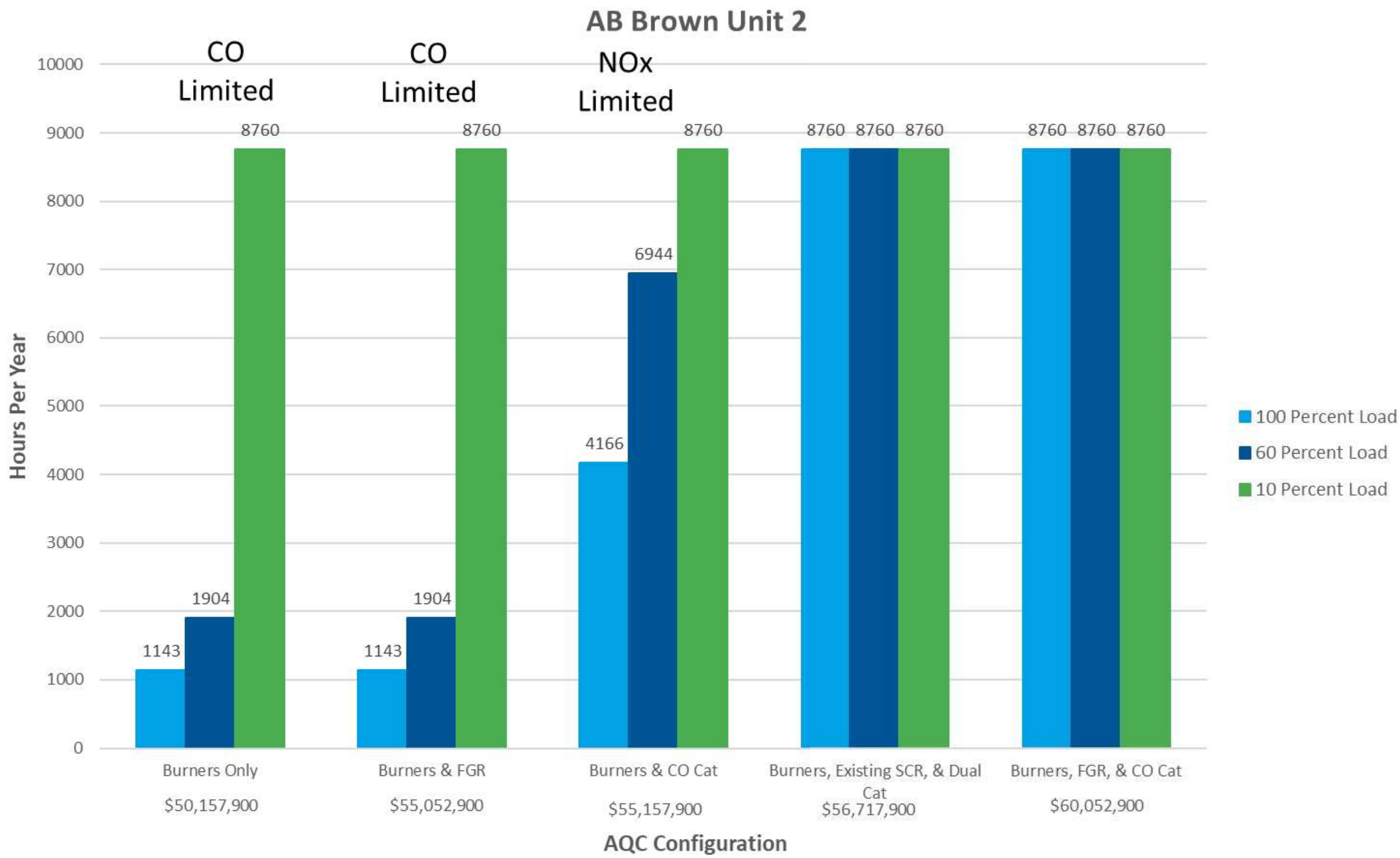

Figure 5-2 Hours of Operation Achievable without Triggering PSD – A.B. Brown Unit 2

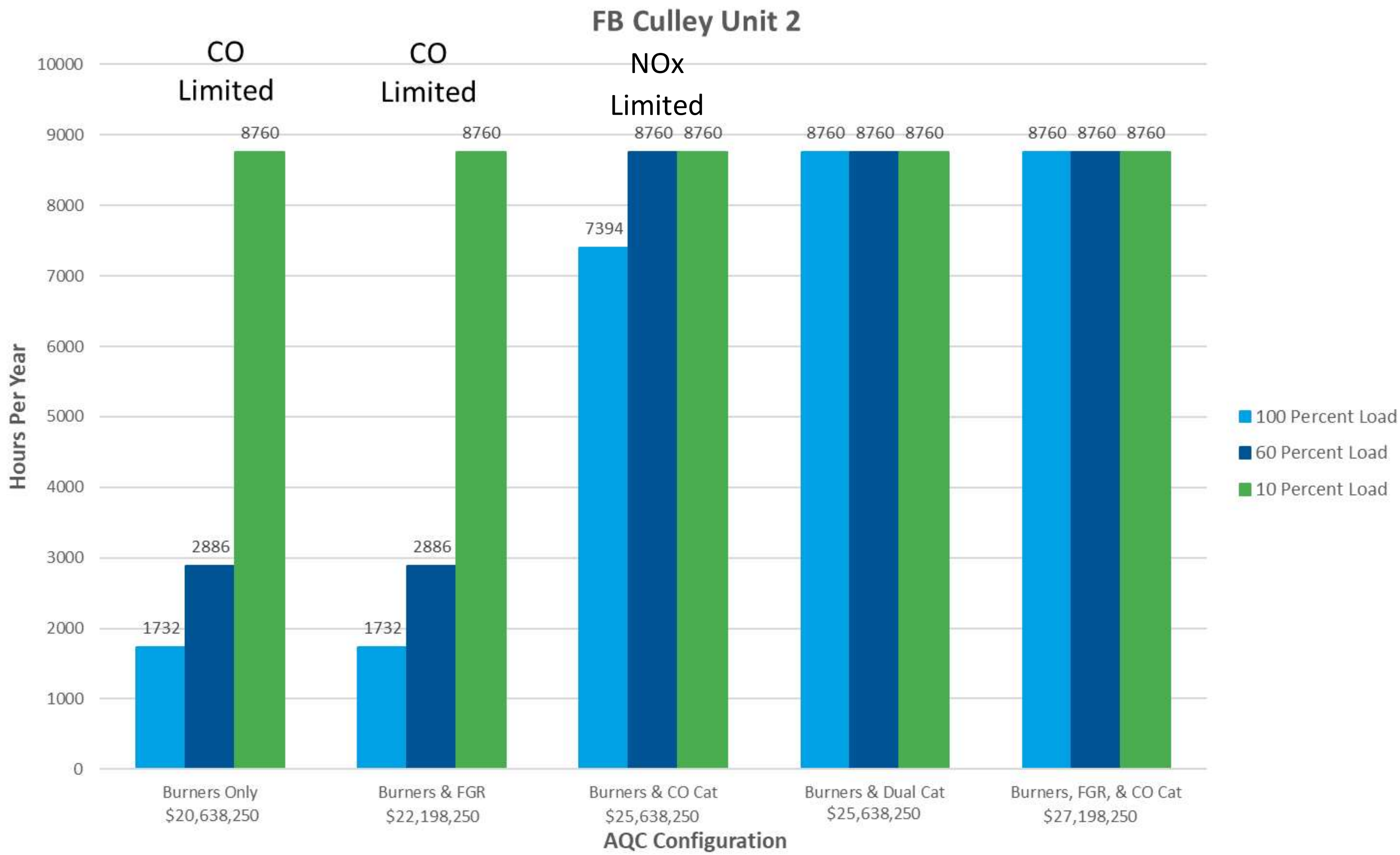

Figure 5-3 Hours of Operation Achievable without Triggering PSD – F.B. Culley Unit 2

6.0 Estimated Costs

The estimated furnish and installation costs for the conversion were provided from multiple sources and are summarized in Table 6-1.

Table 6-1 Estimated Project Costs

	A.B. BROWN UNIT 1	A.B. BROWN UNIT 2	CULLEY , UNIT 2
Materials; burner replacements, ducting metering/regulating station, BOP modifications, etc.	$10,070,000	$11,419,000	$8,880,000
Installation; burner replacements, ducting metering/regulating station, BOP modifications, etc.	$8,639,600	$9,970,000	$3,660,000
Bowen Gas Line from T10 to Tee	$1,618,000	$1,618,000	$685,000
FGD Demo and Bypass Duct	$5,600,000	$7,798,000	N/A
CO Catalyst Layer (materials)	$3,500,000	$3,500,000	$2,000,000
CO Catalyst Layer (installation)	$1,500,000	$1,500,000	$3,000,000
SCR Catalyst (materials) (1)	$1,060,000	$1,060,000	N/A
SCR Catalyst (installation)	$1,000,000	$1,000,000	N/A
Over Fire Air (materials and installation) (1)	$1,000,000	$1,000,000	$975,000
Flue Gas Recirculation System (materials and installation) (1)	$3,880,000	$3,880,000	$1,560,000
General Boiler/Plant Modifications	$9,033,360	$9,185,960	$3,245,273
Owners Consultant (19%)	$8,911,182	$9,866,882	$4,561,002
Total Project Cost	**$55,812,142**	**$61,797,842**	**28,566,275**
Annual Maintenance Costs	**$30,000**	**$30,000**	**$25,000**

Notes:
1. Optional Scope – Pricing included in Total Project Cost

Abbreviations:
BOP – Balance of Plant
DCS - Distributed Control System
CO – Carbon Monoxide
SCR - Selective Catalytic Reduction

7.0 Conclusions

7.1 SUMMARY

A.B. Brown Units 1 and 2 and F.B. Culley Unit 2 were evaluated on the basis of converting the units from firing 100 percent bituminous coal to firing 100 percent natural gas. The study included evaluating design changes that are required to make the conversion: new/modified burners, additional natural gas metering/pressure reducing s, balance-of-plant modifications, BMS controls modifications, etc. Additionally, the evaluations discussed plant performance impacts resulting from the coal-to-natural gas conversion and provided estimated costs for the modifications.

Black & Veatch's review concluded the OEM assessed impacts to performance, reduction in boiler efficiency, gross/net output, auxiliary loads, and an increase in net plant heat rate and steam turbine generator heat rate are consistent and reasonable given our experience and assessments of similar sized units.

Appendix A. Babcock & Wilcox Engineering Study for Natural Gas Firing for A.B. Brown Units 1 and 2

Engineering Study for Natural Gas Firing

for

Vectren Power Supply
AB Brown Station Units 1 & 2
Evansville, Indiana

Contract 591-1048 (317A)
June 13, 2019 - Rev 5

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INTRODUCTION

Vectren Power Supply contracted The Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate natural gas firing at the AB Brown Station Units 1 and 2, originally supplied by B&W under contract RB-557 and RB-599. The boiler performance model was reviewed at 100% (Maximum Continuous rating) MCR and 60% load when firing 100% natural gas. An analysis of the allowable tube metal stresses was performed for 100% gas firing at 100% MCR and 60% boiler loads in regards to the primary superheater, secondary superheater and reheat superheater.

BACKGROUND

The AB Brown Units 1 & 2 (RB-557 & RB599) are presently balanced draft (Unit 1 was originally pressure fired and converted to balanced draft operation), subcritical Carolina type radiant boilers, with secondary superheater, primary superheater, reheater and economizer surfaces arranged in series. Superheater steam temperature is controlled by interstage spray attemperation. Reheater steam temperature is controlled by excess air and spray attemperation. The units were originally designed as a front and rear wall, bituminous coal fired units. The original maximum continuous rating for RB-557 and RB-599 is 1,850,000 lbs/hr of main steam at 1005°F and 1965 psig at the superheater outlet with a feedwater temperature of 467°F. The reheat steam flow is 1,666,500 lbs/hr at 1005 F and 485 psig at the reheater outlet. Spray attemperation is used to control superheat and reheat steam temperatures. The units were to be operated at 5% overpressure over the load range.

The units are front and rear wall fired with twenty-four B&W 4Z low NO_x burners, four wide by three high. There are six B&W EL-76 pulverizers for each unit supplying coal to the burners.

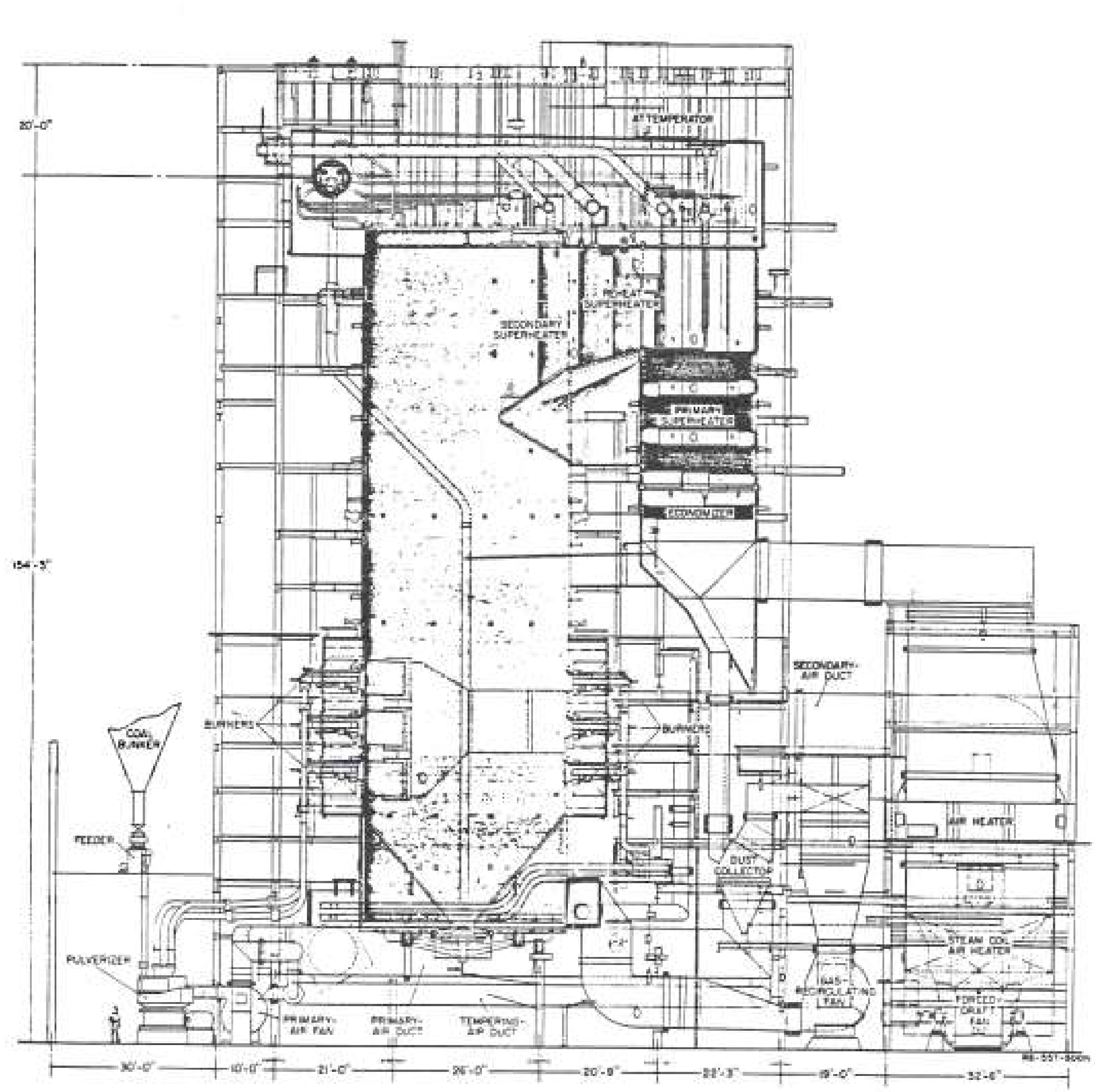
Combustion air is heated through two Ljungstrom regenerative air heaters.

Unit 2 (RB-599) is a semi-duplicate of Unit 1 (RB-557) with the following differences:

- Unit 2 has a furnace height of 124’-0’’ compared to 122’-0” for Unit 1. The vertical burner spacing is 10’-0” for Unit 2 compared to 8’-0” for Unit 1.
- Unit 2 has six water-cooled furnace wing walls. Unit 1 has a full furnace division wall.
- Unit 2 was designed without flue gas recirculation. Unit 1 was originally designed with flue gas recirculation. The flue gas recirculation system on Unit 1 has been removed from service.

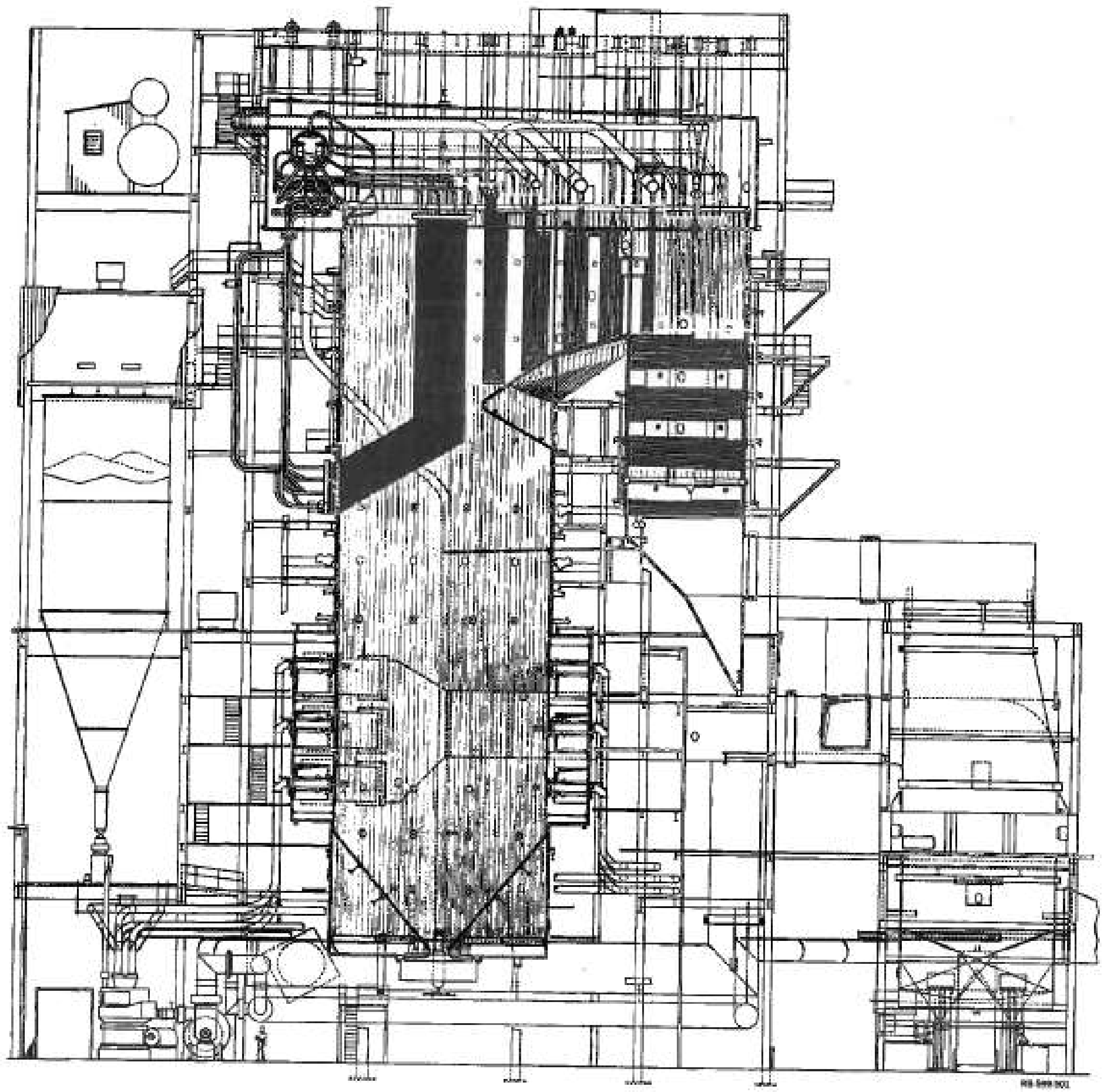
A sectional side view of the boilers is shown in Figures 1a and 1b.

FIGURE 1a



Brown Station Unit 1

B&W Contract Number RB-557



Brown Station Unit 2

B&W Contract Number RB-599

SCOPE FOR PHASE I

B&W evaluated natural gas firing in the radiant boilers originally supplied by B&W under contract numbers RB-557 and RB-599. Boiler component drawings and original performance summary data were used to develop comprehensive thermal models and boiler pressure part assessments. The predicted performance of the proposed natural gas firing was analyzed at MCR load and 60% load. The tube metallurgy requirements for the primary superheater, secondary superheater, reheater and headers were also developed. In addition to superheater metals analysis, predicted performance of the air preheaters and the attemperator capacities were also evaluated relative to overall performance.

SCOPE FOR PHASE II

The Phase II engineering scope of supply includes the entire scope of Phase I. In addition, the need surface modifications for firing 100% natural gas were analyzed. The adequacy of the existing forced draft (FD) fans and the induced draft (ID) fans were also assessed.

BASIS

This boiler pressure part metals assessment requires developing overall unit heat and material balances at the indicated steam flow. The 2015 fuel analyses for coal as supplied by Vectren were found to be very close to original design bituminous coal. Since the 2015 fuel analyses were incomplete, the original design fuel analysis was used. The natural gas analysis was also supplied by Vectren. The original design coal and natural gas fuel analyses are provided in Tables 1 and 2. These were used as a basis for the heat and material balances shown in Table 3.

Table 1: Original Design As-Fired Fuel Analyses for Bituminous Coal, % by weight

Constituent	
C	64.00
H_2	4.44
N_2	1.38
O_2	6.51
Cl	0.00
S	3.52
H_2O	11.35
Ash	8.76
Total	**100.00**
HHV (Btu/lb)	**11533**

Table 2: Proximate Analysis for Natural Gas, % by volume

Constituent	
Nitrogen	0.28
Methane	96.31
Ethane	1.46
CO_2	1.89
Others	0.06
Total	**100.00**
HHV (Btu/ft^3)	**1,037**

Table 3: Boiler Operating Conditions Used in Metals Evaluation

Boiler Load	**MCR**	**60%**
Superheater Steam Flow (lb/hr)	1,850,000	1,110,000
Steam Temperature at SH Outlet (°F)	1005	933
Steam Pressure at SH Outlet (psig)	1965	1917
Reheater Steam Flow (lb/hr) w/o Attemperator Spray	1,666,500	1,000,000
Steam Temperature at RH Outlet (°F)	992	835
Steam Pressure at RH Outlet (psig)	460	261
Feedwater Temperature (°F)	467	417
Excess Air Leaving Econ (%)	10	18

RESULTS

Boiler Performance

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal at the original design data, recent field data for each of the units and predicted unit performance firing 100% natural gas.

Attemperator Capacity

Along with the metals analysis, attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing natural gas. Current attemperator capacities for both units should be satisfactory at all boiler loads. The results are shown in Table 6.

Table 6: Predicted Attemperator Flows (lbs/hr)

Boiler Load	MCR	60%
Bituminous Coal:		
SH Spray Flow	77,870	88,000
RH Spray Flow	19,000	0
Natural Gas		
SH Spray Flow	53,700	0
RH Spray Flow	0	0

Air Heater Performance

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for the natural gas conversion. Since no field data was provided that would show higher than original air heater leakage or other air heater performance degradation, the predicted air heater performance is based on the original design data with an air heater leakage of 7.4%. Predicted performance is shown on Table 7a and 7b.

Table 7a: Regenerative Air Heater Predicted Performance at

Unit	1 & 2	1	2	1 & 2
Boiler load	MCR	95%	94%	MCR
Data Basis	Original Design	7-14-2015 PI Data	7-10-2015 PI Data	Predicted Performance*
Fuel	Bituminous Coal	Bituminous Coal	Bituminous Coal	Natural Gas
Flue Gas Flow Entering Air Heaters, mlb/hr	2,570	2,584	2,422	2,234
Flue Gas Temp Entering Air Heaters, F	705	650	652	697
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	304	336	346	303
Air Flow Leaving Air Heaters, mlb/hr	2,307	2,323	2,174	2,056
Air Temp Entering Air Heaters, F	85	168	138	85
Air Temp Leaving Air Heaters, F	566	535	554	567

*Based on original design data

Table 7b: Regenerative Air Heater Predicted Performance

Unit	1 & 2	1 & 2
Boiler load	60%	60%
Data Basis	Original Design	Predicted Performance*
Fuel	Bituminous Coal	Natural Gas
Flue Gas Flow Entering Air Heaters, mlb/hr	2,060	1,403
Flue Gas Temp Entering Air Heaters, F	675	617
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	283	259
Air Flow Leaving Air Heaters, mlb/hr	1,867	1,273
Air Temp Entering Air Heaters, F	83	83
Air Temp Leaving Air Heaters, F	547	520

*Based on original design data

Tube Metal Temperature Evaluation

B&W uses an ASME Code accepted method to design its tube metallurgies and thicknesses. The method involves applying upsets and unbalances to determine spot and mean tube metal temperatures. The upsets and unbalances include empirical uncertainty in the calculation of furnace exit gas temperature (FEGT), top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and component arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to a single spot in each row of the superheater. Tube row metallurgy and thickness are then determined from the resultant tube spot and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses. B&W policy does not allow the publishing of design tube metal temperatures or unbalanced steam temperatures. However, these values can be reviewed in B&W's offices, if desired.

The remaining life expectancy of the superheaters is dependent on the prior operating history, especially on actual tube operating temperature compared to design temperature. Thus, the assessment of the adequacy of the existing superheaters is not a simple task.

The SSH outlet bank & RSH outlet bank were replaced on unit 1 in the spring of 2012 and on unit 2 in the fall of 2015. The evaluation is based on the design of the present SSH outlet banks & RSH outlet banks which were supplied by B&W.

B&W has determined the operating hoop stress level (based on the current minimum tube wall thickness) at operating pressure. The predicted tube operating temperatures based on B&W's standard design criteria and the resulting ASME Code allowable stress level for the existing material has also been determined. Comparison of the operating hoop stress with the Code allowable stresses results in the percent over the allowable stress. A modest overstress level indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant tube modification at this time.

If the tube analysis shows significant overstress or shows that tubes are predicted to operate at temperatures above those for which ASME Code stresses are published, then serious consideration should be given to tube upgrades and replacement. <u>Significant overstresses are considered those tube rows that are 20% or greater overstressed.</u> An overstress of 20% or more does not necessarily mean that immediate replacement of the tube row is required, but it identifies which tube rows should be examined for potential problems. Potential problems could be signs of creep, internal exfoliation or swelling.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for natural gas firing.

Forced Draft Fans

The existing forced draft fans were analyzed to determine if they meet the requirements of 100% natural gas firing. The Unit 1 FD fans were originally designed to supply the combustion air in a pressure fired boiler operating mode. The boiler has since been converted to balanced draft operation, resulting high static pressure rise margins when firing coal. Unit 2 was originally designed as a balanced draft unit. An adjusted test block static pressure rise and test block capacity for the Unit 2 FD fans was developed from the FD fan curve for 100% natural gas firing. The results show the existing FD fan test block conditions for both Units exceed the requirements in capacity and static pressure rise (including higher natural gas burner pressure drop) for all natural gas firing cases. Predicted fan performance is shown in Table 8A:

Table 8a: Forced Draft Fan Performance at MCR Load (balanced draft operation)

Fuel	FD Fan Test Block Unit 1	FD Fan Original Net Design Conditions Bituminous Coal Unit 1	FD Fan Test Block Unit 2	FD Fan Original Net Design Conditions Bituminous Coal Unit 2	FD Fan Test Block Adjusted for 100%Natural Gas Unit 2 From Fan Curve	FD Fan Net Conditions 100% Natural Gas Units 1 & 2
Flow per fan (lb/hr)	1,417,000	1,180,500	1,512,000	1,260,000	1,225,440	1,104,100
Static Pressure Rise (in WC)	37.3	29.8	19.8	15.8	25.1	20.3
Temperature (F)	105	80	105	80	105	80

Induced Draft Fans

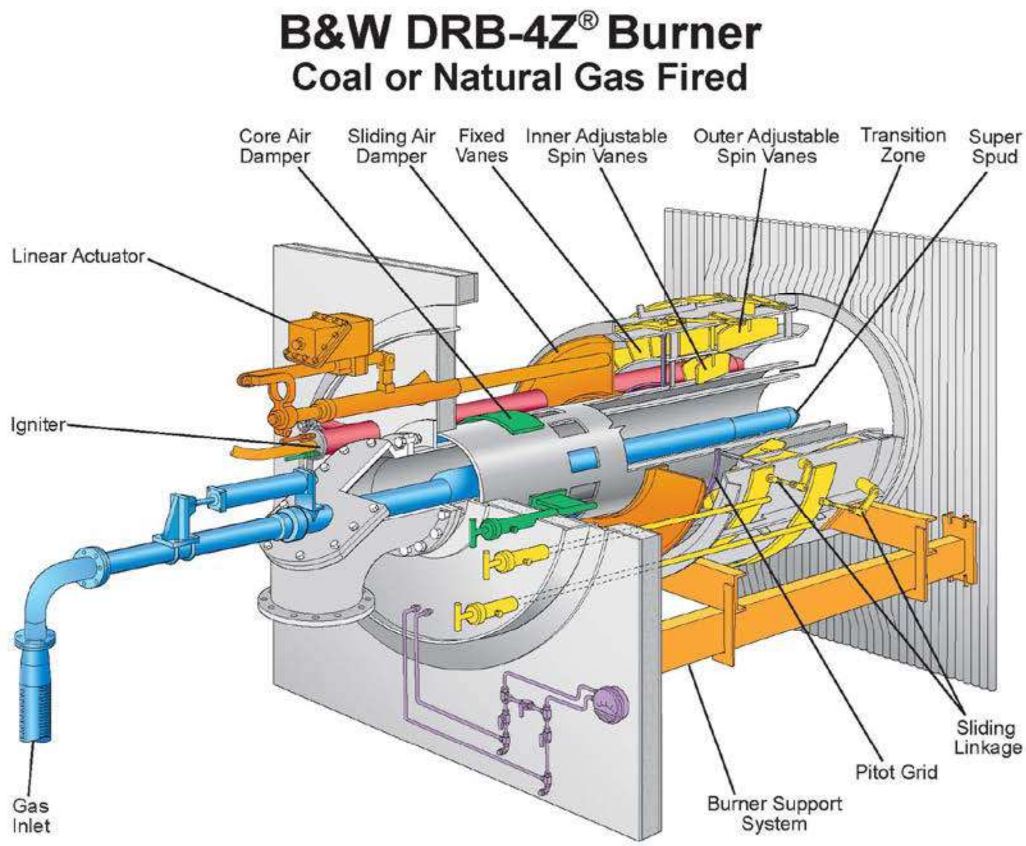
The existing induced draft fans were also analyzed to determine if they meet the requirements of 100% natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table 8B:

Table 8b: Induced Draft Fan Performance at MCR Load (balanced draft operation)

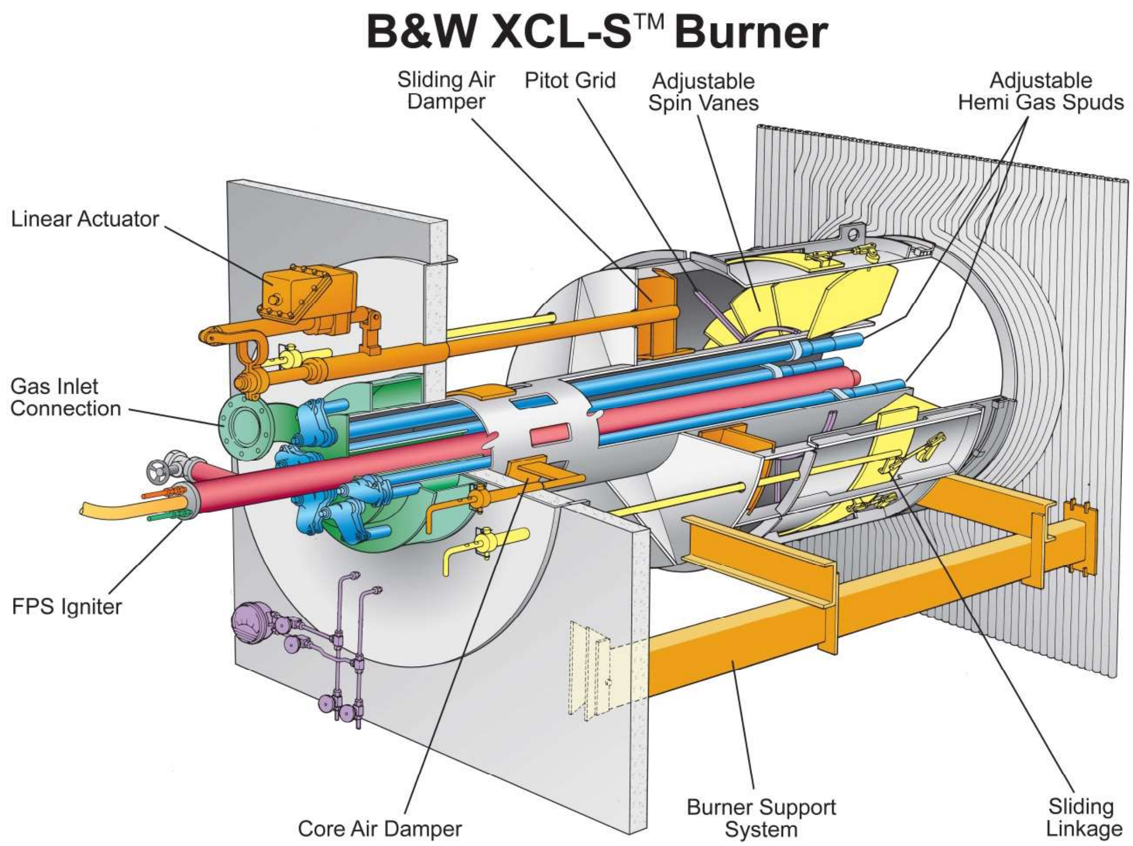
Fuel	ID Fan Test Block Unit 1	Bituminous Coal Unit 1 Original ID Fan Design Net Conditions	100% Natural Gas
Flow per fan (lb/hr)	1,380,100	1,387,610	1,199,390
Static Pressure Rise (in WC)	67.30	47.81	34.22
Temperature (F)	330	305	290

Combustion Equipment

The minimum combustion equipment modifications required to fire natural gas include modifying the twenty-four (24) existing B&W 4Z burners with gas spuds. One option is to add a Super-Spud to each 4Z burner to provide natural gas firing capability to the units. The addition of Super-Spuds will allow the AB Brown units to still fire coal is desired. The figure below shows a 4Z burner with a Super-Spud.



The second option would be to remove the coal nozzle and replace it with a hemi-spud cartridge. This fundamentally converts the 4Z burners to a B&W XCL-S burner as shown in the figure below. B&W XCL-S burner is an advanced low-NOx burner that was developed to achieve superior NOx performance in burner-only applications.



Since the AB Brown units already have SCR's, staged combustion (OFA) or flue gas recirculation (FGR) may not be necessary.

Additional NOx reduction can be achieved with staged combustion and/or flue gas recirculation. For staged combustion, the preferred approach is to locate eight (8) new NOx ports, four on the front wall and four on the rear wall, at an elevation at least eight feet above the top burner row. New NOx ports would require windbox and duct work modifications.

FGR involves the introduction of recirculated flue gas into the combustion air upstream of the burner windbox. A mixing device (such as a slotted air foil in the combustion air duct) is required to adequately distribute the recirculated flue gas in the incoming combustion air.

In addition to the burner modifications, valve racks, gas piping and controls will be needed to supply the natural gas as a main fuel to the modified burners.

Emissions

Emissions predictions are based on converting the unit to fire natural gas as the main fuel. Full load emission predictions for both units are listed in Table 9.

Table 9: Predicted Full Load Emissions on Natural Gas								
	XCL-S Burners only		XCL-S Burners and OFA		XCL-S Burners, OFA, and FGR		XCL-S Burners and FGR	
	Brown Unit 1	Brown Unit 2	Brown Unit 1	Brown Unit 2	Brown Unit 1	Brown Unit 2	Brown Unit 1	Brown Unit 2
FGR Rate (&)	N/A	N/A	N/A	N/A	~16%	~18%	~21.5%	~23.5%
NO_x (lb/10^6 Btu)	0.17	0.19	0.15	0.17	0.07	0.07	0.07	0.07
CO (ppmvd corrected to 3% O_2)	200	200	200	200	200	200	200	200
VOC (lb/10^6 Btu)	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003

- CO is predicted to be less than 200ppm. For 200 ppm (dry vol.) CO @ 3% O2 (dry vol.) firing NG with an Fd factor of 8710, B&W calculates 0.148 lb/mmBTU of CO.

CONCLUSIONS

As a result of this study, a review of the existing tube metallurgies on the AB Brown Station Units 1 and 2 revealed that all existing convection pass tubes had no overstress issues. In addition, all tubes were predicted to operate at temperatures below their ASME material code published limit. Header metal temperatures were also checked and showed to meet B&W's standards.

Along with the metallurgical analysis, superheater and reheater spray attemperation capacities were studied. The attemperator spray flows for gas firing are lower than the spray flows for firing coal due to lower amounts of excess air required when firing 100% natural gas. Current attemperator capacities for both units should be satisfactory at all boiler loads.

No surface modifications or surface removal are required when firing 100% natural gas.

Air heaters were assessed for 100% natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for firing natural gas based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when firing 100% natural gas.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas.

CO-FIRING COAL AND NATURAL GAS

Vectren Power Supply additionally contracted the Babcock and Wilcox Company (B&W), under B&W contract 591-1048 (317A), to evaluate co-firing natural gas and coal in these units.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance co-firing natural gas and the original bituminous coal at MCR boiler load with the following natural gas inputs:

1. 17% heat input from natural gas through four burners. 83% heat input from coal.
2. 33% heat input from natural gas through eight burners. 67% heat input from coal.
3. 16% heat input (maximum heat input through natural gas ignitors). 84% heat input from coal.

A metallurgical analysis and an analysis of the superheater and reheater spray attemperation capacities were performed for the three conditions above. Current attemperator capacities for both units should be satisfactory at all boiler loads when co-firing natural gas and coal.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit. In addition, all existing convection pass tubes and component headers had no overstress issues. Therefore, the existing convection pass tube metallurgy is acceptable for co-firing natural gas and coal.

No surface modifications or surface removal are required when co-firing natural gas and coal.

The air and gas side temperature profiles around the air heater were found to be acceptable for co-firing natural gas and coal based on the original air heater design parameters.

The existing FD and ID fans were found to exceed the performance requirements when co-firing natural gas and coal.

The predicted boiler performance summaries when co-firing natural gas and coal are shown in the Appendix.

Co-firing Operation

When co-firing the two fuels, the preferred arrangement is to fire natural gas through the burners at the higher elevations on a per mill group, or compartment, basis. The compartmented windboxes on the AB Brown units are advantageous for co-firing the multiple fuels. Airflow control by compartment allows each mill group to obtain its own required amount of air, independent of burner load or fuel. The burners firing natural gas will require more secondary air, since primary airflow is zero, than the coal-firing burners. Managing these separate flow rates can be easily accommodated by the compartment controls. Firing coal at the lower elevations takes advantage of the available residence time in the furnace, maximizing coal burnout and optimizing CO and unburned carbon emissions. If a partial conversion were to become the chosen project path, it would be recommended to convert burners on a per mill group basis following the described firing arrangement, adding gas capability to the top mill groups and continuing downward.

It should be noted that while the AB Brown units are already equipped to operate under the third scenario listed above (16% input ignitors, 84% input from coal), it could come at the expense of emissions. With the ignitor being located in an upper quadrant of the burner and operating at 16% of the rated burner input, not all of the air going through the burner is nearby and readily available for the ignitor fuel. This can create scenarios of inadequate fuel and air mixing, resulting in higher CO emissions, especially from the upper burner elevations. NOx emissions may also increase. The annular zone arrangement of the 4Z burner stages the mixing of the fuel and air. With the ignitor being located in the air sleeve, it circumvents this delayed mixing arrangement, potentially increasing NOx. Emissions predictions are not available for this scenario.

APPENDIX A – Preliminary Performance Summaries

Table 10a:

A. B. Brown Units 1 & 2 - Preliminary Performance Summary

Contract No.	317A	GBB	Units 1 & 2	Unit 1	Unit 2	Units 1 & 2
Date	7/31/2015	Load ID	PC Firing	PC Firing	PC Firing	Natural Gas
Revision	0	Boiler Arrangement	Existing	Existing	Existing	Existing
		Data Basis	Original Contract	7-14-2015 PI Data	7-10-2015 PI Data	Predicted Performance
Load Condition			MCR	95% Load	94% Load	MCR
Fuel			Bituminous	Bituminous	Bituminous	Natural Gas
Steam Leaving SH, mlb/hr			1,850	1,814	1,736	1,850
Superheater Spray Water, mlb/hr			77.86	110.32	19.10	53.70
Cold RH Steam Flow, mlb/hr			1,667	1,663	1,590	1,667
Reheater Spray Water, mlb/hr			18.90	60.70	16.30	0.00
% Excess Air Leaving Economizer			20.0	21.9	21.1	10.0
Flue Gas Recirculation, %			None	None	None	None
Heat Input, mmBtu/hr			2,549.3	2,526.4	2,379.8	2,614.9
Quantity mlb/hr	Fuel (mcf/hr if gas)		221.0	219.0	207.0	2604.5
	Flue Gas Entering Air Heaters		2,570	2,584	2,422	2,234
	Total Air To Burners		2,307	2,323	2,174	2,056
Pressure, psig	Steam at SH Outlet		1965	1880	1926	1965
	Steam at RH Outlet		460	431	424	460
Temperature, °F	Steam	Leaving Superheater	1005	1006	999	1005
		Leaving Reheater	1005	997	985	992
	Water	Water Entering Economizer	467	459	452	467
		Superheater Spray Water	380	365	370	380
	Gas	Entering Air Heater	705	650	652	697
		Leaving Air Heater (Excl. Leakage)	304	336	346	303
	Air	Entering Air Heater	85	168	138	85
		Leaving Air Heater	566	535	554	567
Heat Loss Efficiency, %	Dry Gas		4.91	3.86	4.75	3.88
	H_2 & H_2O in Fuel		5.06	4.76	4.92	10.67
	Moisture in Air		0.12	0.10	0.11	0.10
	Unburned Combustible		0.30	0.30	0.30	0.00
	Radiation		0.19	0.19	0.20	0.19
	Unacc. & Mfgs. Margin		1.50	0.50	0.50	1.00
	Total Heat Loss		12.08	9.71	10.78	15.84
	Gross Efficiency of Unit, %		87.92	90.29	89.22	84.16

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Table 10a:

A. B. Brown Units 1 & 2 - Preliminary Performance Summary

Contract No.	317A	GBB	Unit 1 & 2	Unit 1 & 2		
Date	7/31/2015	Load ID	PC Firing	NG Firing		
Revision	0	Boiler Arrangement	Existing	Existing		
		Data Basis	Original Contract	Predicted Performance		
Load Condition			60%	60%		
Fuel			Bituminous	Natural Gas		
Steam Leaving SH, mlb/hr			1,110	1,110		
Superheater Spray Water, mlb/hr			89	0		
Cold RH Steam Flow, mlb/hr			1,000	1,000		
Reheater Spray Water, mlb/hr			0	0		
% Excess Air Leaving Economizer			52.0	18.0		
Flue gas Recirculation, %			None	None		
Heat Input, mmBtu/hr			1,638.3	1,540.9		
Quantity mlb/hr	Fuel (mcf/hr if gas)		142.0	1486.0		
	Flue Gas Entering Air Heaters		2,060	1,403		
	Total Air To Burners		1,867	1,273		
Pressure, psig	Steam at SH Outlet		1917	1917		
	Steam at RH Outlet		261	261		
Temperature, °F	Steam	Leaving Superheater	1005	955		
		Leaving Reheater	1005	835		
	Water	Water Entering Economizer	417	417		
		Superheater Spray Water	350	350		
	Gas	Entering Air Heater	675	617		
		Leaving Air Heater (Excl. Leakage)	283	259		
	Air	Entering Air Heater	83	83		
		Leaving Air Heater	547	520		
Heat Loss Efficiency, %	Dry Gas		5.69	3.35		
	H_2 & H_2O in Fuel		5.03	10.38		
	Moisture in Air		0.14	0.09		
	Unburned Combustible		0.30	0.00		
	Radiation		0.30	0.22		
	Unacc. & Mfgs. Margin		1.50	1.00		
	Total Heat Loss		12.96	15.04		
	Gross Efficiency of Unit, %		87.04	84.96		

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Table 10c:

A. B. Brown Unit 1 - Predicted Performance Summary Co-Firing Coal & Natural Gas

Contract No.	317A	GBB	Unit 1	Unit 1	Unit 1	
Date	8/29/2015	Load ID	PC & NG Firing	PC & NG Firing	PC & NG Firing	
Revision	0	Boiler Arrangement	Existing	Existing	Existing	
		Data Basis	Predicted Performance	Predicted Performance	Predicted Performance	
		Natural Gas Firing Method	Through Burners	Through Burners	Through Ignitors	
		Natural Gas Firing % Heat Input	17	33	16	
		Coal Firing % Heat Input	83	67	84	
Load Condition			MCR	MCR	MCR	
Fuel			Bit. Coal & Natural Gas	Bit. Coal & Natural Gas	Bit. Coal & Natural Gas	
Steam Leaving SH, mlb/hr			1,850	1,850	1,850	
Superheater Spray Water, mlb/hr			99.50	115.17	98.48	
Cold RH Steam Flow, mlb/hr			1,667	1,667	1,667	
Reheater Spray Water, mlb/hr			53.81	57.13	53.80	
% Excess Air Leaving Economizer			21.1	21.1	21.1	
Flue Gas Recirculation, %			None	None	None	
Heat Input Nat. Gas, mmBtu/hr			443.4	869.9	408.0*	
Heat Input Bit. Coal, mmBtu/hr			2164.8	1766.1	2198.6	
Total Heat Input, mmBtu/hr			2608.2	2636.0	2606.6	
Quantity mlb/hr	Coal Flow		187.7	153.2	190.6	
	Natural Gas Flow (mcf/hr)		441.6	866.4	406.3	
	Flue Gas Entering Air Heaters		2,611	2,600	2,612	
	Total Air To Burners		2,358	2,360	2,358	
Pressure, psig	Steam at SH Outlet		1965	1965	1965	
	Steam at RH Outlet		460	460	460	
Temperature, °F	Steam	Leaving Superheater	1005	1005	1005	
		Leaving Reheater	1005	1005	1005	
	Water	Water Entering Economizer	467	467	467	
		Superheater Spray Water	365	365	365	
	Gas	Entering Air Heater	656	658	656	
		Leaving Air Heater (Excl. Leakage)	338	338	338	
	Air	Entering Air Heater	150	150	150	
		Leaving Air Heater	542	544	542	
Heat Loss Efficiency, %	Dry Gas		4.19	4.09	4.19	
	H_2 & H_2O in Fuel		5.76	6.62	5.69	
	Moisture in Air		0.10	0.10	0.10	
	Unburned Combustible		0.25	0.20	0.25	
	Radiation		0.19	0.19	0.19	
	Unacc. & Mfgs. Margin		1.42	1.42	1.42	
	Total Heat Loss		11.91	12.62	11.84	
	Gross Efficiency of Unit, %		88.09	87.38	88.16	

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Predicted performance is based on the original contract boiler performance and PI data as supplied by Vectren
*Maximum heat input from ignitors

Table 10d:

A. B. Brown Unit 2 - Predicted Performance Summary Co-Firing Coal & Natural Gas

Contract No.	317A	GBB	Unit 2	Unit 2	Unit 2	
Date	8/29/2015	Load ID	PC & NG Firing	PC & NG Firing	PC & NG Firing	
Revision	0	Boiler Arrangement	Existing	Existing	Existing	
		Data Basis	Predicted Performance	Predicted Performance	Predicted Performance	
		Natural Gas Firing Method	Through Burners	Through Burners	Through Ignitors	
		Natural Gas Firing % Heat Input	17	33	16	
		Coal Firing % Heat Input	83	67	84	
Load Condition			MCR	MCR	MCR	
Fuel			Bit. Coal & Natural Gas	Bit. Coal & Natural Gas	Bit. Coal & Natural Gas	
Steam Leaving SH, mlb/hr			1,850	1,850	1,850	
Superheater Spray Water, mlb/hr			27.38	42.94	26.70	
Cold RH Steam Flow, mlb/hr			1,667	1,667	1,667	
Reheater Spray Water, mlb/hr			23.02	27.14	23.00	
% Excess Air Leaving Economizer			21.9	21.9	21.9	
Flue Gas Recirculation, %			None	None	None	
Heat Input Nat. Gas, mmBtu/hr			434.6	853.1	408.0*	
Heat Input Bit. Coal, mmBtu/hr			2121.7	1732.0	2147.3	
Total Heat Input, mmBtu/hr			2556.3	2585.1	2555.3	
Quantity mlb/hr	Coal Flow		184.0	150.2	186.0	
	Natural Gas Flow (mcf/hr)		432.8	849.7	406.3	
	Flue Gas Entering Air Heaters		2,568	2,559	2,569	
	Total Air To Burners		2,319	2,322	2,320	
Pressure, psig	Steam at SH Outlet		1965	1965	1965	
	Steam at RH Outlet		460	460	460	
Temperature, °F	Steam	Leaving Superheater	1005	1005	1005	
		Leaving Reheater	1005	1005	1005	
	Water	Water Entering Economizer	467	467	467	
		Superheater Spray Water	380	380	380	
	Gas	Entering Air Heater	668	670	668	
		Leaving Air Heater (Excl. Leakage)	352	353	352	
	Air	Entering Air Heater	150	150	150	
		Leaving Air Heater	552	554	552	
Heat Loss Efficiency, %	Dry Gas		4.51	4.43	4.52	
	H_2 & H_2O in Fuel		5.79	6.66	5.74	
	Moisture in Air		0.11	0.11	0.11	
	Unburned Combustible		0.25	0.20	0.25	
	Radiation		0.19	0.19	0.19	
	Unacc. & Mfgs. Margin		1.42	1.42	1.42	
	Total Heat Loss		12.27	13.01	12.23	
	Gross Efficiency of Unit, %		87.73	86.99	87.77	

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Predicted performance is based on the original contract boiler performance and PI data as supplied by Vectren
*Maximum heat input from ignitors

APPENDIX B – NG Conversion Equipment Scope & Budgetary Costs

SUPER-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Super-Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations excluding vent piping to above the boiler building roof

HEMI-SPUD OPTION - Burner Modifications, Scanners, Valve Racks, NG Piping System

Item 1: B&W 4Z Burners converted to Nat Gas Firing (Quantity: 24)

- Qty 24, Hemispherical Gas Spud Assemblies to replace existing coal nozzles
- Qty 12, Burner Valve Racks
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Burner Front Valves & Gauges

Item 2: Fossil Power Systems (FPS) Flame Scanners

- Qty 24, FPS main UV flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 50 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations
- Vent piping from the regulating stations and the burner valve racks to the boiler roof and above the roof is not included

B&W OVERFIRE AIR (OFA) PORTS OPTION

- Qty 8, Furnace Water Wall Openings
- Windbox Extensions or Individual OFA Windboxes
- Qty 8, Automated Air Flow Control Damper with Rotary Drive - per port
- Boiler Closure Casing
- Temperature Monitoring Thermocouple (port style dependent)

FLUE GAS RECIRCULATION (FGR) OPTION

- Flue Gas Recirculation Fan and Motor
- FGR Flues
- AH Outlet to FGR Fan Inlet
- FGR Fan Outlet to Secondary Air Mixing Foils
- FGR Flue expansion joints, hangers, bridging steel
- FGR Mixing Foils
- Windbox O_2 Monitor
- Burner throat assemblies to accommodate the larger B&W XCL-S burners required for FGR firing.

General Services

- Combustion system tuning services using an economizer outlet sampling grid for measurement of NOx per EPA methods.
- Field Service Engineering outage support for construction, start-up, and post-modification testing.
- Burner System Operator Training consisting of two, one day sessions.
- Training includes project specific training manual for up to 20 participants.
- Brickwork Refractory Insulation & Lagging (BRIL) Specifications and Installation design and materials.
- Contract specific System Requirements Specification, I/O Listing, and Functional Logic Diagrams for all supplied equipment.
- Operating and Maintenance Manuals (10 copies).
- New piping, flue, and duct loading to existing steel
- Delivery F.O.B. Brown Plant, Mt Vernon, IN.

Items not Included

- Hazardous material removal or abatement (i.e., lead paint and asbestos).

- Load analysis of existing structural steel or foundations and any required re-enforcement thereof.
- Hardware or reprograming of existing DCS and/or BMS to support natural gas conversion.
- Gas step down equipment. Equipment scope above assumes incoming gas pressure at B&W's terminal to be 30 to 50psi.

Terminal Points

- Inlet of gas regulating station
- Vent out of any valve rack
- Electrical terminals on provided electrical equipment or instruments
- Electrical terminals in shop provided terminal junction boxes as part of skidded equipment

Budgetary Material & Installation Pricing (USD 2019)

Scope Item	Budgetary	
	Material	**Installation**
Super-Spud Option: Burner Modifications, Scanners, Valve Racks, NG Piping System	$2,602,000	$3,903,000
Hemi-Spud Option: Burner Modifications, Scanners, Valve Racks, NG Piping System	$2,900,000	$4,350,000
Overfire Air (OFA) Option: **Wall Openings, Windbox Modifications, Flow Control Dampers, Temperature Monitoring**	$370,000	$555,000
Flue Gas Recirculation (FGR) Option: **FGR Fan w/ Motor, Flues, Mixing Foils, O_2 Monitoring**	$850,000	$1,275,000

Lead Times

- Material delivery: 52 - 56 weeks
- Installation outage duration: 8 - 10 weeks

B&W has offered these prices in 2019 US dollars and have not attempted to project escalation for time of performance or delivery.

Please note that these prices are budgetary and is not represent an offer to sell, however, we would welcome the opportunity to provide a formal proposal upon request.

Appendix B. Babcock & Wilcox Engineering Study for Natural Gas Firing for F.B. Culley Unit 2

Engineering Study for Natural Gas Firing

for

Vectren Power Supply
Culley Station Unit 2
Newburgh, Indiana

Contract 591-1022 (293H)
June 13, 2019
Rev. 2

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INTRODUCTION

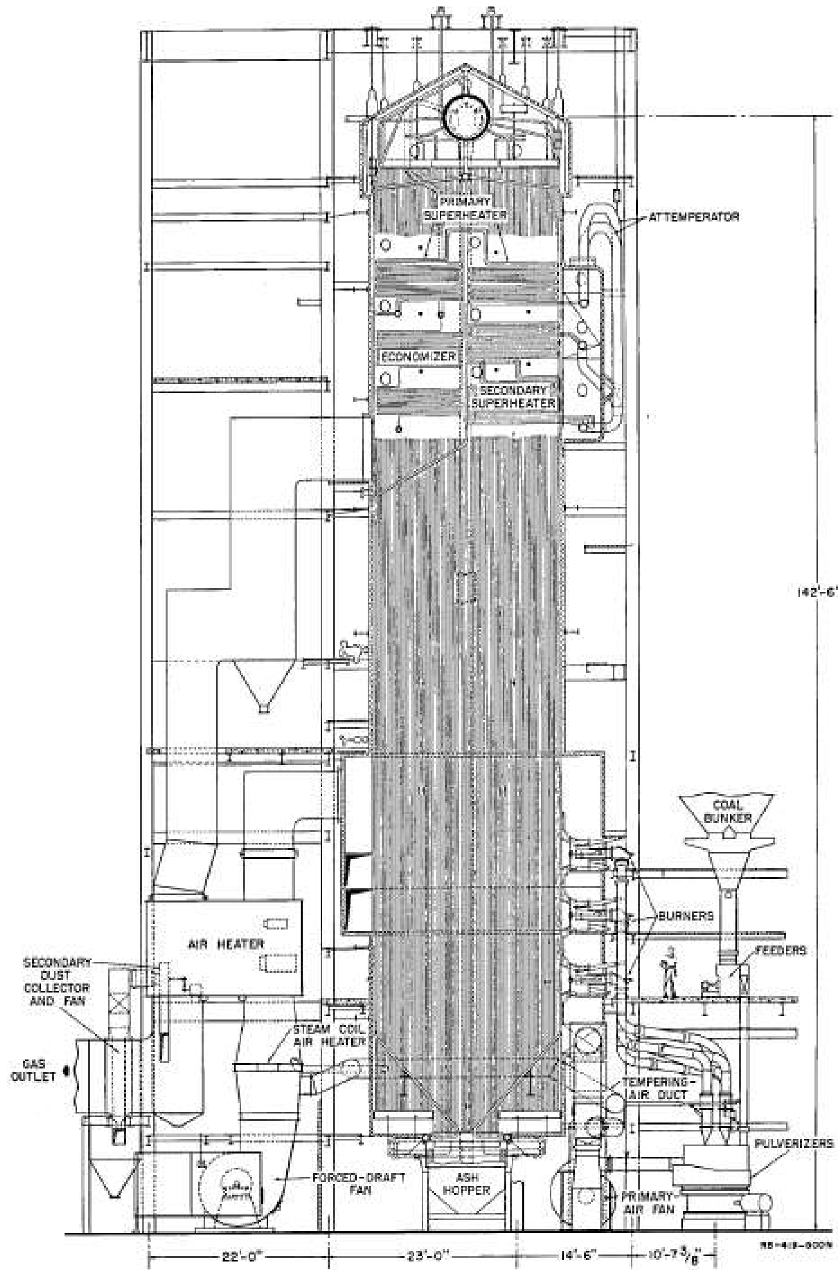
Vectren Power Supply contracted The Babcock and Wilcox Company (B&W), under B&W contract 591-1022 (293H), to evaluate natural gas firing at the Culley Station Unit #2 originally supplied by B&W under contract RB-419. The boiler performance model was reviewed at 100% MCR and 50% load when firing 100% natural gas. An analysis of the allowable tube metal stresses was performed for 100% gas firing at 100% MCR and 50% boiler loads in regards to the primary and secondary superheaters. Modifications to the convection pass components to accommodate natural gas firing were also developed. Also analyzed for adequacy were the forced draft fans, induced draft fans and spray attemperators.

BACKGROUND

Culley Unit #2 (RB-419) is a balanced draft (originally pressure fired), subcritical El Paso type radiant boiler, with secondary superheater, primary superheater, and economizer surfaces arranged in series. Steam temperature is controlled through interstage attemperation. The unit was originally designed as a front wall, bituminous coal fired unit. The original maximum continuous rating for RB-419 is 840,000 lbs/hr of steam at 955°F and 1290 psig at the superheater outlet with a feedwater temperature of 425°F. The unit was designed to accommodate a peak load (low feedwater temperature condition) for a duration of two (2) hours. The peak load rating is 840,000 lbs/hr of steam at 955°F and 1290 psig at the superheater outlet with a feedwater temperature of 383°F.

A sectional side view of the boilers is shown in Figure 1a.

FIGURE 1a



Culley Station Unit 2
B&W Contract Number RB-419

SCOPE FOR PHASE I

B&W evaluated natural gas firing in the radiant boiler originally supplied by B&W under contract RB-419. Boiler component drawings and original performance summary data were used to develop comprehensive thermal models and boiler pressure part assessments. The predicted performance of the proposed natural gas firing was analyzed at MCR load and 50% load. The tube metallurgy requirements for the primary superheater, secondary superheater and headers were also developed. In addition to superheater metals analysis, predicted performance of the air preheaters and the attemperator capacities were also evaluated relative to overall performance.

SCOPE FOR PHASE II

The Phase II engineering scope of supply includes the entire scope of Phase I. In addition, the required surface modifications for firing 100% natural gas were developed. The adequacy of the existing forced draft (FD) fans and the induced draft (ID) fans were also assessed.

BASIS

This boiler pressure part metals assessment requires developing overall unit heat and material balances at the indicated steam flow. The fuel analysis for the original design bituminous coal and natural gas fuel are provided in Tables 1 and 2. These were used as a basis for the heat and material balances shown in Table 3.

Table 1: Original Design As-Fired Fuel Analyses for Bituminous Coal, % by weight

Constituent	
C	55.27
H_2	3.70
N_2	1.05
O_2	5.68
Cl	0.00
S	3.30
H_2O	19.00
Ash	12.00
Total	**100.00**
HHV (Btu/lb)	**10,000**

Table 2: Proximate Analysis for Natural Gas, % by volume

Constituent	
Nitrogen	1.79
Methane	91.88
Ethane	5.12
Others	1.21
Total	**100.00**
HHV (Btu/ft^3)	**1,037**

Table 3: Boiler Operating Conditions Used in Metals Evaluation

Maximum Continuous Rating		
Steam Flow (lb/hr)	840,000	420,000
Steam Temperature at SH Outlet (°F)	955	925
Steam Pressure at SH Outlet (psig)	1290	1260
Feedwater Temperature (°F)	425	360
Excess Air Leaving Econ (%)	10	18

RESULTS

Boiler Pressure Part Modifications

The boiler pressure part modifications consist of a surface reduction to the primary superheater that would be required with both cases where flue gas recirculation (FGR) is required. FGR increases the flue gas flow rate through the convection pass components thus increasing component absorption. A reduction in the PSH surface is required to avoid exceeding the limits of the existing tube metallurgy. Twelve (12) tube rows would be removed from the PSH inlet bank.

Boiler Performance

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas with scenarios including PSH heating surface reduction (if required) and FGR requirements as set by flue gas emissions.

Attemperator Capacity

Along with the metals analysis, attemperation capacities were studied for the boiler operating conditions with and without flue gas recirculation (FGR) and also in regards to surface reductions of the primary superheater (where required). The attemperator spray flows for gas firing are higher than the spray flows for firing 100% coal due to higher flue gas temperatures leaving the furnace and higher component absorption. Required FGR flow rates also raised the total flue gas flow through the convection pass which results in higher convection pass component absorptions. The existing spray water attemperator nozzle size is adequate but would have to be modified by increasing the orifice diameter to meet the required spray flows. With this nozzle modification, capacities should be satisfactory at all boiler loads when firing natural gas. The results are shown in Table 6.

Table 6: Expected Total Attemperator Flows (lbs/hr)

Boiler Load	MCR	50%
Bituminous Coal	54,190	1,800
Natural Gas:		
No FGR or boiler modifications	71,440	27,910
14% FGR with PSH surface reduction	71,750	18,600
19.5% FGR with PSH surface reduction	79,280	18,600

Air Heater Performance

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for the natural gas conversion. Since no field data was provided that would show higher than original air heater leakage or other air heater performance degradation, the predicted air heater performance is based on the original design data with an air heater leakage of 10.0%. Predicted performance is shown on Table 7A & 7 B.

Table 7A: Regenerative Air Heater Predicted Performance at MCR Load

Boiler load	**MCR**	**MCR**	**MCR**	**MCR**
Fuel	**Bituminous Coal**	**Natural Gas**	**Natural Gas**	**Natural Gas**
Boiler Modifications	None	New burners with & without overfire air ports	PSH surface reduction New burners without overfire air ports	PSH Surface Reduction New burners with overfire air ports
Flue Gas Recirculation	None	None	19.5%	14.0%
Flue Gas Flow Entering Air Heaters, mlb/hr	1017	909	918	915
Flue Gas Temp Entering Air Heaters, F	752	726	804	796
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	320	310	334	331
Air Flow Leaving Air Heaters, mlb/hr	902	846	854	851
Air Temp Entering Air Heaters, F	100	100	100	100
Air Temp Leaving Air Heaters, F	604	598	660	653

Table 7B: Regenerative Air Heater Predicted Performance at 50 % Load

Boiler load	**50%**	**50%**	**50%**	**50%**
Fuel	**Bituminous Coal**	**Natural Gas**	**Natural Gas**	**Natural Gas**
Boiler Modifications	None	New burners with & without overfire air ports	PSH surface reduction New burners without overfire air ports	PSH Surface Reduction New burners with overfire air ports
Flue Gas Recirculation	None	None	19.5	14.0
Flue Gas Flow Entering Air Heaters, mlb/hr	541	507	507	507
Flue Gas Temp Entering Air Heaters, F	585	581	606	606
Flue Gas Temp Leaving Air Heaters w/o Leakage, F	264	263	271	270
Air Flow Leaving Air Heaters, mlb/hr	473	466	466	466
Air Temp Entering Air Heaters, F	121	121	121	121
Air Temp Leaving Air Heaters, F	501	504	526	526

Tube Metal Temperature Evaluation

B&W uses an ASME Code accepted method to design its tube metallurgies and thicknesses. The method involves applying upsets and unbalances to determine spot and mean tube metal temperatures. The upsets and unbalances include empirical uncertainty in the calculation of furnace exit gas temperature (FEGT), top to bottom gas temperature deviations, side to side gas temperature deviations, steam flow unbalances (a function of tube side pressure drop and component arrangement) and gas flow unbalances. The method applies these upsets and unbalances simultaneously to a single spot in each row of the superheater. Tube row metallurgy and thickness are then determined from the resultant tube spot and mean temperatures, respectively, according to ASME Code material oxidation limits and allowable stresses. B&W policy does not allow the publishing of design tube metal temperatures or unbalanced steam temperatures. However, these values can be reviewed in B&W's offices, if desired.

The remaining life expectancy of the superheaters is dependent on the prior operating history, especially on actual tube operating temperature compared to design temperature. Thus, the assessment of the adequacy of the existing superheaters is not a simple task.

B&W has determined the operating hoop stress level (based on the current minimum tube wall thickness) at operating pressure. The predicted tube operating temperatures based on B&W's standard design criteria and the resulting ASME Code allowable stress level for the existing material has also been determined. Comparison of the operating hoop stress with the Code allowable stresses results in the percent over the allowable stress. A modest overstress level indicates a modest shortening of remaining life expectancy and, unless otherwise indicated by past maintenance experience, does not warrant tube modification at this time.

If the tube analysis shows significant overstress or shows that tubes are predicted to operate at temperatures above those for which ASME Code stresses are published, then serious consideration should be given to tube upgrades and replacement. Significant overstresses are considered those tube rows that are 20% or greater overstressed. An overstress of 20% or more does not necessarily mean that immediate replacement of the tube row is required, but it identifies which tube rows should be examined for potential problems. Potential problems could be signs of creep, internal exfoliation or swelling.

This study showed that all tubes were predicted to operate at temperatures less than the existing material use limit for all the boiler operating cases shown in Tables 7A and 7B (with PSH surface reduction if required). In addition, all existing convection pass tubes and component headers had no overstress issues.

Therefore, the existing convection pass tube metallurgy is acceptable for natural gas firing for all cases.

Forced Draft Fans

The existing forced draft fans were analyzed to determine if they meet the requirements of natural gas firing. The FD fans were originally designed to supply the combustion air in a pressure fired boiler operating mode. The boiler has since been converted to balanced draft operation, resulting high static pressure rise margins when firing coal. The results showed the existing FD fans far exceed the requirements in capacity and static pressure rise (including higher natural gas burner pressure drop) for all natural gas firing cases. Predicted fan performance is shown in Table 8A:

Table 8A: Forced Draft Fan Performance at MCR Load (balanced draft operation)

Fuel	**FD Fan Test Block**	**Bituminous Coal**	**Natural Gas**	**Natural Gas**	**Natural Gas**
Boiler Modifications		None	New burners with & without overfire air ports	PSH surface reduction New burners with overfire air ports	PSH Surface Reduction New burners with overfire air ports
FGR flow (%)	NA	None	None	19.5	14.0
Flow per fan (lb/hr)	620,000	514,500	468,510	472,960	471,790
Static Pressure Rise (in WC)	25.9	7.5	10.82	10.95	10.88
Temperature (F)	125	100	100	100	100

Induced Draft Fans

The existing induced draft fans were also analyzed to determine if they meet the requirements of natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table 8B:

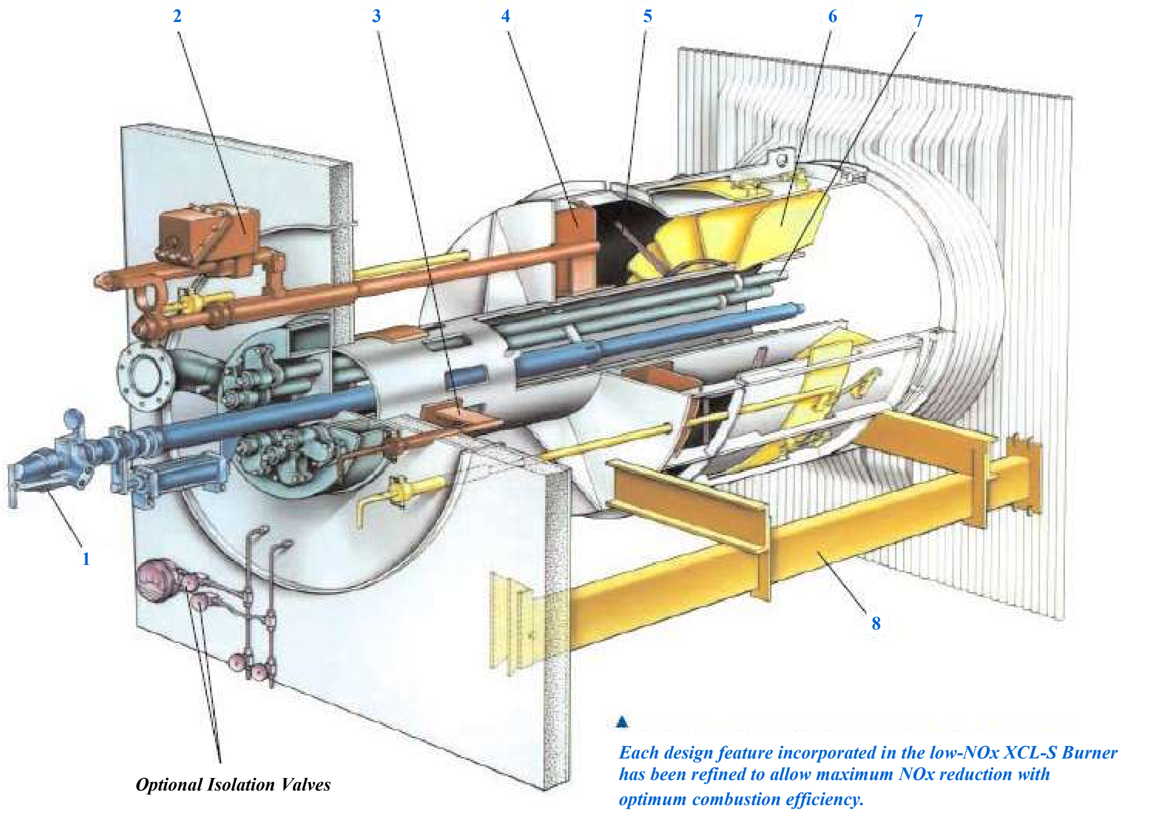
Table 8B: Induced Draft Fan Performance at MCR Load (balanced draft operation)

Fuel	ID Fan Test Block	Bituminous Coal	Natural Gas	Natural Gas	Natural Gas
Boiler Modifications		None	New burners with & without overfire air ports	PSH surface reduction New burners with overfire air ports	PSH Surface Reduction New burners with overfire air ports
FGR flow (%)	NA	None	None	19.5	14.0
Flow per fan (lb/hr)	764,900	559,350	499,450	504,900	503,250
Static Pressure Rise (in WC)	16.0	12.8	9.10	10.13	9.78
Temperature (F)	360	301	293	315	308

Combustion Equipment

The minimum combustion equipment modifications required to fire natural gas include replacing the twelve (12) existing PC burners with twelve (12) XCL-S® natural gas burners with natural gas ignitors. The XCL-S burner, shown below in Figure 2, is an advanced low-NOx burner that was developed to achieve superior NOx performance in burner-only applications and in applications using overfire air (OFA) and/or flue gas recirculation (FGR). It is designed as a simple plug-in, with little or no modifications needed to the rest of the boiler.

Figure 2: Low-NOx XCL-S® Burner



Components	Features
1 I-Jet oil gun (optional))	Produces a finer oil spray, reduces particulate and opacity emissions, minimizes atomizer plugging
2 Linear actuator	Easily adjusts the main air sliding damper position for light-off, full-load and out-of-service cooling
3 Core air damper	Adjusts core air flow to the oil gun or gas spuds for optimizing combustion
4 Sliding air damper	Adjusts the majority of secondary air flow to the outer air zone, independent of swirl, to balance air flow among burners during commissioning
5 Air measurement grid	Ensures an accurate indication of relative air flow with a multi-point impact/suction device
6 Externally adjustable spin vanes	Provide proper mixing of the secondary air and fuel (to the end of the flame) – vane position is optimized and fixed during commissioning
7 Adjustable hemispherical gas spuds	Can be rotated to optimize NOx reduction and are removable while the boiler is in service
8 Burner support system	Supports the burner and allows for differential expansion

Additional NOx reduction can be achieved with staged combustion and/or flue gas recirculation. For staged combustion, the preferred approach is to locate eight (8) new NOx ports, four on the front wall and four on the rear wall, at an elevation at least eight feet above the top burner row. New NOx ports would require windbox and duct work modifications.

FGR involves the introduction of recirculated flue gas into the combustion air upstream of the burner windbox. A mixing device (such as a slotted air foil in the combustion air duct) is required to adequately distribute the recirculated flue gas in the incoming combustion air.

The new burners can be retrofitted into the existing burner pressure part openings on the furnace front wall. Depending on the choice of NOx reduction technologies (i.e., burners, burners plus OFA, burners plus OFA and FGR, or burners plus FGR) and the results of the associated detailed engineering in a material contract phase, adjustment to the existing throat diameter may be required. This can be accomplished by conical ceramic throat inserts (for a smaller diameter throat) or removal of pin studs and refractory (for a larger diameter throat) while retaining the existing pressure parts.

Note that all of the combustion air flow must now be supplied via the secondary air ducts and windbox since primary/pulverized coal transport air is no longer required.

Emissions

Emissions predictions are based on converting the unit to fire natural gas as the main fuel. Full load emission predictions for the various options are listed in Table 9. The values are predicted values with margin which B&W expects to be able to guarantee upon material supply.

Table 9: Predicted Full Load Emissions on Natural Gas

	XCL-S Burners only	XCL-S Burners and OFA	XCL-S Burners, OFA, and FGR	XCL-S Burners and FGR
FGR Rate (%)	NA	NA	~14%	~19.5%
NOx (lb/10^6 Btu)	0.16	0.13	0.07	0.07
CO (ppmvd corrected to 3% O_2)	200	200	200	200
VOC (lb/10^6 Btu)	0.003	0.003	0.003	0.003

CONCLUSIONS

As a result of this study, when firing natural gas with FGR, the PSH heating surface needs to be reduced to maintain existing tube metallurgy. A complete review of the existing tube metallurgies on Culley Station Unit #2 considering all natural gas firing cases revealed that all existing convection pass tubes had no overstress issues. In addition, all tubes were predicted to operate at temperatures below their ASME material code published limit. Header metal temperatures were also checked and showed to meet B&W's standards.

Along with the metals analysis, existing attemperator capacities were studied for the boiler operating conditions with and without flue gas recirculation (FGR) and also in regards to surface reductions of the primary superheater (where required). Existing attemperator capacities should be satisfactory (with the modification to the nozzle orifice size) at all boiler loads when firing natural gas.

Air heaters were assessed for natural gas firing. The air and gas side temperature profiles around the air heater were found to be acceptable for firing natural gas.

The existing FD and ID fans were found to exceed the performance requirements when firing natural gas.

The predicted boiler performance summaries are shown in the Appendix, comparing unit performance firing the original bituminous coal and predicted unit performance firing natural gas.

It is recommended that the twelve (12) existing PC burners be replaced XCL-S natural gas burners with natural gas ignitors. The addition of NOx ports and/or flue gas recirculation is recommended in order to provide reduced NOx emissions.

APPENDIX A - Preliminary Performance Summaries

Table 9.a.

Vectren Culley Unit 2 - Preliminary Performance Summary

Contract No.	293H	GBB				
Date	12/16/2013	Load ID	PC Firing	NG Firing	NG Firing	NG Firing
Revision	0	Boiler Arrangement	Existing	New Burners with & without Overfire Air Ports	PSH Surface Reduction New Burners without Overfire Air Ports	PSH Surface Reduction New Burners with Overfire Air Ports
Load Condition			MCR	MCR	MCR	MCR
Fuel			Bituminous	Natural Gas	Natural Gas	Natural Gas
Steam Leaving SH, mlb/hr			840	840	840	840
Superheater Spray Water, mlb/hr			54,190	71,440	79,281	71750
% Excess Air Leaving Economizer			18	10	10	10
Flue Gas Recirculation, %			None	None	19.5	14.0
Heat Input, mmBtu/hr			1028.0	1077.0	1087.2	1083.5
Quantity mlb/hr	Fuel (mcf/hr if gas)		102.8	1038.6	1048.4	1044.9
	Flue Gas Entering Air Heaters		1017	909	918	915
	Total Air To Burners		902	846	854	851
Pressure, psig	Steam at SH Outlet		1290	1290	1290	1290
Temperature, °F	Steam	Leaving Superheater	955	955	955	955
	Water	Water Entering Economizer	425	425	425	425
		Superheater Spray Water	225	225	225	225
	Gas	Entering Air Heater	752	726	804	796
		Leaving Air Heater (Excl. Leakage)	320	310	334	331
	Air	Entering Air Heater	100	100	100	100
		Leaving Air Heater	604	598	660	653
Heat Loss Efficiency, %	Dry Gas		4.89	3.67	4.18	4.06
	H_2 & H_2O in Fuel		5.94	10.42	10.54	10.51
	Moisture in Air		0.12	0.10	0.11	0.11
	Unburned Combustible		0.30	0.00	0.00	0.00
	Radiation		0.23	0.24	0.24	0.24
	Unacc. & Mfgs. Margin		1.50	1.00	1.00	1.00
	Total Heat Loss		12.98	15.38	16.07	15.92
	Gross Efficiency of Unit, %		87.02	84.58	83.93	84.08

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APPENDIX A - Preliminary Performance Summaries

Table 9.b.

Vectren Culley Unit 2 - Preliminary Performance Summary

Contract No.	293H	GBB				
Date	1/10/2014	Load ID	PC Firing	NG Firing	NG Firing	NG Firing
Revision	1	Boiler Arrangement	Existing	New Burners with & without Overfire Air Ports	PSH Surface Reduction New Burners without Overfire Air Ports	PSH Surface Reduction New Burners with Overfire Air Ports
Load Condition			50%	50%	50%	50%
Fuel			Bituminous	Natural Gas	Natural Gas	Natural Gas
Steam Leaving SH, mlb/hr			420	420	420	420
Superheater Spray Water, mlb/hr			2	28	19	18.5
% Excess Air Leaving Economizer			20	18	18	18
Flue gas Recirculation, %			None	None	19.5	14.0
Heat Input, mmBtu/hr			539.0	561.7	561.5	561.6
Quantity mlb/hr	Fuel (mcf/hr if gas)		53.9	541.7	541.5	541.6
	Flue Gas Entering Air Heaters		541	507	507	507
	Total Air To Burners		473	466	466	466
Pressure, psig	Steam at SH Outlet		1260	1260	1260	1260
Temperature, °F	Steam	Leaving Superheater	955	955	955	955
	Water	Water Entering Economizer	360	360	360	360
		Superheater Spray Water	225	225	225	225
	Gas	Entering Air Heater	585	581	606	606
		Leaving Air Heater (Excl. Leakage)	264	264	271	270
	Air	Entering Air Heater	121	121	121	121
		Leaving Air Heater	501	504	528	525
Heat Loss Efficiency, %	Dry Gas		3.34	2.74	2.90	2.90
	H_2 & H_2O in Fuel		5.76	10.05	10.08	10.08
	Moisture in Air		0.08	0.07	0.08	0.08
	Unburned Combustible		0.30	0.00	0.00	0.00
	Radiation		0.44	0.46	0.46	0.46
	Unacc. & Mfgs. Margin		1.50	1.00	1.00	1.00
	Total Heat Loss		11.42	14.32	14.51	14.51
	Gross Efficiency of Unit, %		88.58	85.68	85.49	85.49

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APPENDIX B – NG Conversion Equipment Scope & Budgetary Costs

BASE SCOPE - Natural Gas Burners, Ignitors, Scanners

Item 1: B&W XCL-S Natural Gas Burners (Quantity: 12)

Each burner to include:

- Externally adjustable secondary air zone spin vanes
- Externally adjustable core zone damper
- Multiple hemispherical gas spuds
- Pitot tube relative air flow measuring device with magnehelic gage
- Provisions to accept ignitor with integral flame detector
- One main flame scanner mount
- Two Type K permanent thermocouples to monitor core zone and burner outer sleeve temperature with two thermocouple heads
- Throat tile ring assembly to reduce the existing burner throat diameter
- Shop insulated cover plate
- Electric Linear Actuator for automated positioning of sliding secondary air damper
- One set of burner support steel with furnace wall and windbox connection hardware

Item 2: Fossil Power Systems (FPS) Gas Ignitors and Flame Scanners

- Qty 12, FPS gas ignitors with high energy spark ignitors and flame rods
- Qty 3 or 6, pre-assembled valve racks
- Qty 1, combustion/cooling air blower skid
- Qty 12, FPS main flame scanners with rigid fiber optic extension
- Qty 1, main flame scanner electronics cabinet
- 1 Lot – Combustion/Cooling air piping from blower skid to burner fronts

Item 3: Natural Gas Regulating Station and Piping

- Main natural gas regulating station – 30 psig supply pressure
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations including vent piping to above the boiler building roof

OPTION 1 SCOPE - B&W Overfire Air Ports (OFA) – Dual Zone

- Qty 8, Furnace Water wall Openings
- Windbox Extensions or Individual OFA Windboxes
- Qty 8, Automated Air Flow Control Damper with Rotary Drive - per port
- Boiler Closure Casing
- Temperature Monitoring Thermocouple (port style dependent)

OPTION 2 SCOPE - Flue Gas Recirculation (FGR)

- Flue Gas Recirculation Fan and Motor
- FGR Flues
- AH Outlet to FGR Fan Inlet
- FGR Fan Outlet to Secondary Air Mixing Foils
- FGR Flue expansion joints, hangers, bridging steel
- FGR Mixing Foils
- Windbox O_2 Monitor
- Burner throat assemblies to accommodate the larger B&W XCL-S burners required for FGR firing.

General Services

- Combustion system tuning services using an economizer outlet sampling grid for measurement of NOx per EPA methods.
- Performance testing
- Field Service Engineering outage support for construction, start-up, and post-modification testing. Coverage includes one engineer for 30 man-days at 10 hours per day, 6 days per week. In addition, Field Service Engineering to be provided to support system tuning and performance testing for a total of 20 man-days at 10 hours per day, 6 days per week.
- Burner System Operator Training consisting of two, one day sessions.
  - Training includes project specific training manual for up to 20 participants.
- Brickwork Refractory Insulation & Lagging (BRIL) Specifications and Installation design and materials.
- Contract specific System Requirements Specification, I/O Listing, and Functional Logic Diagrams for all supplied equipment.
- Operating and Maintenance Manuals (10 copies).
- New piping, flue, and duct loading to existing steel
- Shop tube butt welds shall be 100% radiographed.
- No weld rings for shop or field welds.
- All tube ends will be prepped, primed, capped and taped.
- All attachments will be shop installed, where possible.
- Shop hydrostatic pressure testing, at 1½ times design pressure, of all fabricated tube assemblies. Loose tubes without tube to tube welds will not be tested. Shop hydrostatic pressure testing will be AI witnessed.
- Pressure part fabrication to be estimated for BWM.
- Delivery F.O.B. Culley Plant, Newburgh, IN.

Items not Included

- Hazardous material removal or abatement (i.e., lead paint and asbestos).
- Load analysis of existing structural steel or foundations and any required re-enforcement thereof.
- Hardware or reprograming of existing DCS and/or BMS to support natural gas conversion.
- Gas step down equipment. Equipment scope above assumes incoming gas pressure at B&W's terminal to be 30 to 50psi.

Terminal Points

- Inlet of gas regulating station
- Interface of new burners to the existing furnace wall
- Field weld at the new wall panel inserts (if any)
- Electrical terminals on provided electrical equipment or instruments
- Electrical terminals in shop provided terminal junction boxes as part of skidded equipment
- FGR duct take off near the existing economizer outlet
- FGR duct tie in at the existing secondary air duct(s)
- OFA duct take off(s) from the existing secondary air duct(s) or windbox

Budgetary Material & Installation Pricing (USD 2019)

Scope Item	Budgetary	
	Material	Installation
BASE SCOPE: Burner, Ignitor, Scanner, NG Piping System	$2,900,000	$4,350,000
OPTION 1 SCOPE: Overfire Air System	$370,000	$555,000
OPTION 2 SCOPE: Flue Gas Recirculation System	$412,000	$618,000

Lead Times

- Material delivery: 52 - 56 weeks
- Installation outage duration: 8 - 10 weeks

B&W has offered these prices in 2019 US dollars and have not attempted to project escalation for time of performance or delivery.

Please note that these prices are budgetary and is not represent an offer to sell, however, we would welcome the opportunity to provide a formal proposal upon request.

Appendix C. Burns & McDonnell A.B. Brown Coal to Gas Conversion, Unit 2

A.B. Brown Coal to Gas Conversion

Vectren Energy Delivery

AB Brown Unit 2 Coal to Gas Boiler Conversion
Project No. 113003

Revision 1
April 2019

A.B. Brown Coal to Gas Conversion

prepared for

Vectren Energy Delivery
AB Brown Unit 2 Coal to Gas Boiler Conversion
Evansville, Indiana

Project No. 113003

Revision 1
April 2019

prepared by

Burns & McDonnell Engineering Co.
Kansas City, MO

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1.0 EXECUTIVE SUMMARY

Vectren Energy Deliveries (Vectren) is studying a coal to gas conversion project (Project) at the A.B. Brown facility. The conversion requires boiler burner modifications and gas infrastructure to fire 100% natural gas and remove coal firing capabilities.

Vectren retained Burns & McDonnell (BMcD) to provide conceptual engineering design to support a feasibility grade cost estimate. This report summarizes the conceptual engineering, performance estimates, and cost estimates for Vectren to evaluate the feasibility of the project.

1.1 Purpose

The purpose of this report is to provide the overall scope, schedule, performance, and capital costs to construct the Project based on the assumptions documented herein, and to provide general information to support project screening and evaluations.

1.2 Project Configuration Summary

A.B. Brown currently has two pulverized coal fired boilers that burn a local bituminous fuel. Each unit has a net output of approximately 240 MW. The boilers are a Babcock and Wilcox (B&W) wall fired design. The boilers are not equipped with over fire air or flue gas recirculation. Unit 1 is the northern unit which includes Selective Catalytic Reduction (SCR), baghouse, and dual alkali scrubber. Unit 2 is the southern unit which includes Selective Catalytic Reduction (SCR), precipitator, and dual alkali scrubber.

The A.B. Brown boilers were evaluated by B&W to estimate boiler performance and retrofit costs. This study compiles the findings from the B&W report attached in Appendix E with balance of plant (BOP) impacts to develop a total plant evaluation.

This report documents the 100% gas conversion of Unit 2 only. Vectren is evaluating new natural gas offsite infrastructure which is not included in this evaluation. This report assumes a new gas line tap in the existing gas yard. New metering and regulating is added in the gas yard along with a new onsite pipeline from the gas yard to the boiler house. The regulating station in the gas yard lowers the incoming pressure to 200 psig and an intermediate regulating station in the boiler house lowers the pressure further to 50 psig. Additional regulating stations provided by B&W are located at each boiler to lower the pressure further from 50 psig to the burner front pressure. New gas supply piping, vents, and valve stations are included up to the burner fronts. The existing burners will be retrofitted with the B&W Hemi-Spud nozzle to fire 100% natural gas.

For 100% natural gas firing, the SCR and dual alkali scrubber are not necessary. Natural gas emissions are low enough that additional controls shouldn't be necessary, an updated netting analysis should be performed to confirm this. The particulate control will remain in service during startup and initial operation to limit any potential particulate emissions from residual ash in the boiler and ductwork. The dual alkali scrubber will be demolished and replaced with ductwork. The scrubber tower has problems with erosion and leaks and Vectren wanted to remove it as a potential maintenance item.

1.3 Performance and Air Emissions Summary

Unit 2 will have an estimated electric generating capacity and heat rate as shown in the table below. The performances are based on adjusting the existing coal performance for the natural gas and co-firing cases.

Table 1-1: Unit 2 Performance Summary

	100% Coal	100% Natural Gas
Net Output, kW	240,000	238,950
Net Heat Rate, Btu/kWhr	10,650	11,175
Gross Output, kW	260,870	255,650
Auxiliary Loads, kW	20,870	16,700
STG Heat Rate, Btu/kWhr	8,615	8,790
Boiler Efficiency, %	87.9%	84.2%

BMcD performed a high-level permitting analysis in 2016 that evaluated the plant while firing 100% natural gas. For two units, this analysis found that while burning 100% natural gas the plant can operate at an approximate 10% capacity factor and not trip PSD. CO was the limiting factor for each case which is based on the 200 ppm estimate from B&W (0.148 lb/MMBtu). The CO emissions while burning natural gas will likely be less than 200 ppm. By only converting a single unit (Unit 2), the capacity factor should increase to almost double. This will be affected by the past operation from 2016 to 2019 though (past actuals vs future potential).

1.4 Contracting Approach

The selected contracting strategy for this report is the Multiple Prime Contracts approach with the Owner contracting B&W for the burner modifications and a balance of plant contractor directly.

1.5 Schedule

The schedule for this project was developed for a generic start date at month zero (0). The critical path for the project runs through receipt of gas burner equipment, construction, and continuing through startup and commissioning. This schedule assumes Vectren will start preliminary engineering and design while the air permit is being developed and reviewed. The project for 100% gas conversion will likely not trip PSD so air permitting should not be a big risk. The project schedule is shown in Appendix C.

1.6 Capital Costs

The capital cost for the gas conversion is presented in Table 1-3 below. The capital cost estimate is an Association for the Advancement of Cost Estimates (AACE) Class IV estimate. Per this classification, the estimate could have a lowest accuracy of -30%/+50% and a highest accuracy of -15%/+20%. Since a site visit was performed and engineering documents were created for estimate takeoffs, this estimate is closer to the highest accuracy range. Due to this, the contingency's below are recommended.

Table 1-2: Unit 2 Capital Costs

	100% Natural Gas
Project Costs w/ B&W Contract, $	$16,340,000
Owners Costs, $	$5,485,000
Total Costs, $	**$21,825,000**

The project cost includes direct material and construction costs for the Project as well as indirect costs including engineering, construction management, and other indirects. A project contingency of 5% is applied to the project costs. Owners costs includes owner specific management, operations, legal costs, startup costs, interest during construction, contingency and other owners costs. An owner's project contingency of 10% is included on the total project costs to cover scope definition and estimate accuracy.

2.0 INTRODUCTION

2.1 Background

Vectren is investigating converting the existing A.B. Brown Unit 2 to burn 100% natural gas. For 100% natural gas conversion, a new natural gas supply will be constructed up to the existing burners which will be retrofitted with gas spuds. The existing emissions controls will be taken out of service except for the particulate control during initial operation.

Vectren retained Burns & McDonnell to provide a feasibility grade cost estimate of the Plant. This report summarizes the conceptual design and presents the project costs to be used by Vectren in evaluating project feasibility.

2.2 Study Scope

The scope of work included preparing the following major conceptual design documents:

1. Site Arrangement Drawing
2. Preliminary Process and Instrumentation Diagrams
3. Project Schedule
4. Capital Costs

2.3 Objectives

The objectives of this study were to establish the conceptual design for the project, to provide an overall project schedule, and to provide a capital cost estimate to support project screening and evaluations. Vectren can use the information from this report to evaluate the natural gas conversion against other generation options.

2.4 Limitations and Qualifications

The costs presented within this report are subject to:

- Design changes for enhanced efficiency/operational flexibility.
- Final negotiation of the Terms and Conditions with the contractors and the major equipment suppliers.
- Final geotechnical report findings.
- Final topographical survey.
- Final determination/negotiation of the project schedule.
- Final selection of the equipment.
- Final permit requirements.
- Changes in federal regulations.

- Full evaluation of existing underground interferences.

3.0 PROJECT DEFINITION

3.1 Plant Overview

3.1.1 Scope of work

The assumptions that formed the basis of the plant conceptual design and cost estimate are summarized in this report. The assumptions were developed through meetings with Vectren and a site visit at A.B. Brown to evaluate how the conversion will impact the existing plant.

3.1.2 Key Design Documents

The following preliminary design documents were developed to form the basis of the project preliminary design and are included in the Appendices.

- Appendix A: Site Arrangement
- Appendix B: Process Flow Diagrams
- Appendix C: Project Schedule
- Appendix D: Capital Cost Estimate Summary

3.2 General Design Criteria

3.2.1 Operating and Control Philosophy

The Plant is expected to be operated as a peaking facility on 100% natural gas. Daily on/off cycling of the plant may be required. Considerations for daily cycling and impacts on existing equipment have not been included in this report.

The plant will be controlled using the existing A.B. Brown control room and distributed control system (DCS). The DCS at A.B. Brown station has recently been upgraded to Emerson Ovation version 3.3.1. Given that this is a modern control system, input/output (I/O) modules can be purchased and added to the system with little impact to the overall control system.

The I/O will change with the conversion from coal to natural gas. In general, a coal-fired station requires more I/O than a gas-fired station, so the gas conversion will be an overall reduction in the DCS I/O. It is assumed that B&W will provide updated instrument lists and I/O lists for the coal to gas conversion that indicate the devices to be removed and new devices that will be added to the control system. This in combination with the balance of plant (BOP) modifications will be used to develop an overall I/O impact. For the purposes of this study, a worse-case scenario was assumed that new DCS cabinets will need to be added to the existing BMS system. During detailed design, the system will be evaluated to determine how the existing system can be best utilized. Most likely, I/O can be relocated and spares can be utilized so that additional hardware is not necessary.

The existing logic will be modified to accommodate the modified gas burners, gas supply equipment, and gas interlocks. The existing master fuel trip (MFT) cabinet will be rewired to accommodate the new configuration. Fuel firing, air flow, and interlock logic will be reviewed and implemented based on the logic diagrams provided by B&W. Additional modifications to the BOP logic will be required to remove systems that are out of service and add logic for gas supply skids. The cost estimate assumes that BMcD will review the proposed logic changes by B&W and develop logic updates for Emerson to program.

The graphics will require evaluation and modification with the coal to gas conversion. During detailed design, BMcD will evaluate the existing graphics compared to the instrument list changes and updated piping configuration provided by B&W to develop graphic update sketches. These sketches will be reviewed with Vectren and then transmitted to Emerson for configuration.

An Emerson Field Service Engineer will be on-site for a portion of the outage to assist BMcD with I/O checkout and resolve any logic or graphic issues. Tuning of the air flow, drum level, furnace draft, throttle pressure control, steam temperature control, and other miscellaneous BOP loops will be required by an Emerson Tuner during startup.

The existing plant operators will be trained for natural gas operation. For the 100% gas firing case, plant operations can be reduced as the gas fired plant will have less equipment operating and require less maintenance.

Plant automation will be designed for secure and safe operation of all equipment. Maintenance support will be supplied by on-site staff as required for routine maintenance activities and may be shared with other Vectren units if such need arises.

3.2.2 Plant Design Summary

Design basis of the Plant can be summarized by the key documents accompanying this report as Appendices. Detailed design basis for each discipline as well as system descriptions are presented in this report.

3.2.2.1 Plant Location and Layout

The A.B. Brown plant is located in Mt. Vernon, IN near Evansville, IN. The conversion will have little impact on the existing plant layout. The existing gas yard has adequate space for the new regulating and metering skids. The regulating stations at the boiler will be housed in the southwest corner of the boiler house. Some existing shelving and storage may need to be relocated to allow room for the new regulating stations and valve stations. For the 100% gas conversion, the existing scrubber vessels will be demolished and replaced with ductwork but existing roads and access will not be impacted. The Site Arrangement Drawing is included in Appendix B.

No modifications to existing roads, switchyard, coal yard, or other plant areas are necessary. Existing building and structure modifications are not required.

3.2.2.2 Plant Utilities and Infrastructures

3.2.2.2.1 Fuel Gas Supply

The A.B. Brown plant site currently has existing gas supply utilized as start-up fuel for Units 1 & 2 and as main fuel supply for the GTG units. Plant personnel indicated that an additional gas line would be required for the additional necessary gas quantities for the conversion of Unit 2. A new gas supply line would also require a new revenue quality regulating and metering station. For the purposes of this study, BMcD located the single additional revenue quality regulating and metering station on the west side of the existing gas yard. The cost estimate scope starts at the inlet to the new regulating station and includes the onsite metering and regulation. The offsite supply line is excluded. This regulating station would be the single point of supply for the primary fuel for the converted unit. The new supply line would be fed by an underground line to the southwest corner of the boiler house to an intermediate regulation station to drop the pressure to B&W's required 50 psig. This line will feed B&W's regulating skid, beginning B&W scope of supply. The boiler regulating station would result in reducing the primary fuel pressure from 50 psig to burner supply pressure. The single regulating station located at the gas yard and the boiler supply regulating stations would be designed based upon NFPA 85 code.

3.2.2.2.2 Water Supply & Discharge

The discontinued use of coal after the 100% gas conversion would have considerable impact to water requirements at the A.B. Brown plant site. Both units currently utilize wet scrubber technology for the reduction of acid gases from fuel bound sulfur. This technology requires a continuous water supply to make up the continued blowdown stream. Both A.B. Brown units sluice bottom ash to an ash pond. Fly ash is transported dry to an onsite silo and then conveyed to barge for offsite utilization. The plant will no longer need water for fly ash sluicing or water for the hydroveyor to the barge. Mercury limitations for wastewater discharge (assuming existing coal pile and ponds are closed) will also be mitigated.

3.2.2.3 Buildings and Enclosure

No changes will be made to the existing boiler house building. The gas yard equipment will not be enclosed. The new gas valve stations and regulators for the conversion will be housed in the existing boiler house with no structural modifications necessary. Since the units already use natural gas for startup fuel, additional ventilation (such as louvers or vent fans) should not be required when converting the coal burners to natural gas.

3.2.3 Unit Modifications

When a boiler is converted to gas firing, there is no longer a need for primary air to convey coal from the coal mill to the burners. Instead, all of the air supply will be sent through the windbox as secondary air. B&W

estimates a boiler efficiency impact of almost 4 percentage points; however, the excess air requirement will drop from ~20% to ~10%. This change in operating conditions results in lower air supply requirements than when firing coal. B&W reviewed the draft system and confirmed that the induced draft and forced draft fans will be adequate for the boiler conversion.

The A.B. Brown Units have the full scope of air quality control system (AQCS) technologies. Natural gas still produces nitrogen oxides (NOx), but the SCR will not be necessary for 100% natural gas firing as it produces much lower NOx. In the case of full gas conversion, both the particulate matter (PM) control and flue gas desulphurization (FGD) technologies could be fully removed from service but Vectren has elected to keep the PM control in service for initial operation to remove any residual particulate in the system. When operating on 100% natural gas, the boiler and gas path will clean up with time and the particulate systems can be removed from service. Due to the low operating hours and uncertain life of the converted plant, owners typically don't demolish the precipitator internals but the bags can be removed from the baghouse. This study assumes that the particulate control devices will be abandoned in place with no demolition.

3.2.3.1 Boiler Modifications

In order to convert the boiler for 100% gas firing, the existing coal burners will be retrofitted by removing the coal nozzle and replacing it with a hemi-spud cartridge as indicated by B&W in Appendix E. The existing natural gas pilot fuel system and ignitors will be reused. The following components will be supplied for each boiler by the boiler vendor for this modification:

Boiler Front Equipment

- Hemispherical Gas Spud Cartridges to replace existing coal nozzles
- Burner Valve Racks ("double block & bleed")
- Burner Front Flex Hose and Hardware
- Burner Front Piping
- Gas Header Piping
- Main UV flame scanners with rigid fiber optic extension
- Main flame scanner electronics cabinet
- Combustion/Cooling air piping from blower skid to burner fronts

Natural Gas Transport Piping and Regulating

- Main natural gas regulating station located within boiler – 50 psig supply pressure to regulator
- Natural gas piping from regulating station to the burners
- Natural gas burner front gas piping and valve stations excluding vent piping

This previous scope of work is typical of the boiler vendor, but Vectren would still be required to install a regulating and metering station at the gas yard for the new gas supply for the primary gas and an intermediate regulation station to lower pressure further to the 50 psig supply pressure to B&W's regulating skid. For the purposes of this study, BMcD placed the new regulating and metering station on the west end of the gas yard and routed a new gas feed along the same path as the existing igniter gas piping. This routing would run east, south of the existing gas turbines and plant road, before turning northeast into the boiler house. The intermediate regulation skid would be located in the boiler house near the existing valve station.

The boiler vendor's scope starts at the southwest corner of the boiler house. Each boiler would require its own low pressure regulating station to allow for primary fuel gas to be isolatable. The boiler regulating stations may be placed adjacent to the existing igniter gas regulating station. The primary fuel gas piping can follow the similar pipe routing to the existing igniter fuel piping for each respective boiler. BMcD pipe sizing criteria for fuel gas is as follows:

- 2-1/2" – 8" Pipe : < 4000 ft/min Line Velocity
- 10" – 20" Pipe : < 5000 ft/min Line Velocity

This design criteria provides lower velocities, resulting in less noise and pipe vibrations as compared to typical velocities when designed by boiler vendors. B&W has not confirmed the line velocity assumed for the burner supply piping they are providing.

In addition to the fuel piping, vent pipe will be required per NFPA 85. This vent piping will be required on both the front and rear elevations of the boiler. B&W did not provide any vent piping in their scope. This vent piping is covered in the BOP scope.

The boiler decks at A.B. Brown Unit 2 appear to have sufficient space; however, the coal piping and elbows should be removed for better access the burner fronts for a full gas conversion. Coal piping can be removed from the burner decks, down to the pulverizer top exits. Pulverizers may be abandoned in place and blanked off.

3.2.4 Switchyard

No switchyard modifications will be required.

3.2.5 Unit 2 Performances

Burning natural gas will be less efficient than burning coal. The main impact on boiler efficiency is from hydrogen losses due to the higher hydrogen content of the natural gas fuel. The byproduct of combusting hydrogen is water vapor, and additional heat is needed to vaporize this water and heat it to the internal boiler temperature. This heat is lost in the flue gas rather than absorbed in the boiler's water walls to create steam.

On the other hand, natural gas is more efficient than coal when it comes to dry gas losses due to less combustion air and excess air. B&W assumed that approximately 10% excess air is needed for proper combustion of natural gas vs. 20% excess air for coal. Less flue gas flow for burning natural gas equates to smaller losses for heating the flue gas.

While the reduced natural gas-fired boiler efficiency reduces net plant output, the reduction in auxiliary power requirements for a gas-fired boiler increases the net plant output accordingly. This study assumes a 20% savings in auxiliary loads for pulverizers, coal handling, soot blowers, etc. that will not be operated on 100% natural gas.

Expected performances for natural gas are shown below along with the existing Unit 2 performances. The boiler efficiency is based on B&W's study. Also based on B&W's boiler evaluation, the STG heat rate will be slightly higher due to lower reheat temperatures.

Table 3-1: Unit 2 Performance Estimates

	100% Coal	100% Natural Gas
Net Output, kW	240,000	238,950
Net Heat Rate, Btu/kWhr	10,650	11,175
Gross Output, kW	260,870	255,650
Auxiliary Loads, kW	20,870	16,700
STG Heat Rate, Btu/kWhr	8,615	8,790
Boiler Efficiency, %	87.9%	84.2%

The 100% natural gas performance will have a lower output and higher heat rate compared to the coal performance based on decreased boiler efficiency, decreased steam turbine gross output and decreased steam turbine heat rate. This is mainly due to the decreased hot reheat temperature while operating on natural gas. The reduction in auxiliary loads could not make up for the reduction in steam turbine performance.

3.3 Environmental & Permitting

A high-level permitting analysis was performed in 2016 for the two A.B. Brown units. This evaluation showed that the plant should be able to net out without tripping PSD. By only converting a single unit, the netting analysis and allowed operating hours should improve. An updated netting analysis was not performed for this study.

3.4 Project Schedule

3.4.1 General

The schedule for this project was developed for a generic start date at month zero (0). This schedule assumes Vectren will start preliminary engineering and design while the air permit is being developed and reviewed. The project for 100% gas conversion should not trip PSD so air permitting should not be a big risk. The project schedule is shown in Appendix C.

3.4.2 Major Equipment

The schedule assumes a 12-month lead time for all boiler and burner equipment. B&W provided a lead time of 52-56 weeks.

3.4.3 Construction

Major construction activities will include the new onsite gas pipeline and fuel yard work, boiler modifications including mechanical and electrical work, and the scrubber vessel demo and replacement with ductwork. Construction of Unit 2 is estimated at approximately 12 months.

3.4.4 Startup

Startup for either the 100% natural gas or co-firing options will be relative short with a duration of approximately 2 months. The unit will be fired and tuned for optimum performance. Since the steam side will not be affected, no steam blows or cleanings will be necessary.

4.0 PROJECT COSTS

4.1 Project Cost Estimate

The detailed capital cost build-up for the 100% natural gas is included in Appendix D. The capital cost summary is shown below. The project costs exclude escalation and are shown as 2019$. The capital cost estimate is an Association for the Advancement of Cost Estimates (AACE) Class IV estimate. Per this classification, the estimate could have a lowest accuracy of -30%/+50% and a highest accuracy of -15%/+20%. Since a site visit was performed and engineering documents were created for estimate takeoffs, this estimate is closer to the highest accuracy range. Due to this, the contingency's below are recommended. A project contingency of 5% is included to cover pricing accuracy and potential labor productivity. An owner contingency of 10% is included to cover the accuracy of the estimate for the scope defined in this report. Owner costs are also included to account for all project costs that may be incurred during the project.

Table 4-1: Unit 2 Capital Costs

	100% Natural Gas
Project Costs w/ B&W Contract, $	$16,340,000
Owners Costs, $	$5,485,000
Total Costs, $	**$21,825,000**

4.2 Cost Estimate Basis

The purpose of the cost estimate basis is to generally describe the scope of the cost estimate and the methodology for estimating the costs.

4.2.1 Contracting Approach

The cost estimate was assembled using multiple prime contract approach. The Owner is responsible for the purchase of all equipment, while each prime contractor is responsible for their subcontracts, and labor. The associated risk for the Owner of using multiple contractors is accounted for in the total project contingency. Costs to administer the contract, participate in OEM's meetings, and review submittals are included under engineering cost.

4.2.2 Engineered Equipment

B&W will provide the majority of the major equipment. The B&W supplied scope is outlined in 3.2.3.1 and in Appendix E. B&W provided a supply and installation cost for the burner equipment. BMcD checked the installation estimate using information from previous gas conversion estimates and found that it was a conservative estimate. Based on this, the B&W installation cost was carried in the estimate even though B&W may or may not perform that work when the project is executed. The BOP contractor will provide the gas yard regulating and metering. All BOP equipment and materials were based on in house pricing from recent projects. The productivity factors for the equipment installation were derived from Burns & McDonnell past project information for union labor in the project area.

4.2.3 Civil

Civil scope for this project is very limited. Scope includes excavation and backfill for the onsite natural gas pipeline and finishing work around the gas yard and scrubber vessel areas. No new roads or grading are required.

4.2.4 Concrete

The gas yard metering and regulation is assumed to be field erected. Some foundation work is included for the scrubber vessel replacement where foundations could not be reused. The valve stations and metering in the boiler house will be mounted to the existing floor slab. This scope also includes estimated quantities for the structural excavation and backfill required for foundation construction. For reinforcing steel, a density of rebar per unit of concrete was provided by engineering for estimating purposes. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.2.5 Structural Steel

Miscellaneous steel such as pipe rack, grating, handrail, etc. are included for structure access that is not otherwise provided as part of the equipment contracts. Structural steel is also estimated to replace the existing scrubber vessels with ductwork. The existing structural steel around the absorbers was assumed to be corroded and was replaced with new steel where necessary. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.2.6 Piping

The BOP piping scope of work includes mostly below grade gas supply piping from the gas yard to the boiler house and vent piping. B&W is providing materials and installation of all the burner supply piping. The piping scope covers purchase of pipe, fittings, flanges, valves, specials, bolt-up kits, supports and pre-fabricated pipe. The piping scope of work does include applicable non-destructive evaluation (NDE) and pressure testing. The piping scope of work includes allowances for underground interferences.

The piping estimate was based on a take-off from the general arrangement with P&IDs. Using these quantities, costs for bulk material, valves, pipe fabrication was based on Burns & McDonnell recent project pricing. The production rates developed from Burns & McDonnell previous project estimates for construction in the project area.

4.2.7 Electrical

The auxiliary power requirements for burning natural gas are generally lower than that required for burning coal. Abandonment of the pulverizers will free up considerable load from the aux power system. Power will be required for the new flame scanners, valves, and blowers, but it is assumed that the existing power distribution can accommodate these additional minor loads. New control wiring has been included from the burner devices to the existing burner junction boxes. New marshalling control wiring has also been included from the burner junction boxes back to the DCS. Wiring has been included to the low pressure and high pressure regulating skids. The existing cable tray around the boiler has adequate space to accommodate the new cable. The production rates and material prices were developed from Burns & McDonnell previous project estimates for construction in the project area.

4.2.8 Instrumentation & Controls

The majority of instrumentation for this project is either skid-mounted or included in the B&W installation estimate. The skid-mounted regulating skids and valve stations are specified such that all instrumentation is installed and wired to a junction box. Some instrumentation will be installed separately for the field erected gas yard metering and regulation. This results in negligible BOP instrumentation installation work. As described in the General Design Criteria section, the worst case scenario was assumed where new DCS cabinets would be necessary to accommodate the BMS. An internal estimate was developed for this DCS cost that includes both hardware and software modifications.

4.3 Indirects

The following methods were used for indirects:

- Cost for construction management and construction indirects were based on a percentage of the project costs based on similar past projects. Costs include construction management staff expenses including travel and living expenses, temporary buildings and utilities, and site maintenance. Additional construction management provided by the contractors is included in the wage rates used in this estimate.

- Cost for engineering was based on a percentage of the project costs based on similar past projects. The engineering estimate includes costs for office and field engineering as well as all per diems, expenses, and general overhead and administrative costs. The engineering estimate also includes costs to review submittals from major equipment OEMs and contract administration tasks such as attending progress meeting, expediting drawing submittals, and reviewing progress report.
- Cost for startup was based on a percentage of the project costs based on similar past projects.

4.3.1 Taxes

All taxes are excluded from the estimate.

4.3.2 Construction Labor Basis

The estimate was developed on the basis that there will be a sufficient labor pool to draw from the Evansville/Mount Vernon area to support the project. The productivity factors were developed based on Burns & McDonnell project history for labor in the area.

4.3.2.1 Labor Wage Rates & Expenses

Wage rates were taken from the 2019 RSMeans Construction Labor Rates for the Mount Vernon, IN area. The wage rates include wages, fringes, general liability and workers compensation insurance, overtime, per diem, incentives and contractor indirects.

4.3.2.2 Work Hours

The estimate assumes a 5-day, 50-hour week to incentivize labor. The shifts are based on a 50 hour work week with 25% of hours of overtime per day at one and a half times base wage rate for overtime pay.

4.3.2.3 Labor Per Diem

Craft per diem included in the craft wage rates.

4.3.3 Escalation

Escalation was excluded from the project costs.

4.3.4 Contingency

A project contingency was included to cover typical final accuracy of pricing, commodity estimates, and accuracy of the defined project scope. Typically the level of contingency is set by the amount of scope definition provided, the amount of engineering and estimating conducted by the OE and Vectren prior to providing cost certainty on the project price, and the amount of risk born by the prime contractors (performance, schedule, scope, payment, etc.). This contingency is NOT intended to cover changes in the general project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) NOR major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans). A 5% contingency was included as a typical allowance for this indirect cost.

4.3.5 Owner Costs

Vectren's costs were included in the cost estimate. Burns & McDonnell referenced past projects to develop typical owner costs. Costs were included for the following items:

- Project development
- Vectren's project management
- Vectren's legal counsel
- Permitting and license fees
- Permanent plant operating spare parts
- Startup testing fuels and consumables
- Operator training
- Builder's risk insurance
- Interest during construction (10.2% of project costs provide by Vectren)

Owner's contingency takes into account the level of project scoping and engineering completed during the feasibility design phase to support this cost estimate. 10% contingency on the Total Project Cost and Owner Cost was used at this stage. As the scope and estimating accuracy for this project is refined in subsequent phases the amount of contingency carried will shrink.

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

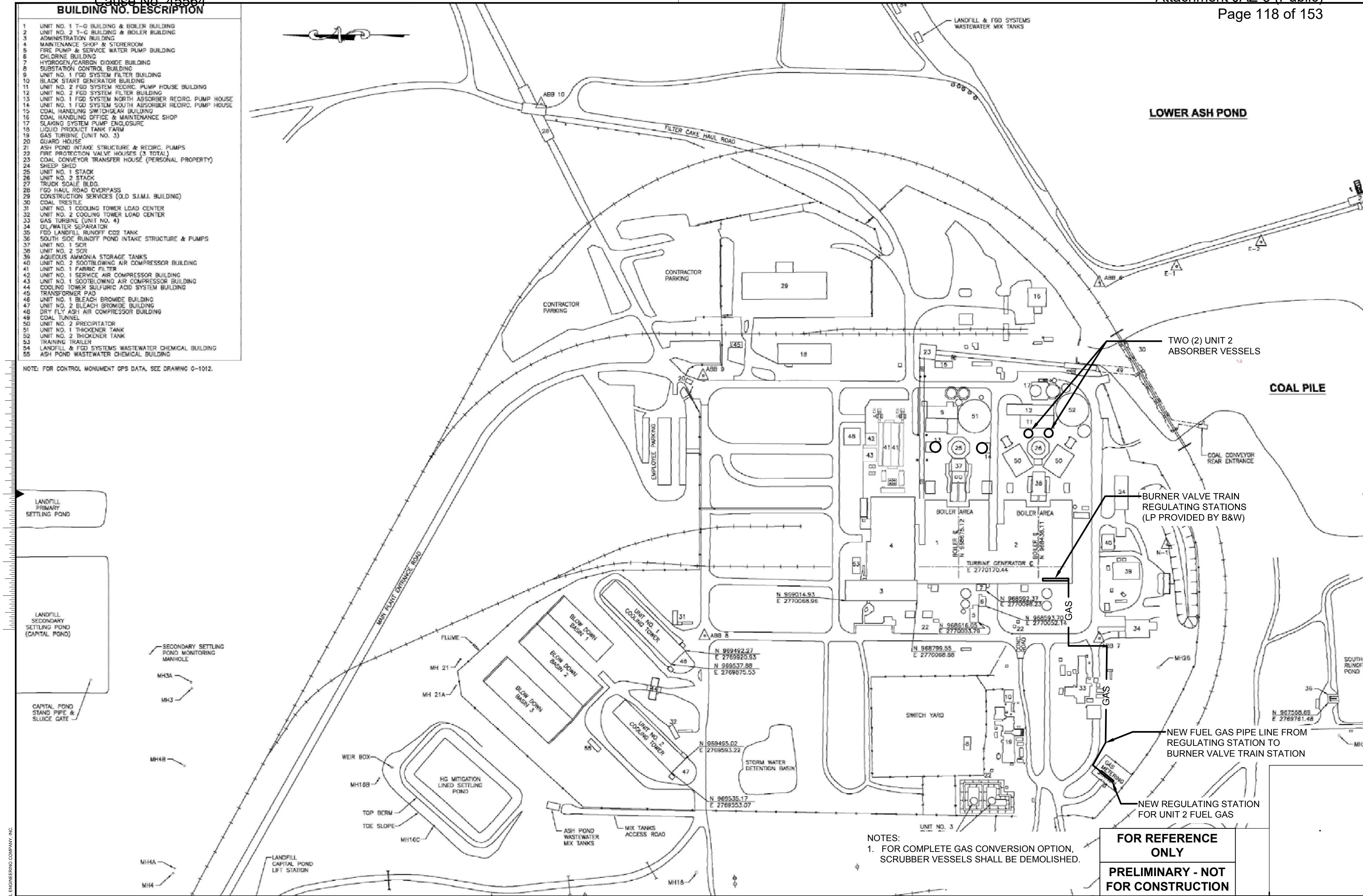
Burns & McDonnell recommends Vectren evaluate the project economics based on the cost and performances presented in this report. If the Plant economics are favorable as a future generation project, then Burns & McDonnell recommends Vectren proceed with a more detailed study to develop budget level pricing and finalize all design and cost considerations.

APPENDIX A – SITE ARRANGEMENT

BUILDING NO. DESCRIPTION

BUILDING NO.	DESCRIPTION
1	UNIT NO. 1 T–G BUILDING & BOILER BUILDING
2	UNIT NO. 2 T–G BUILDING & BOILER BUILDING
3	ADMINISTRATION BUILDING
4	MAINTENANCE SHOP & STOREROOM
5	FIRE PUMP & SERVICE WATER PUMP BUILDING
6	CHLORINE BUILDING
7	HYDROGEN/CARBON DIOXIDE BUILDING
8	SUBSTATION CONTROL BUILDING
9	UNIT NO. 1 FGD SYSTEM FILTER BUILDING
10	BLACK START GENERATOR BUILDING
11	UNIT NO. 2 FGD SYSTEM RECIRC. PUMP HOUSE BUILDING
12	UNIT NO. 2 FGD SYSTEM FILTER BUILDING
13	UNIT NO. 1 FGD SYSTEM NORTH ABSORBER RECIRC. PUMP HOUSE
14	UNIT NO. 1 FGD SYSTEM SOUTH ABSORBER RECIRC. PUMP HOUSE
15	COAL HANDLING SWITCHGEAR BUILDING
16	COAL HANDLING OFFICE & MAINTENANCE SHOP
17	SLAKING SYSTEM PUMP ENCLOSURE
18	LIQUID PRODUCT TANK FARM
19	GAS TURBINE (UNIT NO. 3)
20	GUARD HOUSE
21	ASH POND INTAKE STRUCTURE & RECIRC. PUMPS
22	FIRE PROTECTION VALVE HOUSES (3 TOTAL)
23	COAL CONVEYOR TRANSFER HOUSE (PERSONAL PROPERTY)
24	SHEEP SHED
25	UNIT NO. 1 STACK
26	UNIT NO. 2 STACK
27	TRUCK SCALE BLDG.
28	FGD HAUL ROAD OVERPASS
29	CONSTRUCTION SERVICES (OLD S.I.M.I. BUILDING)
30	COAL TRESTLE
31	UNIT NO. 1 COOLING TOWER LOAD CENTER
32	UNIT NO. 2 COOLING TOWER LOAD CENTER
33	GAS TURBINE (UNIT NO. 4)
34	OIL/WATER SEPARATOR
35	FGD LANDFILL RUNOFF CO2 TANK
36	SOUTH SIDE RUNOFF POND INTAKE STRUCTURE & PUMPS
37	UNIT NO. 1 SCR
38	UNIT NO. 2 SCR
39	AQUEOUS AMMONIA STORAGE TANKS
40	UNIT NO. 2 SOOTBLOWING AIR COMPRESSOR BUILDING
41	UNIT NO. 1 FABRIC FILTER
42	UNIT NO. 1 SERVICE AIR COMPRESSOR BUILDING
43	UNIT NO. 1 SOOTBLOWING AIR COMPRESSOR BUILDING
44	COOLING TOWER SULFURIC ACID SYSTEM BUILDING
45	TRANSFORMER PAD
46	UNIT NO. 1 BLEACH BROMIDE BUILDING
47	UNIT NO. 2 BLEACH BROMIDE BUILDING
48	DRY FLY ASH AIR COMPRESSOR BUILDING
49	COAL TUNNEL
50	UNIT NO. 2 PRECIPITATOR
51	UNIT NO. 1 THICKENER TANK
52	UNIT NO. 2 THICKENER TANK
53	TRAINING TRAILER
54	LANDFILL & FGD SYSTEMS WASTEWATER CHEMICAL BUILDING
55	ASH POND WASTEWATER CHEMICAL BUILDING

NOTE: FOR CONTROL MONUMENT GPS DATA, SEE DRAWING C–1012.



NOTES:
1. FOR COMPLETE GAS CONVERSION OPTION, SCRUBBER VESSELS SHALL BE DEMOLISHED.

FOR REFERENCE ONLY

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
A	09/08/15	ACR	ZDL	FOR OWNER REVIEW

NORTH

0 100' 200'
SCALE IN FEET

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: M. ATHERTON

VECTREN
POSEY COUNTY, INDIANA

A. B. BROWN POWER STATION
SITE ARRANGEMENT
PLAN

project: 85648
contract:
drawing: SKM-1001
rev.: A
sheet 1 of 1 sheets
file 85648-SKM-1001.dwg

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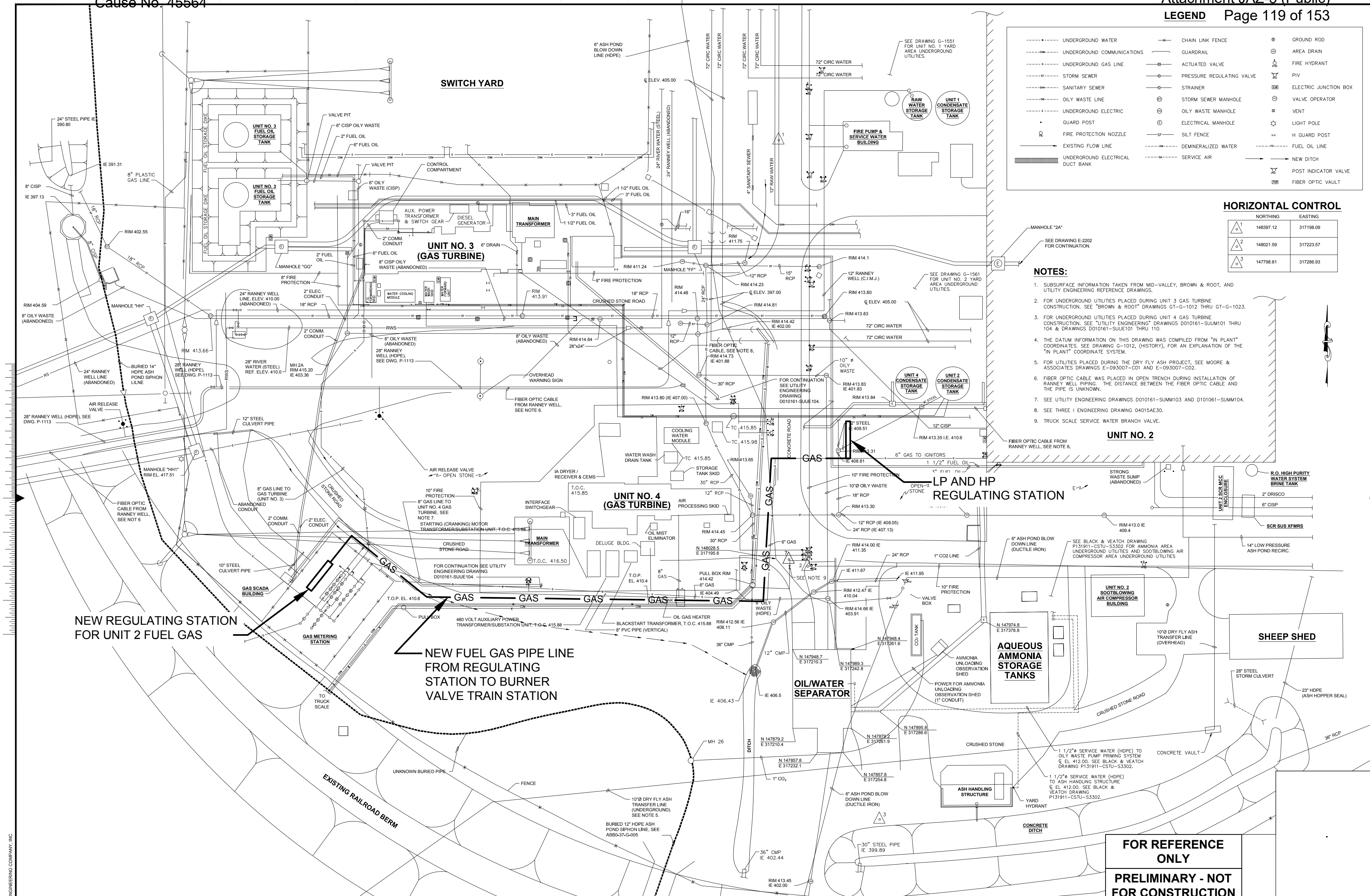

no.	date	by	ckd	description
A	09/08/15	ACR	ZDL	FOR OWNER REVIEW

NORTH
SCALE IN FEET

BURNS & McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: M. ATHERTON

VECTREN
POSEY COUNTY, INDIANA

A. B. BROWN POWER STATION
GENERAL ARRANGEMENT PLAN
project: 85648
contract:
drawing: SKM-1002
rev. A
sheet 1 of 1 sheets
file 85648-SKM-1002.dwg

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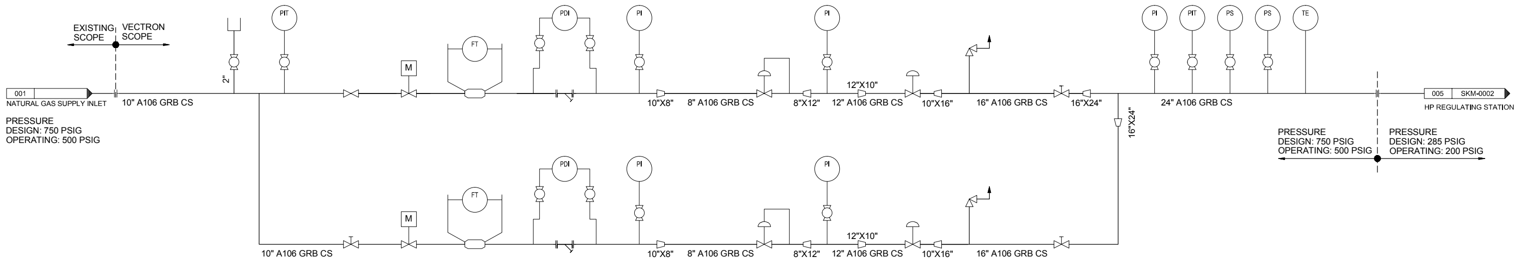
APPENDIX B – PROCESS FLOW DIAGRAMS



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B	02/18/16	ACR	ZDL	REVISED PER B & W REPORT
A	10/29/15	ACR	ZDL	FOR OWNER REVIEW

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT | detailed: S. CHURCHILL

VECTREN

POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
YARD REGULATING STATION SKID
A. B. BROWN

project: 86548 | contract: -

drawing: SKM-0001 | rev. B

sheet 1 of 1 sheets

file 86548-SKM-0001.dwg

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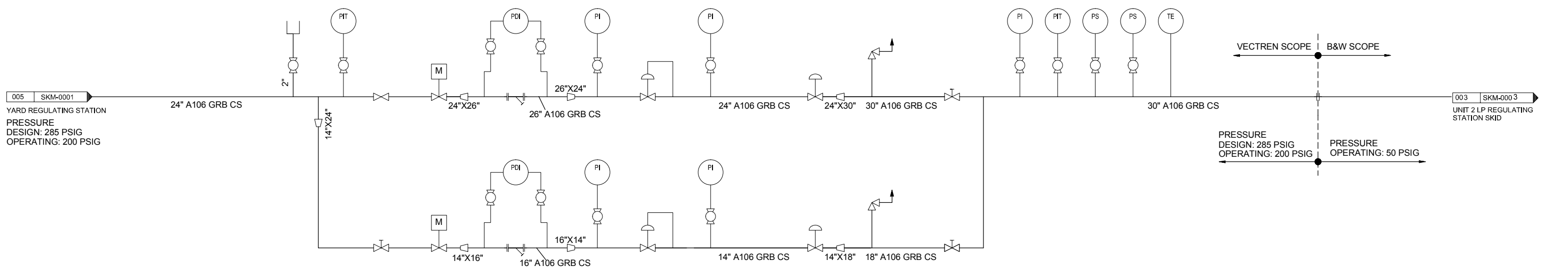

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no.	date	by	ckd	description
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A	10/29/15	ACR	ZDL	FOR OWNER REVIEW

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: S. CHURCHILL

VECTREN
POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
HP REGULATING STATION
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0002
rev.: B
sheet 1 of 1 sheets
file 86548-SMK-0002

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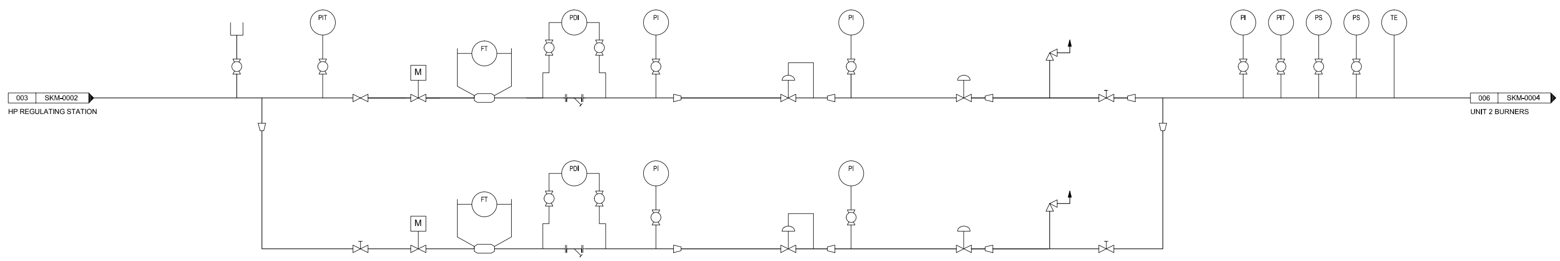

NOTE:

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no.	date	by	ckd	description
B	02/18/16	ACR	ZDL	REVISED PER B & W REPORT
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BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: S. CHURCHILL

VECTREN
POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
UNIT 2 REGULATING STATION SKID
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0003
rev.: B
sheet 1 of 1 sheets
file 86548-SKM-0004.dwg

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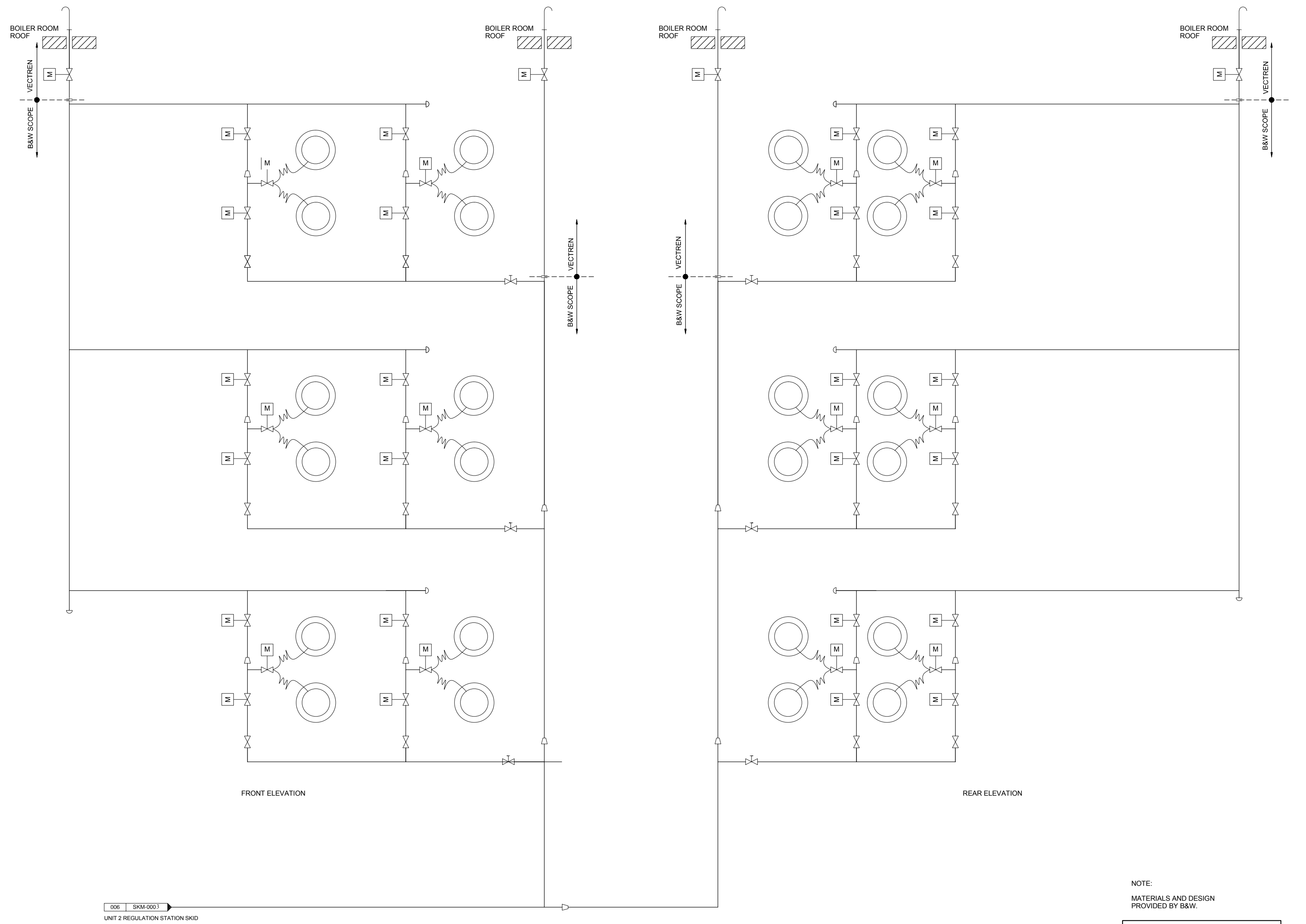

NOTE:

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no.	date	by	ckd	description
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A	10/29/15	ACR	ZDL	FOR OWNER REVIEW

BURNS McDONNELL
9400 WARD PARKWAY
KANSAS CITY, MO 64114
816-333-9400

designed: A. ROOT
detailed: S. CHURCHILL

VECTREN
POSEY COUNTY, INDIANA

VECTREN COAL TO GAS
UNIT 2 BOILER
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0004
rev.: B
sheet 1 of 1 sheets
file 86548-SKM-0006.dwg

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APPENDIX C – PROJECT SCHEDULE