prepared for

VECTREN ENERGY DELIVERY OF INDIANA

*2020-2025 Integrated **Electric** DSM Market Potential Study & Action Plan*

January 2019

FINAL REPORT

prepared by

GDS ASSOCIATES INC

EMI CONSULTING

Attachment 6.3 All Source RFP

All-Source Request for Proposals

VECTREN
A CenterPoint Energy Company

Vectren

6/12/2019

All-Source Request for Proposals

for

Power supply generation facilities, power purchase agreements, and demand resources

Issued
6/12/2019

Proposals due
7/31/2019

prepared by

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

TABLE OF CONTENTS

Page No.

APPENDIX A – NOTICE OF INTENT

APPENDIX B – NON-DISCLOSURE AGREEMENT

APPENDIX C – PRE-QUALIFICATION APPLICATION

APPENDIX D – PROPOSAL DATA

APPENDIX E – PROPOSAL CHECKLIST

LIST OF TABLES

Page No.

LIST OF FIGURES

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
CFR	Code of Federal Regulations
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Commercial Operating Date
CSP	Curtailment Service Providers
DA	Definitive Agreement
DIR	Dispatchable Intermittent Resource
DR	Demand Resource
EFORd	Equivalent Forced Outage Rate Demand
EPC	Engineering, Procurement and Construction
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission
GDPIPD	Gross Domestic Product Implicit Price Deflator
GI	Generation Interconnection
GIA	Generator Interconnection Agreement
Hg	Mercury
ICAP	Installed Capacity
IRP	Integrated Resource Plan
IURC	Indiana Utility Regulatory Commission

kW	Kilowatt
lb	Pound
LCOE	Levelized Cost of Energy
LCR	Local Clearing Requirement
LMR	Load Modifying Resource
LRZ	Local Resource Zone
LSE	Load Serving Entity
MISO	Midcontinent Independent System Operator
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-Hour
NDA	Non-Disclosure Agreement
NO_X	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NRIS	Network Resource Integration Service
OEM	Original Equipment Manufacturer
OVEC	Ohio Valley Electric Corporation
PM	Particulate Matter
PPA	Power Purchase Agreements
PRM	Planning Reserve Margin
RFP	Request for Proposal
SO_2	Sulfur Dioxide

UCAP	Unforced Capacity
Vectren	Vectren Energy Delivery
VOC	Volatile Organize Compounds

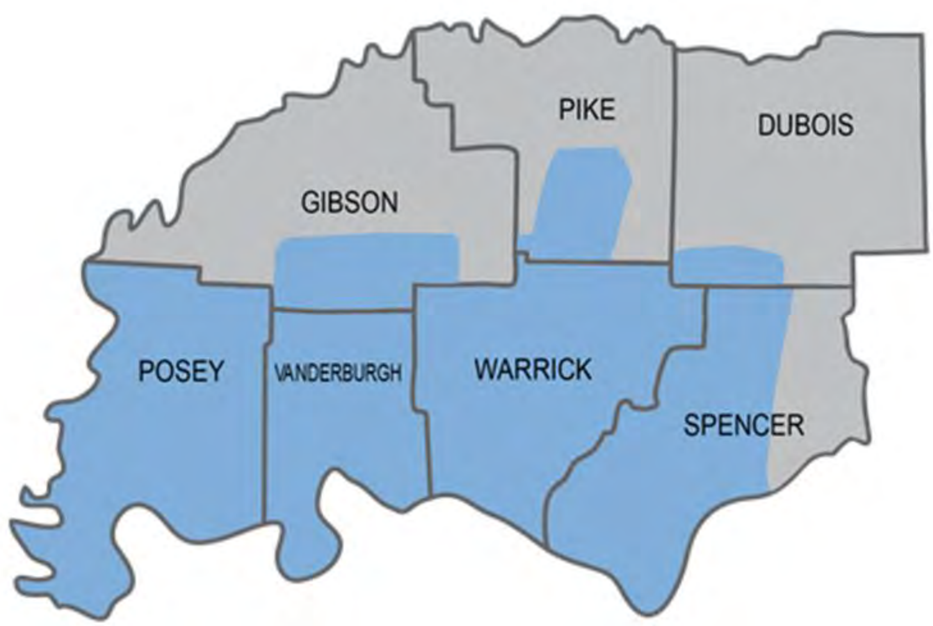
1.0 ALL-SOURCE RFP OVERVIEW

1.1 Introduction

Southern Indiana Gas and Electric (Vectren) is a subsidiary of CenterPoint Energy, headquartered in Houston, Texas. Vectren provides energy delivery services to 144,000 electric customers located in southwestern Indiana. Vectren also owns and operates electric generation to serve its electric customers and optimizes those assets in the wholesale power market.

Vectren's electric customers are currently served by a mixed portfolio of 1,000 megawatts (MW) of coal-fired generation, up to 225 MW of gas-fired generation and 4 MWs of solar coupled with 1 MW of storage. The portfolio also contains 3 MW from a landfill gas to electric project and purchases from the Ohio Valley Electric Corporation (OVEC) of up to 32 MW, wind purchases of up to 80 MW, and purchases from the Midcontinent Independent System Operator (MISO) power pool as needed to meet Vectren’s load requirements. Furthermore, interruptible load and demand-side management initiatives can reduce load by approximately 60 MW if needed.

Figure 1-1: Vectren Electric Service Area



1.2 Purpose

Vectren has issued this all-source Request for Proposals (RFP) seeking power supply and demand-side Proposals for capacity and unit-contingent energy to meet the needs of its customers. For asset purchases and power purchase agreements (PPAs) the capacity is preferred to be fully accredited for the 2023/2024

MISO Planning Year (PY). Vectren intends to submit an updated Integrated Resource Plan (2019/2020 IRP) to the Indiana Utility Regulatory Commission (IURC) in 2020 which will evaluate existing resources and identify the preferred resource options to meet capacity and energy requirements. Only resources capable of firm deliverability, further outlined in Section 4.1.1.2, to MISO Local Resource Zone (LRZ) 6 will be considered.

Vectren's resource planning will balance the need for dispatchable capacity with intermittent and demand-side resources to meet customers' needs reliably and cost effectively in an environmentally sustainable manner in both the short and long term. The IRP is designed to provide Vectren customers with a safe, reliable, and affordable power supply.

Vectren prefers Proposals that reflect all of the costs and characteristics of the resource necessary for energy to be financially settled or directly delivered to Vectren's load node (SIGE.SIGW). All potential agreements are subject to IURC approval and are not effective until such approval is final.

All Proposals must be received by the contact designated in Section 2.1 no later than the Proposal Submittal Due Date shown in Section 2.4. Vectren reserves the right in its sole discretion to modify this schedule for any reason.

In connection with this RFP, Vectren has retained the services of an independent third-party consultant, Burns & McDonnell, to manage the entire RFP process and work with Vectren to perform the quantitative and qualitative evaluations of all Proposals. However, Vectren will make final decisions (subject to IURC review, as applicable) in Vectren's sole discretion.

All Respondents will directly interface with Burns & McDonnell for all communications including questions, RFP clarification issues, and RFP bid submittal. All correspondence concerning this RFP should be sent via e-mail to VectrenRFP@burnsmcd.com.

Long term resource planning requires addressing risks and uncertainties created by a number of factors including the costs associated with new resources. As part of ongoing resource planning, Vectren has concluded that it is in the best interest of its customers to seek information regarding the potential to acquire, construct or contract for additional capacity that qualifies as a MISO internal resource (i.e. not pseudo-tied into MISO) with physical deliverability utilizing Network Resource Integration Service (NRIS) to MISO LRZ 6. Hereafter within this document, zonal restrictions will be referred to as being within MISO LRZ 6. Within the context of the 2019 IRP process, Vectren is soliciting all-source RFP for supply-side and demand-side capacity resources. The purpose of the RFP is to identify viable resources available to Vectren in the marketplace to meet the needs of its customers. Dependent upon further evaluation of aging resources, and subject to actual IRP results, Vectren may identify a capacity need of approximately 700 MW beginning in the 2023/2024 planning year. Because Vectren is looking at a number of potential resource portfolio combinations in the IRP, it is likely the 2019/2020 IRP will have scenarios that could result in a need less than or greater than 700 MW. Therefore, Respondents are encouraged to offer less than, or more than, 700 MW depending on the resources they have available. Vectren will also consider alternative timelines related to the capacity acquisition to the extent Respondents are able to provide more competitive pricing and/or terms for delivery beginning prior to or after 2023/2024 planning year. Vectren will aggregate data from the RFP responses, which include a delivered price (pending verification), and input such data into its IRP modeling. The RFP bid evaluation and selection process will be based upon the specific resource needs identified through this IRP modeling as well as the bid evaluation criteria. Through this RFP, Vectren seeks to satisfy the identified capacity need through either a single resource or multiple resources including dispatchable generation, load modifying resources (LMRs)/demand resource (DRs), renewables, stand-alone and paired storage, and contractual arrangements.

Vectren is seeking to provide reliable generation supply and demand resources for its customers. This RFP is issued to:

- Acquire a generation facility or facilities described further in Section 4.0, including the following:
    - Existing or planned dispatchable generation facilities that, at a minimum, meet established industry-wide reliability and performance standards or development requirement
        - Planned resources can be but are not required to be in the MISO generator interconnection queue
    - Existing or planned utility scale renewable resources
    - Existing or planned utility scale storage facilities, either stand-alone or paired with renewables
- Procure power purchase contract options for capacity and energy described further in Section 5.0.
- Procure LMRs/DRs that satisfy the criteria described further in Section 6.0.

Accordingly, you are invited to submit a written, binding Proposal in accordance with the requirements described in this RFP. Entities that submit a Proposal are referred to as Respondents.

The milestone dates for this RFP process are presented below. Additional information about milestone dates for the RFP is provided in Section 2.4.

Table 1-1: RFP Milestone Dates

Milestone	Date
Issue RFP	Wednesday, June 12, 2019
Notice of Intent w/ Pre-Qualification Documents	Thursday, June 27, 2019
Notification of Pre-Qualification	Wednesday, July 3, 2019
Proposals Due	Wednesday, July 31, 2019

2.0 INFORMATION AND SCHEDULE

2.1 Information Provided to Potential Respondents

This RFP and all of its Appendices are available on the RFP website (http://VectrenRFP.rfpmanager.biz/). Interested parties are expected to be able to download this RFP with its required forms and complete the forms in Microsoft Word, Microsoft Excel[1], and/or PDF format. Respondents should submit properly completed forms by the specified due date to the RFP e-mail address (VectrenRFP@burnsmcd.com). Burns & McDonnell will accept only Proposals that are complete. Proposals that are nonconforming, not complete, or that are mailed, or hand delivered may be deemed ineligible and may not be considered for further evaluation. By submitting a Proposal in response to this RFP, the Respondent certifies that it has not divulged, discussed, or compared any commercial terms of its Proposal with any other party (including any other Respondent and/or prospective Respondent), and has not colluded whatsoever with any other party.

2.2 Information on the RFP Website

The information on the RFP website (http://VectrenRFP.rfpmanager.biz/) contains the following:

- This RFP and associated appendices
- Template Information Form Addendum (as described in Section 8.1)
- Form of Notice of Intent
- Form of RFP Non-Disclosure Agreement
- Form of Pre-Qualification Application including Creditworthiness information
- Frequently asked questions and answers about this RFP
- Updates on this RFP process and other relevant information

2.3 Questions

An e-mail address (VectrenRFP@burnsmcd.com) has been set up to collect all communications and questions from potential Respondents as well as a website (http://VectrenRFP.rfpmanager.biz/) to download the RFP and provide uniform communications, relevant questions and answers, including updates and other details as may be provided throughout the bidding process. Phone calls and verbal conversations with Respondents regarding this RFP are not permitted before the Proposal Submittal Due Date. All Respondents will directly interface with Burns & McDonnell through the RFP e-mail address for all communications regarding this resource request. Proposals will be opened in private by Burns &

[1] Microsoft Excel format is required for the submission of Appendix D.

McDonnell on a confidential basis, but written questions will not be considered confidential. Individual questions submitted by e-mail to Burns & McDonnell before the submittal due date will be answered and responses sent back via e-mail to the Respondent as soon as practical. Responses to any questions may be placed on the RFP website for the benefit of all Respondents, with any identifying information redacted from the question.

Proposals will be reviewed by Burns & McDonnell for completeness and offers that do not include the information requirements of this RFP may be notified by Burns & McDonnell and allowed five business days to conform. After Proposals are submitted, Burns & McDonnell will review, and both quantitatively and qualitatively evaluate all conforming Proposals. During the evaluation process Respondents may be contacted for additional data or clarifications by Burns & McDonnell. Any Respondents contacted for further clarifications may or may not be invited to begin further negotiations of terms and details of the offers.

2.4 Schedule

Vectren has retained Burns & McDonnell to act as an independent third-party consultant to assist with this RFP. All Respondents will directly interface with Burns & McDonnell for all communications including questions, RFP clarification issues, and RFP bid submittal. All correspondence concerning this RFP should be sent via e-mail to VectrenRFP@burnsmcd.com.

The schedule below represents Vectren's expected timeline for conducting this resource solicitation. Vectren reserves the right to modify this schedule as circumstances warrant and/or as Vectren deems appropriate.

Table 2-1: RFP Schedule

Step	Date[2]
RFP Issued	Wednesday, June 12, 2019
Notice of Intent, RFP NDA, and Respondent Pre-Qualification Application Due	5:00 p.m. CDT, Thursday, June 27, 2019
Respondents Notified of Results of Pre-Qualification Application Review	5:00 p.m. CDT, Wednesday, July 3, 2019
Proposal Submittal Due Date	5:00 p.m. CDT, Wednesday, July 31, 2019
Initial Proposal Review and Evaluation Period	Wednesday, July 31, 2019 – Wednesday, September 18, 2019
Proposal Evaluation Completion Target and Input to Vectren	2nd Quarter, 2020
Due Diligence and Negotiations Period	Mid 2020
Definitive agreement(s) Executed (subject to regulatory approvals) with Selected Respondent(s)	Late 2020
Petitions (if required) filed with the IURC, the Federal Energy Regulatory Commission (FERC), or any other required agency/commission	TBD

[2] Negotiation schedule for smaller projects can be expedited at Vectren's discretion

3.0 RFP GENERAL REQUIREMENTS

Proposals must meet the general minimum eligibility requirements described below. Burns & McDonnell will screen all Proposals for compliance with these requirements. Proposals that fail to meet one or more of the general minimum eligibility requirements may be disqualified from further consideration as part of this RFP process. Respondents should refer to the Proposal Checklist in Appendix E for high-level guidance on Proposal requirements.

For a Proposal to be eligible under this RFP, it must offer MISO accredited or accreditable capacity (including Zonal Resource Credits) of no less than 10 MW to MISO LRZ 6[3].

Vectren has a preference for Proposals that provide Vectren with operational control of the asset, regardless of ownership position. Where applicable, proposed generation facilities should have no major operational limitations that reduce the ability to run for extended periods.

3.1 Respondent Pre-Qualification

Respondents to this RFP are required to fill out and sign Appendix A: Notice of Intent to Respond, Appendix B: Non-Disclosure Agreement (NDA), and Appendix C: Pre-Qualification Application in its present form.

3.2 Multiple Proposals

In the event that multiple Proposals are submitted by the same Respondent, the Respondent must indicate whether the Proposals are to be evaluated independently of one another or if Proposals are to be considered together.

Respondents may submit up to three Proposals at no cost in response to this RFP. Respondents submitting more than three responses will incur a Proposal Evaluation Fee for each additional Proposal submitted. The non-refundable fee for evaluating each additional Proposal is $5,000. This sum will serve to defray evaluation costs. Respondents can find instructions for paying fees for their Proposal(s) on the RFP website (http://VectrenRFP.rfpmanager.biz/). Vectren and Burns & McDonnell will have sole discretion to determine whether a submission is deemed a single Proposal or multiple Proposals.

[3] Load Modifying Resource suppliers must be located entirely within MISO LRZ 6.

3.3 Non-Disclosure Agreement

This RFP contains an RFP NDA (Appendix B). Respondents shall submit a signed version to the RFP e-mail address (VectrenRFP@burnsmcd.com) by 5:00 p.m. CDT on June 27, 2019. Respondents may download the form from the RFP website (http://VectrenRFP.rfpmanager.biz/).

3.4 Valid Proposal Duration

Proposals must include pricing that is firm and not subject to any revisions during the initial evaluation process. Vectren will receive all associated allowances or credits, if any. Seller agrees to transfer any Financial Transmission Rights or Auction Revenue Rights associated with the asset to the Buyer. Escalation rates shall be fixed or set annually to the Gross Domestic Product Implicit Price Deflator (GDPIPD). The GDPIPD will be reset annually as published by the U.S. Department of Commerce, Bureau of Economic Analysis. Formulaic mechanisms will not be subject to revisions during the evaluation and negotiation process.

All pricing should be provided in Appendix D in terms of US dollars as of the date the term of the contract begins and not subject to a currency exchange rate adjustment. Respondents are strongly encouraged to provide their best pricing with their initial submittal. Vectren is not obligated to provide an opportunity in the evaluation schedule for Respondents to refresh or update their pricing before the final selection(s) are made (if any). Respondents Proposal pricing shall remain valid for 1-year from the Proposal Submittal Due Date.

3.5 Acknowledgement of RFP Terms and Conditions

The submission of a Proposal shall constitute Respondent’s acknowledgment and acceptance of all the terms, conditions, and requirements of this RFP.

3.6 RFP Response Summary Information

All Proposals must include a table of contents and provide concise and complete information on the topics described below, organized as follows:

3.6.1 Executive Summary

Please provide a one-page executive summary of the Proposal in the form of a cover letter. Include the facility’s location, age or development status and if applicable, MISO generator interconnection project number, size, the primary contact’s name, e-mail, and phone number, and an overview of the major features of the Proposal. The Executive Summary must be signed by an officer of the Respondent who is duly authorized to commit the firm to carry out the proposed transaction should Vectren accept the

Proposal (this does not have to be the primary contact). A Table of Contents should be the first page and immediately precede the Executive Summary.

3.6.2 General Information

3.6.2.1 Respondent's Information and Experience

Please include information on the Respondent's corporate structure (including identification of any parent companies), the project's financing plan, the Respondent's most recent credit rating, quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of Respondent attesting to its accuracy, a copy of Respondent's annual report for the prior three years containing audited consolidated financial statements and a summary of Respondent's relevant experience. Please describe any current litigation or environmental fines involving the Respondent within the last five years, including but not limited to, any litigation, settlements of litigation or fines, that could potentially affect the facility or its operation. Please identify all bankruptcy or insolvency proceedings relating to the Respondent in any way. Please describe any litigation related to PPAs or asset purchases similar to the transactions solicited in this RFP that the Respondent or its parent company have been a party to in the last six years. All financial statements, annual reports and other large documents may be referenced via a website address.

Proposals shall include a list of projects with a brief description of Respondent's experience in the areas of development, financing, permitting, ownership, construction, and operation of all utility-scale power generation facilities or LMRs/DRs.

Please provide a list of projects with a brief description of the Engineering, Procurement and Construction (EPC) contractor's experience as it relates to utility-scale power generation.

4.0 GENERATION FACILITY PROPOSALS

For generation facility Proposals, Vectren will only consider bids for facilities that have an estimated remaining useful life of five or more years from acquisition date. In all cases, Respondents shall describe the expected useful life of all facilities included in their Proposals.

4.1 Content Requirements for Generation Facility Proposals

This section describes Vectren's requirements for the content of any Proposal that is submitted in response to this RFP as an offer to sell a generation facility to Vectren. Proposals that do not include all of the required information may be deemed ineligible and may not be considered for further evaluation. If it appears that certain information has inadvertently been omitted from a Proposal, Burns & McDonnell may, but is not obligated, to contact the Respondent to obtain the missing information, per Section 2.3. If, during the RFP process, there is a material change to the generation facility or the circumstances of the Respondent that could affect the outcome of the RFP evaluation, the Respondent is obligated to inform Burns & McDonnell within five business days. In addition, any winning Respondent must provide such additional information and data as may be requested by Vectren to support regulatory approvals of the generation facility purchase transaction.

Vectren has a preference for projects located near its load. Non-conforming bids by Respondents to sell a generation facility or facilities not meeting the location requirements may be disqualified from consideration on that basis alone.

Vectren will accept Proposals for new or planned generation facilities that will be complete and operational in advance of the expected acquisition date. A project will be defined as complete and commercially operable if, and only if, it includes all facilities necessary to generate and deliver energy into MISO to at least one single point of interconnection within MISO. More detail on the development milestone requirements for planned facilities are included in Section 4.1.7.

If a facility does not have black start capability installed but could be made black start capable, Proposals should indicate the estimated costs to construct and operate and include the estimated construction timeline.

4.1.1 Capacity Characteristics

Respondents shall state the nameplate capacity, net summer operating capacity, net winter operating capacity and the awarded unforced capacity (UCAP) of the generation facility for the last five MISO planning years (existing facilities).

Respondents also should provide the expected UCAP for the first five MISO planning years beginning June 1, 2023 based on current MISO rules for the applicable generating technology.

4.1.1.1 Acquisition Date

In preparing their Proposals, Respondents shall assume the acquisition of the facility shall be closed and transfer of title shall occur on or before the start of the 2023/24 Planning Resource Auction window, subject to regulatory approvals. If Respondent is able to offer more competitive pricing and terms for title transferring prior to or after June 1, 2023, Respondent should detail the drivers and the optimal date for title transfer.

4.1.1.2 Capacity Availability and Deliverability

For Proposals to sell an existing generation facility to Vectren, the existing generating facility must be commercially operable, including all facilities and requirements necessary to deliver capacity (Zonal Resource Credits) to MISO LRZ 6. Respondents must identify the specific point(s) of interconnection including the type(s) of transmission service (e.g. NRIS or Energy Resource Interconnection Service (ERIS)). Proposals for facilities without existing firm deliverability to MISO LRZ 6 should include cost estimates and transmission studies associated with securing such deliverability.

The Proposal should also include nodal economic analyses (2023, 2028, and 2033) showing expected unit economic metrics (including congestion impacts on: capacity factor, produced energy, and generation revenue) for the project at the proposed delivery point(s).

Vectren reserves the right to reject any Proposal that does not include the full cost of any known or potential interconnection costs or network upgrades that may be required to provide firm deliverability to MISO LRZ 6 and/or that does not include interconnection, reliability, and/or economic analyses supporting interconnection and transmission requirements. Such materials should include a technical description and estimated costs of network upgrades from studies completed or underway.

4.1.2 Technical and Economic Detail

4.1.2.1 Generation Technology

Respondents shall describe the generation technology of the facility, including the make, model, and name of the supplier of all major equipment.

All Proposals to sell a generation facility to Vectren must utilize an existing, proven technology, with demonstrated reliable generation performance that is capable of sustained, predictable operation.

4.1.2.2 Dispatch and Emissions Characteristics

Respondents shall provide the dispatch and emissions characteristics of the generation facility in Appendix D, including, but not limited to:

- Minimum load level
- Maximum load level
- Ramp rates (up and down)
- Number of gas turbines that can be started simultaneously (if applicable)
- Heat rate curve for typical operations, including the minimum load and full load heat rates
    - If applicable, Respondent shall also provide heat rate curves for summer and winter seasons
- Fuel consumption and heat rate during startup, including startup time and the total number of hours annually the facility can be assumed to be in startup mode
- Fuel consumption and heat rate when the facility is being shut down, including how long shutdown takes and the total number of hours annually the facility can be assumed to be in shutdown mode
- An estimation of the total number of hours annually that the facility operates at full load
- Capability decreases as a result of ambient temperature increases
- Supplemental firing capability, including black start capability, and any operating limitations caused by such factors of design
- Pounds/megawatt hour (lb/MWh) emissions rates at relevant dispatch levels (startup, minimum, mid and full loading) and seasons (summer, winter, shoulder) for nitrogen oxides (NO_X), sulfur dioxide (SO_2), carbon dioxide (CO_2), volatile organize compounds (VOC), particulate matter (PM) and carbon monoxide (CO)
- Any other operational limitations that reduce unit availability or reduce a unit's ability to dispatch or regulate

For renewable resources Respondents shall provide expected capacity factors, including 8760 hourly profiles (actual or based on weather data) and the expected useful life of the asset. If applicable, Respondents shall also provide expected annual degradation rates.

Regarding any major current and/or historical operational limitations, Respondents shall provide a description of the root causes of the limitations (e.g. original equipment manufacturer (OEM) design, material condition of the facility, environmental permits, etc.). To the extent that expected performance deviates from observed performance, the Respondent shall provide the basis for the assumption.

4.1.2.3 Revenues and Operating Costs

For existing generation facilities, Respondents shall provide a detailed breakout of the facility's actual annual revenues for each of the past five years. This will include energy, capacity, and ancillary service market revenues, as well as any other revenues the facility earned, including any congestion revenue (positive or negative), as well as uplift revenues. Associated with these revenues, Respondents shall state the estimated annual output in MWh as well as the operation and maintenance costs of the facility on a fixed ($) and variable ($/MWh) basis and provide the actual annual operation and maintenance costs of the facility for each of the past five years in nominal dollars.

Respondents shall provide a detailed breakout of the generation facility's estimated and actual annual fixed costs for the following categories: labor, benefits, materials, and all others for the past five years. Respondents shall provide a breakdown of the number of people employed at the facility, including permanent and contracted employees, and whether those employees are organized under any labor agreement.

If fixed or variable costs for the generation facility are expected to change in the foreseeable future (e.g., following planned upgrades, etc.), the Respondent should provide both the new expected cost(s) and the year(s) in which the costs are expected to change.

Respondents shall also state and describe any property, state, and local taxes and tax abatements associated with the generation facility, including all state and local taxes including property taxes.

New generation facilities also must provide reasonable expectations for all of the above details associated with plant revenues and costs, including market revenues, fixed and variable operations costs, expected upgrades and service timing, and taxes.

4.1.3 Operating Considerations

4.1.3.1 Operating Data

For an existing generation facility, Respondents shall provide historical operating data consisting of:

- The commercial operation date (COD) of the facility
- The annual run-time hours (per unit, if applicable)
- The annual operating cycles per year (per unit, if applicable)
- The annual facility capacity and availability factors
- The equivalent forced outage rate demand (EFORd)

The above annual data may be limited to the most recent five years. The EFORd should correspond to the UCAP amounts awarded for the last five Planning Years. Respondents shall provide a breakdown of EFORd by failure mode or North American Electric Reliability Corporation/Generating Availability Data System category. Respondents shall provide a description of the major contributors to the generation facility EFORd. If there are particular costs associated with maintaining the EFORd of a generation facility, those must be provided. Generating facilities considered a Dispatchable Intermittent Resource (DIR) in MISO shall provide historical curtailments over the most recent years. New facilities shall put forth a best effort forecast of curtailments by MISO.

Respondents shall provide details on any current generation facility equipment issues and concerns, including the potential drivers and recommended mitigation procedures for the issues and/or concerns. These may include, but are not limited to, any operation of the turbine, generator, or boiler outside recommended parameters established by OEM, compromised turbine or compressor blades, etc. Respondents shall provide a list of any redundant equipment that is currently bypassed or out of service, and the related reason. Respondents shall also provide historical information on such issues and concerns that have arisen, how they were resolved, and the associated costs for the last ten years of operation, or for the commercial life of the generation facility, whichever is lesser.

Respondents shall provide maintenance history for the lesser of the past ten years of operation or the commercial life of the generation facility consisting of: (i) dates of last full unit inspection and findings based on OEM recommendations; and (ii) outstanding OEM recommendations remaining to be implemented, including the cost and outage duration for any major maintenance requirements expected over the coming ten years. Respondents shall provide the outage reports for major planned and forced outages for each of the past five years.

For new or planned generation facilities, Proposals should include the manufacturer or developer quoted expected performance, as well as historical performance of similar facilities in MISO.

As noted in Section 4.1.5.3, below, Proposals shall disclose if the generation facility or any parts thereof are subject to a service agreement.

4.1.3.2 Operating Plan

Proposals should include a summary of the operating plan for the generation facility. Such plan should include software management system(s) and personnel roles and responsibilities for operating, maintaining, and servicing the facility, including any contractual arrangements currently in place.

Respondent shall provide an overview of key scheduled outage and maintenance plans, as well as plans for procuring and maintaining key spare parts.

For new or planned generation facilities, this should include a summary of the intended operating plan for the facility. The plan should include software management system(s) planned or in use (e.g., SAP, etc.), any third-party roles and responsibilities for operating, maintaining, and servicing the facility, including any contractual arrangements to be executed. Respondent shall provide an overview of key scheduled outage and maintenance plans, as well as plans for procuring and maintaining key spare parts.

4.1.3.3 Fuel Supply

Respondents shall provide a description, including detailed cost information, contract duration, and material contract terms (including whether fuel contracts are take or pay, minimum volume requirements, price reopeners, assignability or termination provisions) of all fuel purchase, storage, and transport agreements related to the generation facility Proposal. Cost of fuel commodities shall be provided separately from the cost of fuel transportation. Respondents also must list any provisions or other considerations that would prohibit or impair the assignment and/or affect the performance obligations of either party under the respective contract(s). Respondents shall describe fuel purchase and transport to the generation facility, as well as any existing or known potential operational restrictions or impediments on such fuel purchase and transportation. Respondents also are required to provide a description of the existing fuel supply (and storage) infrastructure serving the generation facility, including the infrastructure for the delivery of secondary fuel for dual-fuel resources. However, Vectren, through this RFP, is exploring the potential purchase of generation facilities, and it is Vectren's sole discretion whether to assume any contract or contracts associated with the proposed generation facility related to fuel commodities and/or fuel transportation.

Proposals shall describe, to the extent possible, fuel sourcing strategy, including from where their fuel is sourced.

Proposals shall describe the generation facility's ability to access a reliable fuel supply that would support operation for any hour throughout the year, including the plant's on-site fuel storage and dual-fuel capabilities, if applicable. Proposals for gas generators shall indicate whether the facility is dual-fuel capable and Proposals should include an indication of the days of on-site fuel storage available. Gas generators without dual fuel capability shall provide information on the costs required to make the facility dual fuel capable to the extent that such cost estimates are available. Natural gas fired facilities shall have firm gas transportation contracts in place for the amount of gas capacity necessary to fulfill the amount of UCAP being bid. Proposals that do not include firm gas supply may be disqualified.

4.1.4 Environmental Considerations

4.1.4.1 Emissions and Waste Disposal Compliance

New and existing resources must be in compliance with all applicable environmental rules and regulations. To the extent applicable, all environmental attributes, including emission reduction credits and/or allowances, related to the power being purchased should be conveyed to Vectren. This includes, but is not limited to, any and all credits in any form (emissions credits, offsets, financial credits, etc.) or baseline emissions associated with both known and unknown pollutants, including but not limited to SO_2, NO_X, Mercury (Hg), and CO_2. Any and all environmental liabilities, including compliance with known and future or unknown regulations or laws will be the sole responsibility of the generation producer or PPA seller.

For Asset Purchase Proposals, the Seller will retain all pre-closing environmental liabilities and obligations as well as all known future environmental liabilities and obligations, in each case associated with the real and personal property transferred with or as part of a Sale of the Plant. This includes both on and off-site liabilities. The Buyer will assume all other post-closing environmental liabilities and obligations. For purposes of facility design, Seller should assume that the unit will be required to meet the proposed New Source Performance Standards for Greenhouse Gases (40 Code of Federal Regulations (CFR) part 60, subpart TTTT).

4.1.4.2 Water Supply

Respondents shall provide a detailed description of the water supply, including but not limited to, contract term, water usage, and cost of water for the generation facility. Respondents shall also provide the status of the facility's National Pollutant Discharge Elimination System (NPDES) permits, including, but not limited to, permit conditions, permit violations reported over the last five years, the timing of next permit renewal, and any other known concerns.

If applicable, Respondents shall provide a summary of the facility's water chemistry program, including key systems and suppliers, and its performance in the most recent year.

4.1.4.3 Permits

The generation facility must have all relevant environmental and other permits necessary for operation and maintenance. Facilities without such permits may be disqualified from consideration at Vectren's sole discretion. Respondents shall provide a description of all permits currently in place for the operation and maintenance of the facility (e.g., Spill Prevention Containment and Control plans, Title IV and Title V permits of the Clean Air Act, Cap and Trade Permits, NPDES permits, Water Withdrawal, and Pollution

Incident Prevention Plan, etc.). Respondents must also state whether there are any provisions that would prohibit the assignment of such permits and/or any consents required for the assignment of such permits.

Respondents shall describe any operating limitations imposed by permitting or environmental compliance that limit plant availability.

Respondents shall provide a description of any identified environmental liabilities (e.g., potential site remediation requirements, etc.) for the facility.

4.1.5 Financial Considerations

4.1.5.1 Capital Expenditures

Respondents shall provide historical actual and budgeted capital expenditures for the generation facility. Historical capital expenditures shall be provided for each of the past five years in nominal dollars. Planned and budgeted capital expenditures shall be provided for each of next five years in nominal dollars along with a description of the projects involved. Respondents also shall disclose any known capital expenditure needs outside of the five-year time horizon that are expected to exceed $1 million dollars.

Respondents shall supply a summary list of all spare parts and components currently owned by the facility and their approximate dollar value. Respondents shall also identify any spare parts or components that are currently needed and/or on order as of the date the Proposal is submitted.

4.1.5.2 Acquisition Price

Respondents shall submit an acquisition price consisting of a single fixed payment that is inclusive of all monetary consideration for the generation facility, working inventory, and, if applicable, ancillary facilities and contractual arrangements (e.g., for fuel supply and transportation, maintenance, pollution control bonds, etc.). Respondents must submit their best and final price with their Proposal. Respondents must provide details regarding any liabilities that Vectren might assume as a buyer of a generation facility.

For new or planned generation facilities, the price offered in the Proposal shall include all costs associated with providing a completed generating asset whose full output will be accredited to the MISO LRZ 6. This includes, in particular, but without limitation, costs associated with transmission interconnection, including engineering studies, siting, permitting, acquisition and construction.[4]

[4] If, during the evaluation, Burns & McDonnell or Vectren determines that the Proposal will be unable to achieve firm delivery to MISO LRZ 6, the Proposal will be rejected.

4.1.5.3 Other Contractual Commitments

Respondents shall provide a description, including detailed cost information, of any other contracts that are currently necessary for generation facility operations, including, but not limited to, long-term service agreements, state union labor contracts and/or technical support contracts, agreements related to capacity and/or energy sales from the facility and any capacity offers submitted to any independent system operator/regional transmission organization related to the generation facility that, if accepted, would be binding on Vectren as a result of an acquisition. Respondents must also state whether there are any provisions that would prohibit the assignment and/or affect the performance obligations of either party under the respective contract, including transfer or cancellation fees.

4.1.6 Legal Considerations

4.1.6.1 Legal Proceedings, Liabilities & Risks

The Proposal shall include a summary of all material actions, suits, claims or proceedings (threatened or pending) against Respondent, its Guarantor (if applicable) or involving the generation facility or the site as of the Proposal due date, including existing liabilities whether or not publicly disclosed, including but not limited to those related to employment and labor laws, environmental laws, or contractual disputes for the development, construction, maintenance, fueling, or operation of the facility.

4.1.6.2 Material Contingencies

Proposals that have material contingencies, such as for financing, may not be considered.

4.1.7 Additional Items Specific to New Facilities

All Proposals for new generation facilities must have a well-defined and credible development plan for Respondent to complete the development, construction, and commissioning of the facility on their proposed development timeline. Respondents submitting Proposals for new or planned facilities should review the Development Risk evaluation metric and be sure to discuss key development milestones in their Proposal.

If available, Respondents shall submit:

1. A copy of an executed MISO Generator Interconnection Agreement
2. A copy of a completed MISO Facilities Study
3. A copy of a completed MISO System Impact Study

4. Nodal economic analyses (2023, 2028, and 2033) showing expected unit economic metrics (including congestion impacts on: capacity factor, produced energy, and generation revenue) for the project at the proposed delivery point(s)

If Respondent cannot provide this information, Respondent must indicate why it cannot be provided and must provide a timeline showing ability to complete key development milestone requirements prior to or after June 1, 2023 including the above referenced items for the MISO generator interconnection queue.

Respondent shall also detail its MISO generator interconnection queue position, if any, and the types and amounts of transmission service requested (e.g. NRIS or ERIS). Respondents submitting Proposals for a new or planned generation facility should also submit a copy of a fully executed EPC contract if available.

Respondents should also provide the following:

- Roles and responsibilities of the companies involved in the design, development, procurement, and construction of the facility. Information about key contributors shall extend to the status of contractual relationship with each key contributor; key contractual assurances, guarantees, warranties or commitments supporting the Proposal, including an executed EPC contract, and any past experience of Respondent working with each key contributor.
- Description of status of major equipment procurement, as well as processes for engineering, procurement, and construction bids and awards.
- Description of the facility site and Respondent's rights (i.e., whether owned, leased, under option) to such site. Please indicate whether additional land rights are necessary for the development, construction, and/or operation of the facility.
- Discussion of the development schedule and associated risks and risk mitigation plans for that schedule, including whether there are contract commitments from contractors supporting the proposed schedule. The Respondent should be prepared to document and commit to a proposed development schedule, which should include a COD.
- Discussion of the financing arrangements secured by the Respondent, including an overview of the sources of funds, and level of commitment from debt, equity, or other investors.
- Discussion on permitting, including a list of all required permits, permitting status of each, and key risks to securing necessary future permit approvals.
- Description of status in MISO queue process and presentation of documents described above.

- Financial information regarding guarantors and sources of equity funding along with either the Respondent's or guarantors' senior unsecured debt and/or corporate issuer ratings documentation from Moody's and Standard & Poor's showing the name of the rating agency, the type of rating, and the rating of the Respondent or guarantor.

Vectren will not assume any responsibility for the successful development, construction, and/or completion of a proposed facility. Accordingly, development schedule, budget, permits and approval risk will be the sole responsibility of the Respondent.

5.0 POWER PURCHASE AGREEMENT PROPOSALS

Vectren will consider meeting some or all of its resource requirements through short, medium and/or long-term PPAs. Vectren will only consider PPAs that have a term of five years or greater.

5.1 Name and Location

Respondents shall state the name of the generating facility, the county where the generating facility is located, the owner of the facility, and the commercial pricing node associated with the facility, if applicable. The facility must qualify as MISO internal generation (i.e. not pseudo-tied into MISO) and be qualified to receive Zonal Resource Credits for Zone 6 consistent with MISO's Module E Planning Resource Auction. Should the facility not be qualified in Zone 6, Respondents shall detail in their Proposals the means by which Zonal Resource Credits will be delivered/fulfilled in Zone 6.

5.2 Net Capability of Generating Facility

Respondents proposing a PPA for existing assets shall state the nameplate capacity, net summer operating capacity, net winter operating capacity and the UCAP of the facility for the 2019/2020 MISO planning year. Respondents shall specifically identify any known derates affecting the facility.

Respondents proposing existing assets shall also list the UCAP awarded to the facility, for the MISO Planning Years, 2015, 2016, 2017, 2018, and 2019. Respondents shall provide the projected UCAP for the facility. In the event that the projected UCAP has sizable deviation from historical UCAP, Respondents shall provide a detailed explanation. Respondents proposing facilities in development shall provide the anticipated UCAP after the asset acquisition date.

5.3 Generation Technology

Respondents shall describe the generation technology of the facility, including the make of the equipment, model, and name of supplier.

5.4 Dispatch and Emissions Characteristics

Respondents shall state/describe the dispatch characteristics of the facility, including, but not limited to, minimum load level, ramp rates (up and down), number of turbines that can be started simultaneously (if applicable), fuel consumption during startup, capability decreases as a result of ambient temperature increases, supplemental firing capability and any operating limitations caused by such factors as design, material condition of the facility, and various permit restrictions. Respondents shall state/describe the emissions profile of the facility, including but not limited to, the lbs/MMBtu at various dispatch profiles as applicable (startup, minimum load, mid, and max output) by season (summer, winter) for applicable emissions: NO_X, SO_2, CO_2, VOC, PM and CO.

Regarding any major operational limitations, Respondents shall provide a description of the root causes of the limitations (e.g., OEM design, material condition of the facility, environmental permits, etc.) Generating facilities considered a DIR in MISO shall provide historical curtailments over the most recent five years. New facilities shall put forth a best effort forecast of curtailments by MISO. Respondents shall also specify how DIR will be addressed (i.e. agreed to MISO offer price, bank of curtailment energy, etc.) within submitted Proposals. Generally, Proposals shall also take into consideration Vectren acting as the MISO Market Participant (responsible for market offers). However, Vectren is willing to consider Proposals where Vectren is not acting as the MISO Market Participant to the extent it is beneficial to Vectren's customers.

5.5 Fuel Supply

Respondents must supply a detailed fuel supply plan that fully details how fuel is purchased and transported to the facility as well as any existing or known potential operational restrictions or impediments on such fuel supply. This applies to all fuel types used to operate a facility, including natural gas, coal, fuel oil, biomass, etc. The Respondent is also required to provide a description, including detailed cost information, of all fuel service and purchase agreements applicable to the facility.

Respondents proposing a PPA shall be solely responsible for maintaining a reliable fuel supply that is delivered to the Respondent's proposed generating unit(s) to ensure reliable delivery of firm capacity and energy to Vectren throughout the Delivery Term. Facilities operating on natural gas must have firm natural gas supply agreement(s) capable of meeting 100% of the facility's maximum daily consumption requirements throughout the Delivery Term. The supply agreement(s) should provide all services required to cause natural gas to be delivered to the facility on a firm basis, which may include both timely and intraday supply, transportation, storage, and/or balancing.

5.6 Financial Considerations

5.6.1 Power Purchase Agreement

Respondents shall submit an annual power purchase price ($ and/or $/MWh as applicable) consisting of a payment that is inclusive of all monetary consideration for the generation facility, working inventory, and, if applicable, ancillary facilities and contractual arrangements (e.g., for fuel supply and transportation, maintenance, pollution control bonds, etc.). Respondents must submit their best and final price with their Proposal. Respondents must provide details regarding any liabilities that Vectren might assume.

For new or planned generation facilities, the price offered in the Proposal shall include all costs associated with providing a completed generating asset whose full output will be accredited to the MISO LRZ 6. This includes, in particular, but without limitation, costs associated with transmission interconnection, including engineering studies, siting, permitting, acquisition and construction.[5]

5.6.2 Asset(s) Specific Financial Information

Respondents shall submit audited or unaudited Financial Statements including Balance Sheets, Income Statements and Cash Flow Statements for the proposed asset(s) for the past three years. Respondents shall clearly indicate book value of the asset(s) in the financial information submitted.

5.6.3 Other Contractual Commitments

Respondents shall state whether there are other contractual commitments limiting or affecting the operation of the facility. Respondents shall state whether there are any other agreements in place for or claims on output from the facility. Such information should include any obligations that may restrict or compromise Vectren's ability to dispatch the facility.

5.6.4 Assets in Development

For PPA supported by proposed assets or assets that have not yet achieved their COD, Respondents must provide the same information requested in Section 4.1.7 for facilities to be developed.

[5] If, during the evaluation, Burns & McDonnell or Vectren determines that the Proposal will be unable to achieve firm delivery to MISO LRZ 6, the Proposal will be rejected.

6.0 LOAD MODIFYING RESOURCES/DEMAND RESOURCES

LMRs/DRs are demand-side resources and behind the meter generation not typically modeled or measured as part of MISO's operations but used during capacity shortages to help meet the energy balance. Vectren will consider LMRs/DRs from one or more MISO customers or curtailment service providers (CSP). LMR suppliers must be located entirely within MISO LRZ 6. Proposals for LMRs/DRs are to be for assets that are eligible to participate in MISO LRZ 6 and can meet the additional performance requirements of Vectren as described in Sections 6.1 and 6.3. In addition, for LMRs/DRs located within Indiana, Respondent must identify how the Proposal conforms with any requirements of the local utility and state law in order to offer resources for capacity accreditation within the MISO market under Module E Capacity Tracking.

Proposals for LMRs/DRs may be combined with another power supply Proposal or may be submitted on a standalone basis. Vectren will consider LMR/DR Proposals that have a term of one year or longer, consistent with MISO planning years.

6.1 Product Definition

To be eligible for participation in this RFP, the LMR/DR offered by a supplier must:

- Meet LMR/DR Requirements for participation in MISO as a demand-side resource, including any future changes to MISO's requirements for LMRs/DRs for the term of the Proposal
- Meet the additional performance requirements described in Section 6.3
- For capacity accreditation, the Proposal must be sourced from locations entirely within the MISO LRZ 6
- For energy accreditation, the Proposal must be sourced from locations entirely within Vectren's electric service territory
- Be at least 10 MW
- Use an existing, proven technology that has demonstrated reliable demand reduction, which may include use of Behind the Meter Generation (as defined by MISO)
- Reduce load by a predetermined amount when notified by Vectren of a Curtailment Event without further direction or communication by or from Vectren.

6.2 Purchase Agreement

If selected, the LMR/DRs supplier and Vectren will negotiate a mutually acceptable agreement to govern any commercial relationship established by the parties. With respect to a Proposal from a CSP, Vectren will not be responsible for making payments to, communicating with, or managing the relationship or performance of any customer within an aggregation, and the CSP shall be solely responsible for the same in all respects. To mitigate risk, Vectren will require the LMR/DR supplier to provide collateral upon execution of a LMR/DR Proposal. Vectren reserves the right to determine the form of that collateral requirement for a winning Proposal.

6.3 Curtailment Events: Notification and Performance Requirements

LMRs/DRs must meet notification and performance requirements applicable to a Curtailment Event, as defined and described herein and comply with MISO current and future testing requirements. For purposes of this RFP, a Curtailment Event shall be one in which either Vectren or MISO determines, in its respective sole discretion. MISO may also initiate a Curtailment Event upon its sole determination that a pre-emergency situation exists.

6.3.1 Notification, Performance, and Test Requirements

Curtailment Events initiated by MISO: For Curtailment Events initiated by MISO, LMR/DR suppliers shall agree to and be capable of meeting, throughout the entire term of the Proposal, all notification and performance requirements applicable to Capacity Performance demand resources. The supplier shall comply with all MISO Module E Capacity Tracking measurement and verification requirements.

Curtailment Events initiated by Vectren: Suppliers shall also agree to and be capable of meeting the following additional notification and performance requirements applicable to Curtailment Events initiated solely by Vectren:

- Suppliers shall curtail Actual Measured Load to Firm Contract Load within the proposed notification time specified in the Proposal
- Notification of a Curtailment Event initiated solely by Vectren will consist of an electronic message issued by Vectren to a device or devices such as telephone, facsimile, or e-mail, selected and provided by the supplier and approved by Vectren. Two-way information capability shall be incorporated by Vectren and the supplier in order to provide confirmation of receipt of notification messages. Vectren will provide the supplier a notification of when Curtailment Events have ended. Operation, maintenance, and functionality of communication devices for receipt of notifications selected by the supplier shall be the sole responsibility of the supplier, and receipt of notifications set out in this paragraph shall be the sole responsibility of the supplier

- During the entire period of a Curtailment Event initiated by Vectren, the supplier's Actual Measured Load must remain at or below its Firm Contract Load. A supplier's Actual Measured Load shall be determined by integrating the megawatts used over every clock hour (hour-ending).

6.3.2 Remedies for Non-Performance

A supplier whose Actual Measured Load exceeds its Firm Contract Load will be subject to performance penalties which may include, but not be limited to, refunding to Vectren monthly payments under the agreement.

A supplier shall be responsible for, and shall indemnify Vectren for, any non-performance penalties, costs, charges, or other amounts assessed by MISO and incurred by Vectren as a result of non-performance attributable to the supplier's LMR/DR, including but not limited to any Capacity Resource Deficiency Charges, Non-Performance Charges, or similar charges or penalties under the MISO agreements. In no event shall the penalties listed above for non-performance during a Curtailment Event be less than the sum of any MISO non-performance penalties, costs, charges, or other amounts incurred by Vectren as a result of non-performance attributable to the supplier's LMR/DR and the Curtailment Event charge.

6.4 Proposal Requirements

6.4.1 Acquisition Price

Suppliers shall submit an acquisition price consisting of a single fixed amount denominated in units of dollars per megawatt-day ($/MW-day), which is to apply for the term of the Proposal. If a Proposal is accepted, the supplier will be compensated in an amount equal to the monthly Curtailable Load times the Acquisition Price. The Proposal shall include all monetary consideration for the LMR/DR offered. Suppliers must submit their best and final price with their Proposal.

Should Vectren execute an agreement with a Respondent, the contract price between Vectren and the Respondent will be the Acquisition Price submitted in its respective Proposal through this RFP process.

6.4.2 Product Description

A Proposal shall include a description of the individual LMR/DR customer(s) and expected load drop values (kW), equipment, and technology that will be deployed and make available any other information required by MISO to meet its registration process, and for CSPs, plans for recruiting, engaging, and maintaining Program Participants.

Proposals should discuss the experience, qualifications, and financial strength of the supplier and other key contributors including the specific number of months the supplier has been providing LMR/DR services in MISO. Responses should indicate whether the supplier has ever been assessed a performance penalty in association with the resource and if so, when any penalties were assessed. For CSPs, Proposals should describe well-defined roles and responsibilities of the supplier and its participants. The supplier should describe successful protocols, if any, they have employed in the MISO LRZ 6 or other MISO zones for dispatching their LMR/DR.

While the product definition requires a load reduction upon notification by Vectren or MISO of a Curtailment Event, there is a preference for resources that can provide a more rapid response and/or ramp up or down in response to specific control signals. Respondents are urged to detail the full, demonstrated capability of the proposed resource in accordance with the evaluation criteria included in Section 7.0.

For planned LMRs/DRs, the supplier must fully describe specific plans detailing what equipment or technology it will deploy and/or utilize to support its operations. For CSPs, Proposals must describe supplier's processes for aggregating participants, how the supplier intends to recruit and engage participants, and/or provide lists of participants. The Proposal also must describe curtailment systems and procedures, budgeting for and structure of dispute resolution, and plans for communicating with participants in connection with a curtailment period.

6.4.3 Technical Requirements

Vectren shall acquire all rights, titles, and interests in the LMR/DR including all the potential capacity and energy revenues. Suppliers must agree to cooperate with Vectren in providing information needed to meet all MISO LMR/DR information requirements.

The supplier will assume all responsibilities and liabilities associated with providing LMRs/DRs. Accordingly, Proposals offering LMRs/DRs must include acknowledgment and agreement that the supplier is responsible for the following non-exhaustive list of activities and obligations:

- Managing load reductions, including all notices, communications, controls, equipment, or other processes required
- If the supplier is a CSP, determining the number of participants, in its aggregation, the number of interruptible hours per customer, and the size of each participant's load reduction
- If the supplier is a CSP, paying any participants according to the CSP's agreement with those participants. Such agreements shall be independent of Vectren's agreement with the CSP and

must hold Vectren harmless for any direct or indirect obligations or liability associated with the program

- Paying penalties assessed due to the non-performance of the LMR/DR

The agreement shall reflect that it will be the supplier's responsibility to reimburse Vectren for any penalties, fees, or charges resulting from non-performance of its LMR/DR, including replacement capacity to maintain Vectren's planning reserve margin requirement, and the supplier's obligation to indemnify and hold Vectren harmless against any claim arising from such non-performance. In the case of a supplier who is a CSP, the agreement will additionally set forth CSP's responsibility to reimburse Vectren for any penalties, fees, or charges resulting from non-performance of any CSP participant, and CSP's obligation to indemnify and hold Vectren harmless against any claim arising from such CSP participants' non-performance.

6.5 Evaluation Methodology

Burns & McDonnell will identify for recommendation to Vectren the LMR/DR Proposal or portfolio of Proposals that contribute to Vectren's capacity needs consistent with the evaluation methodology outlined in Section 7.0. LMRs/DRs will be evaluated independently of supply-side resources and may include other scoring criteria.

6.6 Contract Execution

Vectren does not, by this RFP, obligate itself to purchase any LMR/DR, or to execute an agreement with any Respondent who submits an offer to sell a LMR/DR to Vectren. Vectren may, in its discretion, reject any or all Proposals to sell a LMR/DR to Vectren, as such are described in this RFP.

Selection of a Proposal as a finalist shall not be construed as a commitment by Vectren to execute an agreement. Execution of any agreement is contingent upon Vectren receiving all required regulatory approvals and completion of such due diligence as Vectren in its sole discretion determines is reasonable to confirm the qualifications and performance of a given LMR/DR. During the period between when Burns & McDonnell makes its recommendation(s) to Vectren, and the date of execution of the agreement, Vectren may conduct additional due diligence on the Proposal.

7.0 PROPOSAL EVALUATION AND CONTRACT NEGOTIATIONS

7.1 Initial Proposal Review

An initial review of the bids will be performed by Burns & McDonnell. Proposals will be reviewed for completeness. Proposals that do not meet the requirements of this RFP may be notified. Respondents may also be contacted for additional data or clarifications by Burns & McDonnell, these communications will be initiated via e-mail (VectrenRFP@burnsmcd.com). Each complete bid will be evaluated by quantitative and qualitative factors. The evaluation criteria outlined in this section are intended to relatively compare each Proposal to analogous submissions and will be the starting guidelines for the evaluation. If needed, the scoring may be adjusted to provide distinction between Proposals. This evaluation, in conjunction with the IRP, will be used to determine which resources are most capable of providing Vectren customers with a safe, reliable, and affordable power supply.

7.2 Evaluation Criteria - Generation Facility

Burns & McDonnell will quantitatively and qualitatively evaluate all conforming generation facility Proposals' ability to meet power supply needs. During this evaluation process, Burns & McDonnell may or may not choose to initiate more detailed clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations. A more detailed quantitative evaluation for select bidders will consider production cost models and nodal analysis.

Table 7-1: Generation Facility Scoring Criteria Summary[6]

	LCOE Evaluation	Energy Settlement Location	Interconnection/ Development Status & LCR	Project Risk Factors
Points	150	100	90	160
%	30%	20%	18%	32%

7.2.1 Levelized Cost of Energy - 150 Points

The initial evaluation will be primarily based on a comparison of each Proposal's Levelized Cost of Energy (LCOE). A LCOE allows for Proposals within asset classes, which have different sizes, pricing, operating characteristics, ownership structures, etc. to be evaluated and compared to each other on an equivalent economic basis. The LCOE analysis will incorporate all costs associated with an asset purchase or PPA over a 20-year/standardized amount of time. These costs will include the applicable

[6] Vectren reserves the right to add up to 100 points to Proposals located in Southern Indiana, as local resources provide multiple benefits: VAR support, economic development, less future congestion risk, etc.

purchase or PPA cost, fixed costs, and variable operating expenses across standard technology respective operating parameters. The levelized value of these costs over this time period are then divided by the energy produced by the respective Proposal.

Vectren specific assumptions used in this analysis will be in accordance with Vectren's 2019/2020 IRP assumptions, including but not limited to

- Discount rate
- Capital recovery factor
- Escalation
- Commodity forecasts

The LCOE evaluation is a screening level economic evaluation which will determine the cost of energy provided by each Proposal relative to similar technology types. Proposals within an evaluation class with the lowest LCOE will receive full scoring for this metric. Based on variance of costs and number of Proposals in each class, points awarded to higher cost Proposals will be scaled accordingly.

The rules for performing the LCOE analysis will be determined by Burns & McDonnell and Vectren in advance of the receipt and review of any Proposals. However, as part of the process of evaluating Proposals, cases may arise where, in order to adequately project asset costs or to facilitate a comparison between qualified Proposals, the rules related to the LCOE analysis may require review and/or adjustment. To the extent that any additions or adjustments are required, such additions or adjustments will be made solely by Burns & McDonnell. In such cases, any and all rules will be applied consistently across all Respondents.

While performing LCOE analyses of Proposals, Burns & McDonnell may request additional or clarifying information from a given Respondent regarding unit performance, operating costs, or other factors that influence the LCOE calculation for a given resource. This evaluation will also include grid congestion analysis. Requests for additional information may be required to ensure that all qualified Proposals are fairly and consistently evaluated. Consistent with Section 2.3, in such cases, Respondents will be required to respond within five business days of receipt of such request. Burns & McDonnell will not consider unsolicited updates from Respondents related to the cost of any power supply resource.

7.2.2 Energy Settlement Location - 100 points

Vectren has a preference for Proposals that include all costs to have energy financially settled or directly delivered to Vectren's load node (SIGE.SIGW). Proposals that meet one of these criteria will receive 100 points, while Proposals failing to meet either criteria will be awarded zero points. Market data from Proposals that include the aforementioned costs will be carried forward into the IRP modeling analysis as described in Section 7.5.

7.2.3 Interconnection and Development Status - 60 Points

Existing resources will receive full credit under this evaluation category. Plants that have not achieved commercial operation but that are in the MISO Generation Interconnection (GI) Queue will be awarded points based on the Definitive Planning Phase they are in. Other projects not in the MISO GI Queue must demonstrate development progress. Facilities failing to meet critical development milestones may be disqualified from consideration at Vectren's sole discretion.

Up to 60 points will be will awarded based on the achievement of certain development milestones towards the facility COD. Five milestones have been selected and 12 points will be awarded for each equally. The selected milestones are as follows:

- Executed a MISO Generator Interconnection Agreement
- Completed a MISO Facilities Study
- Completed a MISO System Impact Study
- Achieved site control and completed zoning requirements
- EPC Contract awarded

7.2.4 Local Clearing Requirement Risk - 30 Points

The MISO footprint is split into ten LRZs. All load serving entities within MISO are required to obtain capacity which meets their respective Planning Reserve Margin (PRM). A Local Reliability Requirement is also established for each LRZ which is the aggregate of all Load Serving Entity's (LSE's) PRMs. Due to Zonal capacity import/export limitations a portion of each LRZ's Local Reliability Requirement must be served locally, this requirement is the zone's Local Clearing Requirement (LCR). The LCR establishes the amount of Unforced Capacity which is required to be located in each respective LRZ.

Proposals located within LRZ 6 provide additional risk avoidance to Vectren's LCR requirements and will receive 30 points; Proposals located outside of LRZ 6 will receive zero points.

7.2.5 Project Risk Factors - 160 Points

Certain risk factors may be unique to a Proposal. Such factors may be significant enough to independently impact the overall ability of the Proposal to meet Vectren's needs.

This category is intended to capture unspecified risk that may be highlighted by a bidder or identified during the Proposal review. The Project Risk Factors Section attempts to identify and score potential risks which may compromise the future performance of the asset[7]. In situations where the level of risk is not accurately represented, scoring may be adjusted. Potential considerations include, but may not be limited to the following:

- Credit and financial plan - Proposals with a long term unsecured credit rating below BBB+ (Baa1 for Moody's) will not be considered in this evaluation. Proposals which have internal financing are preferred and will receive the 20 points for this category[8].
- Development experience - Relevant technology development experience is an important risk factor. Proposals will receive up to 20 points based on the following formula:

$$Points\ awarded = \frac{(nameplate\ MW\ in\ service)}{1{,}500} * 20$$

- Sole ownership vs. partial owner - Due to site and dispatch rights/preferences, a sole ownership Proposal will receive 20 points.
- Proposal ownership structure - Due to a preference for ownership Asset Purchase Proposals will receive 20 points while PPA Proposals will receive zero points.
- Operational control - Proposals which offer Vectren operational control will receive 20 points
- Fuel risk - For applicable Proposals, sites with firm and reliable fuel supply will receive 20 points.
- Delivery date - For each year prior or after 2023, 25% of the 20 possible points will be deducted.
- Site Control - Proposals which have fully achieved site control will receive 20 points

Any such risks shall be disclosed along with a description of the associated measures taken to mitigate the risk. Failure to disclose a reasonably foreseeable risk or risks may be a basis to disqualify a Proposal.

Proposals with no such risks as determined by Burns & McDonnell will receive the full number of points available in this category. Proposals with asset or project-specific risks that are not able to be fully mitigated may receive fewer points depending on Burns & McDonnell's assessment.

7.3 Evaluation Criteria - LMR/DR

Burns & McDonnell will quantitatively and qualitatively evaluate all conforming LMR/DR Proposals. During this evaluation process, Burns & McDonnell may or may not choose to initiate more detailed

[7] Vectren reserves the right to add up to 100 points to Proposals located in Southern Indiana, as local resources provide multiple benefits: VAR support, economic development, less future congestion risk, etc.
[8] Vectren reserves the right to re-evaluate credit rating and exclude bidders at its sole discretion.

clarification discussions with one or more Respondents. Discussions with a Respondent shall in no way be construed as commencing contract negotiations. A more detailed quantitative evaluation for select bidders will consider production cost models and nodal analysis.

Vectren will accept Proposals from LMRs/DRs that meet the requirements as established in this RFP and conforms to MISO requirements. These requirements include but are not limited to, the ability to respond to Curtailment Events initiated either by MISO or by Vectren.

LMR/DR proposals will be evaluated across the following criteria:

Table 7-2: LMR/DR Scoring Criteria Summary[9]

	Cost Evaluation	Historical Performance	Response Time	Proposal Risk Factors
Points	200	100	100	100
%	40%	20%	20%	20%

7.3.1 Cost Evaluation - 200 Points

The cost of each Proposal will be evaluated based on the annual payment per MW for the LMR/DR. The lowest $/MW cost Proposal will receive 200 points for the cost evaluation category. Based on variance of costs and number of Proposals, points awarded to higher cost Proposals will be scaled accordingly.

7.3.2 Historical Performance - 100 Points

An end use customer or CSP with a historical performance record of successfully providing demand response services for three or more years without being assessed a non-performance penalty will receive 100 points for this category.

An end use customer or CSP that has provided such services for between one year and three years without being assessed a non-performance penalty will receive 50 points for this category.

An end use customer or CSP that has not provided such services in the past or that has been assessed a non-performance penalty will receive zero points for this category.

[9] Due to benefits other than capacity accreditation, Vectren reserves the right to add up to 100 points to LMR/DR Proposals located within Vectren's electric service territory.

7.3.3 Response Time - 100 Points

While the product defines a load reduction response time within a Respondent's Proposal, there is a preference for resources that can provide a more rapid response to specific control signals.

Proposals for LMR/DR that have the ability to follow a real-time signal will be awarded 100 points for the response time category. Proposals for LMR/DR that can achieve the load reduction target within 30 minutes of notification will receive 75 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 60 minutes of notification will receive 50 points for this category. Proposals for LMR/DR that can achieve the load reduction target within 120 minutes of notification will receive 25 points for this category.

7.3.4 Proposal Risk Factors - 100 Points

This category is intended to capture unspecified risk that may be highlighted by a LMR/DR Proposal or identified during the Proposal review. The Proposal risk factors category will be used to adjust the overall scoring in cases where there is a material risk identified that may create concerns about the ability of the provider to deliver on their Proposal or that may create a material uncertainty about the cost to Vectren or its customers, significant regulatory uncertainty, or other considerations.

7.4 Discussion of Proposals During Evaluation Period

Based on the quantitative and qualitative evaluations and needs identified during the 2019/2020 IRP, Vectren may or may not select candidates for further discussions. Vectren will contact any selected Respondent in writing to confirm interest in commencing contract negotiations. All negotiations will begin with Vectren's standard contract as a starting point. Vectren's commencement of and participation in negotiations shall not be construed as a commitment to execute a contract. If a contract is negotiated, it will not be effective unless and until it is fully executed with the receipt of all required regulatory approvals.

7.5 Selection of Highest Scoring Proposal(s) based on IRP Analysis

Where possible, aggregated cost and performance information from the RFP bids, which provide a delivered price (pending verification), will be provided to the IRP team to facilitate certain portfolio modeling[10]. The IRP analysis will provide the RFP team with a preferred portfolio based on these costs. RFP bids will be rank ordered consistent with the evaluation criteria and assets will be selected consistent with the RFP evaluation and the IRP determined need. Consistent with that objective, Vectren may need

[10] Proposals that do not provide an energy settlement contract or physical deliverability to Vectren's load node (SIGE.SIGW) will not be included in the IRP analysis, but may be considered for procurement.

to contract with multiple generating assets. Cost certainty and project implementation are key considerations that will be included in qualitative analysis and that will include the ranking of projects with firm price offers and price caps, projects in the MISO GI queue or with signed Generator Interconnection Agreements (GIAs), recent prior development experience, etc. Vectren will seek to secure resources consistent with the preferred portfolio identified in the 2019/2020 IRP. As such, there is no assurance that the individual, highest-scoring qualified Proposal(s) will be selected.

7.6 Contract Execution

Vectren does not, by this RFP, obligate itself to purchase any generation facility or facilities, or to execute the Asset Purchase Agreement or PPA with any Respondent who submits an offer to sell generation capacity and/or energy to Vectren and Vectren may, in its discretion, reject any or all Proposals, as such are described in this RFP.

Selection of a winning Proposal shall not be construed as a commitment by Vectren to execute an agreement. During the period between Burns & McDonnell's delivery of results to Vectren and the date of execution of any agreement, Vectren will conduct additional due diligence on the Proposal which may include, but not be limited to, onsite visits, management interviews, legal and regulatory due diligence, and detailed engineering assessments and facility dispatch modeling.

8.0 PROPOSAL SUBMISSION

All Proposal documents must be submitted to the RFP Manager via e-mail to VectrenRFP@burnsmcd.com.

8.1 Format and Documentation

All Proposals submitted in response to this RFP must be received by Burns & McDonnell (VectrenRFP@burnsmcd.com) no later than the Proposal Submittal Due Date shown in Section 2.4. Burns & McDonnell and Vectren will not evaluate Proposals as part of this RFP process if submitted after this date and time. Multiple Proposals submitted by the same Respondent must be identified and submitted separately. Financial statements, annual reports, technical specification documents, and other large documents can be sent electronically to the RFP e-mail address. Each Proposal must contain the following:

1. Appendix B: Non-Disclosure Agreement (NDA) in its present form
2. Appendix D: Proposal Data in Excel format

8.2 Certification

A Respondent's Proposal must certify that:

1. There are no pending legal or civil actions that would impair the Respondent's ability to perform its obligations under the proposed PPA or Asset Purchase
2. The Respondent has not directly or indirectly induced or solicited any other Respondent to submit a false Proposal
3. The Respondent has not solicited or induced any other person, firm, or corporation to refrain from submitting a Proposal
4. The Respondent has not sought by collusion to obtain any advantage over any other Respondent.

9.0 RESERVATION OF RIGHTS

Nothing contained in this RFP shall be construed to require or obligate Vectren to select any Proposals or limit the ability of Vectren to reject all Proposals in its sole and exclusive discretion. Vectren further reserves the right to withdraw and terminate this RFP at any time prior to the Proposal Submittal Due Date, selection of bids or execution of a contract. All final contracts will be contingent on IURC approval.

All Proposals submitted to Vectren pursuant to this RFP shall become the exclusive property of Vectren and may be used for any reasonable purpose by Vectren. Vectren and Burns & McDonnell shall consider materials provided by Respondent in response to this RFP to be confidential only if such materials are clearly designated as Confidential. Respondents should be aware that their Proposal, even if marked Confidential, may be subject to discovery and disclosure in regulatory or judicial proceedings that may or may not be initiated by Vectren. Respondents may be required to justify the requested confidential treatment under the provisions of a protective order issued in such proceedings. If required by an order of an agency or court of competent jurisdiction, Vectren may produce the material in response to such order without prior consultation with the Respondent.

10.0 CONFIDENTIALITY OF INFORMATION

All Proposals submitted in response to this RFP become the responsibility of Burns & McDonnell and Vectren upon submittal. Respondents should clearly identify each page of information considered to be confidential or proprietary. Consistent with the RFP NDA (Appendix B), Burns & McDonnell will take reasonable precautions and use reasonable efforts to maintain the confidentiality of all information so identified. Vectren reserves the right to release any Proposals, or portions thereof, to agents, attorneys, or consultants for purposes of Proposal evaluation. Regardless of the confidentiality claimed, however, and regardless of the provisions of this RFP, all such information may be subject to review by, and disclosable by Vectren, to the appropriate state authority, or any other governmental authority or judicial body with jurisdiction relating to these matters, and may also be subject to discovery by other parties subject to fully executed NDAs/confidentiality agreements. Further, because Vectren is conducting this RFP as part of the IRP public advisory process, Vectren will disclose the UCAP MW offered, technology/resource type, average price, general location, proposed ownership structure, and Proposal duration of all Proposals unless a given technology has less than three Respondents in order to inform our stakeholders of the summary results of the RFP. Vectren will also disclose the names of Respondents participating in the RFP.

11.0 REGULATORY APPROVALS

Pursuant to the terms of the definitive agreement(s), the Respondent will agree to use its reasonable best efforts, including, if necessary, providing data and testimony, to obtain any and all State, Federal, or other regulatory approvals required for the consummation of the transaction.

Please note in particular that approval by the IURC, MISO and FERC may be required before the transaction can be consummated between the selected Respondent and Vectren. As part of the regulatory process, responses to the RFP may be provided to parties who have executed an NDA/confidentiality agreement, specifically acknowledging that they are neither affiliated with any party responding to the RFP or serving as a conduit for any party responding to the RFP.

12.0 CREDIT QUALIFICATION AND COLLATERAL

The credit and commitment of any bid will be a critical part of the bid evaluation process. A Respondent must have a credit rating for its senior unsecured debt of BBB+ or higher for Standard & Poor's (or Baa1 or higher for Moody's). If a Respondent is unrated or does not meet this minimum credit rating requirement, the Respondent may provide credit support from a corporate guarantor that meets the requirement.

As part of a final binding contract, and depending on the structure of the transaction, Vectren will further review the credit of the Respondent and the risk associated with the transaction to determine what, if any, additional credit requirements may be necessary to protect its ability to serve its customers in a reliable manner.

For asset purchases, a Respondent shall have the corresponding obligation to post Definitive Agreement (DA) collateral as determined in accordance with its Proposal if selected for the definitive agreement phase of the RFP. DA Collateral must be posted at the execution of the definitive agreement and will be in force until the transfer of title to Vectren for generating asset Proposals.

For PPAs and LMRs/DRs, winning Respondents may be required to post operating collateral over the term of any PPA or LMR/DR agreement consistent with the terms and conditions of final agreements as negotiated between Vectren and the supplier.

In each case, the collateral must be in the form of either: (a) a letter of credit, (b) cash, or (c) a construction bond. Burns & McDonnell and Vectren reserve the right to require a Respondent to post DA Collateral in an amount that exceeds the amounts listed herein as conditions warrant.

Table 12-1: Collateral

Asset	Collateral Amount
Asset Purchase	$50.00/kW (UCAP) at execution of definitive agreement
Asset Purchase	$150.00/kW (UCAP) at regulatory approval
Power Purchase Agreement	12-months expected revenues
LMR/DR	12-months expected revenues

13.0 MISCELLANEOUS

13.1 Non-Exclusive Nature of RFP

Vectren may procure more or less than the amount of assets solicited in this RFP from one or more Respondent(s). Respondents are advised that any definitive agreement executed by Vectren and any selected Respondent may not be an exclusive contract for the provision of assets. In submitting a Proposal(s), Respondent will be deemed to have acknowledged that Vectren may contract with others for the same or similar deliverables or may otherwise obtain the same or similar deliverables by other means and on different terms.

13.2 Information Provided in RFP

The information provided in this RFP, or on the RFP website (http://VectrenRFP.rfpmanager.biz/), has been prepared to assist Respondents in evaluating this RFP. It does not purport to contain all the information that may be relevant to Respondent in satisfying its due diligence efforts. Vectren makes no representation or warranty, express or implied, as to the accuracy, reliability or completeness of the information in this RFP, and shall not be liable for any representation, expressed or implied, in this RFP or any omissions from this RFP, or any information provided to a Respondent by any other source.

13.3 Proposal Costs

Vectren shall not reimburse Respondent and Respondent is responsible for any cost incurred in the preparation or submission of a Proposal(s), in negotiations for an agreement, and/or any other activity contemplated by the Proposal(s) submitted in connection with this RFP. The information provided in this RFP, or on Vectren's RFP website, has been prepared to assist Respondents in evaluating this RFP. It does not purport to contain all the information that may be relevant to Respondent in satisfying its due diligence efforts.

13.4 Indemnity

Supplementing Respondent's assumption of liability pursuant to this RFP, Respondent shall indemnify, hold harmless and defend Vectren and its parent company, officers, employees and agents, from any and all damages, liabilities, claims, expenses (including reasonable attorneys' fees), losses, judgments, proceedings or investigations incurred by, or asserted against, Vectren or its officers, employees or agents, arising from, or are related to, this RFP, or the execution or performance of one or more definitive agreements.

13.5 Hold Harmless

Respondent shall hold Vectren harmless from all damages and costs, including, but not limited, to legal costs in connection with all claims, expenses, losses, proceedings or investigations that arise as a result of this RFP or the award of a Proposal pursuant to the RFP or the execution or performance of a definitive agreement.

13.6 Further Assurances

By submitting a Proposal, Respondent agrees, at its expense, to enter into additional agreements, and to provide additional information and documents, in either case as requested by Burns & McDonnell in order to facilitate: (a) the review of a Proposal, (b) the execution of one or more definitive agreements, or (c) the procurement of regulatory approvals required for the effectiveness of one or more definitive agreements.

13.7 Licenses and Permits

Respondent shall obtain, at its cost and expense, all licenses and permits that may be required by any governmental body or agency necessary to conduct Respondent's business or to perform hereunder. Respondent's subcontractors, employees, agents and representatives of each in performance hereunder shall comply with all applicable governmental laws, ordinances, rules, regulations, orders and all other governmental requirements.

APPENDIX A – NOTICE OF INTENT TO RESPOND

Notice of Intent to Respond

CONTACT INFORMATION			
Company			
Primary Contact:			
Name			
Title			
Telephone			
E-mail			
Mailing Address			
Signature of Respondent		Date	

Due: June 27, 2019

E-mail: VectrenRFP@burnsmcd.com

APPENDIX B – NON-DISCLOSURE AGREEMENT

NON-DISCLOSURE AGREEMENT

THIS NON-DISCLOSURE AGREEMENT (Agreement) is entered into as of the __ day of _________, 2019, between Southern Indiana Gas and Electric Company, Inc., Vectren Energy Delivery of Indiana, Inc. (Vectren) having its headquarters and principal place of business in Evansville, Indiana, and [_________________________________], a [___________] corporation/llc/partnership (the Company), (collectively, the Parties, and individually, Party).

R E C I T A L S:

A. The Parties intend to discuss and evaluate proposals regarding possible energy/capacity transactions that could be entered into between Vectren and the Company, which discussions may include sharing of bid proposal information received from the Company during the competitive bid process administered by Burns & McDonnell on behalf of Vectren (the Transaction).

B. The Parties acknowledge that each Party may make available to the other Party, from time to time, in connection with such discussions, certain Confidential Information, as defined below.

NOW, THEREFORE, in consideration of the premises and the mutual promises and covenants hereinafter set forth, the Parties agree as follows:

1. <u>Non-Disclosure</u>. Subject to Section 4 below, the Party receiving confidential information (the <u>Receiving Party</u>) shall keep strictly confidential and not disclose the following:

(i) all information provided by the disclosing Party (Disclosing Party) or any affiliate, director, officer, employee, agent, advisor, contractor or other representative (individually, Representative, or collectively, Representatives) of the Disclosing Party to the Receiving Party or its Representative(s) in writing, orally or electronically in the course of the Parties' evaluation of the Transaction, whether before or after the date hereof, including, without limitation, any such information

(A) concerning the business, financial condition, operations, products, services, assets and/or liabilities of the Disclosing Party,

(B) relating to technologies, intellectual property or capital, models, concepts, or ideas of the Disclosing Party,

(C) including information from third parties that the Disclosing Party is required under applicable law, contract or other agreement to keep confidential, or

(D) otherwise, clearly identified as confidential or proprietary, including all bid proposal information received by the Receiving Party, during the competitive bid process for intermediate capacity being conducted by Vectren (collectively, the "Confidential Information"); and

(ii) the Disclosing Party's participation in discussions concerning the Transaction, including execution of this Agreement, the Disclosing Party's disclosures of Confidential Information to the Receiving Party or its Representative.

Receiving Party may disclose Confidential Information provided by the Disclosing Party to any Representative of the Receiving Party who needs this Confidential Information to evaluate the Transaction. Receiving Party remains responsible for its Representative(s) compliance with the terms of this Agreement.

2. Use Restriction. The Receiving Party shall not use any Confidential Information of the Disclosing Party for any purpose other than for the Transaction or for regulatory proceedings and RTO/ISO studies and analyses, including for example, an Indiana Utility Regulatory Commission ("IURC") proceeding in which information about the Transaction must be produced by Vectren to satisfy its evidentiary burden. In any such regulatory proceeding, study or analysis, Receiving Party will take care to protect Confidential Information from public disclosure through redacted public filings and other similar measures available to Receiving Party to protect Confidential Information. Receiving Party will advise Disclosing Party as soon as practical, of any such use and the protections in place for the Confidential Information.

3. Exceptions to Confidential Information. Under this Agreement, Confidential Information shall not include information that: (i) is already in Receiving Party's possession at the time of disclosure, as documented by the Receiving Party; (ii) becomes available subsequently to the Receiving Party on a non-confidential basis from a source not known or reasonably suspected by the Receiving Party to be bound by a confidentiality agreement or secrecy obligation owed to the Disclosing Party; (iii) is or becomes generally available to the public other than as a result of a breach of this Agreement by the Receiving Party or its Representative; or (iv) is independently developed by the Receiving Party without use, directly or indirectly, of Confidential Information of the Disclosing Party. If only a portion of the Confidential Information falls under one of the foregoing exceptions, then only that portion shall not be deemed Confidential Information.

4. Required Disclosure. If Receiving Party or its Representative is required, pursuant to any applicable court order, administrative order, statute, regulation or other official order by any government or any agency or department thereof, to disclose Confidential Information, the Receiving Party shall:

(i) provide the Disclosing Party with prompt written notice of any such request or requirement so that the Disclosing Party may seek a protective order or other appropriate remedy or protection and/or waive compliance with the provisions of this Agreement; and

(ii) reasonably cooperate with the Disclosing Party to obtain such protective order or other remedy. If Disclosing Party waives compliance with the relevant provisions of this Agreement or

the Disclosing Party does not receive a protective order or other remedy or protection, the Receiving Party agrees to

(a) provide only that portion of the Confidential Information for which the Disclosing Party has waived compliance with the relevant provisions of this Agreement, or which the Receiving Party is legally required to disclose,

(b) use commercially reasonable efforts to obtain assurances that confidential treatment will be accorded to such information, at Disclosing Party's expense, and

(c) give the Disclosing Party written notice in advance of any disclosure of Confidential Information.

5. Return or Destruction of Confidential Information. Either Party may terminate this Agreement with thirty days written notice. Additionally, at any time for any reason, upon the written request of the Disclosing Party, the Receiving Party and its Representative(s) will promptly:

(i) deliver to the Disclosing Party all original Confidential Information (whether written or electronic) furnished to the Receiving Party by or on behalf of the Disclosing Party, and

(ii) destroy any copies of such Confidential Information (including any extracts there from) if specifically requested by the Disclosing Party, with Receiving Party allowed to retain one archival copy of the Confidential Information in strict confidence for purposes of record retention and compliance or as otherwise required by applicable laws. If the Disclosing Party requests written proof, Receiving Party shall cause a duly authorized officer to certify in writing to the Disclosing Party that the requirements of the preceding sentence have been satisfied in full.

Regardless of the status of discussions regarding the Transaction and any request for return or destruction of Confidential Information, the Receiving Party will continue to be bound by terms of this Agreement.

6. Term. This Agreement is effective as of the date first written, above. It will terminate one (1) year after its effective date unless extended for additional one year terms by agreement of the Parties. If this Agreement is terminated during a term by either Party providing a termination notice pursuant to Section 5 above; the non-disclosure and use restriction obligations for Confidential Information under this Agreement shall survive any termination and remain in effect for the longer of (i) five (5) years, or (ii) such period during which any Confidential Information retains its status as a trade secret or qualifies as confidential under applicable law.

7. Miscellaneous.

(a) The Parties acknowledge and agree that unless and until a definitive agreement with respect to the Transaction has been executed by the Parties, no Party shall be under any legal obligation of any kind whatsoever to the other Party with respect to the Transaction, except as expressly provided in this Agreement.

(b) Receiving Party acknowledges that the Confidential Information is and at all times remains the sole and exclusive property of the Disclosing Party and that the Disclosing Party has the exclusive right, title, and interest to its Confidential Information. No right or license, by implication or otherwise, is granted by the Disclosing Party as a result of disclosure of Confidential Information hereunder. Each Party reserves the right at any time in its sole discretion, for any reason or no reason, to refuse to provide any further access to and to demand the return of the Confidential Information. The Receiving Party agrees that the Disclosing Party and its Representatives (i) makes no warranty as to the accuracy or completeness of the Confidential Information; and (ii) shall have no liability to the Receiving Party or its Representatives resulting from the use of any Confidential Information.

(c) Neither this Agreement nor any right, remedy, obligation or liability arising hereunder shall be assigned by any Party (whether by operation of law or otherwise), and any such assignment shall be null and void, except with the prior written consent of the other Party. Subject to the foregoing, this Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns. No provision of this Agreement shall create a third-party beneficiary relationship or otherwise confer any benefit, entitlement or right upon any person or entity other than the Parties.

(d) The Parties acknowledge and agree that no failure or delay by a Party in exercising any right or privilege hereunder shall operate as a waiver of that right or privilege. The provisions of this Agreement may be modified or waived only in writing signed by both Parties.

(f) This Agreement shall be governed by and construed in accordance with the laws of the State of Indiana.

(g) This Agreement may be executed in one or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

(h) Each Party acknowledges and agrees that money damages would not be a sufficient remedy for any breach of this Agreement by such Party and that the other Party shall be entitled to seek equitable relief, including seeking an injunction and specific performance, as a remedy for any such breach. Such remedies shall not be deemed to be the exclusive remedies for a breach of this

Agreement, but shall be in addition to all other remedies available at law or equity.

(i) This Agreement constitutes the entire agreement between the Parties with respect to the subject matter herein and supersedes and cancels any prior agreements, representations, warranties, or communications, whether oral or written, between the Parties relating to the subject matter herein.

IN WITNESS WHEREOF, each Party hereto has executed this Agreement, or caused this Agreement to be executed on its behalf, all as of the day and year first above written.

Southern Indiana Gas and Electric Company, Inc.,
d/b/a Vectren Energy Delivery of Indiana, Inc.:

By:____________________________________
Name:
Title:

____________<company name>____________

By:____________________________________
Name:
Title:

APPENDIX C – PRE-QUALIFICATION APPLICATION

PRE-QUALIFICATION APPLICATION

Respondent's Credit-Related Information

Provide the following data to enable Vectren to assess the financial viability of the Respondent as well as the entity providing the credit support on behalf of the Respondent (if applicable). Include any additional sheets and materials with this Appendix as necessary. As necessary, please specify whether the information provided is for the Respondent, its parent, or the entity providing the credit support on behalf of the Respondent.

Full Legal Name of the Respondent: ____

Dun & Bradstreet No. of Respondent: ____

Type of Organization: (Corporation, Partnership, etc.) ____________________________________

State of Organization: ____

Respondent's Percent Ownership in Proposal: ____________________________________

Full Legal Name(s) of Parent Corporation: ____________________________________

Entity Providing Credit Support on Behalf of Respondent (if applicable): ___________________________

Dun & Bradstreet No. of Entity Providing Credit Support: ______________________________

Address for each entity referenced (provide additional sheets, if necessary): ______________________

____

Type of Relationship: ____

Current Senior Unsecured Debt Rating from each of S&P and Moody's Rating Agencies (specify the entity these ratings are for): ____

OR, if Respondent does not have a current Senior Unsecured Debt Rating, then Tangible Net Worth (total assets minus intangible assets (e.g. goodwill) minus total liabilities):______________________________

Bank References & Name of Institution: ____________________________________

Bank Contact: Name, Title, Address and Phone Number: ______________________________

____

Pending Legal Disputes, if any (describe): ____________________________________

____

General description of Respondent's ability to construct, operate and maintain project, to the extent applicable:

____

____

Financial Statements of the Respondent or its Credit Support Provider, where applicable, must include Income Statement, Balance Sheet, Statement of Cash Flows, all notes corresponding to those financial statements and applicable schedules for three most recent fiscal years and financial report for the most recent quarter or year-to-date period. Also if available, please provide copies of the Annual Reports and/or 10K for the three most recent fiscal years and quarterly report (10Q) for the most recent quarter ended, if available. If such reports are available electronically, please provide link.

____

____

APPENDIX D – PROPOSAL DATA

SEE ATTACHMENT:
APPENDIX D – PROPOSAL DATA.xlsx

APPENDIX E – PROPOSAL CHECKLIST

PROPOSAL CHECKLIST

Required:

☐Appendix A – Notice of Intent

☐Appendix B – Non-Disclosure Agreement

☐Appendix C – Pre-Qualification Application

☐Appendix D – Proposal Data

☐Executive Summary

☐MISO Generator Interconnection Agreement

☐MISO Facilities Study

☐MISO System Impact Study

☐Proposal Evaluation Fee (if applicable)

☐EPC Contract (if applicable)

Other Data:

☐Nodal economic analyses

☐PSS/E v33 raw or idev file that reflects modeling parameters of the Project at the respective point of interconnection

☐Unit inspection findings and dates and outstanding recommendations yet to be implemented, summary of operating plan, and outage and maintenance plans

☐Water supply description, NPDES permit details, all relevant environmental permits, environmental liabilities, and water chemistry program summary and performance

☐Emissions credits or offsets and baseline emissions of known and unknown pollutants

☐Spare parts list

☐Other contractual commitments

☐Summary of all legal proceedings, claims, actions, or suits against the Respondent, Guarantor, or involving the facility or site

☐Discussion regarding roles and responsibilities of any companies involved, status of major equipment procurement, facility site and Respondent's rights to such site, development schedule and associated risks and risk mitigation plans, and financing arrangements

☐Description of fuel supply, fuel cost information, and fuel contract duration and terms

☐Audited or unaudited financial statements including balance sheets, income statements, and cash flow statements for the proposed asset(s) for the past three years.

LMR/DR Only:

☐Description of how Proposal conforms with requirements of local utility and state law in order to offer resources for capacity accreditation within MISO under Module E Capacity Tracking

☐Description of LMR/DR customer(s), load drop values, equipment and technology, plans detailing deployment or utilization to support its operations, LMR/DR supplier and other key contributors, the supplier's process for aggregating and/or plan for recruiting participants, curtailment systems and procedures, and plans for communicating with participants during curtailment periods

☐Acknowledgement and agreement that LMR/DR supplier is responsible for activities and obligations listed in Section 6.4.3

BURNS & McDONNELL

CREATE AMAZING.

Attachment 6.4 1x1 CCGT Study (Redacted)

FINAL

EPC COST - BASIS OF ESTIMATE

A.B. Brown 1x1

B&V PROJECT NO. 400278
B&V FILE NO. 41.0001

PREPARED FORREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

Executive Summary

The following is a basis of estimate summary for the EPC capital cost AACE Class 2 estimate for the A.B. Brown 1X1 Combined Cycle. The cost estimates contained in this report are based on the preliminary design by Black & Veatch, equipment pricing bids from suppliers of power island, and utilizing prior EPC contractor and vendor bid data. Power island equipment includes the combustion turbine(s), steam turbine, and HRSG(s).

The two plant alternatives that were estimated are as follows:

1X1 CCPP
GE 7FA.05 Fired
GE 7HA.01 Fired

1.0 Estimate Basis

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

The cost estimate is based upon a lump-sum turnkey EPC approach. Owner will purchase Power Island Equipment and assign to EPC contractor. Under this approach, the EPC contractor would have the responsibility for administration and performance interface of the power island equipment. The EPC structure used for the estimate is based upon the EPC contractor self-performing the work rather than utilizing multiple subcontractors.

The cost estimates are based on competitive bids obtained for power island equipment. Equipment, commodity, and construction services rates were based on EPC contractor and vendor data. Detailed material takeoffs based on the preliminary design of the A.B. Brown combined cycle with reference to similar sized plants that Black & Veatch has designed, constructed, and/or estimated on an EPC basis.

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 - A Labor Market Survey may identify craft labor conditions unique to this project that are recommended for further review and evaluation prior to start of construction.
- Final site conditions - Soil boring were secured for the proposed site.
- Noise requirements - Night-time steam blow conditions were assumed.
- Final project schedule.

1.1 QUANTITIES

Quantities that form the basis of the estimate were based on the engineering conceptual design and the engineering Bill of Quantities (BOQ) developed. The conceptual design was based on utilizing some of the existing A.B. Brown common system to support the new combined cycle, detailed information from equipment suppliers for new equipment, and specific site conditions. Where details were not available, assumptions were made based on similar sized plants and arrangements.

1.2 DIRECT COSTS

EPC bid pricing is 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 by the EPC bidders.

- Unit manhour rates and wage rates are applied against the 1x1 quantities to develop labor cost.

- Unit material cost are applied against the updated quantities for commodities to develop material cost. Cost for major equipment has been scaled off the equipment cost for the major equipment obtained by the EPCs.
- Subcontract pricing was adjusted based upon the rates developed as part of the EPC bid analysis.

To develop the definitive capital cost estimate an RFI was issued to the major OEM Power Island equipment suppliers to obtain budgetary quotes. The OEM proposals included:

- Combustion Turbine and Generator Package
- Steam Turbine and Generator Package
- Heat Recovery Steam Generator

Bid tabulations were developed to evaluate the bids for completeness, scope, and adherence to the specification. The lowest evaluated bid was selected to use as the basis of the estimate.

1.3 CONSTRUCTION MANAGEMENT AND CONSTRUCTION INDIRECTS AND ENGINEERING

Construction Management and Construction Indirects (CMCI) were based on a self-perform (direct-hire) EPC approach instead of a multiple subcontract EPC approach. 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. Under a multiple subcontract approach, these costs would be included in the subcontractor unit rates and appear in the direct cost line items.

Construction management and indirects were estimated based on Black & Veatch's experience with similar plants and scopes of work as well as comparison against the EPC bids. The following costs were developed based upon Black & Veatch's internal metrics and experience then adjusted for schedule and man power loading:

- Project Engineering
- Project Construction Management including Safety, QC, Orientation
- Material Handling
- Mobilization and Demobilization
- Consumables & Small Tools
- Warranty

To obtain competitive bids Black & Veatch, in accordance with IURC code, the estimate includes competitive bids for the following costs:

- Cranes and Construction Equipment
- Scaffolding
- Temporary Facilities

Heavy haul transportation was based on Power Island Equipment delivery to the site and heavy cranes included in the Cranes and Construction Equipment RFQ.

1.4 INDIRECTS

Insurances, warranty, performance bonds, and a letter of credit costs are included, based on the EPC bids.

1.5 CONTINGENCY

[redacted]

[redacted]

[redacted]

FINAL

HRSG BYPASS STACK ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1201F

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the benefits and drawbacks of adding a flue gas bypass stack between the combustion turbine and the heat recovery steam generator (HRSG). The bypass stack would allow the HRSG to be taken offline while the combustion turbine operates in simple cycle mode and would also allow the combustion turbines to be put into service up to 6 months before the erection and commissioning of the balance-of-plant equipment.

This analysis considered such factors as cost, plant design, environmental permitting, schedule, and operations, and maintenance. One major consideration is whether a selective catalytic reduction (SCR) system would be required to meet US Environmental Protection Agency (USEPA) emissions permitting requirements. The base cost for the installation of an HRSG bypass stack is estimated as [redacted] the estimated cost with the addition of an SCR system would be [redacted]

The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. USEPA standards, however, might limit the number of hours the unit could operate in simple cycle mode. While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design.

1.0 Introduction

HRSG stack flue gas bypass systems provide the benefit of adding operational flexibility to power plant generation. Flue gas bypasses consist of installing a stack between the combustion turbine and HRSG; a diversion damper allows the combustion turbine exhaust to be diverted either to the bypass stack or the HRSG. Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. The bypass stack would also allow for the combustion turbines to be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction. The benefits must outweigh the cost in order for a flue gas bypass system to be feasible.

This evaluation of adding a flue gas bypass on each Combustion Turbine will help determine the cost (+/- 30%) and design impact of a flue gas bypass system to the plant design. Environmental permit considerations due to the flue gas bypass addition will also be reviewed. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

2.0 Arrangement

On a combined cycle power plant, the flue gas bypass stack would be installed between the combustion turbine and the HRSG. Figure 2-1 shows a typical arrangement of a combustion turbine with a HRSG and a bypass stack. The bypass stack contains a damper that diverts the combustion turbine exhaust either up the bypass stack or to the HRSG. During simple cycle operation, the damper would be positioned to shut off flow to the HRSG and direct flow up the bypass stack. Under combined cycle operation, the damper would be positioned to shut off flow to the bypass stack and allow flow through to the HRSG. The diverter damper is actuated through the operating positions by electronically controlled hydraulic system. Figure 2-2 shows the components of the bypass stack.

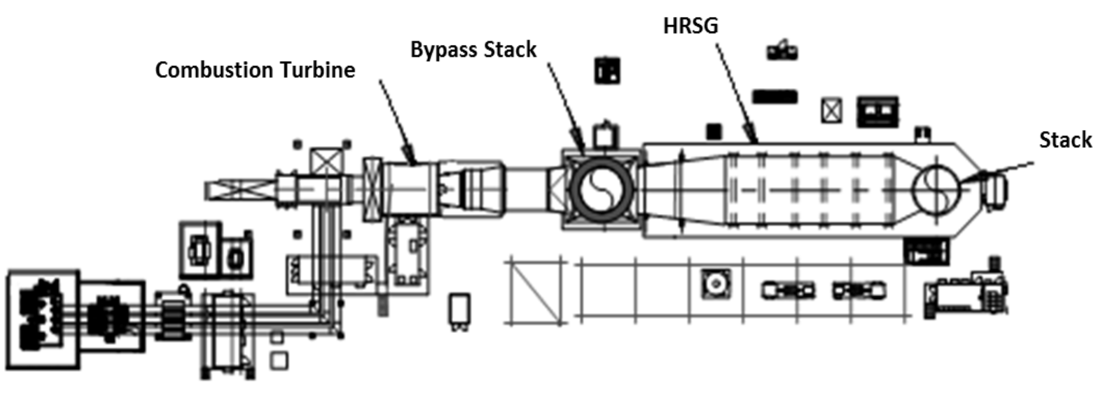


Figure 2-1 Combined Cycle Layout with Bypass Stack

ITEM NO	QTY	DESCRIPTION
1	1	INTEGRATED EXPANSION JOINT
2	2	TRANSITION DUCT HALVES
3	4	SILENCER DUCT QUARTER SECTIONS
4	4	SILENCER DUCT FLAT WALL PANELS
5	2	TRANSITION DUCT HALVES
6	8	VERTICAL STACK SEGMENTS
7	2	VERTICAL STACK SEGMENTS
8		BOTTOM SILENCER PANELS
9		TOP SILENCER PANELS
10		SUPPORT STRUCTURE
11		LADDERS AND PLATFORMS
12		PERSONNEL PROTECTION
13	1	HORIZONTAL TRANSITION
14	1	GUILLOTINE DUCT
15	1	DAMPER

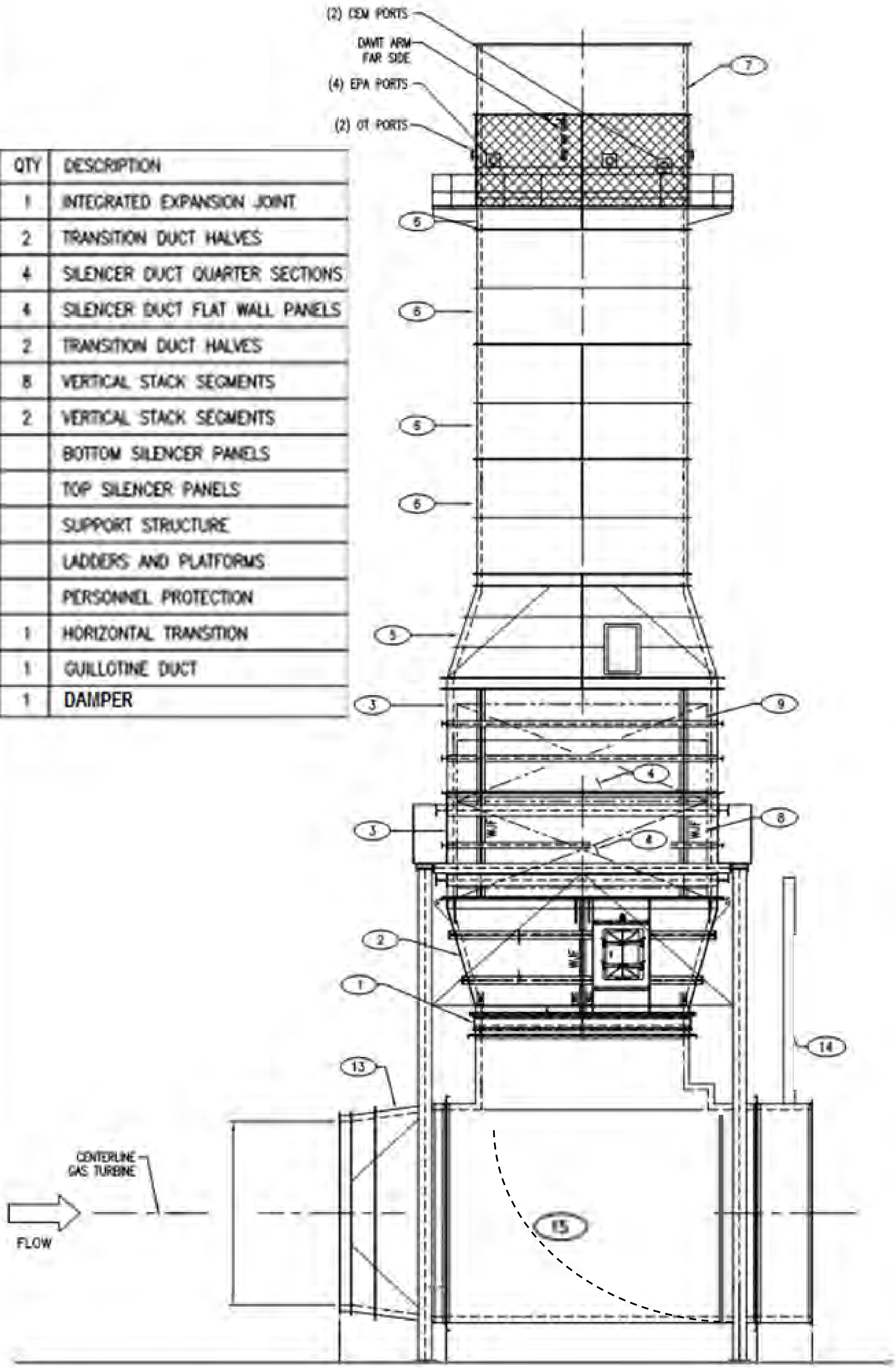


Figure 2-2 Typical Gas Bypass Stack

If an SCR were required, a section could be added to the stack upstream of the silencer to house catalyst, tempering air skid, and ammonia injection equipment. While there is not much industry experience with installing SCRs in the vertical sections of combustion turbine bypass stacks, the technical challenges would be similar to those seen in a coal facility where vertical SCRs are common. The SCR would consist of the following components:

- Catalyst
- Tempering air system to lower combustion turbine exhaust gas to an allowable inlet temperature for the catalyst (<800 °F)
- Mixing vanes and flow distribution
- Ammonia distribution manifold and injection grid
- Ammonia vaporization and flow control unit
- Emission monitoring system

Alternatively, the SCR may be horizontal and then the SCR and bypass stack would be placed in parallel with the HRSG. Air emission requirements are discussed in Section 6.0.

3.0 Capital Costs

Typical suppliers of HRSG bypass stacks include Braden Manufacturing, Peerless-Aarding, and Clyde Bergmann.

Pricing from recent proposals was reviewed to find a budgetary estimate for a bypass stack with a height of 135 ft with stack silencer and continuous emission monitoring (CEMS) system. Also included were all required dampers, motors, controls, insulation, lighting, support steel and platforming as required.

Table 3-1 is a high level breakdown of the costs associated with the bypass stack.

Table 3-1 Capital Costs for HRSG Bypass Stack

DESCRIPTION	INSTALLED COST / UNIT
FOUNDATIONS/CIVIL WORK	[redacted]
STACK (including ductwork, damper, supplementary steel, lighting, electrical)	[redacted]
CEMS (NOx and CO analyzers, includes electrical and controls)	[redacted]
BYPASS STACK (no SCR)	[redacted]
VERTICAL SCR (includes ammonia injection, NO_X and CO catalyst)	[redacted]
BYPASS STACK (with vertical SCR)	[redacted]

4.0 Performance Impacts

Installation of a bypass stack allows for the operation of the combustion turbine in simple cycle mode; however, operating in simple cycle mode may have limited operating hours as discussed in Section 6.0, Permitting and Emissions.

[redacted] It would normally be expected that plant output would decrease due to increased exhaust pressure drop due to a reduction in CTG load, which is only partially offset by an increase in STG load resulting from increased CTG exhaust energy. However, the 7F.05 is shaft-limited at this operating condition and the CTG output is not reduced due to the increased exhaust pressure. Instead, the CTG fires harder to maintain its output, resulting in an increase in exhaust flow, thereby increasing steam production and STG output. Other OEM machines may not have this characteristic and net plant output could be expected to decrease due to increased CTG exhaust pressure.

If an SCR is required, a tempering air skid is required to keep the CTG exhaust below 800 °F to prevent damage to the catalyst. The CTG exhaust reaches 800 °F in less than a minute from ignition as the CTG reaches 5% load. The tempering air fan and the ammonia vaporization and flow control system will have an auxiliary load of 1,000 kW.

5.0 Maintenance

Maintenance consists of correcting deficiencies noted during inspection. For HRSG bypass stacks without an SCR, the primary maintenance concern is the damper seals, diverter damper bearings, and the dampers hydraulic power unit.

Typical diverter maintenance activities include:

- Shaft seal replacement.
- Housing perimeter seal replacement.
- High temperature bearing repair or replacement.
- Shaft seals are typically designed to last five years.

Recommended spare parts include:

- Spare limit switches.
- Position transmitters.
- Seal-air pressure blower.
- Main drive bearing kit.
- Damper seal sets.
- Expansion joints.

If an SCR is required, additional maintenance is required for the hot air tempering skids, ammonia flow control units, and replacement of NO_x and CO catalysts.

6.0 Permitting and Emissions

6.1 FEDERAL REGULATIONS POSING CHALLENGES

Officially titled *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 40 CFR Part 60, Subpart TTTT was finalized by the USEPA on August 3, 2015. In this rulemaking, the USEPA established output-based emissions standards for two subcategories of power plants; electric utility steam generating units (e.g., coal-fired power plants) and stationary combustion turbines. The rule makes no distinction between simple cycle and combined cycle combustion turbines. Rather, it requires combustion turbines to meet certain CO_2 emissions standards depending on whether they are classified as baseload or non-baseload units.

The distinction between baseload and non-baseload units is made based upon the number of hours a combustion turbine can operate relative to its design efficiency. If a combustion turbine operates more hours than its net, Lower Heating Value (LHV) design efficiency, then it is considered a baseload unit. Baseload units are required to meet an output-based CO_2 emission standard of 1,000 lb/MWh (gross output, 12-operating month basis).

[redacted]

If the plant is restricted in hours less than the percent of net design efficiency hours, the plant is classified as a non-baseload unit with respect to NSPS Subpart TTTT. Natural gas-fired non-baseload units are subject to a heat-input based CO_2 emission standard 120 lb/MBtu (HHV, 12-operating month basis). This standard is readily achievable because the CO_2 emission rate of natural gas is 117 lb/MBtu.

6.2 AIR PERMITTING CHALLENGES

While an emissions netting analysis (wherein any recent unit shutdowns can be used to demonstrate that net emissions increases from the new installation would not exceed major source permitting thresholds) could allow the project to avoid major source permitting requirements there is still a possibility the project could trigger major source permitting. In such a scenario, the air permitting process would be dictated by the Prevention of Significant Deterioration (PSD) regulations which require, among other things, an evaluation of Best Available Control Technology (BACT). Should BACT be required for NO_X emissions, the project's air construction permit could require the use of an SCR.

7.0 Conclusions

Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. In addition, the combustion turbines could be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction.

While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design. The total installed cost of the bypass stack for a single 1x1 train is approximately [redacted] without an SCR. A vertical SCR would be considered a first of a kind for this application so no cost is easily achievable without a prior design. It is expected that if an SCR is required due to concerns with emissions the cost would be approximately double [redacted] with an SCR. If a horizontal SCR is required due to emission limits, the SCR would not be feasible as it would be approximately the size of the HRSG. The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. The amount of hours where the unit can operate in simple cycle mode with the HRSG bypassed may be limited due to NSPS 40 CFR Part 60, Subpart TTTT.

FINAL

HEAT REJECTION / EXISTING COOLING TOWER ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1202F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

In developing this report, Black & Veatch focused its attention to the specific areas directed by Vectren by analyzing the design impacts and cost comparison of using one existing cooling tower, circulating water pumps, and circulating water pipe for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple existing cooling tower reuse scenarios to evaluate the performance against the design for a new cooling tower. A performance summary for the two most optimal scenarios is provided in Section 2.0.

Black & Veatch evaluated the following three cooling tower alternatives for this study:

- Alternative 1: Reuse Cooling Tower, Circulating Water Pumps, and Existing Piping
- Alternative 2: Reuse Cooling Tower and Circulating Water Pumps with All New Piping
- Alternative 3: All New Cooling Tower, Circulating Water Pumps, and Piping

This report has been summarized in a Cooling Tower Alternatives Comparison Matrix provided in Table ES-1. [redacted] Consequently, it is recommended that Vectren utilize the existing Unit 1 cooling tower, circulating water pumps and piping as the design basis for the new combined cycle power plant.

Table ES-1 Cooling Tower Alternatives Comparison Matrix

ALTERNATIVE	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
Description	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

ALTERNATIVE	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
Disadvantages	[redacted]	[redacted]	[redacted]

1.0 Introduction

The purpose of this study is to analyze the A.B. Brown Unit 1 circulating water system to determine whether all or portions of the existing cooling towers, circulating water pumps, and circulating water piping can be reused for use with a new Combined Cycle Power Plant (CCPP). Black & Veatch has evaluated the performance of the existing cooling towers and circulating water pumps to determine the optimal operating scenarios [redacted] when paired with the new CCPP.

This evaluation of reusing the existing circulating water system components will help determine the [redacted] design impact of this system to the new CCPP design. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

2.0 Performance Evaluation

Several operating scenarios were evaluated to determine the best preliminary design basis for reusing the existing cooling towers and circulating water pumps. Upon selection of the final plant design, the preferred number of cooling tower cells in service should be reviewed.

Alternatives 1 and 2 utilize the Unit 1 existing seven cell cooling tower and two circulating water pumps provide a total circulating water flow of 125,000 gallons per minute (gpm).

The existing cooling tower would be larger than the cooling tower for Alternative 3. The design flow rate of the existing cooling tower is larger than the design flow rate would be for the new cooling tower. To accommodate the larger flow rate, the condenser will be larger, and more expensive, but provides better performance. The overall heat rejection system for Alternatives 1 and 2 result in a decrease in steam turbine backpressure and an increase in auxiliary power when compared to the new heat rejection system considered in Alternative 3.

The estimated performance based on nominal 1x1 7F.05 combined cycle performance for the alternatives is shown on Figure 2-1 for unfired heat recovery steam generator (HRSG) operation and Table 2-2 for fired HRSG operation. For reference, Tables 2-1 and 2-2 provide the estimated performance values shown on the graphs.

[redacted]

Table 2-1 Comparative Unfired Plant Performance for Cooling Tower Alternatives

UNFIRED OPERATING CONDITIONS	1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING OFF	1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING OFF	1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING OFF
7 Cell Net Plant Output, kW	[redacted]	[redacted]	[redacted]
7 Cell Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]
New Tower Net Plant Output, kW	[redacted]	[redacted]	[redacted]
New Tower Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]

Table 2-2 Comparative Fired Plant Performance for Cooling Tower Alternatives

FIRED OPERATING CONDITIONS	1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING ON	1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING ON	1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING ON
7 Cell Net Plant Output, kW	[redacted]	[redacted]	[redacted]
7 Cell Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]
New Tower Net Plant Output, kW	[redacted]	[redacted]	[redacted]
New Tower Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]

3.0 Existing Equipment

3.1 EXISTING COOLING TOWER CONDITION

The Unit 1 cooling tower cells were recently rebuilt from wood to fiberglass as such the condition is assumed satisfactory and no major repairs are required. Three of the seven Unit 2 cooling tower cells were recently rebuilt from wood to fiberglass. To extend the life of the Unit 2 cooling tower the remaining four (4) cells would require rebuilding to fiberglass at a cost of approximately [redacted] To eliminate the need for this expenditure, the Unit 1 cooling tower will be used for the new CCPP. The existing cooling tower basins for Unit 1 and Unit 2 are lacking an intake structure for an auxiliary cooling water pump. Modifications will be needed to the basin to add the new intake and pump structure.

3.2 EXISTING CIRCULATING WATER PUMPS

The existing circulating water pumps have been evaluated for both Alternatives 1 and 2 and it has been determined that they have sufficient capacity to meet the required flow and head for the new CCPP circulating water system. To extend the life of the two pumps and motors a shop overhaul would be required.

Black & Veatch evaluated the use of variable frequency drives (VFDs) on the existing circulating water pumps to modify the pump flow rate for different CCPP operating scenarios. Because the static head component is constant for all operating conditions and accounts for the majority of the circulating water pump head requirement, a VFD would provide minimal performance gains [redacted] per pump.

3.3 EXISTING CIRCULATING WATER PIPE

The existing circulating water piping is carbon steel piping with a bitumastic coating. Coatings have been maintained and repaired during normal inspection and repairs throughout the life of the existing A.B. Brown Plant. For this study, it is assumed that the condition of the pipe is satisfactory and no repairs will be required to the piping that is being reused as part of Alternative 1.

4.0 Constructability

For each of the cooling tower reuse alternatives there are several items to consider that could impact both the new CCPP and existing A.B. Brown Unit 1 during the installation and commissioning phase of the project.

4.1 ALTERNATIVE 1

Alternative 1 reuses a significant amount of existing underground steel piping, which will require continued inspection and maintenance to last the 30 year design life of the new CCPP. The existing piping is assumed to be in satisfactory condition given feedback from Vectren that they have performed scheduled inspections and coatings on the piping as required.

4.2 ALTERNATIVE 2

Alternative 2 will require unit outages considerably longer than Alternative 1, up to 2 or 3 months, given that a large section of existing Unit 1 circulating water piping and cooling tower risers are to be replaced in-kind with new steel piping. Once completed, Alternative 2 will result in the existing cooling tower and circulating water pump connected to the new CCPP circulating water system with all new piping, resulting in shutdown of the existing Unit 1 at the time of the tie-in.

4.3 ALTERNATIVE 3

Alternative 3 is an all new circulating water system that includes a 6 cell back-to-back mechanical draft counter flow cooling tower, 2x50 percent circulating water pumps, and steel circulating water piping. Because this system is independent of the existing equipment no unit outage will be required and the existing Units 1 and 2 will be able to operate during and after the installation of the new circulating water system. This alternative also results in the least auxiliary load because of minimizing the size of the circulating water pumps for the new CCPP design conditions.

5.0 Capital Costs

Table 5-1 is a high-level breakdown of the costs for both reusing the existing cooling towers and installing new cooling towers with a new basin.

Table 5-1 Estimated Costs for Cooling Tower Alternatives

DESCRIPTION	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
New 6 Cell Cooling Tower with Basin (F&E)	[redacted]	[redacted]	[redacted]
Condenser Adder	[redacted]	[redacted]	[redacted]
Circulating Water Pumps	[redacted]	[redacted]	[redacted]
New Piping and Valves (A/G and U/G)	[redacted]	[redacted]	[redacted]
Basin Modifications for Auxiliary Cooling Water Pump	[redacted]	[redacted]	[redacted]
Site Work	[redacted]	[redacted]	[redacted]
Mechanical Installation (Does not include tower erection)	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]
Cost Difference	[redacted]	[redacted]	[redacted]

6.0 Conclusions

Based on the evaluation, the reusing the existing Unit 1 cooling tower, pumps and piping (Alternative 1) is the lowest cost technically acceptable solution and should be used as the design basis for the new combined cycle power plant.

FINAL

FAST START VS. CONVENTIONAL START ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1203F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1.0 Introduction

This study evaluates designing a 1x1 GE 7F.05 combined cycle power plant with "fast start" capabilities versus a plant design for "conventional" start. The GE 7F.05 is one of several candidate F-Class combustion turbine offerings.

1.1 STARTUP DURATION DEFINITION

Since plant load is affected by ambient conditions, startup durations are typically defined based on achieving a certain operating condition and not a specified operating load. The beginning of the start is typically defined as combustion turbine roll-off or first ignition. Startup is complete when a predefined operating condition is reached.

Startup can be a confusing term as it is used to describe the start from ignition to various ending operating conditions across the industry. These ending operating scenarios can include:

- CTG Full Speed No Load – The point at which the combustion turbine is removed from the static starter and brought to full speed.
- CTG Sync - The point at which the combustion turbine (CTG) is synchronized with the grid.
- Emission Start - Achieving minimum emissions compliance load. This occurs when stack discharge emissions reaching steady state compliance with air quality standards.
- CTG Full Load Start - Combustion turbine at baseload with permitted emissions at the stack.
- Plant Full Load Start - Combustion turbine at baseload and steam turbine bypass valves fully closed. Steam turbine in service.

For the purpose of this study Fast Start is being defined as a rapid start commencing with ignition until the combustion turbine reaches minimum emission load compliance (MECL). When speaking with others in the industry the ending operating condition should be defined.

The type of start is also defined by the amount of time the unit has been shutdown. It is typical to assume the shutdown begins at fuel flow shutoff to the combustion turbines during a normal plant shutdown sequence from a steady state baseload condition. Durations as defined by the project are:

- Hot start = Shutdown 8 hours or less
- Warm start = > 8 hours and < 48 hours
- Cold start = Shutdown 48 hours or more

The lead time activities prior to a warm or cold fast startup typically commence with startup of the auxiliary boiler. Depending on the start condition for the auxiliary boiler and the features incorporated to permit its fast start, this activity may need to commence approximately three hours before the actual combustion turbine start condition.

1.2 CONVENTIONAL VERSUS FAST START

Conventional combined cycle facility startup durations are constrained by steam cycle equipment limitations, specifically the heat recovery steam generator and steam turbine temperature ramp capabilities. Heat recovery steam generators and steam turbines are designed to operate at very high temperatures and pressures and, therefore, are comprised of very thick metal alloy components (e.g. steam drums, steam turbine rotors). These thick components can suffer from high thermal stress and increased life expenditure if they are subjected to large temperature differentials (e.g., 1,000°F steam across an ambient temperature steam turbine rotor) or rapid temperature ramp rates. HRSG and steam turbine suppliers provide strict temperature ramp rates and temperature differential requirements for their equipment that must be used to define and limit the startup sequence and duration in order to protect the equipment.

HRSGs designed through the middle of the last decade were generally not capable of allowing combustion turbines to start at their maximum capability without incurring significant maintenance impacts. These units required pauses ("holds") at low CTG loads to "heat soak" their heavy-walled components prior to releasing the unit on sustained ramp rates of typically less than 7°F per minute, as measured by the high-pressure (HP) drum steam saturation temperature.

Today's HRSGs can be more robustly designed for the rapid ramp rates of advanced class combustion turbines, which can exceed 50 megawatts (MW) per minute and yield HRSG temperature ramp rates exceeding 30°F per minute.

Though HRSGs are now designed to allow combustion turbines to start at their maximum capability, steam turbines are not. Cold steam turbines require relatively cool steam, typically in the range of 700°F, on first admission to the equipment. During the startup sequence, steam temperatures downstream of the HRSG are primarily controlled through two means working in tandem, CTG exhaust temperature control and desuperheating of the generated steam. CTG exhaust temperature control tunes the CTG to minimize the exhaust temperature into the HRSG during the startup sequence, as a cooler exhaust temperature produces cooler steam. Desuperheaters spray water into the steam headers to reduce, or "attemperate", the steam by reducing the level of superheat above the steam saturation temperature.

Most HRSGs include interstage desuperheaters that are installed between superheater and reheater sections to control the final HRSG exit steam temperatures. As the combustion turbine ramps above very low loads towards the MECL, the CTG exhaust temperature control and HRSG interstage desuperheaters are no longer capable of cooling the steam to the temperatures permitted by a relatively cool steam turbine. The steam turbine becomes a critical constraint on the start time unless the HRSG exit steam temperatures can be further reduced to match the steam turbine steam temperature requirements. In effect, the steam turbine must be 'decoupled' from the combustion turbine so that the combustion turbine start is not constrained by the steam cycle.

The steam turbine can be decoupled and its steam temperature requirements met irrespective of combustion turbine load by adding terminal desuperheaters (i.e., desuperheaters downstream of the HRSG in the high-pressure (HP) and hot reheat steam headers) to cool the HRSG exit steam to the steam turbine requirements.

Decoupling the steam turbine from the CTG/HRSG train allows the combustion turbine to ramp to emissions compliance load levels without hold periods in the firing sequence. A no-holds startup sequence is typically referred to as an uninhibited start.

Figure 1-1 provides a high-level comparison of the typical CTG load path for a 1x1 conventional combined cycle to that of a fast-start combined cycle. Additional details on the performance differences between the two startup types are discussed in Section 4.0.

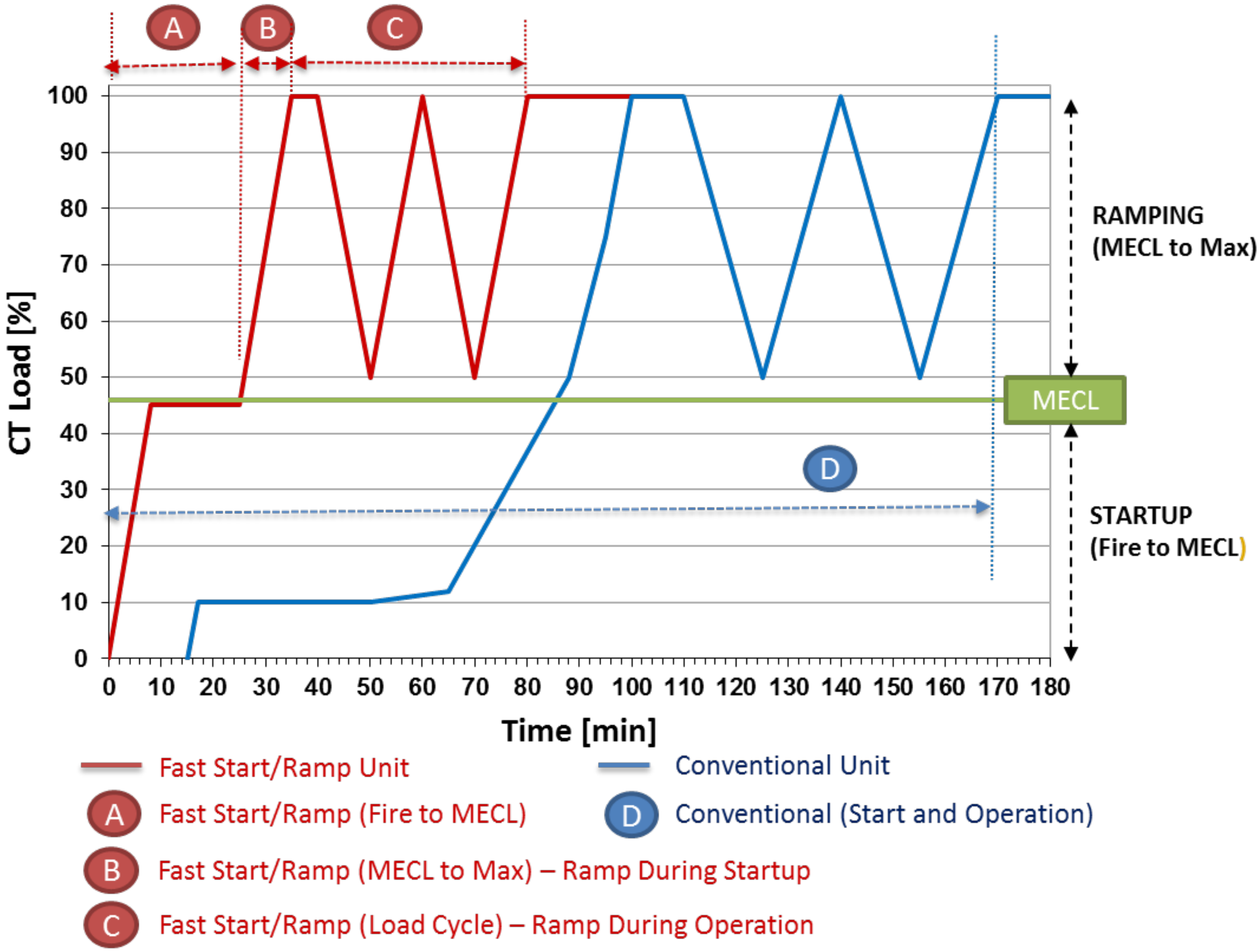


Figure 1-1 **Comparison of Combustion Turbine Loading during Hot Start Event (Excludes Purge)**

2.0 Design Features

Capital costs are higher for fast start plants than plants designed for conventional starts. Equipment and balance of plant systems affected by the additional design consideration for fast start are as described below and in Table 2-1. Column A of Table 2-1 lists specific design features and equipment required for fast start operation. Column D of Table 2-1 lists design features of conventional start units. Columns B and C will be discussed in the Fast Start vs. Conventional Unit Ramp Rate Analysis (File No. 400278.41.1204F).

Table 2-1 Design Features of Combined Cycles Designed for Various Operating Scenarios

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Required Option = ● , Recommended Option = ☐ , Standard Option = ◆				
Combustion Turbine				
Fast Start Equipped	●			
Natural Gas Purge Credits	●			☐
Service Life Monitoring System	◆	◆	◆	◆
Advanced Control System	●	●	●	
HRSG				
Advanced Drum Design	●	●		
Enhanced Nozzle Connections	●	●		
Improved HRSG Materials	●	●		
Improved HRSG Geometries	◆	◆	◆	◆
Service Life Monitoring System	☐	☐	☐	
Stack Damper and Insulation	●			☐
Terminal Attemperators	●	●	●	
LP Economizer Recirculation/ Heat Exchanger	●	●		
Steam Turbine				
Optimized Casing Design	●	●		
Advanced Control System	●	●	●	

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Service Life Monitoring System	●	●	□	
Advanced Stop Valve Design	●			
Increased Thermal Clearances	●	●		
Advanced Turbine Water Induction Protection	●	●	●	
Emissions Control				
Feed-forward Ammonia Controls	●	●	●	
Auxiliary Steam				
Auxiliary Boiler	●			
Condenser and HRSG Sparging	●			
Feedwater System				
Larger Condensate Pump	●	●	●	
Larger Feedwater Pump	●	●	●	
Higher Stage IP Bleed	●	●	●	
Heat Rejection System				
Surface Condenser – Fast Start Design	●			
Fuel Gas System				
Supplementary Fuel Gas Heating(1)	□			
Water Treatment System				
Condensate Polisher(2)	□			
Auxiliary Electrical System				
Larger Equipment for Higher Loads	●	●	●	

Notes:

1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

2.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

2.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, and reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

2.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

2.4 EMISSIONS AND AMMONIA FEED

Outlet NO_x from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure NO_x at the stack; for fast ramping units limiting NO_x measurements to the stack only can lead to over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO_2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO_2 dew points.

2.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establishing the steam turbine seals, warming up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

2.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for steam turbine temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

2.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

2.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

2.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

2.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

3.0 Capital Costs

Capital costs are higher for fast-start plants than plants designed for conventional starts. Additional costs that must be considered are requirements for a more flexible HRSG (e.g., header returns, tube to header connections, harps per header limits), terminal attemperators and associated systems; more flexible steam piping; improved steam piping drain systems, improved bypass system and controls integration, and requirements for auxiliary steam.

Table 3-1 lists the costs to include the design features listed in Column A of Table 2-1 for a fast start unit. Costs listed in the study are budgetary costs (+/- 30%).

Table 3-1 Fast Start (Fire to MECL) Operating Scenario Costs

FAST START SYSTEM COSTS FOR A 1X1 7F.05 COMBINED CYCLE	
Fast Start Options (Required options in Column A excluding Aux Boiler and Stress Monitoring Systems)	[redacted]
Auxiliary Boiler	[redacted]
Stress Monitoring Systems	[redacted]
Total	[redacted]

4.0 Performance Impacts

Startup durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 4-1 provides comparative durations [redacted] All fuel consumption and net generation values are based on combustion turbine ignition through the indicated end point.

Table 4-1 Estimated Nominal Startup Times (Minutes)

START TYPE	CONVENTIONAL START TO MECL	FAST START TO MECL	DIFFERENCE (CONVENTIONAL – FAST)
Hot Start = Shutdown 8 hours or less	[redacted]	[redacted]	[redacted]
Warm Start = > 8 hours and < 48 hours	[redacted]	[redacted]	[redacted]
Cold Start = Shutdown 48 hours or more	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

5.0 Startup Emissions

Stack emissions vary widely prior to reaching steady state emissions compliance due to the complexity of starting a combined cycle facility and the plant equipment's ability to operate within threshold limits across a certain operating range. The combustion turbine and the HRSG post-combustion emissions control components (if applicable) are the main equipment governing stack emissions variation.

Combustion turbines are designed with multiple fuel nozzles in each combustor. As combustion turbines start and ramp up to normal operating flow, load, and temperature, the combustion nozzles are sequenced through various combustion operating modes that vary the deflagration type (i.e., diffusion or pre-mixed [i.e., the air and fuel are pre-mixed prior to ignition of the fuel]) and nozzle firing sequences (i.e., which of the multiple nozzles are in service). These startup combustion modes are required so that stable combustion can be maintained in the unit during startup to avoid flame outs. As illustrated in Figure 2-1, in these off-design startup combustion modes, the combustion of the fuel is generally incomplete resulting in higher than normal nitrous oxide (NO_x), carbon monoxide (CO), and volatile organic compound (VOC) emissions concentrations. As the turbine reaches a minimum operating load where its normal combustion mode can be stably maintained, combustion becomes more complete and emissions decrease to a level that can be maintained across a wide operating range. The minimum operating load of the combustion turbine in this emissions compliant operating range is called the Minimum Emissions Compliance Load (MECL).

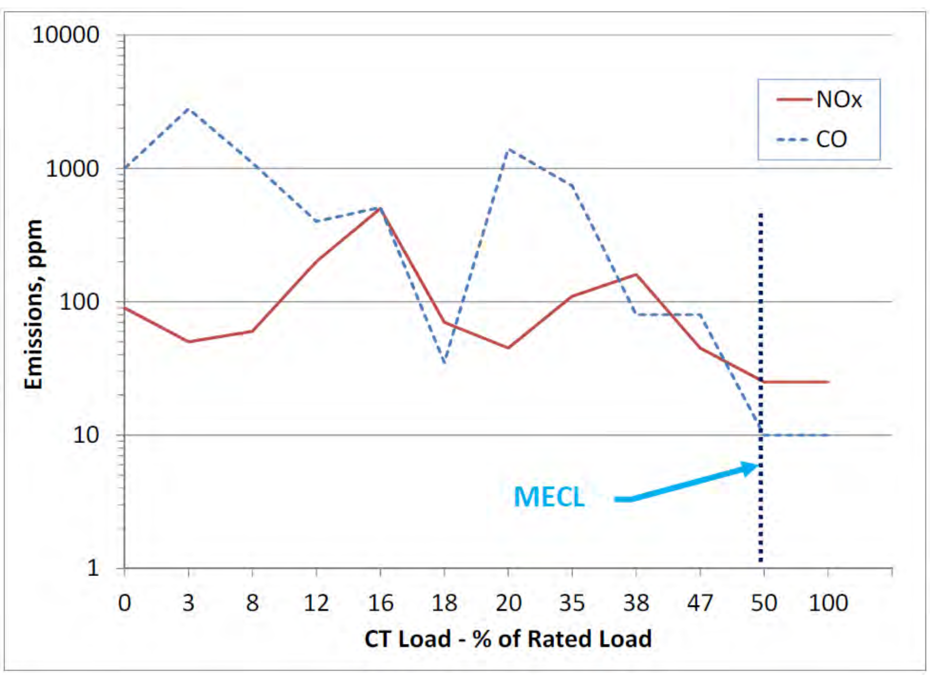


Figure 5-1 Example Combustion Turbine NO_x and CO Emissions versus Rated Load

Below MECL, the mass of air pollutant emissions can accumulate quickly and, therefore, these “startup emissions” are of particular interest to regulators. The steady-stated CTG design exhaust emissions for the turbine technologies considered are approximately 15-25 ppmvd @15% O2 for NO_x and 4-10 ppmvd @15% O2 for CO when operating on natural gas. Steady-state VOC emissions are dependent on the site specific natural gas composition.

An emissions netting analysis will be performed for the new combined cycle plant. If a Prevention of Significant Deterioration (PSD) review is required, the emissions standard that must be met is Best Available Control Technology (BACT), an emissions control mandate by the Environmental Protection Agency (EPA). If applicable, combined cycle BACT requirements dictate NO_x and CO emissions shall be no greater than 2 ppm (parts per million) at the HRSG stack discharge over the entire normal operating range. CTG emissions levels are not sufficient for BACT and post-combustion emissions controls components; oxidation catalyst to reduce CO/VOC emissions and a selective catalytic reduction (SCR) system to reduce NO_x emissions, must be installed in the HRSG to further reduce emissions to BACT levels.

Oxidation catalysts and SCR systems are not effective until they are warmed to a minimum threshold temperature and the SCR ammonia injection (utilized with the catalyst to reduce NO_x emissions) is tuned. In general, these post-combustion emissions controls components are designed such that the minimum threshold temperatures are achieved on a startup at or below the combustion turbine MECL. As noted previously, an “emissions” startup sequence is considered complete after the CTG reaches MECL, and in the event of post-combustion emissions control components, they reach their minimum threshold temperatures, and the SCR ammonia injection is tuned such that stack emissions meet the air quality requirements.

FINAL

FAST START VS. CONVENTIONAL UNIT RAMP RATE ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1204F

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1.0 Introduction

The purpose of this study is to evaluate the differences for conventional and fast ramping options between MECL and full load on unit startup for a 1x1 7F.05 combined cycle. The GE 7F.05 is one of several candidate F-Class combustion turbine offerings.

Since the temperature differential between components is the primary concern of fast ramping between MECL and full load; many of the design features required for fast ramping between MECL and full load are the same as the features required for fast start between combustion turbine ignition to MECL as discussed in the Fast Start vs. Conventional Start Analysis (File No. 400278.41.1203F). Figure 1-1 shows the regions covered under this study noted as Ramping and that covered in the Fast Start vs. Conventional Start Analysis noted as Startup.

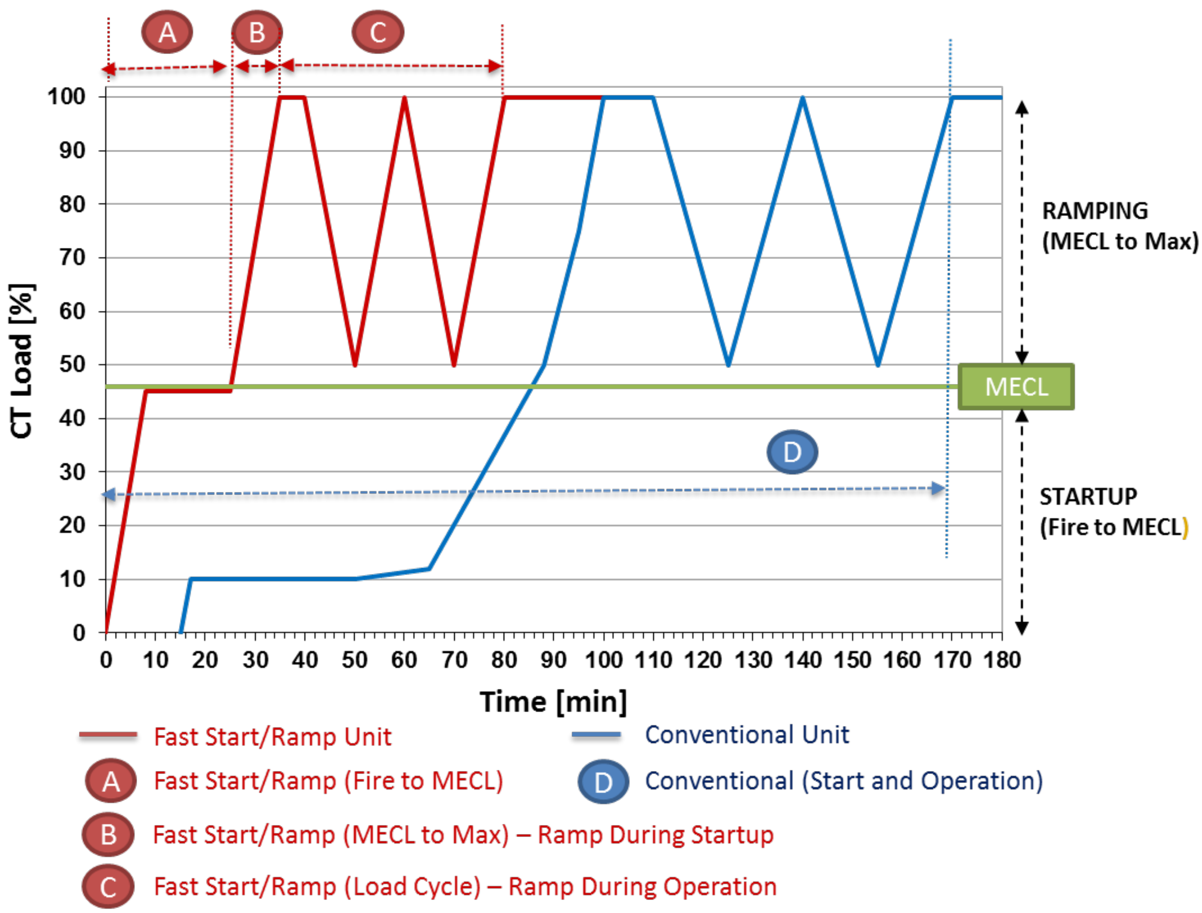


Figure 1-1 Comparison of Combustion Turbine Loading From MECL to Full Load

Table 1-1, Column B indicates the design features that would be required for fast ramping and how they differentiate from a conventional unit, Column D, and a fast start unit, Column A. Descriptions for each of the design features can be found in the Fast Start vs. Conventional Start

Analysis and also included in Appendix A. Items included in Column B also encompass those features in Column C which are required for fast ramping during operation.

Table 1-1 Design Features of Combined Cycles Designed for Various Operating Scenarios

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Required Option = ●, Recommended Option = ☐, Standard Option = ◆				
Combustion Turbine				
Fast Start Equipped	●			
Natural Gas Purge Credits	●			☐
Service Life Monitoring System	◆	◆	◆	◆
Advanced Control System	●	●	●	
HRSG				
Advanced Drum Design	●	●		
Enhanced Nozzle Connections	●	●		
Improved HRSG Materials	●	●		
Improved HRSG Geometries	◆	◆	◆	◆
Service Life Monitoring System	☐	☐	☐	
Stack Damper and Insulation	●			☐
Terminal Attemperators	●	●	●	
LP Economizer Recirculation/Heat Exchanger	●	●		
Steam Turbine				
Optimized Casing Design	●	●		
Advanced Control System	●	●	●	
Service Life Monitoring System	●	●	☐	
Advanced Stop Valve Design	●			
Increased Thermal Clearances	●	●		
Advanced Turbine Water Induction Protection	●	●	●	
Emissions Control				
Feed-forward Ammonia Controls	●	●	●	

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Auxiliary Steam				
Auxiliary Boiler	●			
Condenser and HRSG Sparging	●			
Feedwater System				
Larger Condensate Pump	●	●	●	
Larger Feedwater Pump	●	●	●	
Higher Stage IP Bleed	●	●	●	
Heat Rejection System				
Surface Condenser – Fast Start Design	●			
Fuel Gas System				
Supplementary Fuel Gas Heating(1)	□			
Water Treatment System				
Condensate Polisher(2)	□			
Auxiliary Electrical System				
Larger Equipment for Higher Loads	●	●	●	

Notes:
1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

2.0 Capital Costs

Note that all of the features required for fast ramp are included in Column A of Table 1-1 discussed in the Fast Start vs. Conventional Start Analysis. The costs in Table 2-1 indicate only the costs for Column B of Table 1-1. Costs listed in the study are budgetary costs (+/- 30%).

Table 2-1 Fast Ramp (MECL to Full Load) Operating Scenario Costs

FAST RAMP SYSTEM COSTS FOR A 1X1 7F.05 COMBINED CYCLE	
Fast Ramp Options (Required options in Column B excluding Stress Monitoring Systems)	[redacted]
Stress Monitoring Systems	[redacted]
Total*	[redacted]
NOTE: If a fast start plant is selected, the above costs are not additive to those listed in the Fast Start Study.	

3.0 Performance Impacts

Startup and ramping durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 3-1 provides comparative durations for a GE 7F.05 1x1 combined cycle. [redacted]

Table 3-1 Estimated Nominal Startup Times (Minutes)

START TYPE	CONVENTIONAL START TO MECL	CONVENTIONAL START TO STG FULL LOAD	FAST START TO MECL	FAST START, TO CTG BASELOAD	FAST START, TO CTG BASELOAD WITH STG LOADED
Hot Start = Shutdown 8 hours or less	Base Conv.	42	Base Fast	7.1	54
Warm Start = > 8 hours and < 48 hours	Base Conv.	37	Base Fast	21	47
Cold Start = Shutdown 48 hours or more	Base Conv.	67	Base Fast	62	98

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For a conventional start, each combustion turbine is ramping at a nominal rate from MECL to combustion turbine baseload of 17 MW/min or 7.09%/min, while the combustion turbine ramp rate for fast start is 40 MW/min or about 16.66%/min from MECL to combustion turbine baseload.

After startup and after thermal soaking, the unit will able to achieve fast ramping. For a GE 7F.05, each combustion turbine has the ability to ramp 40 MW/minute. For a 1x1 combined cycle, the ramp rate can be stated to be 40 MW/minute. The steam turbine contribution toward fast ramping is typically not quoted since the steam turbine response is much less predictable than the combustion turbine load response. This is due to a lag in HRSG steam production response due to the CTG load changes. Depending on how the combustion turbine is ramped up and down, the output contribution from the steam turbine would take some time to settle out into a steady state performance level. For conventional units, the combustion turbine ramp rates may be limited by the HRSG and steam turbine limitations. For units equipped with fast ramping, the steam conditions can be conditioned to allow the combustion turbine to ramp independently of the steam turbine.

4.0 Emissions

The period for ramping is defined as the period between minimum emissions compliance load and full load. Once the unit has obtained emission compliance, the unit generally stays in compliance for ramping conditions. During a fast ramp the outlet NO_X from the combustion turbine is variable. Conventional units only measure NO_X at the stack; this may lead to short durations of higher NO_X or ammonia slip. For fast ramping units limiting NO_X measurements to the stack only can lead to over injecting or under injecting ammonia. To address this, fast ramping units are equipped with feed-forward NO_X controls which take NO_X measurements at the combustion turbine exhaust as well as the stack to quicken the response to changing combustion turbine exhaust conditions. Both conventional and fast ramping units are designed to operate in compliance with stack emission limits across the averaging period.

Appendix A. Fast Start and Fast Ramp Design Features

Design features for fast start and fast ramping units are as follows:

A.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

A.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

A.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

A.4 EMISSIONS AND AMMONIA FEED

Outlet NO_X from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure NO_X at the stack; for fast ramping units limiting NO_X measurements to the stack only can lead over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO2 dew points.

A.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

A.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

A.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

A.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

A.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

A.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

FINAL

NUMBER OF COLD, WARM, AND HOT STARTS ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1207F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1.0 Introduction

Prior to the early 2000s, combined cycles were predominately designed for base load operation with high focus on highest full load efficiency and lowest capital cost. Due to increases in gas pricing, changing power market production cost structure, and renewable energy generation, many of these plants were forced into intermediate or even daily cycling mode. Many problems associated with the fast changing temperatures in the equipment resulted, such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction.

As a result of these industry issues, today's major equipment suppliers design their equipment to withstand the cumulative wear and damage caused by frequent starts and stops. For modern combined cycle equipment operating as high cycling units, major equipment manufacturers take the following into consideration:

- Base equipment designs consider high cycling
- Service life monitoring equipment is recommended for high cycling units
- Time between service intervals decreases with higher cycling

In addition to the number of starts, the time between the unit shutdown and start also has a significant impact on the equipment. When a unit is shutdown, equipment begins to cool. Upon the next start, the equipment would have to be brought back up to operating temperature putting the equipment through a thermal cycle. The duration between shutdown and startup is usually broken down between different start modes whether the equipment is considered hot, warm, or cold. Equipment manufacturers each have their own definition for hot, warm, and cold starts; however, typical start mode durations are listed in Table 1-1.

Table 1-1 Start Mode Definitions

START TYPE	SHUTDOWN DURATION
Hot	< 8 hours
Warm	8-48 hours
Cold	> 48 hours

1.1 BASE EQUIPMENT DESIGN

During startup and shutdown, the unit sees large temperature gradients and thermal stresses. Cycling increases concern for thermally induced creep-fatigue damage as a result of rapid heating of the surface of components such as turbine blades, rotors, casings, drums, and other heavy walled components. Creep-fatigue damage can also result from different thermal expansion between thin and thick components or dissimilar metal welds.

To resolve these issues, manufacturers have incorporated the knowledge of these earlier failures into their standard designs. Manufacturers select geometries, materials, thicknesses, and coatings in such a way as to limit the damage of thermal cycling. Geometries and material selection also alleviate other issues such as flow accelerated corrosion, vibration, and water induction. These designs do not alleviate all the issues with thermal factors but allow the equipment to be monitored in such a way to determine its service life.

1.2 MAINTENANCE INTERVALS

The design life for the facility is 30 years and the operating equipment will need regular maintenance including hot gas path and major inspections. Figure 1-1 shows the equivalent hours-based and starts-based maintenance intervals for GE and Siemens F-class combustion turbines and the potential impact of maintenance factors on maintenance intervals.

The timing of maintenance intervals are impacted by maintenance factors. Hours based maintenance factors consider fuel type, firing temperature, and water or steam injection used for emissions control or power augmentation. Starts based maintenance factors consider the type of start; whether it is a conventional start, fast start, cold start, warm start; load achieved during each start; and shutdown type such as normal cooldown, rapid cooldown or unit trip. The red lines in Figure 1-1 show how starts or hours based factors could affect the timing of maintenance intervals.

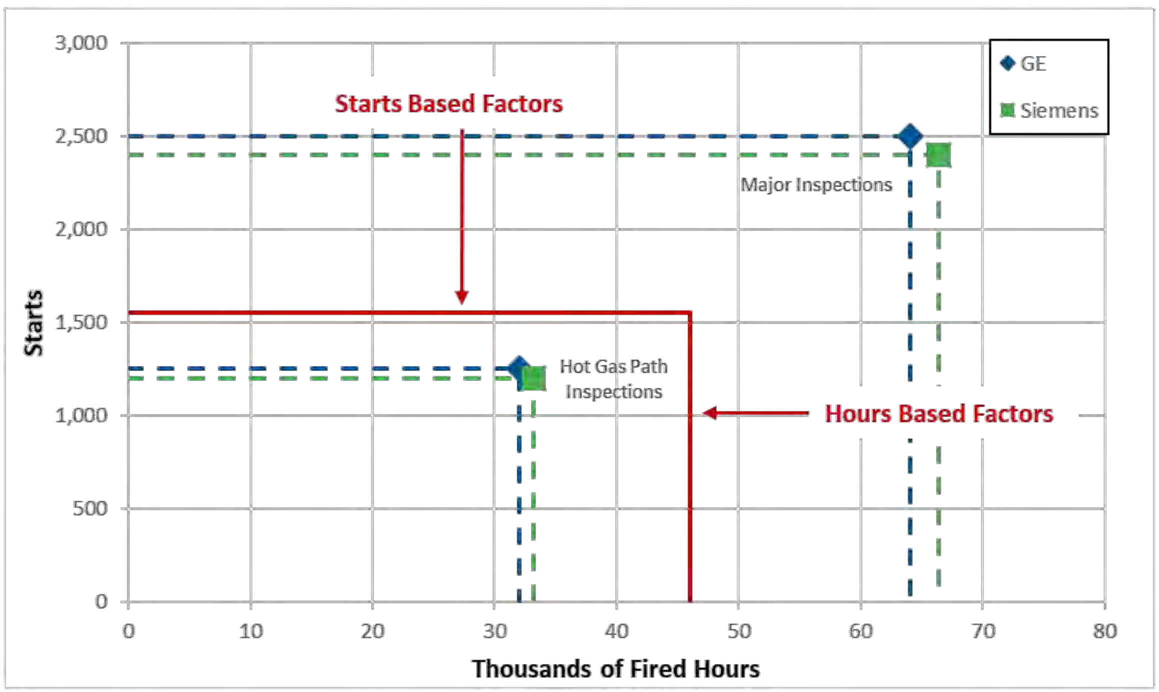


Figure 1-1 Maintenance Factors Reduce Maintenance Intervals

Per GE's Heavy-Duty Gas Turbine Operating and Maintenance Considerations (GER-3620N), a GE unit with a baseline maintenance factor would equate to 4,800 operating hours per year (16 hours/start, 6 starts/week, 50 weeks/year) and 300 starts per year. Those 300 starts would consist of 249 hot starts, 39 warm starts, and 12 cold starts. For the design life of 30 years, GE would base their Long Term Service Agreement (LTSA) on 4 maintenance cycles for a GE 7F.05 with a baseline operating profile. The LTSA relates to the serviceable life of the combustion turbine.

Figure 1-2 shows how operating hours and the number of starts per year affect the duration of the LTSA. A 30 year life is based on roughly 333 equivalent starts per year. An operating regime requiring above 333 equivalent starts per year would have service intervals based on equivalent life and start decreasing the life expectancy of the LTSA. For example, 500 equivalent starts per year would be roughly equivalent to a 20 year LTSA life. When operating below 333 equivalent starts per year the figure shows whether hours based operation or number of starts based operation would determine the maintenance intervals for the plant. Since the facility has a 30 year design life, 333 equivalent starts would be the average yearly allowable for the plant. Based on a design basis of 310 starts per year, the breakdown of recommended number of design basis cold, warm, and hot starts would be as shown in Table 1-2.

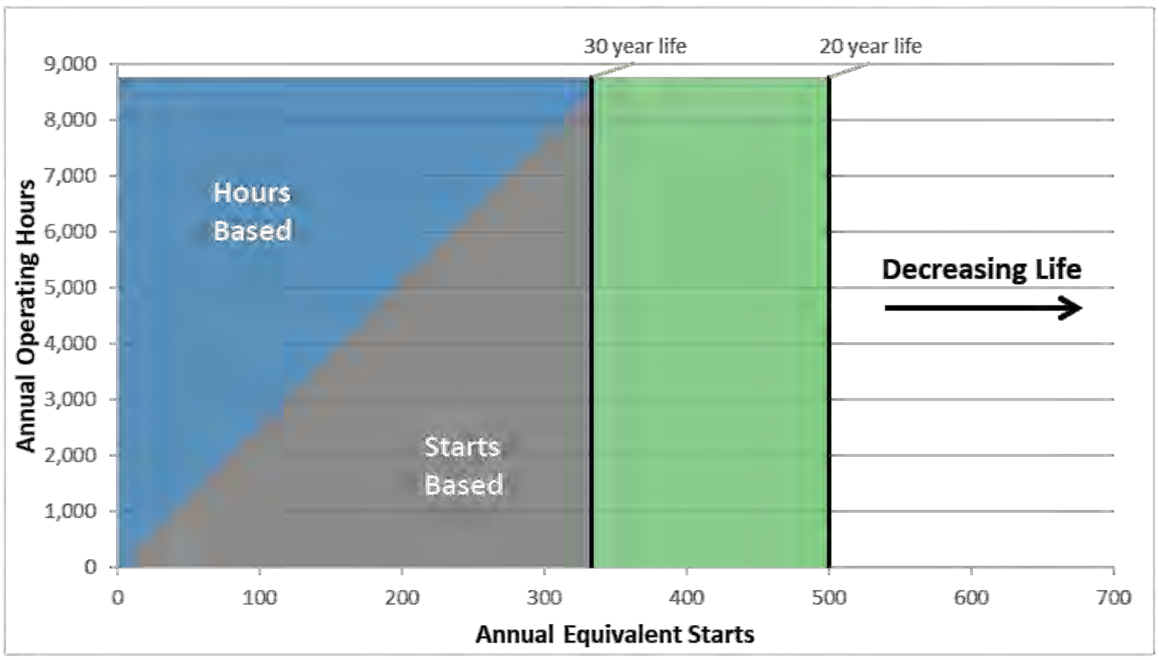


Figure 1-2 Combustion Turbine LTSA Term vs. Starts and Operating Hours Service Intervals

Table 1-2 Operating Conditions Used in Design Basis

OPERATING CONDITIONS	DESIGN BASIS
Operation	Daily Cycling
Yearly Operating Hours	Up to 8,760
Annual Capacity Factor	45% to 100%
Cold Starts Per Year	10
Warm Starts Per Year	100
Hot Starts Per Year	200
Total Starts Per Combustion Turbine	<310

1.3 SERVICE LIFE MONITORING EQUIPMENT

For plants operating in a regime where the starts based maintenance factors are determining the service intervals, it becomes useful to monitor the equipment to avoid costly outages. Service life monitoring systems perform three functions: instrumentation, evaluation, and determination. The instrumentation and sensor systems record the operating parameters such as localized temperature, pressure, and vibration. Based upon the readings, evaluations can be made such as stresses in critical locations in the turbines and the HRSG. The evaluated data is then combined with the operating history of the system to determine the impact on the remaining service life.

Recommended monitoring systems for high cycling plants include:

- Combustion Turbine Stress Controller
- Steam Turbine Stress Controller
- HRSG Stress Controller
- Condition Monitoring System
- Water Quality Monitoring System

Today's F-class combustion turbines come equipped with control systems that monitor speed, acceleration, temperature, and verify that all sensors are active. These sensors measure performance and monitor the machine's health. These systems also count the operating hours and number of equivalent starts or calculate the equivalent life of each start sequence in order to calculate the next service interval.

The steam turbine stress controller consists of a stress evaluation system that calculates and controls stresses in thick walled components including stop and control valves, HP casing and rotor body, and the IP rotor body. The stress controller monitors and controls ramp rates during start up to calculate the cumulative fatigue of cycling the unit. The stress controller also determines the remaining time to the next service interval.

The HRSG stress controller performs a dynamic analysis of the HRSG to determine fatigue. The stress controller determines risk factors based upon the evaluations, such as the probability of crack initiation. These risk factors are used to plan and indicate HRSG maintenance.

Condition monitoring systems measure critical asset parameters such as vibration, temperature, and speed of rotating equipment including boiler feed pumps, condensate pumps, circulating water pumps, cooling tower fans, and fuel gas compressors. The monitoring systems also evaluate trends, such as vibration amplification, and compare it against set points, historical readings, and known failure patterns.

The water quality monitoring system provides additional water and steam sampling to monitor issues with cycling units. Cycling units result in a large demand on the condenser and, in peak demands, on condensate supply and oxygen controls. Additional controls include online monitoring for condenser tube leaks and condenser air in leakage. It also includes monitoring steam blowdown lines for high level of particulates to indicate any safety issues. Water quality monitoring systems are not as important if the unit includes a condensate polisher.

2.0 Service Life Monitoring System Costs

As outlined in Section 1.2, service life monitoring systems are recommended for high cycling plants to help predict and plan maintenance. Table 2-1 provides budgetary cost (+/- 30%) for service life monitoring systems.

Table 2-1 Service Life Monitoring System Costs

SERVICE LIFE MONITORING SYSTEM COSTS	
Combustion Turbine Stress Controller	[redacted]
Steam Turbine Stress Controller	[redacted]
HRSG Stress Controller	[redacted]
BOP Condition Monitoring System	[redacted]
Water Quality Monitoring System	[redacted]
Additional cable and I/O	[redacted]
Total	[redacted]

3.0 Conclusion

Today's combined cycle equipment is designed for high cycling applications and consider problems associated with the fast changing temperatures in the equipment such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction. The design life of the equipment is 30 years with major overhauls of the combustion turbines occurring every 7.5 to 8 years. The time duration between major overhauls is based upon maintenance factors associated with hours of operation and the number of starts.

While the number of operating hours is not expected to shorten the time between maintenance cycles, the number of starts could decrease the operational life. In order to maintain the 7.5 to 8 years between major overhauls, the combustion turbine should have an equivalent number of annual starts less than 333. To avoid decreasing the life of the LTSA, the typical combined cycle design including balance of plant equipment should not exceed 333 starts per year. The breakdown of the recommended number of design cold, warm, and hot starts would be as shown in Table 3-1.

Table 3-1 Design Cold, Warm, and Hot Starts

OPERATING CONDITIONS	
Operation	[redacted]
Yearly Operating Hours	[redacted]
Annual Capacity Factor	[redacted]
Cold Starts Per Year	[redacted]
Warm Starts Per Year	[redacted]
Hot Starts Per Year	[redacted]
Total Starts Per Combustion Turbine	[redacted]

If the plant is expected to be a high cycling unit with a maintenance cycle that would be determined based upon the number of starts rather than the number of hours operated per year, Vectren should consider additional service life monitoring systems to assist in predictive maintenance, as shown in Table 3-2. While these systems do not prevent maintenance, they allow the operator to better understand how the operation of the unit is impacting the service life of the equipment.

Table 3-2 Service Life Monitoring Systems

SERVICE LIFE MONITORING SYSTEM COSTS	
Combustion Turbine Stress Controller	[redacted]
Steam Turbine Stress Controller	[redacted]
HRSG Stress Controller	[redacted]
BOP Condition Monitoring System	[redacted]
Water Quality Monitoring System (not required with a condensate polishing system)	[redacted]
Additional cable and I/O	[redacted]
Total	[redacted]

FINAL

AUXILIARY BOILER ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1209F

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

Executive Summary

In developing this report, Black & Veatch reviewed the requirements for the auxiliary steam system for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and shutdown scenarios to determine the required sizing and operation of the auxiliary steam boiler.

The auxiliary steam system users have been summarized in the Auxiliary Steam Demands provided in Table 2-1. The users were estimated based on previous projects using the 7F.05 gas turbines. Based on the maximum co-incident steam demand of the 7F.05 configuration it is recommended that Vectren utilize an auxiliary boiler designed for [redacted] lb/hr and an outlet pressure of [redacted]

1.0 Introduction

The purpose of this study is to determine the specific requirements for the Auxiliary boiler to be installed with the new Combined Cycle Power Plant (CCPP). These Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This auxiliary steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable quicker startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures. Black & Veatch has previously performed the "Fast Start vs Conventional Start Analysis" which demonstrates the need for an auxiliary boiler for a unit with fast start capability.

This evaluation will help determine the design impact of this system to the new CCPP design. Auxiliary system users, auxiliary boiler sizing and operation will also be identified and discussed.

2.0 Auxiliary Boiler Sizing and Outlet Pressure

The auxiliary steam system provides steam to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the best preliminary design basis for sizing the auxiliary boiler. Upon selection of the final plant design, the selected size of auxiliary boiler should be reviewed.

2.1 COINCIDENT STEAM DEMANDS

The maximum co-incident auxiliary boiler steam demand occurs during startup when supplying maximum steam turbine sealing, fuel heating, maximum condenser sparing steam, and maximum combustion turbine inlet air heating as shown in Table 2-1.

Table 2-1 Coincident Auxiliary Steam Demands

AUXILIARY STEAM USERS	1X1 7F.05
ST Gland Sealing	[redacted]
Startup Steam to Fuel Gas Heater	[redacted]
Condenser Hotwell Sparging	[redacted]
Combustion Turbine Inlet Air Heating	[redacted]
Total Coincident Boiler Steam Flow Required	[redacted]

2.2 NON-COINCIDENT STEAM DEMANDS

During unit pre-start, there are two activities that require auxiliary steam flow, but are not co-incident with the other users. These non-coincident activities occur during HRSG pre-warming and HRSG HP pressure holding. The non-coincident auxiliary steam demands are listed in Table 2-2.

Table 2-2 Non-Coincident Auxiliary Steam Demands During Pre-Start Activities

AUXILIARY STEAM USERS	1X1 7F.05
HRSG Warming	[redacted]
HRSG Pressure Holding	[redacted]

2.3 DESCRIPTION OF USERS

- The turbine seals require steam from the auxiliary system to provide sealing until the steam turbine increases load and becomes self-sealing. When the steam turbine exceeds the point of self-sealing, the flow from the auxiliary system will decrease to near zero.
- A startup steam to fuel gas heater is used to raise the fuel gas to the CT manufacturers specified minimum fuel temperature via a steam to water heat exchanger.
- Condenser hotwell sparging is used to heat the condensate in the condenser to normal operating temperatures prior to starting the units.
- The gas turbine inlet air heating system uses auxiliary steam to provide heat via coils in the CT inlet air structure to minimize the possibility for ice formation in the CT compressor section.
- The HRSG HP warming flow increases the metal temperature of the steam drums and the tubes, allowing for faster startup capability.
- The HRSG HP pressure holding maintains the HP evaporator at a minimum of 275 psig to maintain drum and tube temperatures for faster startup capability.

2.4 BOILER OUTLET CONDITIONS

The delivery steam pressure of the auxiliary boiler is typically 300 psig at saturation temperature to facilitate HP evaporator pressure holding of approximately 275 psig. Electric superheaters will be used to provide superheated steam to the turbine seals. Delivering saturated steam will reduce the heat input to the auxiliary boiler which is limited due to air permits.

3.0 Auxiliary Boiler Operation

3.1 PRE-START CONDITION

The auxiliary steam system should be pressurized, heated and drained up to the steam seal feed valve during pre-start activities. The operating conditions of the auxiliary boiler and system must be verified prior to initiating a unit startup. During cold pre-start activities, the steam for turbine sealing, condenser sparging steam and HP evaporator warming is supplied by the auxiliary boiler. During hot start activities, the steam demand for the HP evaporator warming steam is replaced by the steam demand for HP evaporator pressure holding. Following an HRSG outage or cold restart, the HRSG HP warming flow is set to a maximum flowrate to accelerate warming.

3.2 INITIAL STARTUP AND SHUTDOWN

During initial startup the auxiliary steam for the turbine sealing, CT air inlet heating, fuel gas heating and condenser sparging is provided from an auxiliary boiler. As the plant cycle steam from the HRSG IP drum becomes available it allows the auxiliary boiler to be shut down or unloaded to idle as plant operations allow. During normal operation the HRSG IP drum provides all required auxiliary steam flow for the plant.

During plant shutdown or trip, it is expected that there is enough residual energy in the HRSG to provide auxiliary steam until the steam turbine exhaust vacuum is broken or the auxiliary boiler can be brought online to provide sealing steam. The auxiliary boiler must remain in a ready condition at all times during combined cycle operation. During overnight plant shutdowns the aux boiler can remain in operation to provide sealing steam, condenser sparging steam and allow rapid starting in the morning.

4.0 Conclusions

The purpose of this evaluation was to determine the specific requirements for the auxiliary boiler for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed pre-start, start-up and shut down scenarios to determine the required sizing and operation of the auxiliary boiler.

This report has shown:

- Auxiliary steam users and the estimated demand.
- Non-coincident auxiliary steam users and the estimated demand
- Black & Veatch's recommendation for steam requirements listed in Table 2-1 for various plant configurations.

FINAL

EXISTING FIRE WATER SYSTEM REVIEW

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 42.1212F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

Table of Contents

Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed the piping and instrumentation diagrams (P&IDs) for the existing fire protection and service water systems.

The existing system includes existing pumps and a 75,000 gallon raw water storage tank. The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. To meet the new fire water system design requirements, a third diesel motor fire pump should be added to the system and the pump arrangement modified to a 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump, which is rated for approximately 1 percent for the main pumps flow and same discharge pressure, should remain.

1.0 Existing Equipment

Based on the existing site Fire Protection and Service Water Systems P&ID (F-1024) there are 2x100 percent fire pumps (one electric driven and one diesel driven) that are rated for 1,500 gpm @ 300 FT TDH each. The fire water pumps normally take suction from existing Ranney Well pumps of adequate capacity and the Raw Water Storage Tank (75,000 gallons) via a 12" nominal diameter suction header. The Raw Water Storage Tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. The fire protection water supply system is also cross tied to the River Water pumps. The existing site has a 10" underground fire water loop. This pipe is assumed to be ductile iron.

Per NFPA 850, the existing water source is large enough to be considered a reliable water source. The multiple pumps installed provide reliability such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. If a single pump were to be out of service, the remaining pumps will still have sufficient capacity to supply water to the existing water users as well as the maximum fire water demand of 2,500 gpm.

2.0 Design Basis and Clarifications

- A search of the NFPA codes on the Indiana State website did not include NFPA 850. However, for the purposes of this assessment and the design of the new power plant, Black & Veatch has referenced NFPA 850 – 2015.
- There is a discrepancy between some of the code years referenced on the Indiana State website and from the IBC or IFC. Our basis is the most current version when this occurs.
- It is not clear from the P&ID what the material used for the existing underground fire water supply mains. Our basis is currently ductile iron material; please clarify if different.
- Please clarify who the Authority Having Jurisdiction (AHJ) is for the A.B. Brown Site. We have identified the state fire marshal below.

  Indiana State Fire Marshal
  Stephen Cox
  317-232-2222
  http://www.in.gov/dhs/2445.htm

3.0 New Plant Fire Protection Requirements

The new plant's required fire water system supply flow is based on a worst case fire scenario, plus a hose allowance (500 gpm), and any adjacent systems in the immediate area of a potential fire area; as defined in NFPA 850, Section 6.2. The largest system demand is expected to be the Steam Turbine Building/Enclosure at 1,800 gpm in combination with the turbine generator bearings closed head sprinkler system with directional nozzles with a demand of approximately 200 gpm. This total demand will require a main fire pump rated at 2,500 gpm. The velocity limits at this flow require either a 10" DI or 12" HDPE DR 11 pipe.

To meet the new fire water system design requirements a third diesel motor fire pump (1,500 gpm @ 300ft) should be added to the system modifying the pump arrangement to 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump which is rated for approximately 1 percent for the main pumps flow and same discharge pressure should remain. There are no elevated areas for the new or existing plant areas that require booster pumps to obtain adequate pressure for hose stations so a standard pressure rating of 300 ft-H2O at the rated point is expected to be sufficient.

Per NFPA 850 the multiple Ranney Well pumps installed will provide a reliable source of water such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. In a single pump out of service case the two remaining Ranney Well pumps can provide up to 4,000 gpm. The preliminary water mass balance for other uses states the normal use from non-fire protection demands is approximately 150 gpm. This allows the fire water demand of 2,500 gpm to be met along with the other non-fire protection water users.

The existing 10" fire protection underground system can be reused with new 12" HDPE used for any new underground headers and around the cooling tower. Hydrants will be located as per NFPA 850 and the local code requirements.

4.0 List of Applicable Codes and Standards

675 IAC 13-2.6	Indiana Building Code, 2014 Edition (IBC, 2012 Edition, 1st printing) ANSI A117.1-2009	Effective 12/1/14
675 IAC 22-2.5	Indiana Fire Code, 2014 Edition (IFC 2012 Edition, 1st printing)	Effective 12/1/14

NFPA Standards

NFPA #	**Description**	**Effective Date**	**IAC Cite**
10-2010	Portable Fire Extinguishers	December 15, 2012	675 IAC 28-1-2
11-2005	Low Expansion Foam and Combined Systems	September 22, 2006	675 IAC 28-1-3
12-2005	Carbon Dioxide Extinguishing Systems	September 22, 2006	675 IAC 28-1-4
13-2010	Installation of Sprinkler Systems	September 26, 2012	675 IAC 28-1-5
14-2000	Installation of Standpipe and Hose Systems	December 13, 2001	675 IAC 13-1-9 Repealed 3/21/14
15-2001	Water Spray Fixed Systems	September 22, 2006	675 IAC 28-1-8
20-1999	Installation of Centrifugal Fire Pumps	December 13, 2001 Amended 12/26/02	675 IAC 13-1-10
25-2011	Inspection, Testing and Maintenance of Water Based Fire Protection Systems	May 12, 2013	675 IAC 28-1-12
37-2002	Installation and Use of Stationary Combustion Engines and Gas Turbines	September 22, 2006	675 IAC 28-1-15
70-2008	National Electrical Code	August 26, 2009	675 IAC 17-1.8
72-2010	National Fire Alarm Code	March 23, 2014	675 IAC 28-1-28
2001-2004	Clean Agent Fire Extinguishing Systems	September 22, 2006	675 IAC 28-1-40

5.0 Conclusions

The purpose of this evaluation was to review the existing fire water system. Black & Veatch reviewed P&IDs for both the existing fire protection and service water systems.

This report has shown:

- The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use.
- The existing pressure maintenance pump is sufficient.
- The existing 10 inch fire protection underground system can be reused with new 12 inch HDPE used for any new underground headers and around the cooling tower.
- Black & Veatch's recommendation is to add a third diesel motor fire pump and modify the pump arrangement to a 3x50 percent configuration.

FINAL

NOISE REGULATION REVIEW

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1213F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

Table of Contents

Executive Summary

Black & Veatch reviewed the noise regulations that might apply to the new Combined Cycle Power Plant (CCPP).

Indiana, Posey County, and Marrs Township have no far field noise regulation or ordinances. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Occupational Safety and Health Administration (OSHA) standards will apply to near field noise emissions. Near field noise requirements are measured along the equipment envelope. During off-normal and intermittent operation such as startup, shutdown, and upset conditions, the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

1.0 Results of Noise Regulation Review

Noise requirements fall into two categories: far field or near field. These categories are based upon the distance from the emitter to the receptor. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Near field noise requirements are measured along the equipment envelope. The envelope is defined as the perimeter line that completely encompasses the equipment package a distance of 3 feet from the face of the equipment.

1.1 FAR FIELD NOISE REQUIREMENTS

There are no extant noise regulations or ordinances for Indiana, Posey County, or Marrs Township. The expectation would be that the general environmental sound levels in the surrounding area would not be substantially different from the sound levels with the two coal units in operation, assuming the coal units will be decommissioned after the new unit is operational.

1.2 NEAR FIELD NOISE REQUIREMENTS

Near field noise requirements are limited by OSHA requirements. The near-field noise emissions for each equipment component furnished under these specifications shall not exceed a spatially-averaged free-field A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 feet above floor/ground level and any personnel platform during normal operation.

During off-normal and intermittent operation such as start-up, shut-down, and upset conditions the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

2.0 Conclusions

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

The attached V100 supplemental, contains the noise abatement requirements to be included with the procurement specifications. Since there were no extant noise regulations specific to this site, the V100 supplemental was developed using the near field requirements which are the typical OSHA limits.

FINAL

CONDENSATE POLISHER EVALUATION SUMMARY

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1214F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

Table of Contents

Executive Summary

This report provides a summary of Black & Veatch's evaluation of including a condensate polisher system in the conceptual design of the new A.B. Brown Combined Cycle. This summary of the evaluation will show that:

- Five selection criteria for Pre-Coat Condensate Polishers are present in the conceptual design. General industry practice to consider polishing is three or more.

PRE-COAT POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Steam Cation Conductivity ≤0.2uS/cm	**Yes – 0.2uS/cm Allowed***
Graywater Cooling	No – River Water
Air Cooled Condenser	No – Wet Surface Condenser
All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry	**Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)**
HP/Main Stream Pressure >2,400 psig	**Yes – HP/Main Steam >2,500 psig**
Cycling with Short Start-up Time	**Yes – Cycling Units with Rapid start**
LP Steam Conductivity Limit?	No
Suspended Solids (TSS) process contamination possible?	**Yes – River water contains levels of TSS**
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

[redacted]

PARAMETERS	1X1 7F.05 (FIRED)
Condensate Design Flow, gpm	[redacted]
Estimated Equipment Costs ($450 per gpm)	[redacted]
Estimated Total Installed Capital Cost (Equipment Costs + $2.28M installation)	[redacted]

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

1.0 Introduction

1.1 GENERAL FACILITY OVERVIEW

Vectren (Company) is planning the construction of a combined cycle plant at its existing A.B. Brown Station (ABB) in Evansville, Indiana. This combined cycle configuration will utilize a heat recovery steam generators (HRSG), combustion turbine generator and steam turbine generator to output 440 MW.

Condensate polishing is the process of purifying condensate before returning it to a boiler. Feedwater (condensate and boiler feed) contain various impurities. Corrosion products from the steam cycle, mostly iron, travel through the cycle and can concentrate in the boiler. Impurities in feedwater can affect HRSG performance and can be transported from the HRSG to the steam turbine, causing damage to piping and turbine components from pitting, corrosion, or scaling. They can inhibit heat transfer, cause hot spots and eventual failure of the boiler tubes. Additionally, they can carryover with the steam and degrade the steam purity to the level that it no longer meets the steam turbine suppliers steam purity guarantee requirements.

The water quality required for feedwater is defined by the HRSG manufacturers and is dependent on the unit cycling, chemistry program, and operating pressure of the plant. High pressure (1500 psi or greater) drum boilers have stringent feed water quality requirements in order to meet the steam turbine suppliers steam purity guarantee. Drum boilers meet theses water quality requirements by blowdown to eliminate impurities from the cycle and making up with fresh demineralized water. Condensate polishing provides a means to minimize blowdown and better ensure boiler water quality requirements.

In addition to improving condensate/feed water quality, condensate polishers can decrease unit startup time by minimizing chemistry related delays, minimize impacts of condenser leaks, and reduce frequency of boiler chemical cleaning. Consequently, condensate polishers are a worthy consideration in most high pressure steam cycle units, especially cycling units designed with rapid start.

1.2 EVALUATION OBJECTIVE

The purpose of this study is to:

- Identify the selection criteria for condensate polishing and determine if/which criterion is applicable to the project.
- Evaluate the capital costs associated with condensate polishing.

The following evaluation reports should be viewed in conjunction with this document:

- 41.1207F – Number of Cold, Warm and Hot Starts Analysis
- 41.1203F – Fast Start vs. Conventional Start Analysis
- 41.1217F – Demin Water Analysis Evaluation.

2.0 Condensate Polishing

2.1 SELECTION CRITERIA

Figure 1 below is a flow chart used to confirm whether or not condensate polishing is necessary in the power plant design basis. The primary and secondary factors shown in Figure 1 are used to identify, if necessary, which type of condensate polisher is to be used based on the parameters of the unit; Deep Bed type or Pre-coat type polishers.

Figure 1 –Condensate Polisher Selection Flow Chart

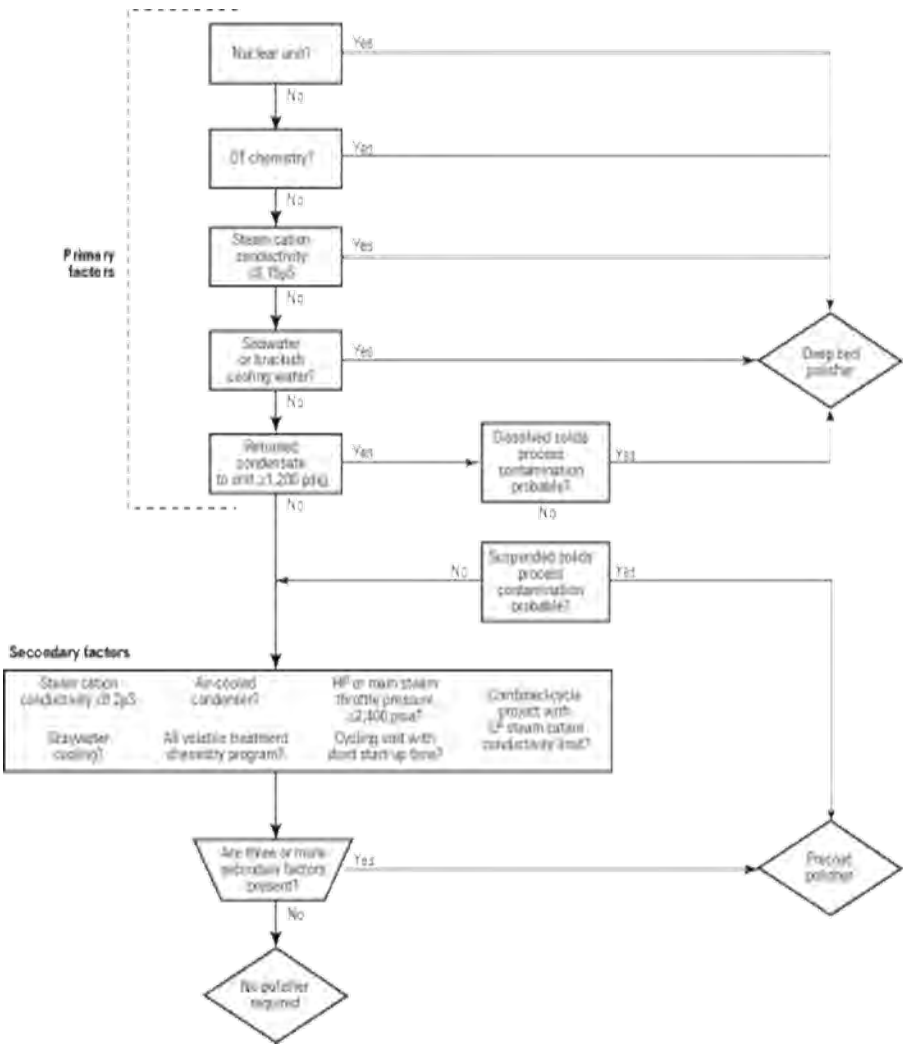


Table 1 reviews the criteria for deep bed type polishers listed and indicates if these factors apply to the project. If one or more of the selection criteria, or factors, apply to ABB, then deep bed condensate polishing should be considered.

Table 1 – Deep Bed Condensate Polisher Selection Criteria

DEEP BED POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Nuclear Plant	No – Fossil Fuel
Oxygenated Treatment (OT) Cycle Chemistry	No – All-Volatile Treatment-Oxidizing with Phosphate
Steam Cation Conductivity <0.15uS/cm	No – 0.2uS/cm Allowed*
Seawater or Brackish Cooling Water	No – Surface Water, Well Water
Returned Condensate to unit >1200 psig	No - 400 psig
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

Based on the design parameters of the plant as shown in Table 1, deep bed condensate polishing would not be considered.

Table 2 reviews the criteria for pre-coat type polishers listed and indicates if these factors apply to the project. General industry practice is if three or more factors apply to ABB, pre-coat polishers should be strongly considered.

Table 2 – Pre-Coat Condensate Polisher Selection Criteria

PRE-COAT POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Steam Cation Conductivity ≤0.2uS/cm	Yes – 0.2uS/cm Allowed*
Graywater Cooling	No – River Water
Air Cooled Condenser	No – Wet Surface Condenser
All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry	Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)
HP/Main Stream Pressure >2,400 psig	Yes – HP/Main Steam >2,500 psig
Cycling with Short Start-up Time	Yes – Cycling Units with Rapid start
LP Steam Conductivity Limit	No
Suspended Solids (TSS) Process Contamination Possible	Yes – River water contains levels of TSS
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

As shown in Table 2, five factors are present in the current design of the project. As a result, pre-coat polishers or design provisions to include future polishers should be considered. The next sections review the benefits of the pre-coat polisher design.

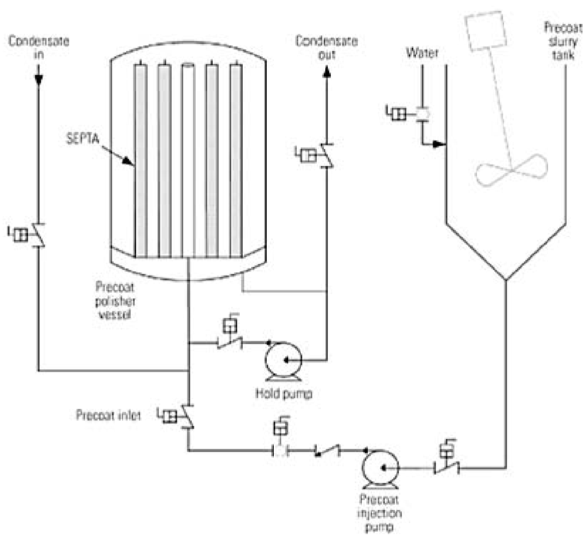
2.2 PRE-COAT TYPE CONDENSATE POLISHING

2.2.1 Overview

Pre-coat polisher is a vessel containing media-retaining filter elements. A powdered media is placed on the elements and the condensate is passed through the media coated filter element and returned to the condensate flow. Figure 2 shows a diagram of a Pre-coat polisher system.

These filter elements, combined with the ion exchanging media (powder coating), has the capability of simultaneous removal of total dissolved solids (TDS) and total suspended solids (TSS). Pre-coat polishers in particular, perform the dual purpose of straining the TSS particulates (iron oxides produced in the condensate system) and removing dissolved solids. Air in-leakage causes corrosion from oxygen pitting and to a lesser degree acidic attack from CO2. Not only does the oxygen damage the carbon steel surfaces but the iron oxides from this corrosion process, both soluble (TDS) and insoluble (TSS), will be transported into the heat recovery steam generator (HRSG) and will deposit on tube surfaces. Over time these deposits reduce unit efficiency, create an environment for under deposit corrosion (boiler tube failures) and necessitate the need for more frequent chemical cleanings.

Figure 2 – Pre-Coat Polisher Diagram



The condensate polisher improves condensate/feed water quality during steady state operations by minimizing the impacts of condenser leaks by the removal of dissolved solids and improves unit startup time by minimizing chemistry related delays by the removal of suspended solids.

2.2.2 Operational Impacts

Dissolved gases can enter the cycle as impurities in the makeup water as well as through air in-leakage to the condenser which is under vacuum. Dissolved gases, particularly uncontrolled oxygen and carbon dioxide, can cause corrosion in the cycle and are generally removed in the condenser and deaerator. However, carbon dioxide can accumulate in the condensate/feed water/boiler train because of its pH equilibrium chemistry and can only be effectively removed with condensate polishing. Particularly during startup and shutdown the condensate/feedwater cycle can and will be exposed to carbon dioxide and oxygen. Their corrosive effects on the carbon steel condensate/feedwater piping can be mitigated with the proper chemistry and blowdown over time, but a polishing unit greatly improves the amount of time necessary to reach optimal cycle chemistry.

If left untreated or detected, these impacts will lead to any number of issues including boiler tube failures, damage to the steam turbine and condenser tube failures.

A condensate polisher is warranted for combined-cycle plants where the steam turbine cation conductivity limit is $\leq$ 0.2 μS/cm, and especially cycling units designed with rapid start. The cation conductivity of the condensate/feedwater stream can typically reach 0.5 to 0.6 μS/cm due to carbon dioxide absorption in the water. The GE steam turbine cation conductivity requirement for A.B. Brown is <0.2 μS/cm.

Without a condensate polisher, and in the event of a major feedwater chemistry excursion, typically a plant will either dump the "out-of-spec" water and re-fill the system with "in-spec" water or operate the feedwater system without generating steam until the boiler feedwater chemical treatment system brings the water back into spec. Worst case scenario for ABB is dumping the approximate +100,000 gallons of water from the cycle (one HRSG and condenser).

Utilizing condensate polishing can reduce the average cycle blowdown during both startup and normal operation to approximately 0.5%-1%. For the ABB project, this blowdown reduction can save up to 1,000,000 gallons of demineralized water each year. This is based on the estimated number of starts per year and capacity factor found in 41.1207F – Number of Cold, Warm and Hot Starts Analysis. Condensate polishing can also potentially reduce the number of boiler chemical cleans over the 30 year expected life of the plant.

3.0 Risk AND Cost Analysis

3.1 RISK ANALYSIS

As stated in Section 3.0, there are several risks associated with operating a combined cycle plant with three or more of the selection factors present in the design. The risk of operating with poor steam/water quality can lead to boiler tube failures, condenser tube failures, and damage to the steam turbine. Table 3 below provides a high level risk analysis of not utilizing a condensate polisher unit.

Table 3 – Risk Analysis Without Condensate Polishing

RISK	SEVERITY	OCCURANCE	DETECTION	LENGTH OF OUTAGE	OVERALL RISK FACTOR
Boiler Tube Failure	High	Medium	High	Medium	High
Steam Turbine Damage	High	Low	Low	High	Medium
Condenser Tube Failure	Medium	Medium	Medium	Medium	Medium
Overall risk factors are indications of estimated number of failure occurrences per year: High = 1 occurrences/yr; Medium = 0.33 occurrences/yr; Low = 0.11 occurrences/yr					

The overall risk factor provides an indication of estimated number of failure occurrences per year. A high overall risk will generally indicate one occurrence per year, while the occurrences per year drop to 33 percent and 11 percent for medium and low factors, respectively.

Utilizing a condensate polisher and a good chemical conditioning program can potentially drop the overall risk factor to the next lower tier for each type of failure.

3.2 COST ANALYSIS

A budgetary cost for a full 2x100% pre-coat condensate polishing system (with pre-coating skid, slurry pumps, air receiver, and resin/precoat recovery tank) is approximately [redacted] An estimated [redacted] for installation, project management, and risk and contingency is used to estimate the total installed cost.

Table 4 – Cost Evaluation - Condensate Polishing

PARAMETERS	1X1 7F.05 (FIRED)
Condensate Design Flow, gpm	[redacted]
Estimated Equipment Costs [redacted]	[redacted]
Estimated Total Installed Capital Cost [redacted]	[redacted]

A temporary/mobile rental condensate polisher could be considered. [redacted]

4.0 Conclusions

4.1 SUMMARY OF CONCLUSIONS

This evaluation report has shown that:

- Five selection factors for Pre-coat condensate polishers are present in the current design of the project. General industry practice to consider polishing is three or more.
- Cycling with rapid startup and <0.2 μS/cm steam cation conductivity, are the two key selection factors that are a part of this project.
- Pre-coat condensate polishers have the capability of simultaneous removal of both TDS and TSS. TSS process contamination is a possibility with any cooling water tube leak utilizing river water makeup.
- The condensate polisher, in combination with a sound cycle chemistry scheme, protects all equipment components in the steam/feedwater cycle.

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

FINAL

AUXILIARY COOLING WATER SYSTEM ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1215F

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

Table of Contents

LIST OF TABLES

Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed different design scenarios for the auxiliary cooling water system. It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated:

- Alternative 1--Auxiliary cooling from makeup and circulating water.
- Alternative 2--Circulating water to cool the closed cycle cooling water equipment.
- Alternative 3--Circulating water to cool closed cycle cooling water equipment and hydrogen and lube oil coolers.

The performance, plant area required, reliability and maintenance, and cost of both shell and tube and plate and frame heat exchangers were considered in conjunction with the three alternatives for the auxiliary cooling water system. [redacted]

1.0 Introduction

Equipment throughout the plant is cooled by water. The source of this cooling water is through a closed loop system Closed Cycle Cooling Water (CCCW) or directly from an auxiliary cooling water source. This report looks at the sources for water for equipment cooling.

The existing plant cooling system is cooled by the raw water system. The raw water system consists of three (3) 3,300 gpm river water pumps which provide cooling water for the coal units closed cooling heat exchangers. The discharge from these existing heat exchangers is then routed to the cooling towers for makeup. The heat duty of the existing closed cycle cooling water system is minimized as the circulating water system directly provides cooling water flow to the generator hydrogen coolers and lube oil coolers.

In developing this report, Black & Veatch reviewed different design scenarios for the auxiliary cooling system for the new Combined Cycle Power Plant (CCPP). It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated.

- The first alternative uses a combination of water from the cooling tower makeup to the cooling towers and circulating water to cool closed cycle cooling water equipment. Turbine hydrogen and lube oil coolers would be cooled directly from the cooling tower makeup.
- The second alternative uses circulating water to cool the closed cycle cooling water equipment. The closed cycle cooling water equipment provides cooling water to all equipment including the turbine hydrogen and lube oil coolers.
- The third alternative uses circulating water to cool the closed cycle cooling water equipment and the turbine hydrogen and lube oil coolers. This scenario differs from the second alternative as circulating water is used to directly cool the hydrogen and lube oil coolers.

This evaluation will evaluate the different alternatives looking at the system performance and cooling capability of the different cooling configurations.

2.0 System Performance – Cooling Capability

Table 2-1 provides a table listing the pros and cons of the different auxiliary cooling water arrangements

Table 2-1 System Performance Capability

ARRANGEMENT	PROS	CONS
Aux Cooling Water from Raw Water Makeup	-	Not Practical for CCPP
Alternative 1 - Circulating water cools CCCW equipment. Aux Cooling Water cools Turbine Lube Oil and Hydrogen Cooling.	Cooler auxiliary cooling water temps. Smaller circulating water pumps. Smaller CCCW system.	Long, large diameter stainless pipe runs to generators. Warmer makeup to cooling tower. Specialized OEM heat exchangers.
Alternative 2 - Circulating water cools CCCW. CCCW cools all equipment.	Standard OEM heat exchangers. Typical CCPP design. Minimizes piping costs.	Warmer circulating water temps. Larger circ water pumps.
Alternative 3 - Circulating water cools CCCW equipment. Circulating water cools Turbine Lube Oil and Hydrogen Cooling.	Cooler auxiliary cooling water temps. Smaller circulating water pumps. Smaller CCCW system.	Long, large diameter stainless pipe runs to generators. Warmer makeup to cooling tower. Specialized OEM heat exchangers.

2.1 ALL AUXILIARY COOLING FROM RAW WATER MAKEUP

The existing raw water makeup pumps consist of three (3) pumps each having a rated a flow capability of 3,300 gpm at 176 ft of head. To maintain a N+1 sparing philosophy, two pumps would be operating and one pump would be in standby providing a cooling water flow of 6,600 gpm since pressure drop to the new cooling tower is expected to be similar to that the existing system.

If the raw water system provides all of the cooling water for the combined cycle, the temperature rise across the heat exchangers would result in an elevated summer make up temperature to the cooling tower not considered acceptable with the cooling tower fill. To limit the temperature rise across the heat exchanger, it is recommended to use the circulating water system instead of the river water for a minimum of the cooling the generator hydrogen coolers and lube oil coolers.

2.2 ALTERNATIVE 1 – AUX COOLING FROM MAKEUP AND CIRC WATER

For Alternative 1, most auxiliary cooling water would be supplied from the river water make up to cool the closed cycle cooling water system while the generator hydrogen coolers and lube oil coolers would be cooled from the circulating water system directly. This scenario would result in a temperature rise for the makeup water system to match the hot water returning from the cooling tower. The temperature rise to the generator hydrogen coolers and lube oil coolers would be designed to match the circulating water temperature rise across the condenser; additional flow to the circulating water system to cool the steam turbine and combustion turbine generator hydrogen coolers and lube oil coolers would be about 3,600 gpm.

Due to the corrosive nature of the circulating water system stainless steel pipe would be required for the piping runs to the generator hydrogen coolers and lube oil coolers. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. The advantage to supplying cooling water directly from circulating water is that auxiliary cooling water to the generator hydrogen and lube oil coolers is 10°F cooler than if supplied from the closed cycle cooling water system.

2.3 ALTERNATIVE 2 – CIRC WATER COOLS CCCW

A typical design for combined cycle plants is to supply the auxiliary cooling water from the circulating water system. Under this design, circulating water would be supplied to the closed cycle cooling water system. The design of the closed cycle cooling water heat exchangers would limit the temperature rise of the circulating water to match the temperature rise of the circulating water across the condenser; the auxiliary cooling water flow would be sized as required to reject the heat of the closed cycle cooling water system. The cold water temperature of the CCCW would have a design temperature of 105°F; this is standard for equipment provided on combined cycle power plants. Circulating water flow to supply auxiliary cooling water system would be about 5,700gpm.

2.4 ALTERNATIVE 3 – CIRC WATER COOLS CCCW AND HYDROGEN AND LUBE OIL COOLERS

If the 105°F cooling water is a concern for the generator hydrogen and lube oil coolers and hydrogen coolers, they could be cooled directly from the circulating water system. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. Circulating water flow to supply auxiliary cooling water system would be about 2,000 gpm.

3.0 Conclusions

Since the existing raw water pumps that provide makeup to the cooling tower do not have sufficient flow to meet the requirements of the new combined cycle, a new cooling water arrangement utilizing circulating water is recommended. Since the turbine manufacturers design their heat exchangers including turbine lube oil and hydrogen coolers for cooling water up to 105°F and the CCCW system is designed to meet this condition under the extreme hot summer day, Alternative 2 with all equipment cooling water coming from the CCCW system as it is the lowest cost and allows the use of standard OEM equipment.

FINAL

DEMIN WATER USAGE ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1217F

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

Executive Summary

In developing this report, Black & Veatch reviewed the requirements for demineralized water for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and steady state scenarios to determine the required sizing and operation of the demineralized water system. Demineralized water storage capacity was evaluated in parallel with system operation. Black & Veatch evaluated water usage based on 1x1 7F.05 gas turbines for this analysis.

The demineralized water system users have been summarized in the steady state demands provided in Table 2-1. Plant pre-start demands have been summarized in Table 2-2 and plant startup demands have been summarized in Table 2-3. For all scenarios, the difference between water demand and existing system capacity is compared. Based on the demineralized water requirements for the multiple scenarios, it is recommended that Vectren utilize an additional water treatment system with a water capacity of [redacted] gpm per Table 3-1. No additional demineralized water storage capacity is required.

1.0 Introduction

The purpose of this study is to determine the specific requirements for demineralized water with the new Combined Cycle Power Plant (CCPP). Based on steady state operation, the existing cycle makeup treatment system can meet water demand. However, during startup and steady state operation with the evaporative cooler in operation, water demand exceeds the existing system capacity. The following tables detail differences in water demand for each configuration and condition.

2.0 Demineralized Water System Operation Demands

The demineralized water system provides water to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the maximum water usage for the demineralized water system. Plant pre-start activities, plant startup, and plant steady state operation was evaluated for maximum demineralized water demand. The existing demin water treatment system capacity is [redacted] gpm. Demineralized water storage will need to be sufficient to hold three (3) days storage of the CCPP steady state demineralized water demand without evaporative cooling water makeup. Demin water demands excluded in this steady state operation are evaporative cooler makeup for the CCPP, CT#3 water injection and existing Unit 3 and 4 steam cycle demands.

2.1 STEADY STATE AND NON-STEADY STATE DEMANDS

The steady state demineralized water demand occurs during operation when supplying makeup water for CCPP blowdown and sampling losses. Non-steady state demineralized water demands occurs during operation when supplying makeup water for steady state CCPP users plus evaporative cooler operation, existing unit operation and CT#3 water injection operation. Demineralized water demands are shown in Table 2-1. Steady state operation assumes 2% blowdown per the water mass balances. Steady state flows are based on Hot Day Case (93.7F) heat balance. Due to the infrequent operation of existing units and CT#3, storage volume recommendations will account for the excursion in steady state demand for demineralized water.

Table 2-1 Demineralized Water Demands

DEMIN WATER USERS	1X1 7F.05
STEADY STATE DEMANDS	
2% blowdown (gpm)	[redacted]
Sample Analytics (gpm)	[redacted]
Demand w/o Evaporative Cooler Makeup (gpm)	[redacted]
NON-STEADY STATE DEMANDS	
Existing Unit 3 steam cycle demands (gpm)	[redacted]
Evaporative Cooler Makeup on RO Permeate (gpm)	[redacted]
Demand w/ Evaporative Cooler Makeup @ 6 COC (gpm)	[redacted]
CT #3 Water Injection	[redacted]
Instantaneous Demand for Steady State Operation with CT#3 water injection (1)	[redacted]
[redacted]	

2.2 PRE-START DEMANDS

During unit pre-start, the auxiliary boiler is used to warm the HRSG and steam turbine seals. The assumption of 2% blowdown on the auxiliary boiler during this operation is included. During this operation, it is assumed all water is non recoverable. The pre-start usage demands are listed in Table 2-2.

Table 2-2 Demineralized Water Demands during Pre-Start Activities

PRESTART USAGE	1X1 7F.05
Aux Boiler Makeup (gpm) HRSG warming	[redacted]
Difference (gpm) - Existing	[redacted]
Difference (gpm) - Proposed new	[redacted]

2.3 STARTUP DEMANDS

During unit startup, demineralized water usage is at the maximum. HRSG is warm and the condenser sparging and gland steam flows are recovered in the condenser. Steam drains are open until superheat targets are met. 5% blowdown is utilized for startup. The demineralized water demands are listed in Table 2-3.

Table 2-3 Demineralized Water Demands During Startup Activities

STARTUP DEMAND	1X1 7F.05
Aux Boiler Makeup Fast Start (gpm)	[redacted]
Steam Drains to HRSG Blowdown Tank (gpm)	[redacted]
Blowdown (gpm)	[redacted]
Total Instantaneous Startup Demand (gpm)	[redacted]
Difference (gpm)	[redacted]
Difference (gpm) - Proposed new	[redacted]
Hot start lost capacity (gallons) (1)	[redacted]
Warm start lost capacity (gallons) (1)	[redacted]
Cold start lost capacity (gallons) (1)	[redacted]
Time to replace lost capacity during normal op (Hot Start), min	[redacted]
Time to replace lost capacity during normal op (Warm Start), min	[redacted]
Time to replace lost capacity during normal op (Cold Start), min	[redacted]
[redacted]	

3.0 Demineralized System

3.1 WATER REPLENISHMENT

The demineralized water system provides minimal margin for replenishment from startup of the combined cycle. For a typical combined cycle plant, the rule of thumb for storage is 3 days of steady state demand capacity. This relates to a 3 day outage on the demin supply. Table 3-1 details the time to replenish demineralized water capacity.

Table 3-1 Demineralized Water Volumes and Treatment Capacities

DEMINERALIZED WATER SYSTEM	1X1 7F.05
STORAGE CAPACITY	
Existing Demin storage (gallons)	[redacted]
3 day Demin storage capacity required @ steady state demand	[redacted]
Storage Surplus (+) / Storage Deficient (-) during a 3 day outage.	[redacted]
Recommended Additional Demin Storage (gallons) (1)	[redacted]
STEADY STATE TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Steady State Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
NON-STEADY STATE TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Non- Steady State Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
PEAK TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Peak (CT#3 + Non- Steady State) Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
PROPOSED ADDITIONAL DEMINERALIZED WATER TREATMENT CAPACITY (GPM)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
Recover 3 day outage volume, Steady state after (HOURS)	[redacted]
Recover 3 day outage volume, Non-Steady state after (HOURS)	[redacted]
[redacted]	

[redacted]

Based on Black & Veatch's evaluation, the existing demineralized water storage capacity can provide sufficient storage of demineralized water based on the design parameters. Furthermore, a new demineralized water treatment system sized to supplement [redacted] gpm (coupled with the existing [redacted] gpm system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

4.0 Conclusions

Based on the evaluation Black & Veatch can conclude:

- The existing demineralized water storage capacity provides adequate storage of demineralized water based on the design parameters.
- A new demineralized water treatment system sized to supplement [redacted] (coupled with the existing [redacted] system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

FINAL

BLACK START ANALYSIS

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1221F

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the capability of using the existing combustion turbine generator (CTG) peaking Unit 3 at A.B. Brown as a means of black starting CTG 5 of the new CCPP

Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. Two scenarios were modeled for this evaluation:

- Starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation.
- Static starting of CTG 5 with all necessary auxiliary electric loads in operation.

For analysis modeling purposes, the aggregate auxiliary electrical load necessary to start a combustion turbine were based on the preliminary conceptual design of the new CCPP. In addition, the excitation system was assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals.

Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting one combustion turbine of the new CCPP. Further analysis would be required to verify that generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator.

1.0 Introduction

The purpose of this evaluation is to examine the capability of the existing combustion turbine generator peaking Unit 3 at A.B. Brown to be utilized as a black starting means for the new combined cycle power plant (CCPP). Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. The unit has a dedicated diesel generator and starting motor necessary to start. Unit 3 is utilized as a black starting means for existing A.B. Brown coal-fired Units 1 and 2.

Electrical power system analysis software ETAP was utilized to model and evaluate Unit 3 to verify the capability of black starting CTG 5 of the new CCPP. Figure 1-1 provides the one line diagram that was modeled in ETAP. Two scenarios were modeled for this evaluation, starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation, and static starting of CTG 5 with all necessary auxiliary electric loads in operation.

[redacted]

2.0 Assumptions

In order to simulate the scenarios included in this evaluation, reasonable assumptions were made in order to model and simulate the black start capability. The assumptions are defined as follows.

2.1 LOAD LIST

It is necessary to determine the aggregate auxiliary electrical load that is necessary to start a combustion turbine of the new CCPP. Table 2-1 provides the load list of all loads considered to be in operation to support the black start. Except ACWP, BFP, CWP, CCWP & CP (major loads), all other loads were modeled as a lump load. For lump load motor power factor of 85% has been considered. A 20 percent margin was added to the lump loads of Table 2-1 for modeling purposes. The loads of Table 2-1 are based on the conceptual design of the new CCPP and are preliminary. All cooling tower fans and CWP have been modeled to show to feed from 6.9kV BUS A & existing 4.16kV BUS 1B respectively.

Table 2-1 Operating Loads during CCPP Starting

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

2.2 UNIT 3 EXCITATION SYSTEM

This study does not include analysis of the excitation model or transfer function for Unit 3. Therefore, the excitation system is fixed in the ETAP simulation. Additional modeling of the excitation system and transfer function would be necessary in order to more accurately simulate the response to the reactive power demands imposed when black starting one combustion turbine generator of the new CCCP, however, the excitation system is assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals, as long as the real and reactive demands on the Unit 3 generator do not exceed the limits of the reactive capability curve.

2.3 PROTECTION, CONTROL AND SYNCHRONIZATION

It is recommended during the detailed design phase that the turbine control system of the new CCPP is designed to be capable of allowing the new combustion turbine generator to synchronize with Unit 3 and that existing and new protection schemes are designed to permit synchronization. It also recommended during the detailed design phase that the control system of the existing Unit 3 combustion turbine generator is verified or modified as necessary to permit load sharing of the auxiliary electrical demands of the new CCPP. No investigation into the existing Unit 3 control system or switchyard protection schemes has been performed in support of this black start capability evaluation.

3.0 Static Motor Starting of Largest Motor

The starting of a large motor can have a brief, but significant, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650 percent of FLA.

In the scenario of the black start, motor starting can result in voltage and frequency sags at the generator output, which will have a corresponding impact on the capability of the motor to start and to the existing loads in operation. The ability of the generator to accommodate starting of large motors is dependent upon the generator capacity, the response of the excitation system, the rotating inertia of the generator and the characteristics of the motor at starting. Should a sag in voltage during motor starting result in the motor's inability to develop the torque necessary to accelerate to full speed, the motor could stall. It is necessary to analyze the worst-case motor starting scenario for the purpose of determining the black start capability of the Unit 3 generator.

As a worst-case scenario, static motor starting of the Boiler Feed Pump, the largest medium voltage motor, was analyzed for 1x1 F class case with all other loads necessary for a black start in operation, with the exception of the Unit 5 generator static starting system. Static motor starting models the motor by locked-rotor impedance during acceleration, simulating the worst impact to loads in operation at the time of motor starting. The properties of the modeled Boiler Feed Pump is 6100 HP, 6.6 kV, 452 FLA, 0.93 power factor, 94 percent efficiency and 6.5 pu LRA.
Figure 3-1 provides the bus voltage, as a percent of nominal, at each bus during starting of the Boiler Feed Pump. The Watt and VAR demand from the Unit 3 generator and the starting motor are also displayed.

The maximum demand from the Unit 3 generator during starting of the Boiler Feed Pump is 8.2 MW and 30.04MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2. The worst-case motor terminal voltage during starting of the Boiler Feed Pump is 80.54 percent of nominal system voltage. It is typical to specify medium voltage motors rated to start at 80 percent of nameplate voltage. It is also typical to specify motor nameplate voltage below nominal system voltage. In the case of a nominal 6.9 kV system, the corresponding motor nameplate is 6.6 kV, consistent with ANSI C84.1. The result of the static motor starting analysis for the Boiler Feed Pump indicates that the momentary sag in voltage at the motor terminals is not prohibitive to the starting of the motor. The worst-case bus voltage for the BUS & MCC A (6.9kV) is 78.17 percent during starting of the Boiler Feed Pump for F Class. This will not result in drop out of motor contactors since the nominal bus voltage is above 70%. All other medium voltage motors connected to BUS & MCC A (6.9kV) were considered to be running in this scenario. The bus voltage of MCC A1 recovers to 99.96 percent of nominal system voltage once the Boiler Feed Pump has accelerated to rated speed.

UAT impedance have been modeled with 6.5%for this study. The short circuit current level will be well below 40kA for 6.9kV SWGR and MCC A. UAT primary tap position has been set at
-2.5% in order to achieve motor terminal voltage of higher than 80%. There is a possibility of further reducing UAT 5 impedance and motor locked rotor amperes to improve starting motor terminal voltage if necessary. A 3-3/C-500kcmil conductor has been considered to feed the BFP during this study.

[redacted]

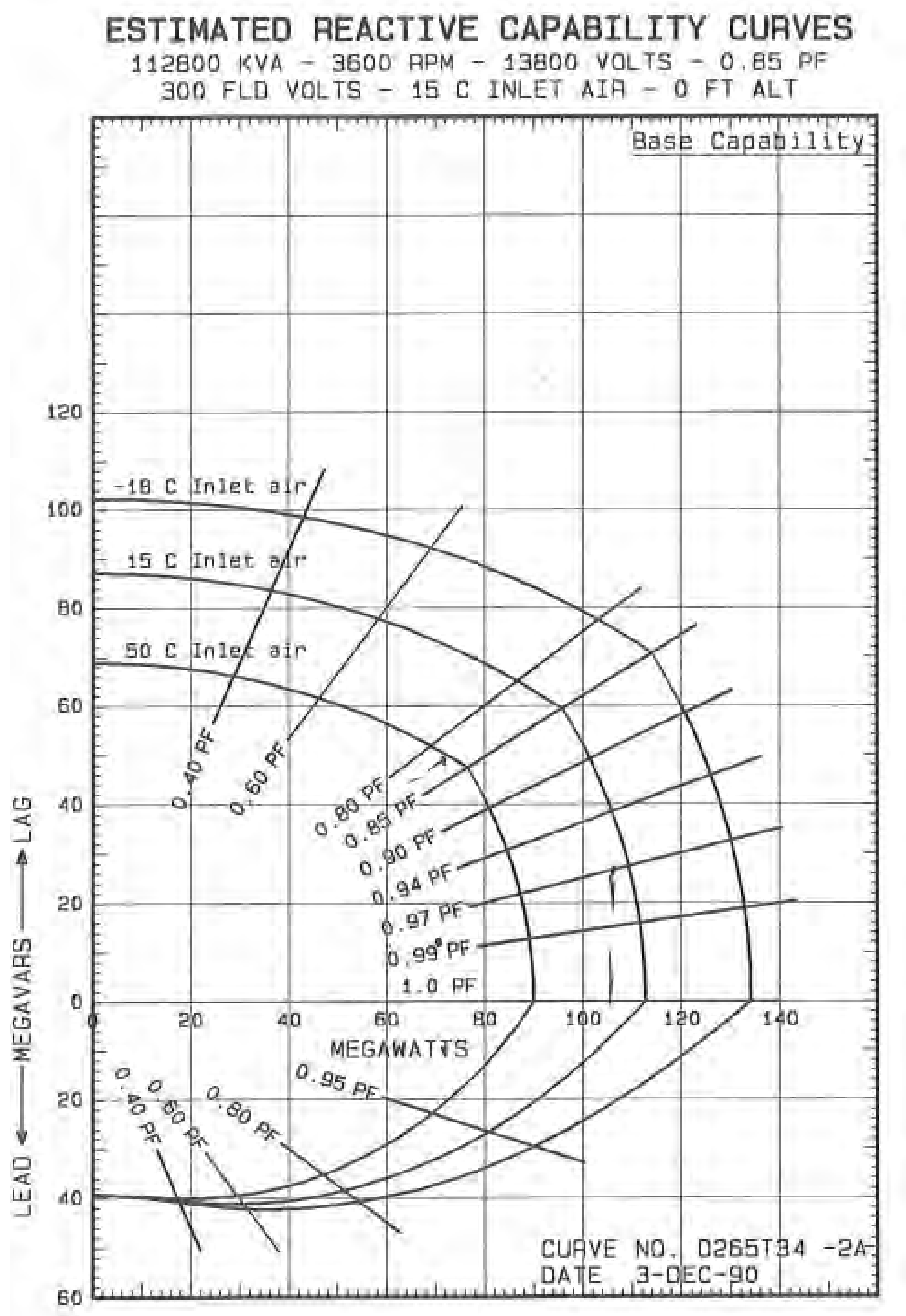


Figure 3-2 Unit 3 Generator Reactive Capability Curve

4.0 CTG 5 Static Starting Load Flow

A load flow model was analyzed during the static starting of the Unit 5 combustion turbine generator. This scenario considered all loads necessary for black starting to be in operation at the time the static starting system was energized. The maximum demand from the Unit 3 generator during static starting of Unit 5 CTG is as 10.55 MW and 5.81 MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2.

The bus voltage during operation of the static starting system on 6.9 kV BUS A & 4.16kV BUS 1B will be 99.96 and 98.83 percent of nominal system voltage. This is well within the normal operating 'voltage range A' as per ANSI C84.1 and not considered to be a prohibitive impact to operation during black start. Additionally, the static starting system operates for a short duration until the combustion turbine reaches approximately 90 percent of rated speed, at which point it is self-sustaining and the static starting system is removed from operation and the turbine control system receives control of the turbine. This duration is approximately 30 minutes or less, dependent upon starting conditions with respect to the purging of combustible gases from the hot gas path prior to ignition.

[redacted]

[redacted] [redacted]

5.0 Conclusions

The analyses performed in support of the black starting capabilities of the existing Unit 3 generator at A.B. Brown indicate that the generator has sufficient capacity to provide the required real and reactive power necessary to start the largest medium voltage motor as well as operate the static starting system of the new CCPP. The starting of the Boiler Feed Pump was simulated as a worst-case scenario, with all other loads necessary to support a black start in operation with the exception of the static starting system. Motor terminal voltage and bus voltages were maintained within reasonable limits for the scenario of a black start. Power requirements to support Boiler Feed Pump starting and the static starting system operation were within the capability curve of the Unit 3 generator. Both analyses assume that the Unit 3 generator excitation system is capable of responding appropriately to meet the reactive power needs, and further analysis with the excitation system modeled is necessary to confirm this response. Additionally, further analysis would be required to verify generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator in order to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator. Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting the combustion turbine of the new CCPP.

FINAL

SWITCHYARD EVALUATION AND SEQUENCE

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1222F

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

Executive Summary

In developing this report, Black & Veatch evaluated the suitability of the existing A.B. Brown 138 kV switchyard for interconnection of a new combustion turbine generator (CTG) and steam turbine generator (STG) operating as a 1x1 Combined Cycle Power Plant (CCPP). This evaluation was performed with existing Unit 2 remaining in operation. Black & Veatch considered preliminary heat balance data for a GE 7FA.05 CCPP as a conservative approach to this evaluation. Switchyard connections and connection sequence were also evaluated.

The continuous current loading of the 3000 Ampere (A) main buses 1 and 2 as well as the 2000 A interpass conductors are not exceeded for the switchyard configurations evaluated. The loading evaluation does not identify any major bus work necessary to independently connect the generators associated with the 1x1 CCPP.

As a result of the available fault current contribution at the existing 138 kV switchyard exceeding 40 kiloampere (kA), with new generation and Unit 2 in service, circuit breakers with a symmetrical interrupting rating 40 kA require replacement. Of the existing 20 circuit breakers in the 138 kV switchyard, 13 are rated 40 kA. [redacted] Therefore, it is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

[redacted]

1.0 Introduction

The A.B. Brown 1x1 CCPP is a multi-shaft arrangement, with the combustion turbine (CT) and steam turbine (ST) individually coupled to dedicated generators rated to convert maximum turbine capabilities to electric power. The multi-shaft arrangement differs from a single shaft arrangement, with respect to electrical equipment, in that independent generators coupled to each turbine will transmit electric power via dedicated isolated phase bus duct (IPBD) to dedicated generator step-up transformers (GSU). Each GSU is sized to permit maximum real electric power to be transmitted to the electric power grid, with minimal losses, and to permit reactive electric power to be delivered to and absorbed from the electric power grid. Each turbine generator will also provide source power to 100 percent redundant unit auxiliary transformers (UAT). The high voltage side of each GSU will be independently connected to the existing 138 kV switchyard. Interconnection of the CTG and STG to the existing 138 kV switchyard requires consideration of fault current availability and system load flow relative to existing equipment ratings. Black & Veatch considered preliminary heat balance data for a GE 7FA.05 CCPP as a conservative approach for this evaluation. Configurations of a 1x1 CCPP comprised of turbine classes with lower gross megawatt (MW) output will result in additional margin with respect to switchyard loading and fault current. Each of the new generators were modelled with independent connections to the existing 138 kV switchyard, with Unit 2 remaining in operation.

The method of connection for each generator in a given configuration to the existing 138 kV switchyard is based upon the electrical ratings of the switchyard components, switchyard expansion capability, and operation of existing units. The existing 138 kV switchyard is a breaker and a half configuration with two main buses, rated 3000 A continuous. [redacted] 13 of the 20 existing circuit breakers in the 138 kV switchyard are rated to interrupt 40 kA.

2.0 Switchyard Evaluation

2.1 LOAD FLOW

The interpass connections between Bus 1 and Bus 2 are rated 2,000 A, therefore a single connection to the switchyard is acceptable when the kilowatts (kW) transmitted remain below 430,000 kW at a power factor equal to 0.9. For a single connection above 430,000 kW and less than 645,000 kW, upgrades are required to the entire 138 kV switchyard, such as circuit breaker and disconnect switch replacement with 3000 A continuous rating. Generation exceeding 645,000 kW at a single connection point is not practical at a voltage level of 138 kV as equipment rated above 3000 A continuous is typically not available.

The maximum CTG and STG gross output based on the preliminary fired GE 7FA.05 1x1 considered for this evaluation are 233,750 kW and 243,950 kW and correspond to approximately 974 A and 840 A, respectively. Detailed load flow modelling of the 138 kV switchyard with case permutations of outgoing transmission lines in and out of service is necessary in order to verify the suitability of the 138 kV switchyard to accommodate the connection of two CTGs and identify any overload cases. Initial analysis indicates that the 138 kV switchyard is generally suitable to accommodate independent connection of the new 1x1 CTG and STG while Unit 2 remains in operation.

The maximum current flow in the main and interpass busses for each analyzed case are represented in Table 2-1.

Table 2-1 Max Load in Main and Interpass Buses - 2026 Summer Peak

138 kV Switchyard Loading 1x1 and Unit 2				
Case	Current in 3kA Main Bus (A)	Percent Loading (%)	Current in 2kA Interpass (A)	Percent Loading (%)
All In Service	689.7	22.99	605.1	30.26
Bus 1 Outage	1936.5	64.55	994.3	49.72
Bus 1 and Line Z95 Outage	2219.7	73.99	1166.5	58.33
Bus 1 and Line Z96 Outage	2072.2	69.07	1078.8	53.94
Bus 1 and Line Z94 Outage	2401.8	80.06	1136.8	56.84
Bus 1 and Line Z73 Outage	1996.3	66.54	1031.3	51.57
Bus 1 and Line Z98 Outage	1657.9	55.26	1082	54.10
Bus 1 and Line Z99 Outage	1748.1	58.27	1294	64.70
Bus 1 and Line Z93 Outage	1744.4	58.15	1162.9	58.15
Bus 1 and Line to Culley Outage	1936.5	64.55	994.3	49.72
Bus 1 and Francisco to Gibson Outage	2254.6	75.15	1188.4	59.42
Bus 1 and AB Brown – BREC Reid Outage	2072	69.07	1539	76.95
Bus 2 Outage	1935.6	64.52	1049	52.45

138 kV Switchyard Loading 1x1 and Unit 2				
Case	Current in 3kA Main Bus (A)	Percent Loading (%)	Current in 2kA Interpass (A)	Percent Loading (%)
Bus 2 and Line Z95 Outage	2219	73.97	1167	58.35
Bus 2 and Line Z96 Outage	2071.2	69.04	1079	53.95
Bus 2 and Line Z94 Outage	2401.2	80.04	1137.2	56.86
Bus 2 and Line Z73 Outage	1995.3	66.51	1051.5	52.58
Bus 2 and Line Z98 Outage	1656.8	55.23	1082.3	54.12
Bus 2 and Line Z99 Outage	1747.6	58.25	1293.5	64.68
Bus 2 and Line Z93 Outage	1742.8	58.09	1161.9	58.10
Bus 2 and Line to Culley Outage	1935.6	64.52	1049	52.45
Bus 2 and Francisco to Gibson Outage	2253.7	75.12	1209.7	60.49
Bus 2 and AB Brown – BREC Reid Outage	2071.2	69.04	1539.7	76.99

2.2 FAULT CAPABILITY

13 of the 20 circuit breakers in the existing 138 kV switchyard are rated to withstand and interrupt 40 kA symmetrical fault current. The interrupting capability of the 13 40 kA rated circuit breakers is marginal for three phase faults and exceeded for single phase to ground faults for this evaluated case. Due to the available fault current contribution it is recommended to replace these existing circuit breakers with circuit breakers having sufficient margin beyond maximum fault current contribution. The remaining seven existing circuit breakers are oil filled and are considered to be near the end of service life. It is recommended to replace all of the existing 138 kV switchyard circuit breakers with breakers rated 63 kA symmetrical interrupting duty. This will ensure fault interrupting capability exceeds maximum available fault contribution.

The results of the fault study are included in Table 2-2.

Table 2-2 138 kV Switchyard Fault Currents

Fault Current Availability 1x1 and Unit 2		
Fault type	Fault Component	Value
3-phase fault	Fault Current (A)	39304
	Phase Angle (°)	-87
	Calculated X/R	19.07
1-phase fault	Fault Current (A)	45908.6
	Phase Angle (°)	-87
	Calculated X/R	19.17

3.0 Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.0 Conclusions

The withstand and interrupting rating of 40 kA for thirteen of the twenty existing 138 kV switchyard breakers is exceeded for the fault conditions evaluated, therefore circuit breaker replacement is necessary. The remaining seven switchyard circuit breakers are oil-filled breakers and near the end of their service life. It is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

The evaluated load flow of the existing 138 kV switchyard permits independent connection of the CTG and STG of the new 1x1 CCPP considering a fired GE 7FA.05 and associated preliminary heat balance gross output. In general, the existing switchyard is capable of a single point of interconnection for 430,000 kW and below. This evaluation did not identify any major bus or interpass modifications for the existing 138 kV switchyard to accommodate the new CCPP and operation of Unit 2.

Connections to the existing switchyard have been planned to permit the construction and commissioning schedule of the new CCPP, while maintaining the existing A.B. Brown Unit 1 connection as late as practical into construction of the new CCPP.

Appendix A. Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

Appendix B. Construction Schedule

FINAL

AUXILIARY ELECTRIC SYSTEM MEDIUM VOLTAGE LEVEL COMPARISON

A.B. Brown 1x1 F-Class

B&V PROJECT NO. 195523
B&V FILE NO. 41.1223F

PREPARED FOR

Vectren

19 FEBRUARY 2020

Table of Contents

LIST OF TABLES

Executive Summary

This evaluation provides a summary comparison of nominal 6.9 kV and 4.16 kV auxiliary electric systems for the conceptual design (CPCN project) of the new A.B. Brown Combined Cycle Power Plant (CCPP). The medium voltage switchgear and motor controllers distribute power to large motor loads, ranging from greater than 250 HP up to several thousand HP, as well as to secondary unit substation (SUS) transformers, which derive 480V to be distributed to the low voltage system components and electrical loads.

Both nominal system voltages of 4.16 kV and 6.9 kV are commonly utilized within power generation and supported by most transformer and motor manufacturers.

Table ES-1 Advantages of 4.16kV and 6.9kV Medium Voltage Systems

MEDIUM VOLTAGE	4.16 KV	6.9 KV
Lower Running Current/Starting Current		X
Smaller Conductor Size		X
Less Heating in Below Grade Cable Ductbank		X
Reduction of Bus Short Circuit Rating		X
Overvoltage Withstand	X	
Conductor Cost Savings		X
UAT Cost Savings		[redacted]
Switchgear Cost Savings		[redacted]
Motor Cost Saving	Equal	Equal

1.0 Auxiliary Electric System Cabling Design Considerations

The cross-sectional area (CSA) of a current-carrying copper conductor is largely dependent upon the continuous current required for rated operation of the electrical load. A larger continuous current necessitates are larger CSA in order to ensure the thermal limitations of the cable insulation and the equipment terminals are not exceeded. An electrical load with a nominal system voltage rating of 6.9 kV will result in an approximate 40% reduction of running current than that of an electrical load with the same power rating, in kVA or HP, and a nominal system voltage rating of 4.16 kV.

For power cables installed in below grade duct bank, a de-rating study must be performed in order to ensure that the implications of the concrete-encased, below grade cable duct on the current-carrying capability of the conductors are properly applied during conductor sizing. The aggregate of thermal impact of the continuous current flowing through the conductors within the duct bank, depth of duct bank, and soil thermal resistivity determine the de-rating of the conductor ampacity. The ampacity of a current-carrying conductor in below grade duct bank is reduced compared to the ampacity of the same conductor in above grade raceway or free air.

It is typical in a CCPP that the electrical loads, particularly medium voltage, are not installed within proximity of the electrical distribution equipment from which the load is sourced. Voltage drop calculations must be performed in order to ensure that the voltage at the load terminals does not fall below the equipment minimum operating voltage. Voltage drop is directly proportional to current, cable length and cable impedance.

2.0 Medium Voltage Motor Starting System Impact

The starting of a large motor can have a significant, albeit brief, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650% of FLA.

As voltage drop is directly proportional to current, the voltage drop at motor starting due to LRA must be analyzed in order to ensure the motor will start. It is typical to specify medium voltage motors capable of starting at 80% of rated voltage as a means of mitigating this concern.

The starting current of a motor can also have an adverse impact on equipment already in operation at the time of motor starting. Voltage sag resulting from the LRA of the starting motor can result in contactor drop-out in certain circumstances. Methods of avoiding adverse impact of large motor starting to the auxiliary electrical system include on-load tap changers (OLTC) integral to the unit auxiliary transformers for bus voltage regulation, dedicated variable frequency drives (VFD) or soft-starters for the motors of concern. The approximate 40% reduction of FLA and LRA resulting from a 6.9 kV compared to 4.16 kV provides for improved results relative to motor starting.

3.0 Short Circuit Contribution During a System Fault

During a system fault, a motor in operation will contribute current to the fault, in attempt to stabilize the decaying system voltage, as a result of the rotating magnetic field that exists in the rotor at the inception of the fault. Analyses of the auxiliary electric system during a faulted condition must be performed in order to ensure that the bus bracing of the electrical distribution equipment is appropriate relative to fault levels. The reduction of FLA of a higher system voltage correlates to reduced short circuit contribution during in a fault condition. Black & Veatch analyses of system faults utilizing Electrical Transient and Analysis Program (ETAP) indicate that motor short circuit contribution can be reduced by up to 50% by increasing the system voltage from 4.16 kV to 6.9 kV.

The reduction of bus short circuit rating of electrical distribution equipment corresponds to a reduction in capital expenditure for 6.9 kV compared to 4.16 kV.

4.0 Cost Impact of Equipment Voltage Rating

Manufacturers of switching assemblies offer various equipment voltage ratings above typical industry nominal system voltages. Metal-clad switchgear voltage ratings of 5 kV and 7.2 kV are common and correspond to nominal system voltages of 4.16 kV and 6.9 kV, respectively. Confirmation from switching assembly manufacturers indicates that bus and breaker continuous current and interrupting ratings, as well as bus bracing and short circuit rating, are the primary cost drivers. The cost difference of a line-up of metal-clad switchgear with the same continuous current rating, interrupting capability and bus bracing, but different system voltage ratings, is negligible.

Black & Veatch has received similar confirmation from motor suppliers, with respect to the negligible cost difference between 6.6 kV and 4.0 kV rated motors.

5.0 System Loading

The preliminary electrical load list associated with the 2x1 (F and H Class) configuration of the A.B. Brown CCPP conceptual design indicates a total plant running load of approximately 30 MVA. At 6.9 kV, this corresponds to approximately 2500 A of running current in combined cycle operation. The preliminary UAT required to support this auxiliary load is a two-winding transformer with a maximum forced-air cooled rating of 36 MVA. With 100% redundancy, two (2) two-winding UATs correspond to one (1) double-ended (main-tie-main) lineup of 3000A, 6.9 kV switchgear.

With the total plant running MVA, at a system voltage of 4.16 kV, the corresponding running current is approximately 4200 A. Typical switchgear manufacturers offer maximum continuous current ratings of 4000 A, which is achieved using 3000 A rated, fan cooled main circuit breakers. The condition of fan cooling required to achieve this rating is not recommended as it introduces an additional point of failure to the auxiliary electric system.

A system voltage of 4.16 kV would necessitate two (2) three-winding UATs and two (2) double-ended lineups of switchgear in order to adequately source the plant auxiliary load requirements for combined cycle operation. A budgetary cost estimate of [redacted] per UAT and [redacted] of additional metal-clad switchgear would be necessary in order to accommodate auxiliary loads at 4.16 kV system voltage.

6.0 Overvoltage Withstand

Equipment manufacturers specify maximum voltage ratings above the nominal system voltage rating. An industry typical maximum voltage rating for a 4.16 kV nominal system voltage is 5.0 kV, providing approximately 20% headroom in an overvoltage condition. Industry typical maximum voltage rating for a 6.9 kV system voltage is 7.2 kV, though some manufacturers are now offering equipment with maximum system voltage rating of up to 7.65 kV. A maximum voltage rating of 7.2 kV provides approximately 4.3% headroom in an overvoltage condition before exceeding the maximum voltage rating. Dependent upon the generator output voltage and the UAT tap, it is possible to exceed this maximum voltage rating with a 6.9 kV system. However, this is not a normal operating condition and could be mitigated with appropriate protective relaying.

7.0 Conclusions

This evaluation report has shown that:

- The design of insulated conductors is directly impacted by the medium voltage system level.
- Disturbances to the auxiliary electric system as well as motor starting concerns are mitigated by an elevated system voltage.
- Short circuit contribution from medium voltage motors is reduced by an elevated system voltage, which can correspond to a reduction in the short circuit bus rating of electrical distribution equipment.
- The cost associated with an elevated system voltage to plant equipment such as switching assemblies and motor windings is considered negligible.
- The preliminary plant auxiliary loading required for combined cycle operation of the 2x1 configuration is supported by two-winding UATs and one (1) double-ended lineup of medium voltage switchgear at a system voltage of 6.9 kV. A system voltage of 4.16 kV would necessitate three-winding UATs and two (2) double-ended lineups of medium voltage switchgear.
- 4.16 kV system voltage provides more headroom for an overvoltage condition than that of a 6.9 kV system, for industry typical maximum voltage ratings. However, this condition can be mitigated with protective relaying.

Total cost savings for using 6.9 kV medium voltage system in lieu of a 4.16 kV medium voltage system is approximately [redacted]

FINAL

EPC COST - BASIS OF ESTIMATE

A.B. Brown 1x1

B&V PROJECT NO. 400278
B&V FILE NO. 41.0001

PREPARED FORREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

Executive Summary

The following is a basis of estimate summary for the EPC capital cost AACE Class 2 estimate for the A.B. Brown 1X1 Combined Cycle. The cost estimates contained in this report are based on the preliminary design by Black & Veatch, equipment pricing bids from suppliers of power island, and utilizing prior EPC contractor and vendor bid data. Power island equipment includes the combustion turbine(s), steam turbine, and HRSG(s).

The two plant alternatives that were estimated are as follows:

1X1 CCPP
GE 7FA.05 Fired
GE 7HA.01 Fired

1.0 Estimate Basis

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

The cost estimate is based upon a lump-sum turnkey EPC approach. Owner will purchase Power Island Equipment and assign to EPC contractor. Under this approach, the EPC contractor would have the responsibility for administration and performance interface of the power island equipment. The EPC structure used for the estimate is based upon the EPC contractor self-performing the work rather than utilizing multiple subcontractors.

The cost estimates are based on competitive bids obtained for power island equipment. Equipment, commodity, and construction services rates were based on EPC contractor and vendor data. Detailed material takeoffs based on the preliminary design of the A.B. Brown combined cycle with reference to similar sized plants that Black & Veatch has designed, constructed, and/or estimated on an EPC basis.

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 - A Labor Market Survey may identify craft labor conditions unique to this project that are recommended for further review and evaluation prior to start of construction.
- Final site conditions - Soil boring were secured for the proposed site.
- Noise requirements - Night-time steam blow conditions were assumed.
- Final project schedule.

1.1 QUANTITIES

Quantities that form the basis of the estimate were based on the engineering conceptual design and the engineering Bill of Quantities (BOQ) developed. The conceptual design was based on utilizing some of the existing A.B. Brown common system to support the new combined cycle, detailed information from equipment suppliers for new equipment, and specific site conditions. Where details were not available, assumptions were made based on similar sized plants and arrangements.

1.2 DIRECT COSTS

EPC bid pricing is 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 by the EPC bidders.

- Unit manhour rates and wage rates are applied against the 1x1 quantities to develop labor cost.

- Unit material cost are applied against the updated quantities for commodities to develop material cost. Cost for major equipment has been scaled off the equipment cost for the major equipment obtained by the EPCs.
- Subcontract pricing was adjusted based upon the rates developed as part of the EPC bid analysis.

To develop the definitive capital cost estimate an RFI was issued to the major OEM Power Island equipment suppliers to obtain budgetary quotes. The OEM proposals included:

- Combustion Turbine and Generator Package
- Steam Turbine and Generator Package
- Heat Recovery Steam Generator

Bid tabulations were developed to evaluate the bids for completeness, scope, and adherence to the specification. The lowest evaluated bid was selected to use as the basis of the estimate.

1.3 CONSTRUCTION MANAGEMENT AND CONSTRUCTION INDIRECTS AND ENGINEERING

Construction Management and Construction Indirects (CMCI) were based on a self-perform (direct-hire) EPC approach instead of a multiple subcontract EPC approach. 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. Under a multiple subcontract approach, these costs would be included in the subcontractor unit rates and appear in the direct cost line items.

Construction management and indirects were estimated based on Black & Veatch's experience with similar plants and scopes of work as well as comparison against the EPC bids. The following costs were developed based upon Black & Veatch's internal metrics and experience then adjusted for schedule and man power loading:

- Project Engineering
- Project Construction Management including Safety, QC, Orientation
- Material Handling
- Mobilization and Demobilization
- Consumables & Small Tools
- Warranty

To obtain competitive bids Black & Veatch, in accordance with IURC code, the estimate includes competitive bids for the following costs:

- Cranes and Construction Equipment
- Scaffolding
- Temporary Facilities

Heavy haul transportation was based on Power Island Equipment delivery to the site and heavy cranes included in the Cranes and Construction Equipment RFQ.

1.4 INDIRECTS

Insurances, warranty, performance bonds, and a letter of credit costs are included, based on the EPC bids.

1.5 CONTINGENCY

[redacted]

[redacted]

FINAL

HRSG BYPASS STACK ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1201H

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the benefits and drawbacks of adding a flue gas bypass stack between the combustion turbine and the heat recovery steam generator (HRSG). The bypass stack would allow the HRSG to be taken offline while the combustion turbine operates in simple cycle mode and would also allow the combustion turbines to be put into service up to 6 months before the erection and commissioning of the balance-of-plant equipment.

This analysis considered such factors as cost, plant design, environmental permitting, schedule, and operations, and maintenance. One major consideration is whether a selective catalytic reduction (SCR) system would be required to meet US Environmental Protection Agency (USEPA) emissions permitting requirements. The base cost for the installation of an HRSG bypass stack is estimated as [redacted] the estimated cost with the addition of an SCR system would be [redacted]

The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. USEPA standards, however, might limit the number of hours the unit could operate in simple cycle mode. While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design.

1.0 Introduction

HRSG stack flue gas bypass systems provide the benefit of adding operational flexibility to power plant generation. Flue gas bypasses consist of installing a stack between the combustion turbine and HRSG; a diversion damper allows the combustion turbine exhaust to be diverted either to the bypass stack or the HRSG. Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. The bypass stack would also allow for the combustion turbines to be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction. The benefits must outweigh the cost in order for a flue gas bypass system to be feasible.

This evaluation of adding a flue gas bypass on each Combustion Turbine will help determine the cost (+/- 30%) and design impact of a flue gas bypass system to the plant design. Environmental permit considerations due to the flue gas bypass addition will also be reviewed. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

2.0 Arrangement

On a combined cycle power plant, the flue gas bypass stack would be installed between the combustion turbine and the HRSG. Figure 2-1 shows a typical arrangement of a combustion turbine with a HRSG and a bypass stack. The bypass stack contains a damper that diverts the combustion turbine exhaust either up the bypass stack or to the HRSG. During simple cycle operation, the damper would be positioned to shut off flow to the HRSG and direct flow up the bypass stack. Under combined cycle operation, the damper would be positioned to shut off flow to the bypass stack and allow flow through to the HRSG. The diverter damper is actuated through the operating positions by an electronically controlled hydraulic system. Figure 2-2 shows the components of the bypass stack. Site specific requirements may result in modifications to the arrangement. For example, if air quality controls such as a selective catalytic reduction (SCR) system were required.

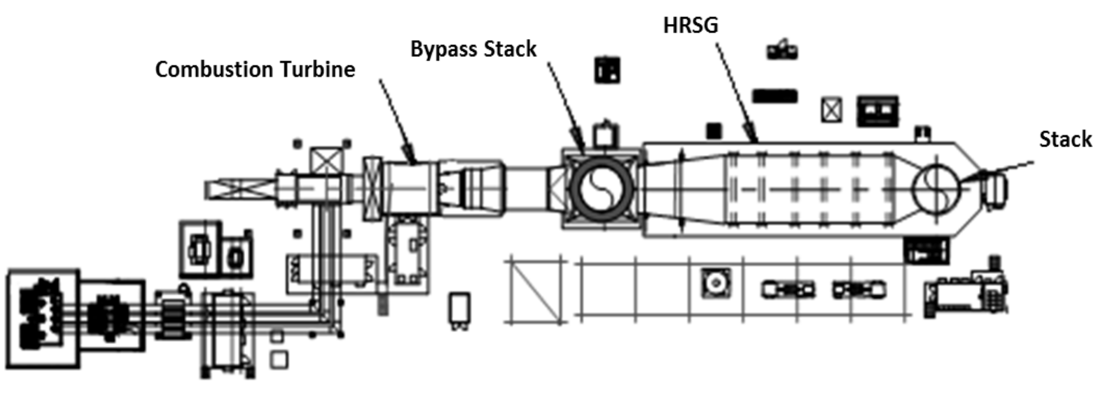
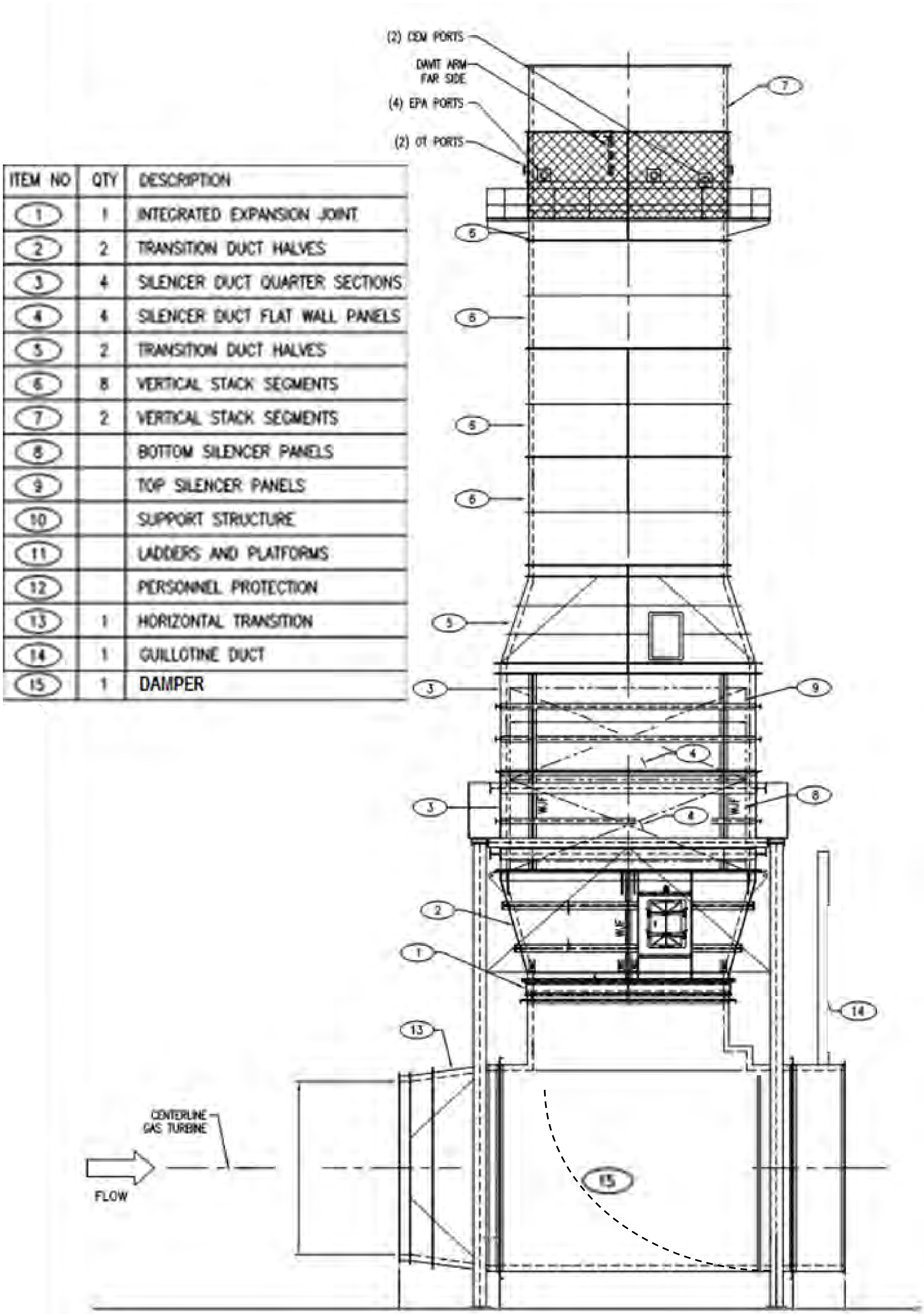


Figure 2-1 Combined Cycle Layout with Bypass Stack



ITEM NO	QTY	DESCRIPTION
1	1	INTEGRATED EXPANSION JOINT
2	2	TRANSITION DUCT HALVES
3	4	SILENCER DUCT QUARTER SECTIONS
4	4	SILENCER DUCT FLAT WALL PANELS
5	2	TRANSITION DUCT HALVES
6	8	VERTICAL STACK SEGMENTS
7	2	VERTICAL STACK SEGMENTS
8		BOTTOM SILENCER PANELS
9		TOP SILENCER PANELS
10		SUPPORT STRUCTURE
11		LADDERS AND PLATFORMS
12		PERSONNEL PROTECTION
13	1	HORIZONTAL TRANSITION
14	1	GUILLOTINE DUCT
15	1	DAMPER

Figure 2-2 Typical Gas Bypass Stack

If an SCR were required, a section could be added to the stack upstream of the silencer to house catalyst, tempering air skid, and ammonia injection equipment. While there is not much industry experience with installing SCRs in the vertical sections of combustion turbine bypass stacks, the technical challenges would be similar to those seen in a coal facility where vertical SCRs are common. The SCR would consist of the following components:

- Catalyst
- Tempering air system to lower combustion turbine exhaust gas to an allowable inlet temperature for the catalyst (<800 °F)
- Mixing vanes and flow distribution
- Ammonia distribution manifold and injection grid
- Ammonia vaporization and flow control unit
- Emission monitoring system

Alternatively, the SCR may be horizontal and then the SCR and bypass stack would be placed in parallel with the HRSG. Air emission requirements are discussed in Section 6.0.

3.0 Capital Costs

Typical suppliers of HRSG bypass stacks include Braden Manufacturing, Peerless-Aarding, and Clyde Bergmann.

Pricing from recent proposals was reviewed to find a budgetary estimate for a bypass stack with a height of 135 ft with stack silencer and continuous emission monitoring (CEMS) system. Also included were all required dampers, motors, controls, insulation, lighting, support steel and platforming as required.

Table 3-1 is a high level breakdown of the installed costs associated with the bypass stack.

Table 3-1 Capital Costs for HRSG Bypass Stack

DESCRIPTION	INSTALLED COST / UNIT
FOUNDATIONS/CIVIL WORK	[redacted]
STACK (including ductwork, damper, supplementary steel, lighting, electrical)	[redacted]
CEMS (NOx and CO analyzers, includes electrical and controls)	[redacted]
BYPASS STACK (no SCR)	[redacted]
VERTICAL SCR (includes ammonia injection, NO_X and CO catalyst)	[redacted]
BYPASS STACK (with vertical SCR)	[redacted]

4.0 Performance Impacts

Installation of a bypass stack allows for the operation of the combustion turbine in simple cycle mode; however, operating in simple cycle mode may have limited operating hours as discussed in Section 6.0, Permitting and Emissions.

[redacted]

If an SCR is required, a tempering air skid is required to keep the CTG exhaust below 800 °F to prevent damage to the catalyst. The CTG exhaust reaches 800 °F in less than a minute from ignition as the CTG reaches 5% load. The tempering air fan and the ammonia vaporization and flow control system will have an approximate auxiliary load of 1,000 kW.

5.0 Maintenance

Maintenance consists of correcting deficiencies noted during inspection. For HRSG bypass stacks without an SCR, the primary maintenance concern is the damper seals, diverter damper bearings, and the dampers hydraulic power unit.

Typical diverter maintenance activities include:

- Shaft seal replacement.
- Housing perimeter seal replacement.
- High temperature bearing repair or replacement.
- Shaft seals are typically designed to last five years.

Recommended spare parts include:

- Spare limit switches.
- Position transmitters.
- Seal-air pressure blower.
- Main drive bearing kit.
- Damper seal sets.
- Expansion joints.

If an SCR is required, additional maintenance is required for the hot air tempering skids, ammonia flow control units, and replacement of NO_x and CO catalysts.

6.0 Permitting and Emissions

6.1 FEDERAL REGULATIONS POSING CHALLENGES

Officially titled *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*, 40 CFR Part 60, Subpart TTTT was finalized by the USEPA on August 3, 2015. In this rulemaking, the USEPA established output-based emissions standards for two subcategories of power plants; electric utility steam generating units (e.g., coal-fired power plants) and stationary combustion turbines. The rule makes no distinction between simple cycle and combined cycle combustion turbines. Rather, it requires combustion turbines to meet certain CO_2 emissions standards depending on whether they are classified as baseload or non-baseload units.

The distinction between baseload and non-baseload units is made based upon the number of hours a combustion turbine can operate relative to its design efficiency. If a combustion turbine operates more hours than its net, Lower Heating Value (LHV) design efficiency, then it is considered a baseload unit. Baseload units are required to meet an output-based CO_2 emission standard of 1,000 lb/MWh (gross output, 12-operating month basis).

[redacted]

If the plant is restricted in hours less than the percent of net design efficiency hours, the plant is classified as a non-baseload unit with respect to NSPS Subpart TTTT. Natural gas-fired non-baseload units are subject to a heat-input based CO_2 emission standard 120 lb/MBtu (HHV, 12-operating month basis). This standard is readily achievable because the CO_2 emission rate of natural gas is 117 lb/MBtu.

6.2 AIR PERMITTING CHALLENGES

While an emissions netting analysis (wherein any recent unit shutdowns can be used to demonstrate that net emissions increases from the new installation would not exceed major source permitting thresholds) could allow the project to avoid major source permitting requirements there is still a possibility the project could trigger major source permitting. In such a scenario, the air permitting process would be dictated by the Prevention of Significant Deterioration (PSD) regulations which require, among other things, an evaluation of Best Available Control Technology (BACT). Should BACT be required for NO_X emissions, the project's air construction permit could require the use of an SCR.

7.0 Conclusions

Having a bypass stack available allows the HRSG to be taken offline or out of service, while the combustion turbine operates in simple cycle mode. In addition, the combustion turbines could be put into service up to 6 months prior to erection and commissioning of the balance of plant under a typical consecutive construction schedule or longer for phased or delayed construction.

While the addition of a HRSG stack flue gas bypass would provide the benefit of operational flexibility for the power plant, cost and performance impacts typically do not justify including this equipment in the power plant design. The total installed cost of the bypass stack fora 1x1 CTG train is approximately [redacted] without an SCR. A vertical SCR would be considered a first of a kind for this application so no cost is easily achievable without a prior design. It is expected that if an SCR is required due to concerns with emissions the cost would be approximately double [redacted] with an SCR. If a horizontal SCR is required due to emission limits, the SCR would not be feasible as it would be approximately the size of the HRSG. The performance of the combined cycle would not be adversely affected by the inclusion of the bypass stack. The amount of hours where the unit can operate in simple cycle mode with the HRSG bypassed may be limited due to NSPS 40 CFR Part 60, Subpart TTTT.

FINAL

HEAT REJECTION / EXISTING COOLING TOWER ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1202H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

In developing this report, Black & Veatch focused its attention to the specific areas directed by Vectren by analyzing the design impacts and cost comparison of using one existing cooling tower, circulating water pumps, and circulating water pipe for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple existing cooling tower reuse scenarios to evaluate the performance against the design for a new cooling tower. A performance summary for the two most optimal scenarios is provided in Section 2.0.

Black & Veatch evaluated the following three cooling tower alternatives for this study:

- Alternative 1: Reuse Cooling Tower, Circulating Water Pumps, and Existing Piping
- Alternative 2: Reuse Cooling Tower and Circulating Water Pumps with All New Piping
- Alternative 3: All New Cooling Tower, Circulating Water Pumps, and Piping

This report has been summarized in a Cooling Tower Alternatives Comparison Matrix provided in Table ES-1. [redacted] Consequently, it is recommended that Vectren utilize the existing Unit 1 cooling tower, circulating water pumps and piping as the design basis for the new combined cycle power plant.

Table ES-1 Cooling Tower Alternatives Comparison Matrix

ALTERNATIVE	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
Description	[redacted]	[redacted]	[redacted]
Constructability			
Tower Performance			
Condenser Adder			
Tie-In Outage Length			
Total Installed Cost			
Operating and Maintenance Cost			
Circulating Water Pump Auxiliary Load			
New Major Equipment			
Advantages			

ALTERNATIVE	REUSE TOWER, PUMPS, AND PIPING (ALTERNATIVE 1)	REUSE TOWER AND PUMPS WITH ALL NEW PIPING (ALTERNATIVE 2)	NEW TOWER, PUMPS, AND PIPING (ALTERNATIVE 3)
Disadvantages	[redacted]	[redacted]	[redacted]

1.0 Introduction

The purpose of this study is to analyze the A.B. Brown Unit 1 circulating water system to determine whether all or portions of the existing cooling towers, circulating water pumps, and circulating water piping can be reused for use with a new Combined Cycle Power Plant (CCPP). Black & Veatch has evaluated the performance of the existing cooling towers and circulating water pumps to determine the optimal operating scenarios [redacted] when paired with the new CCPP.

This evaluation of reusing the existing circulating water system components will help determine the [redacted] design impact of this system to the new CCPP design. Schedule impacts, operations, and maintenance activities will also be identified and discussed.

2.0 Performance Evaluation

Several operating scenarios were evaluated to determine the best preliminary design basis for reusing the existing cooling towers and circulating water pumps. Upon selection of the final plant design, the preferred number of cooling tower cells in service should be reviewed.

Alternatives 1 and 2 utilize the Unit 1 existing seven cell cooling tower and two circulating water pumps provide a total circulating water flow of 125,000 gallons per minute (gpm).

The existing cooling tower would be larger than the cooling tower for Alternative 3. The design flow rate of the existing cooling tower is larger than the design flow rate would be for the new cooling tower. To accommodate the larger flow rate, the condenser will be larger, and more expensive, but provides better performance. The overall heat rejection system for Alternatives 1 and 2 result in a decrease in steam turbine backpressure and an increase in auxiliary power when compared to the new heat rejection system considered in Alternative 3.

The estimated performance based on nominal 1x1 7HA.01 combined cycle performance for the alternatives is shown on Figure 2-1 for unfired heat recovery steam generator (HRSG) operation and Table 2-2 for fired HRSG operation. For reference, Tables 2-1 and 2-2 provide the estimated performance values shown on the graphs.

[redacted]

Table 2-1 Comparative Unfired Plant Performance for Cooling Tower Alternatives

UNFIRED OPERATING CONDITIONS	1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING OFF	1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING OFF	1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING OFF
7 Cell Net Plant Output, kW	[redacted]	[redacted]	[redacted]
7 Cell Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]
New Tower Net Plant Output, kW	[redacted]	[redacted]	[redacted]
New Tower Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]

Table 2-2 Comparative Fired Plant Performance for Cooling Tower Alternatives

FIRED OPERATING CONDITIONS	1X100% CTG LOAD 8.1F/70% AMBIENT EVAP COOLING OFF DUCT FIRING ON	1X100% CTG LOAD 56.8F/48% AMBIENT EVAP COOLING OFF DUCT FIRING ON	1X100% CTG LOAD 93.7F/45% AMBIENT EVAP COOLING ON DUCT FIRING ON
7 Cell Net Plant Output, kW	[redacted]	[redacted]	[redacted]
7 Cell Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]
New Tower Net Plant Output, kW	[redacted]	[redacted]	[redacted]
New Tower Net Plant Heat Rate (LHV), Btu/kWh	[redacted]	[redacted]	[redacted]

3.0 Existing Equipment

3.1 EXISTING COOLING TOWER CONDITION

The Unit 1 cooling tower cells were recently rebuilt from wood to fiberglass as such the condition is assumed satisfactory and no major repairs are required. Three of the seven Unit 2 cooling tower cells were recently rebuilt from wood to fiberglass. To extend the life of the Unit 2 cooling tower the remaining four (4) cells would require rebuilding to fiberglass at a cost of approximately [redacted] To eliminate the need for this expenditure, the Unit 1 cooling tower will be used for the new CCPP. The existing cooling tower basins for Unit 1 and Unit 2 are lacking an intake structure for an auxiliary cooling water pump. Modifications will be needed to the basin to add the new intake and pump structure.

3.2 EXISTING CIRCULATING WATER PUMPS

The existing circulating water pumps have been evaluated for both Alternatives 1 and 2 and it has been determined that they have sufficient capacity to meet the required flow and head for the new CCPP circulating water system. To extend the life of the two pumps and motors a shop overhaul would be required.

Black & Veatch evaluated the use of variable frequency drives (VFDs) on the existing circulating water pumps to modify the pump flow rate for different CCPP operating scenarios. Because the static head component is constant for all operating conditions and accounts for the majority of the circulating water pump head requirement, a VFD would provide minimal performance gains [redacted] per pump.

3.3 EXISTING CIRCULATING WATER PIPE

The existing circulating water piping is carbon steel piping with a bitumastic coating. Coatings have been maintained and repaired during normal inspection and repairs throughout the life of the existing A.B. Brown Plant. For this study, it is assumed that the condition of the pipe is satisfactory and no repairs will be required to the piping that is being reused as part of Alternative 1.

4.0 Constructability

For each of the cooling tower reuse alternatives there are several items to consider that could impact both the new CCPP and existing A.B. Brown Unit 1 during the installation and commissioning phase of the project.

4.1 ALTERNATIVE 1

Alternative 1 reuses a significant amount of existing underground steel piping, which will require continued inspection and maintenance to last the 30 year design life of the new CCPP. The existing piping is assumed to be in satisfactory condition given feedback from Vectren that they have performed scheduled inspections and coatings on the piping as required.

4.2 ALTERNATIVE 2

Alternative 2 will require unit outages considerably longer than Alternative 1, up to 2 or 3 months, given that a large section of existing Unit 1 circulating water piping and cooling tower risers are to be replaced in-kind with new steel piping. Once completed, Alternative 2 will result in the existing cooling tower and circulating water pump connected to the new CCPP circulating water system with all new piping, resulting in shutdown of the existing Unit 1 at the time of the tie-in.

4.3 ALTERNATIVE 3

Alternative 3 is an all new circulating water system that includes a 6 cell back-to-back mechanical draft counter flow cooling tower, 2x50 percent circulating water pumps, and steel circulating water piping. Because this system is independent of the existing equipment no unit outage will be required and the existing Units 1 and 2 will be able to operate during and after the installation of the new circulating water system. This alternative also results in the least auxiliary load because of minimizing the size of the circulating water pumps for the new CCPP design conditions.

5.0 Capital Costs

Table 5-1 is a high-level breakdown of the costs for both reusing the existing cooling towers and installing new cooling towers with a new basin.

Table 5-1 Estimated Costs for Cooling Tower Alternatives

Description	Reuse tower, Pumps, and Piping (Alternative 1)	Reuse tower and Pumps wIth ALL new piping (Alternative 2)	New tower, pumps, and piping (Alternative 3)
New 6 Cell Cooling Tower with Basin (F&E)	[redacted]	[redacted]	[redacted]
Condenser Adder	[redacted]	[redacted]	[redacted]
Circulating Water Pumps	[redacted]	[redacted]	[redacted]
New Piping and Valves (A/G and U/G)	[redacted]	[redacted]	[redacted]
Basin Modifications for Auxiliary Cooling Water Pump	[redacted]	[redacted]	[redacted]
Site Work	[redacted]	[redacted]	[redacted]
Mechanical Installation (Does not include tower erection)	[redacted]	[redacted]	[redacted]
Total	[redacted]	[redacted]	[redacted]
Cost Difference	[redacted]	[redacted]	[redacted]

6.0 Conclusions

Based on the evaluation, reusing the existing Unit 1 cooling tower, pumps and piping (Alternative 1) is the lowest cost technically acceptable solution and should be used as the design basis for the new combined cycle power plant.

FINAL

FAST START VS. CONVENTIONAL START ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1203H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1.0 Introduction

This study evaluates designing a 1x1 GE 7HA.01 combined cycle power plant with “fast start” capabilities versus a plant design for “conventional” start. The GE 7HA.01 is one of several candidate H-Class combustion turbine offerings.

1.1 STARTUP DURATION DEFINITION

Since plant load is affected by ambient conditions, startup durations are typically defined based on achieving a certain operating condition and not a specified operating load. The beginning of the start is typically defined as combustion turbine roll-off or first ignition. Startup is complete when a predefined operating condition is reached.

Startup can be a confusing term as it is used to describe the start from ignition to various ending operating conditions across the industry. These ending operating scenarios can include:

- CTG Full Speed No Load – The point at which the combustion turbine is removed from the static starter and brought to full speed.
- CTG Sync - The point at which the combustion turbine (CTG) is synchronized with the grid.
- Emission Start - Achieving minimum emissions compliance load. This occurs when stack discharge emissions reaching steady state compliance with air quality standards.
- CTG Full Load Start - Combustion turbine at baseload with permitted emissions at the stack.
- Plant Full Load Start - Combustion turbine at baseload and steam turbine bypass valves fully closed. Steam turbine in service.

For the purpose of this study Fast Start is being defined as a rapid start commencing with ignition until the combustion turbine reaches minimum emission load compliance (MECL). When speaking with others in the industry the ending operating condition should be defined.

The type of start is also defined by the amount of time the unit has been shutdown. It is typical to assume the shutdown begins at fuel flow shutoff to the combustion turbines during a normal plant shutdown sequence from a steady state baseload condition. Durations as defined by the project are:

- Hot start = Shutdown 8 hours or less
- Warm start = > 8 hours and < 48 hours
- Cold start = Shutdown 48 hours or more

The lead time activities prior to a warm or cold fast startup typically commence with startup of the auxiliary boiler. Depending on the start condition for the auxiliary boiler and the features incorporated to permit its fast start, this activity may need to commence approximately three hours before the actual combustion turbine start condition.

1.2 CONVENTIONAL VERSUS FAST START

Conventional combined cycle facility startup durations are constrained by steam cycle equipment limitations, specifically the heat recovery steam generator and steam turbine temperature ramp capabilities. Heat recovery steam generators and steam turbines are designed to operate at very high temperatures and pressures and, therefore, are comprised of very thick metal alloy components (e.g. steam drums, steam turbine rotors). These thick components can suffer from high thermal stress and increased life expenditure if they are subjected to large temperature differentials (e.g., 1,000°F steam across an ambient temperature steam turbine rotor) or rapid temperature ramp rates. HRSG and steam turbine suppliers provide strict temperature ramp rates and temperature differential requirements for their equipment that must be used to define and limit the startup sequence and duration in order to protect the equipment.

HRSGs designed through the middle of the last decade were generally not capable of allowing combustion turbines to start at their maximum capability without incurring significant maintenance impacts. These units required pauses ("holds") at low CTG loads to "heat soak" their heavy-walled components prior to releasing the unit on sustained ramp rates of typically less than 7°F per minute, as measured by the high-pressure (HP) drum steam saturation temperature.

Today's HRSGs can be more robustly designed for the rapid ramp rates of advanced class combustion turbines, which can exceed 50 megawatts (MW) per minute and yield HRSG temperature ramp rates exceeding 30°F per minute.

Though HRSGs are now designed to allow combustion turbines to start at their maximum capability, steam turbines are not. Cold steam turbines require relatively cool steam, typically in the range of 700°F, on first admission to the equipment. During the startup sequence, steam temperatures downstream of the HRSG are primarily controlled through two means working in tandem, CTG exhaust temperature control and desuperheating of the generated steam. CTG exhaust temperature control tunes the CTG to minimize the exhaust temperature into the HRSG during the startup sequence, as a cooler exhaust temperature produces cooler steam. Desuperheaters spray water into the steam headers to reduce, or "attemperate", the steam by reducing the level of superheat above the steam saturation temperature.

Most HRSGs include interstage desuperheaters that are installed between superheater and reheater sections to control the final HRSG exit steam temperatures. As the combustion turbine ramps above very low loads towards the MECL, the CTG exhaust temperature control and HRSG interstage desuperheaters are no longer capable of cooling the steam to the temperatures permitted by a relatively cool steam turbine. The steam turbine becomes a critical constraint on the start time unless the HRSG exit steam temperatures can be further reduced to match the steam turbine steam temperature requirements. In effect, the steam turbine must be 'decoupled' from the combustion turbine so that the combustion turbine start is not constrained by the steam cycle.

The steam turbine can be decoupled and its steam temperature requirements met irrespective of combustion turbine load by adding terminal desuperheaters (i.e., desuperheaters downstream of the HRSG in the high-pressure (HP) and hot reheat steam headers) to cool the HRSG exit steam to the steam turbine requirements.

Decoupling the steam turbine from the CTG/HRSG train allows the combustion turbine to ramp to emissions compliance load levels without hold periods in the firing sequence. A no-holds startup sequence is typically referred to as an uninhibited start.

Figure 1-1 provides a high-level comparison of the typical CTG load path for a 1x1 conventional combined cycle to that of a fast-start combined cycle. Additional details on the performance differences between the two startup types are discussed in Section 4.0.

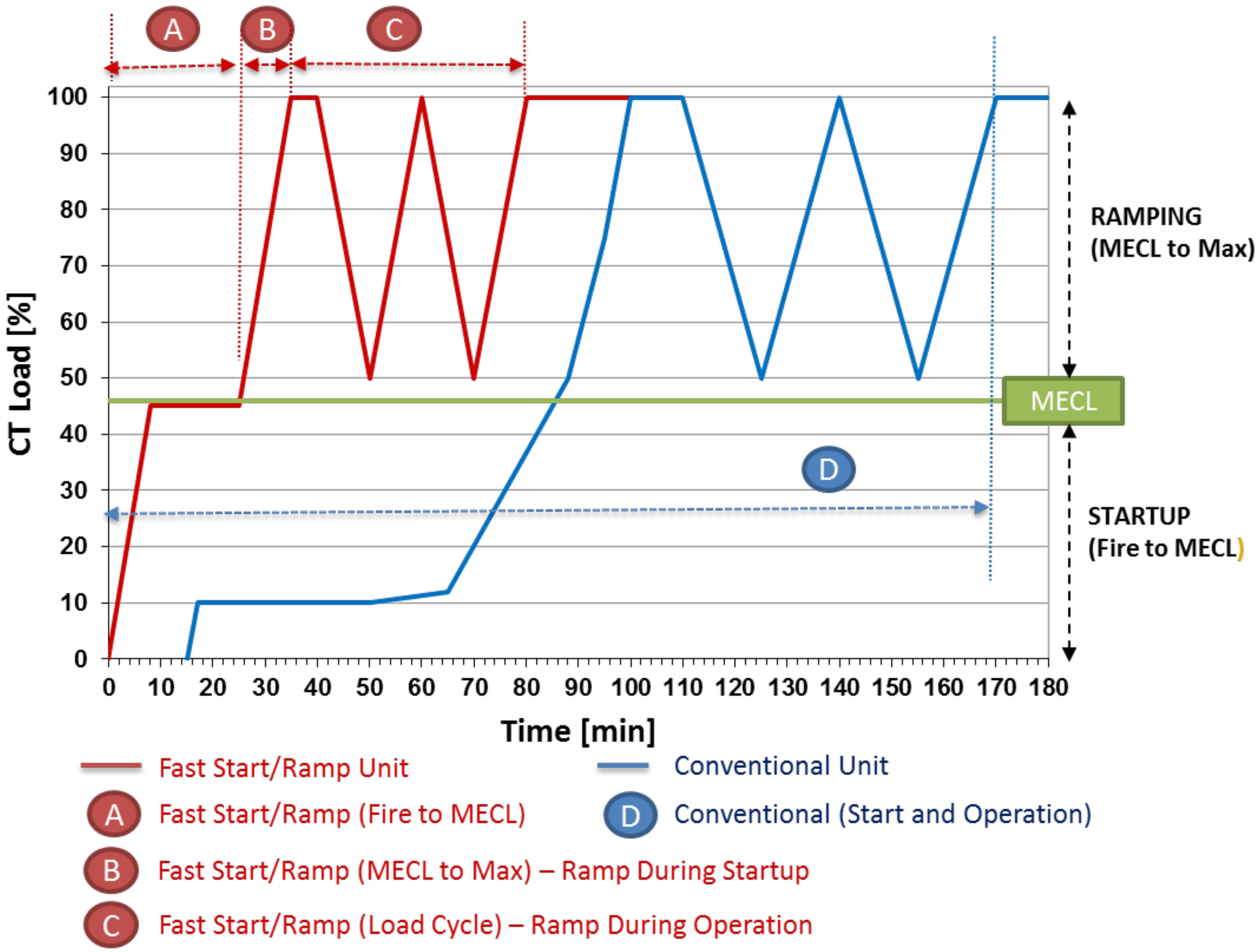


Figure 1-1 Comparison of Combustion Turbine Loading during Hot Start Event (Excludes Purge)

2.0 Design Features

Capital costs are higher for fast start plants than plants designed for conventional starts. Equipment and balance of plant systems affected by the additional design consideration for fast start are as described below and in Table 2-1. Column A of Table 2-1 lists specific design features and equipment required for fast start operation. Column D of Table 2-1 lists design features of conventional start units. Columns B and C will be discussed in the Fast Start vs. Conventional Unit Ramp Rate Analysis (File No. 400278.41.1204H).

Table 2-1 Design Features of Combined Cycles Designed for Various Operating Scenarios

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Required Option = ●, Recommended Option = ☐, Standard Option = ◆				
Combustion Turbine				
Fast Start Equipped	●			
Natural Gas Purge Credits	●			☐
Service Life Monitoring System	◆	◆	◆	◆
Advanced Control System	●	●	●	
HRSG				
Advanced Drum Design	●	●		
Enhanced Nozzle Connections	●	●		
Improved HRSG Materials	●	●		
Improved HRSG Geometries	◆	◆	◆	◆
Service Life Monitoring System	☐	☐	☐	
Stack Damper and Insulation	●			☐
Terminal Attemperators	●	●	●	
LP Economizer Recirculation/ Heat Exchanger	●	●		
Steam Turbine				
Optimized Casing Design	●	●		
Advanced Control System	●	●	●	
Service Life Monitoring System	●	●	☐	

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Advanced Stop Valve Design	●			
Increased Thermal Clearances	●	●		
Advanced Turbine Water Induction Protection	●	●	●	
Emissions Control				
Feed-forward Ammonia Controls	●	●	●	
Auxiliary Steam				
Auxiliary Boiler	●			
Condenser and HRSG Sparging	●			
Feedwater System				
Larger Condensate Pump	●	●	●	
Larger Feedwater Pump	●	●	●	
Higher Stage IP Bleed	●	●	●	
Heat Rejection System				
Surface Condenser – Fast Start Design	●			
Fuel Gas System				
Supplementary Fuel Gas Heating(1)	□			
Water Treatment System				
Condensate Polisher(2)	□			
Auxiliary Electrical System				
Larger Equipment for Higher Loads	●	●	●	

Notes:

1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

2.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

2.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, and reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

2.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

2.4 EMISSIONS AND AMMONIA FEED

Outlet NO_x from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure NO_x at the stack; for fast ramping units limiting NO_x measurements to the stack only can lead to over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO_2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO_2 dew points.

2.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establishing the steam turbine seals, warming up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

2.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for steam turbine temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

2.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

2.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

2.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

2.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

3.0 Capital Costs

Capital costs are higher for fast-start plants than plants designed for conventional starts. Additional costs that must be considered are requirements for a more flexible HRSG (e.g., header returns, tube to header connections, harps per header limits), terminal attemperators and associated systems; more flexible steam piping; improved steam piping drain systems, improved bypass system and controls integration, and requirements for auxiliary steam.

Table 3-1 lists the costs to include the design features listed in Column A of Table 2-1 for a fast start unit. Costs listed in the study are budgetary costs (+/- 30%).

Table 3-1 Fast Start (Fire to MECL) Operating Scenario Costs

FAST START SYSTEM COSTS FOR A 1X1 7HA.01 COMBINED CYCLE	
Fast Start Options (Required options in Column A excluding Aux Boiler and Stress Monitoring Systems)	[redacted]
Auxiliary Boiler	[redacted]
Stress Monitoring Systems	[redacted]
Total	[redacted]

4.0 Performance Impacts

Startup durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 4-1 provides comparative durations, [redacted] All fuel consumption and net generation values are based on combustion turbine ignition through the indicated end point.

Table 4-1 Estimated Nominal Startup Times (Minutes)

START TYPE	CONVENTIONAL START TO MECL	FAST START TO MECL	DIFFERENCE (CONVENTIONAL – FAST)
Hot Start = Shutdown 8 hours or less	[redacted]	[redacted]	[redacted]
Warm Start = > 8 hours and < 48 hours	[redacted]	[redacted]	[redacted]
Cold Start = Shutdown 48 hours or more	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

5.0 Startup Emissions

Stack emissions vary widely prior to reaching steady state emissions compliance due to the complexity of starting a combined cycle facility and the plant equipment's ability to operate within threshold limits across a certain operating range. The combustion turbine and the HRSG post-combustion emissions control components (if applicable) are the main equipment governing stack emissions variation.

Combustion turbines are designed with multiple fuel nozzles in each combustor. As combustion turbines start and ramp up to normal operating flow, load, and temperature, the combustion nozzles are sequenced through various combustion operating modes that vary the deflagration type (i.e., diffusion or pre-mixed [i.e., the air and fuel are pre-mixed prior to ignition of the fuel]) and nozzle firing sequences (i.e., which of the multiple nozzles are in service). These startup combustion modes are required so that stable combustion can be maintained in the unit during startup to avoid flame outs. As illustrated in Figure 2-1, in these off-design startup combustion modes, the combustion of the fuel is generally incomplete resulting in higher than normal nitrous oxide (NO_x), carbon monoxide (CO), and volatile organic compound (VOC) emissions concentrations. As the turbine reaches a minimum operating load where its normal combustion mode can be stably maintained, combustion becomes more complete and emissions decrease to a level that can be maintained across a wide operating range. The minimum operating load of the combustion turbine in this emissions compliant operating range is called the Minimum Emissions Compliance Load (MECL).

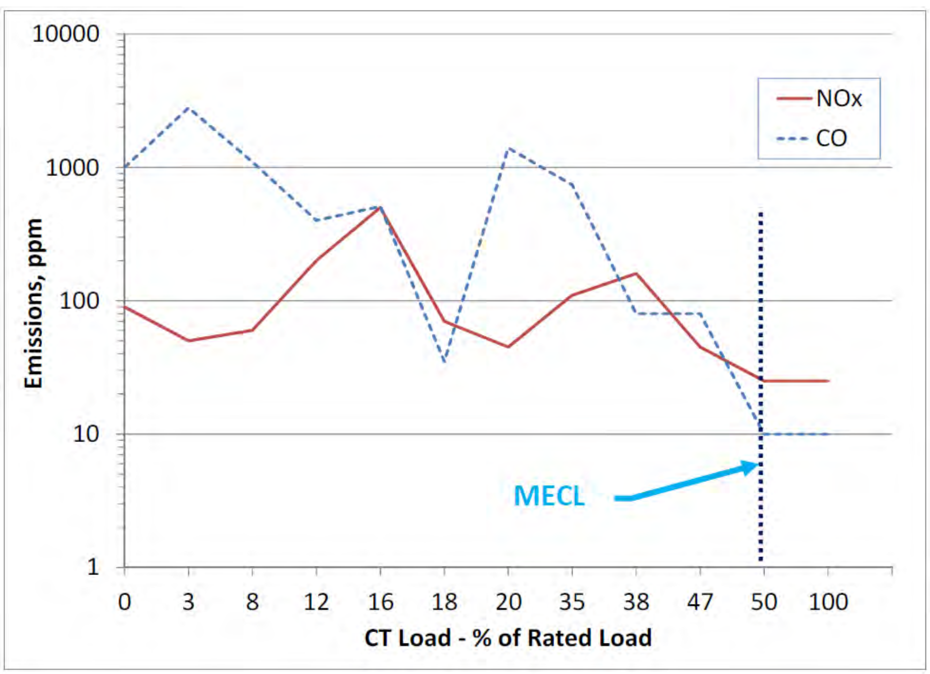


Figure 5-1 Example Combustion Turbine NO_x and CO Emissions versus Rated Load

Below MECL, the mass of air pollutant emissions can accumulate quickly and, therefore, these “startup emissions” are of particular interest to regulators. The steady-stated CTG design exhaust emissions for the turbine technologies considered are approximately 15-25 ppmvd @15% O2 for NO_x and 4-10 ppmvd @15% O2 for CO when operating on natural gas. Steady-state VOC emissions are dependent on the site specific natural gas composition.

An emissions netting analysis will be performed for the new combined cycle plant. If a Prevention of Significant Deterioration (PSD) review is required, the emissions standard that must be met is Best Available Control Technology (BACT), an emissions control mandate by the Environmental Protection Agency (EPA). If applicable, combined cycle BACT requirements dictate NO_x and CO emissions shall be no greater than 2 ppm (parts per million) at the HRSG stack discharge over the entire normal operating range. CTG emissions levels are not sufficient for BACT and post-combustion emissions controls components; oxidation catalyst to reduce CO/VOC emissions and a selective catalytic reduction (SCR) system to reduce NO_x emissions, must be installed in the HRSG to further reduce emissions to BACT levels.

Oxidation catalysts and SCR systems are not effective until they are warmed to a minimum threshold temperature and the SCR ammonia injection (utilized with the catalyst to reduce NO_x emissions) is tuned. In general, these post-combustion emissions controls components are designed such that the minimum threshold temperatures are achieved on a startup at or below the combustion turbine MECL. As noted previously, an “emissions” startup sequence is considered complete after the CTG reaches MECL, and in the event of post-combustion emissions control components, they reach their minimum threshold temperatures, and the SCR ammonia injection is tuned such that stack emissions meet the air quality requirements.

FINAL

FAST START VS. CONVENTIONAL UNIT RAMP RATE ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1204H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1.0 Introduction

The purpose of this study is to evaluate the differences for conventional and fast ramping options between MECL and full load on unit startup for a 1x1 7HA.01 combined cycle. The GE 7HA.01 is one of several candidate H-Class combustion turbine offerings.

Since the temperature differential between components is the primary concern of fast ramping between MECL and full load; many of the design features required for fast ramping between MECL and full load are the same as the features required for fast start between combustion turbine ignition to MECL as discussed in the Fast Start vs. Conventional Start Analysis (File No. 400278.41.1203H). Figure 1-1 shows the regions covered under this study noted as Ramping and that covered in the Fast Start vs. Conventional Start Analysis noted as Startup.

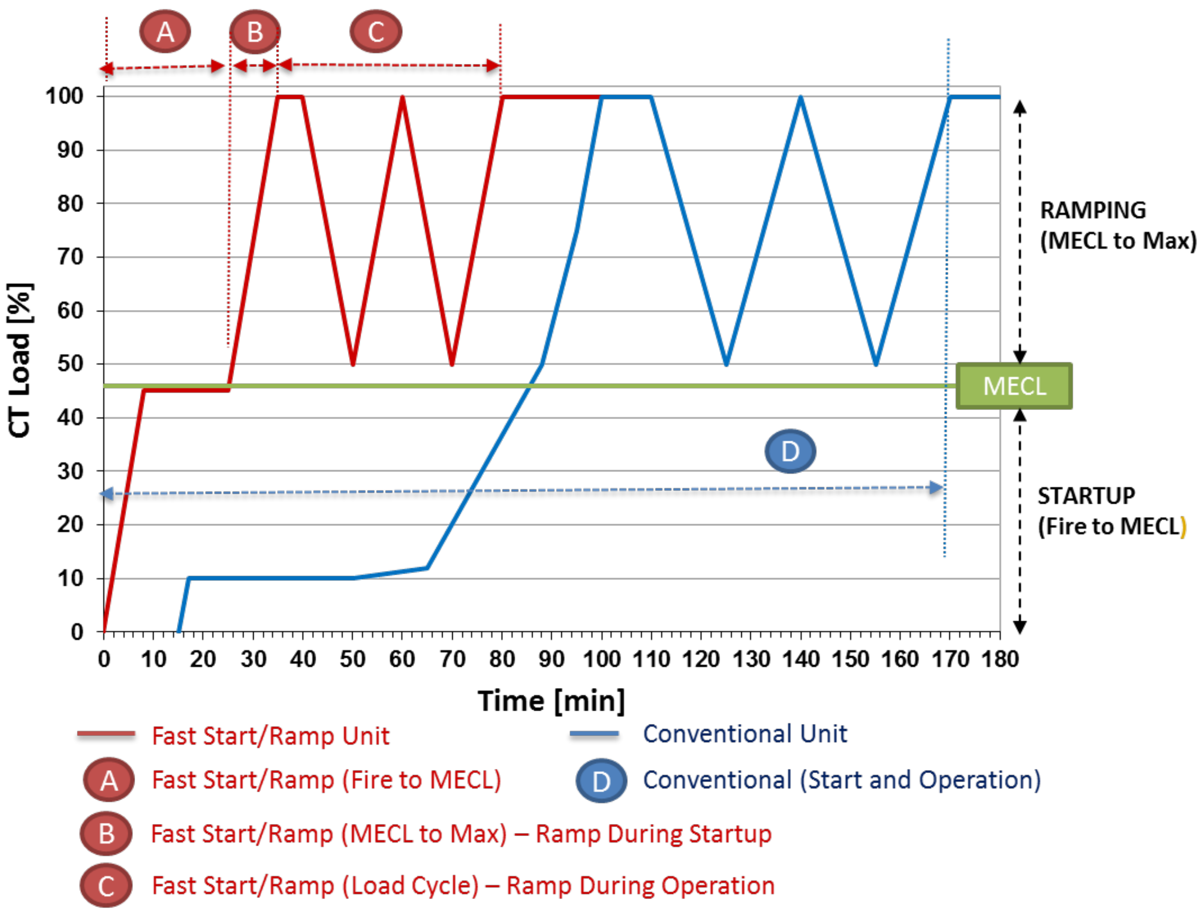


Figure 1-1 Comparison of Combustion Turbine Loading From MECL to Full Load

Table 1-1, Column B indicates the design features that would be required for fast ramping and how they differentiate from a conventional unit, Column D, and a fast start unit, Column A. Descriptions for each of the design features can be found in the Fast Start vs. Conventional Start

Analysis and also included in Appendix A. Items included in Column B also encompass those features in Column C which are required for fast ramping during operation.

Table 1-1 Design Features of Combined Cycles Designed for Various Operating Scenarios

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Required Option = ● , Recommended Option = ☐ , Standard Option = ◆				
Combustion Turbine				
Fast Start Equipped	●			
Natural Gas Purge Credits	●			☐
Service Life Monitoring System	◆	◆	◆	◆
Advanced Control System	●	●	●	
HRSG				
Advanced Drum Design	●	●		
Enhanced Nozzle Connections	●	●		
Improved HRSG Materials	●	●		
Improved HRSG Geometries	◆	◆	◆	◆
Service Life Monitoring System	☐	☐	☐	
Stack Damper and Insulation	●			☐
Terminal Attemperators	●	●	●	
LP Economizer Recirculation/Heat Exchanger	●	●		
Steam Turbine				
Optimized Casing Design	●	●		
Advanced Control System	●	●	●	
Service Life Monitoring System	●	●	☐	
Advanced Stop Valve Design	●			
Increased Thermal Clearances	●	●		
Advanced Turbine Water Induction Protection	●	●	●	
Emissions Control				
Feed-forward Ammonia Controls	●	●	●	

FEATURES REQUIRED TO MEET OPERATING SCENARIO	A FAST START (FIRE TO MECL)	B FAST RAMP (MECL TO MAX)	C FAST RAMP (LOAD CYCLE)	D CONVENTIONAL (START AND OP)
Auxiliary Steam				
Auxiliary Boiler	●			
Condenser and HRSG Sparging	●			
Feedwater System				
Larger Condensate Pump	●	●	●	
Larger Feedwater Pump	●	●	●	
Higher Stage IP Bleed	●	●	●	
Heat Rejection System				
Surface Condenser – Fast Start Design	●			
Fuel Gas System				
Supplementary Fuel Gas Heating(1)	□			
Water Treatment System				
Condensate Polisher(2)	□			
Auxiliary Electrical System				
Larger Equipment for Higher Loads	●	●	●	

Notes:

1. Supplementary fuel gas heating as required by combustion turbine supplier.
2. Space should be allotted for future condensate polisher installation, if required.

2.0 Capital Costs

Note that all of the features required for fast ramp are included in Column A of Table 1-1 discussed in the Fast Start vs. Conventional Start Analysis. The costs in Table 2-1 indicate only the costs for Column B of Table 1-1. Costs listed in the study are budgetary costs (+/- 30%).

Table 2-1 Fast Ramp (MECL to Full Load) Operating Scenario Costs

FAST RAMP SYSTEM COSTS FOR A 1X1 7HA.01 COMBINED CYCLE	
Fast Ramp Options (Required options in Column B excluding Stress Monitoring Systems)	[redacted]
Stress Monitoring Systems	[redacted]
Total*	[redacted]
NOTE: If a fast start plant is selected the above costs are not additive to those listed in the Fast Start Study.	

3.0 Performance Impacts

Startup and ramping durations are dependent on the ambient conditions, time after shutdown, initial steam turbine rotor temperatures, and the particular OEM equipment/features used in the power train in addition to any margins (if the required start-up times are to be guaranteed). There is a relatively wide range variation, however, for rough indicative values, Table 3-1 provides comparative durations for a GE 7HA.01 1x1 combined cycle. [redacted]

Table 3-1 Estimated Nominal Startup Times (Minutes)

START TYPE	CONVENTIONAL START TO MECL	CONVENTIONAL START TO STG FULL LOAD	FAST START TO MECL	FAST START, TO CTG BASELOAD	FAST START, TO CTG BASELOAD WITH STG LOADED
Hot Start = Shutdown 8 hours or less	Base Conv.	42	Base Fast	7.1	54
Warm Start = > 8 hours and < 48 hours	Base Conv.	34	Base Fast	26	52
Cold Start = Shutdown 48 hours or more	Base Conv.	67	Base Fast	67	103

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

For a conventional start, each combustion turbine is ramping at a nominal rate from MECL to combustion turbine baseload of 20.7 MW/min or 7.09%/min, while the combustion turbine ramp rate for fast start is 50 MW/min or about 17.1%/min from MECL to combustion turbine baseload.

After startup and after thermal soaking, the unit will able to achieve fast ramping. For a GE 7HA.01, each combustion turbine has the ability to ramp 50 MW/minute. For a 1x1 combined cycle, the ramp rate can be stated to be 50 MW/minute. The steam turbine contribution toward fast ramping is typically not quoted since the steam turbine response is much less predictable than the combustion turbine load response. This is due to a lag in HRSG steam production response due to the CTG load changes. Depending on how the combustion turbine is ramped up and down, the output contribution from the steam turbine would take some time to settle out into a steady state performance level. For conventional units, the combustion turbine ramp rates may be limited by the HRSG and steam turbine limitations. For units equipped with fast ramping, the steam conditions can be conditioned to allow the combustion turbine to ramp independently of the steam turbine.

4.0 Emissions

The period for ramping is defined as the period between minimum emissions compliance load and full load. Once the unit has obtained emission compliance, the unit generally stays in compliance for ramping conditions. During a fast ramp the outlet NO_X from the combustion turbine is variable. Conventional units only measure NO_X at the stack; this may lead to short durations of higher NO_X or ammonia slip. For fast ramping units limiting NO_X measurements to the stack only can lead to over injecting or under injecting ammonia. To address this, fast ramping units are equipped with feed-forward NO_X controls which take NO_X measurements at the combustion turbine exhaust as well as the stack to quicken the response to changing combustion turbine exhaust conditions. Both conventional and fast ramping units are designed to operate in compliance with stack emission limits across the averaging period.

Appendix A. Fast Start and Fast Ramp Design Features

Design features for fast start and fast ramping units are as follows:

A.1 COMBUSTION TURBINE

Combustion turbines designed for fast-ramping will be equipped with fast start features. These include positive isolation to ensure that purge credits have been maintained per NFPA 85 and that the gas path will not require a purge prior to startup. The control system for fast start of the plant should be fully automated to minimize times between sequential steps and allow for greater consistency during startup.

Both fast start and conventional units are equipped with service life monitoring systems that control unit ramp operations based on predetermined thermal stress limitations. Fast Start units are equipped with advanced control schemes incorporating model based controls (MBC) to optimize startup based on these monitoring systems.

Purge credits established during the shutdown must still be intact. NFPA 85 requires that a fresh air purge of the combustion turbine and HRSG be accomplished prior to start. NFPA 85 requires that at least five volume changes be completed or a minimum purge of 5 minutes prior to ignition. Typical purge durations can range from 5 to 20 minutes. The 2011 edition of NFPA 85 allowed for purge credits to be achieved when the unit is taken off line if the purge is completed and the valving arrangement is shown to positively isolate any fuel from entering the system. The combustion turbine can usually achieve the required purge when coasting down following a loss of ignition.

A.2 HRSG

HRSGs designed for fast-start plants can subject HRSG components such as superheaters and reheaters to rapid heating. Large thermal stresses can be produced by the differential expansion of the tubes within the HRSG. HRSG designs in such plants must be capable of accommodating the rapid change in temperature and flow of flue gas generated by load ramping of advanced class combustion turbines.

To reduce thermal capacity of drums many options are used to decrease the drum size and wall thickness including utilizing Benson style drums, utilizing multiple drums, high strength drum materials, reduced residence time. Self-reinforced nozzles, full penetration nozzles, full penetration welds, and steam sparger systems further improve the ability to accept rapidly changing exhaust gas conditions and steam conditions. Improved materials throughout the high pressure superheater and reheater can be required. Online, real-time monitoring system should be included to evaluate HRSG life consumption.

In order to reduce the thermal capacity of drums, the residence time may also be reduced for fast start units. Fast start units typically have drum storage time around two minutes. Conventional start plants have drum storage time from 3-5 minutes.

Fast start plants are equipped with a stack damper and with an insulated stack up to the stack damper. The stack damper and insulation are critical as they restrict the flow of flue gas out the HRSG stack minimizing heat loss when the unit is offline. While conventional units do not require stack dampers and insulation, it is a recommended practice to minimize heat loss when the unit is offline.

Both fast start and conventional units have improved HRSG geometries compared to those built a decade ago. Improvements in geometries have been to decrease thermal stresses from unit cycling and are part of the HRSG standard design such as coil flexibility to superheater/reheater interconnecting piping and accommodations for tube-to-tube temperature differentials.

A.3 STEAM TURBINE

The steam turbine must also be designed for the thermal gradients experienced while ramping during start-up. For fast start machines, the casing design must be optimized to reduce the thermal stress during temperature fluctuations and to accept faster start up and load change gradients. The use of higher grade material may be employed in the high pressure and intermediate casings and valves to reduce component thickness. Main steam stop valves must be designed so that these valves can be opened at a relatively higher pressure. Integral rotor stress monitors can be provided; the rotor stress monitor is typically capable of limiting or reducing the steam turbine load or speed increase and is designed to trip the turbine when the calculated rotor stresses exceed allowable limits.

For machines undergoing a fast ramp, attemperators are often required on the high pressure and hot reheat steam lines. Overspray on these attemperators can lead to water in these steam lines; special attention needs to be provided for turbine water induction prevention for units equipped with terminal attemperators.

A.4 EMISSIONS AND AMMONIA FEED

Outlet NO_X from the combustion turbine can vary highly when undergoing fast startup and fast ramp conditions. Conventional units only measure NO_X at the stack; for fast ramping units limiting NO_X measurements to the stack only can lead over injecting or under injecting ammonia. Higher ammonia slip and potentially greater SO2 conversion in fast-start and fast-ramp units create additional challenges for control of sulfur-bearing deposits in the colder HRSG areas. Low-pressure evaporators and economizers are particularly at risk. For fast ramping plants, addition of feed forward controls to quicken the saturation of the SCR catalyst (if included) is required. Also the HRSG should be equipped with LP economizer recirculation or heating systems to maintain surfaces above SO2 dew points.

A.5 AUXILIARY STEAM

Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable uninhibited startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures.

Conventional units without an auxiliary boiler must use the combustion turbine and HRSG to produce steam to warm the unit and establish seals. During a conventional unit startup, holds are required to complete these warm up periods.

Provisions for fast start of the auxiliary boiler should also be considered which include equipping the auxiliary boiler mud drums with heating coils. Auxiliary boiler heat input, operating hour limits, and emission limits must also be considered.

Note that the auxiliary boiler makes up the majority of the cost to equip a combined cycle with fast start capabilities.

A.6 TERMINAL STEAM ATTEMPERATORS

Conventional start plants hold the combustion turbine load during startup as needed to meet the steam turbine startup steam temperature requirements. Fast-start plants decouple the CTG/HRSG startup from the steam turbine startup by using terminal attemperators at the HRSG outlet for meeting steam turbine startup steam temperature requirements, irrespective of CTG/HRSG load. This allows the steam turbine to come on line independently from the CTG and HRSG. As a result, the plant can increase load more quickly.

While the addition of terminal (final stage) steam attemperators on the main steam and hot reheat lines allow for temperature matching, they introduce the risk of two phase flow in the steam lines. An adequate run of straight piping downstream of the attemperators, adequate drainage, and robust instrumentation are a must to minimize the risk of condensate carry-over to the steam turbine. Additional controls should be considered to prevent turbine water induction.

A.7 FEEDWATER SYSTEM

For fast start plants equipped with terminal attemperators, additional condensate and feedwater pump flow is required to meet the attemperation demands. Inter-stage feedwater used for attemperation may be taken off at a later pump stage to meet the pressure demands of the attemperators which could impact feedwater piping wall thickness.

A.8 FUEL GAS SYSTEM

In order to reduce emissions and maintain flame stability, some manufacturers require supplementary fuel gas heating as a part of startup. This heating is in addition to any startup heater used to raise the fuel gas temperature above the dew point.

A.9 WATER TREATMENT SYSTEM

Maintaining water chemistry and meeting the water chemistry requirements of the HRSG and steam turbine are a critical part of startup. Blowdown and makeup systems should be sized accordingly to meet expected startup demands. Provisions for the inclusion of a future condensate polisher should be considered should problems arise. Condensate polishers ensure top quality feedwater.

A.10 AUTOMATED STARTUP SEQUENCE

Additional controls and automation are required for fast-ramp plants to ensure the matching of steam temperatures and to maintain emission compliance. As a result, more plant instrumentation is required in automated plants to allow the plant control system to monitor system status, minimize times between sequential steps and provide consistent startups.

Also fast-ramp plants should consider the use of service life monitoring systems such as thermal stress indicators on the HRSG and steam turbine. These systems allow control of the unit ramp operations based on predetermined thermal stress limitations.

FINAL

NUMBER OF COLD, WARM, AND HOT STARTS ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1207H

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1.0 Introduction

Prior to the early 2000s, combined cycles were predominately designed for base load operation with high focus on highest full load efficiency and lowest capital cost. Due to increases in gas pricing, changing power market production cost structure, and renewable energy generation, many of these plants were forced into intermediate or even daily cycling mode. Many problems associated with the fast changing temperatures in the equipment resulted, such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction.

As a result of these industry issues, today's major equipment suppliers design their equipment to withstand the cumulative wear and damage caused by frequent starts and stops. For modern combined cycle equipment operating as high cycling units, major equipment manufacturers take the following into consideration:

- Base equipment designs consider high cycling
- Service life monitoring equipment is recommended for high cycling units
- Time between service intervals decreases with higher cycling

In addition to the number of starts, the time between the unit shutdown and start also has a significant impact on the equipment. When a unit is shutdown, equipment begins to cool. Upon the next start, the equipment would have to be brought back up to operating temperature putting the equipment through a thermal cycle. The duration between shutdown and startup is usually broken down between different start modes whether the equipment is considered hot, warm, or cold. Equipment manufacturers each have their own definition for hot, warm, and cold starts; however, typical start mode durations are listed in Table 1-1.

Table 1-1 Start Mode Definitions

START TYPE	SHUTDOWN DURATION
Hot	< 8 hours
Warm	8-48 hours
Cold	> 48 hours

1.1 BASE EQUIPMENT DESIGN

During startup and shutdown, the unit sees large temperature gradients and thermal stresses. Cycling increases concern for thermally induced creep-fatigue damage as a result of rapid heating of the surface of components such as turbine blades, rotors, casings, drums, and other heavy walled components. Creep-fatigue damage can also result from different thermal expansion between thin and thick components or dissimilar metal welds.

To resolve these issues, manufacturers have incorporated the knowledge of these earlier failures into their standard designs. Manufacturers select geometries, materials, thicknesses, and coatings in such a way as to limit the damage of thermal cycling. Geometries and material selection also alleviate other issues such as flow accelerated corrosion, vibration, and water induction. These designs do not alleviate all the issues with thermal factors but allow the equipment to be monitored in such a way to determine its service life.

1.2 MAINTENANCE INTERVALS

The design life for the facility is 30 years and the operating equipment will need regular maintenance including hot gas path and major inspections.**Error! Reference source not found.Error! Reference source not found.** Figure 1-1 shows the equivalent hours-based and starts-based maintenance intervals for GE and Siemens H-class combustion turbines and the potential impact of maintenance factors on maintenance intervals.

The timing of maintenance intervals are impacted by maintenance factors. Hours based maintenance factors consider fuel type, firing temperature, and water or steam injection used for emissions control or power augmentation. Starts based maintenance factors consider the type of start; whether it is a conventional start, fast start, cold start, warm start; load achieved during each start; and shutdown type such as normal cooldown, rapid cooldown or unit trip. The red lines in Figure 1-1 show how starts or hours based factors could affect the timing of maintenance intervals.

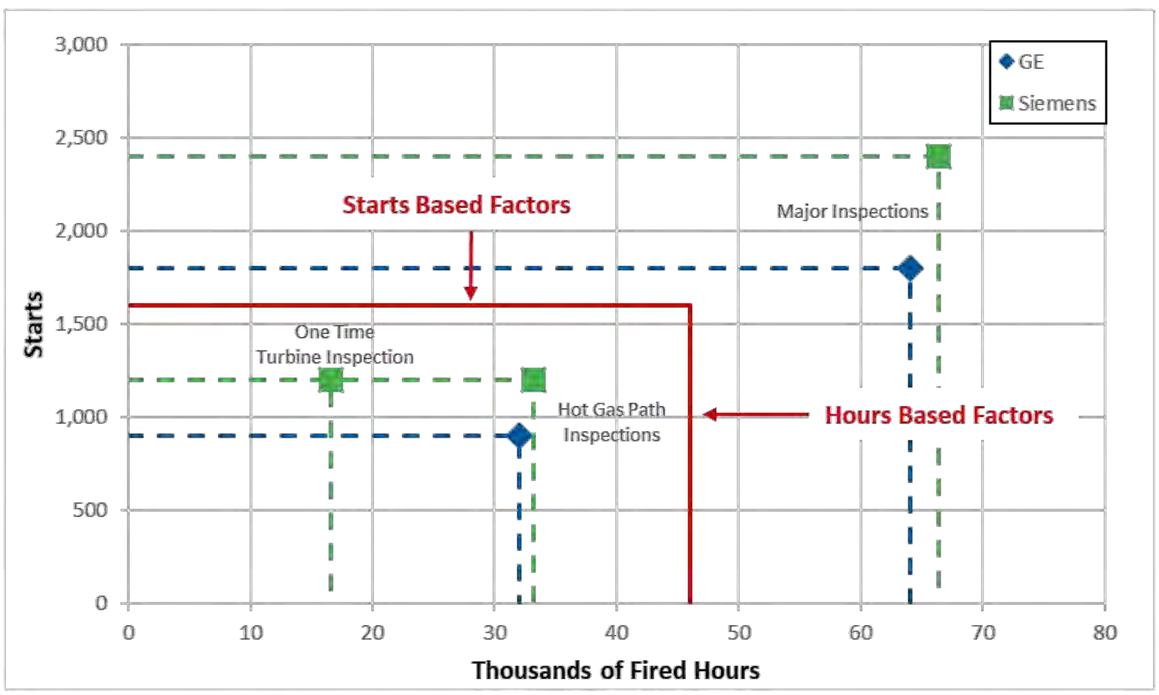


Figure 1-1 Maintenance Factors Reduce Maintenance Intervals

Per GE's Heavy-Duty Gas Turbine Operating and Maintenance Considerations (GER-3620N), a GE unit with a baseline maintenance factor would equate to 4,800 operating hours per year (16 hours/start, 6 starts/week, 50 weeks/year) and 300 starts per year. Those 300 starts would consist of 249 hot starts, 39 warm starts, and 12 cold starts. For the design life of 30 years, GE would base their Long Term Service Agreement (LTSA) on 5 maintenance cycles for a GE 7HA.01 with a baseline operating profile. The LTSA relates to the serviceable life of the combustion turbine.

Error! Reference source not found. Figure 1-2 shows how operating hours and the number of starts per year affect the duration of the LTSA. A 30 year life is based on roughly 300 equivalent starts per year. An operating regime requiring above about 300 equivalent starts per year would have service intervals based on equivalent life and start decreasing the life expectancy of the LTSA. For example, 450 equivalent starts per year would be roughly equivalent to a 20 year LTSA life. When operating below 300 equivalent starts per year the figure shows whether hours based operation or number of starts based operation would determine the maintenance intervals for the plant. Since the facility has a 30 year design life, 300 equivalent starts would be the average yearly allowable for the plant. Based on a design basis of 310 starts per year, the breakdown of calculated and recommended number of design basis cold, warm, and hot starts would be as shown in Table 1-2.

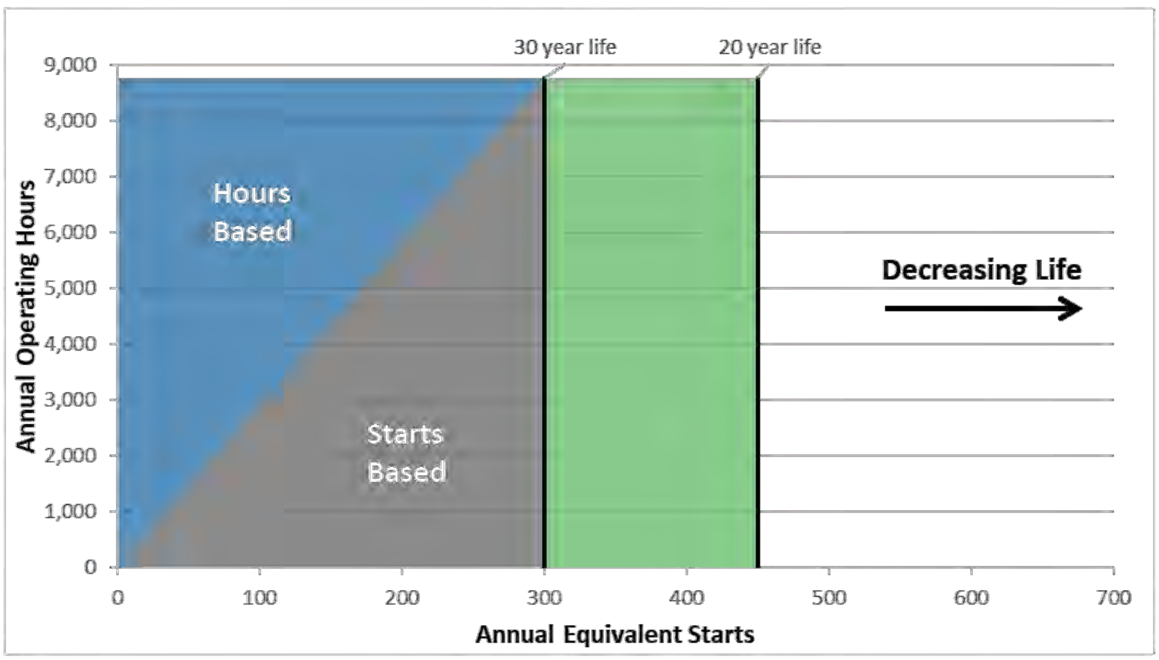


Figure 1-2 Combustion Turbine LTSA Term vs. Starts and Operating Hours Service Intervals

Table 1-2 Operating Conditions Used in Design Basis

OPERATING CONDITIONS	DESIGN BASIS
Operation	Daily Cycling
Yearly Operating Hours	Up to 8,760
Annual Capacity Factor	45% to 100%
Cold Starts Per Year	10
Warm Starts Per Year	100
Hot Starts Per Year	200
Total Starts Per Combustion Turbine	<310

1.3 SERVICE LIFE MONITORING EQUIPMENT

For plants operating in a regime where the starts based maintenance factors are determining the service intervals, it becomes useful to monitor the equipment to avoid costly outages. Service life monitoring systems perform three functions: instrumentation, evaluation, and determination. The instrumentation and sensor systems record the operating parameters such as localized temperature, pressure, and vibration. Based upon the readings, evaluations can be made such as stresses in critical locations in the turbines and the HRSG. The evaluated data is then combined with the operating history of the system to determine the impact on the remaining service life.

Recommended monitoring systems for high cycling plants include:

- Combustion Turbine Stress Controller
- Steam Turbine Stress Controller
- HRSG Stress Controller
- Condition Monitoring System
- Water Quality Monitoring System

Today's H-class combustion turbines come equipped with control systems that monitor speed, acceleration, temperature, and verify that all sensors are active. These sensors measure performance and monitor the machine's health. These systems also count the operating hours and number of equivalent starts or calculate the equivalent life of each start sequence in order to calculate the next service interval.

The steam turbine stress controller consists of a stress evaluation system that calculates and controls stresses in thick walled components including stop and control valves, HP casing and rotor body, and the IP rotor body. The stress controller monitors and controls ramp rates during start up to calculate the cumulative fatigue of cycling the unit. The stress controller also determines the remaining time to the next service interval.

The HRSG stress controller performs a dynamic analysis of the HRSG to determine fatigue. The stress controller determines risk factors based upon the evaluations, such as the probability of crack initiation. These risk factors are used to plan and indicate HRSG maintenance.

Condition monitoring systems measure critical asset parameters such as vibration, temperature, and speed of rotating equipment including boiler feed pumps, condensate pumps, circulating water pumps, cooling tower fans, and fuel gas compressors. The monitoring systems also evaluate trends, such as vibration amplification, and compare it against set points, historical readings, and known failure patterns.

The water quality monitoring system provides additional water and steam sampling to monitor issues with cycling units. Cycling units result in a large demand on the condenser and, in peak demands, on condensate supply and oxygen controls. Additional controls include online monitoring for condenser tube leaks and condenser air in leakage. It also includes monitoring steam blowdown lines for high level of particulates to indicate any safety issues. Water quality monitoring systems are not as important if the unit includes a condensate polisher.

2.0 Service Life Monitoring System Costs

As outlined in Section 1.2, service life monitoring systems are recommended for high cycling plants to help predict and plan maintenance. Table 2-1 provides budgetary cost (+/- 30%) for service life monitoring systems.

Table 2-1 Service Life Monitoring System Costs

SERVICE LIFE MONITORING SYSTEM COSTS	
Combustion Turbine Stress Controller	[redacted]
Steam Turbine Stress Controller	[redacted]
HRSG Stress Controller	[redacted]
BOP Condition Monitoring System	[redacted]
Water Quality Monitoring System	[redacted]
Additional cable and I/O	[redacted]
Total	[redacted]

3.0 Conclusion

Today's combined cycle equipment is designed for high cycling applications and consider problems associated with the fast changing temperatures in the equipment such as high thermal stresses, high cyclic fatigue, vibration, flow accelerated corrosion, and water induction. The design life of the equipment is 30 years with major overhauls of the combustion turbines occurring every 6 years. The time duration between major overhauls is based upon maintenance factors associated with hours of operation and the number of starts.

While the number of operating hours is not expected to shorten the time between maintenance cycles, the number of starts could decrease the operational life. In order to maintain the 6 years between major overhauls, the combustion turbine should have an equivalent number of annual starts less than 310. To avoid decreasing the life of the LTSA, the typical combined cycle design including balance of plant equipment should not exceed 310 starts per year. The breakdown of the recommended number of design cold, warm, and hot starts would be as shown in Table 3-1.

Table 3-1 Design Cold, Warm, and Hot Starts

OPERATING CONDITIONS	
Operation	[redacted]
Yearly Operating Hours	[redacted]
Annual Capacity Factor	[redacted]
Cold Starts Per Year	[redacted]
Warm Starts Per Year	[redacted]
Hot Starts Per Year	[redacted]
Total Starts Per Combustion Turbine	[redacted]

If the plant is expected to be a high cycling unit with a maintenance cycle that would be determined based upon the number of starts rather than the number of hours operated per year, Vectren should consider additional service life monitoring systems to assist in predictive maintenance, as shown in Table 3-2. While these systems do not prevent maintenance, they allow the operator to better understand how the operation of the unit is impacting the service life of the equipment.

Table 3-2 Service Life Monitoring Systems

SERVICE LIFE MONITORING SYSTEM COSTS	
Combustion Turbine Stress Controller	[redacted]
Steam Turbine Stress Controller	[redacted]
HRSG Stress Controller	[redacted]
BOP Condition Monitoring System	[redacted]
Water Quality Monitoring System (not required with a condensate polishing system)	[redacted]
Additional cable and I/O	[redacted]
Total	[redacted]

FINAL

AUXILIARY BOILER ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1209H

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

Executive Summary

In developing this report, Black & Veatch reviewed the requirements for the auxiliary steam system for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and shutdown scenarios to determine the required sizing and operation of the auxiliary steam boiler.

The auxiliary steam system users have been summarized in the Auxiliary Steam Demands provided in Table 2-1. The users were estimated based on previous projects using the 7HA.01 gas turbines. Based on the maximum co-incident steam demand of the 7HA.01 configuration it is recommended that Vectren utilize an auxiliary boiler designed for [redacted] lb/hr and an outlet pressure of [redacted].

1.0 Introduction

The purpose of this study is to determine the specific requirements for the Auxiliary boiler to be installed with the new Combined Cycle Power Plant (CCPP). These Fast start units require an auxiliary boiler to produce steam prior to the startup of the unit. This auxiliary steam is used for steam line warming, establish the steam turbine seals, warm up HRSG drums, and condenser sparging to enable quicker startup of the unit. The auxiliary boiler may also produce steam when the unit is off line to maintain drum and turbine temperatures. Black & Veatch has previously performed the "Fast Start vs Conventional Start Analysis" which demonstrates the need for an auxiliary boiler for a unit with fast start capability.

This evaluation will help determine the design impact of this system to the new CCPP design. Auxiliary system users, auxiliary boiler sizing and operation will also be identified and discussed.

2.0 Auxiliary Boiler Sizing and Outlet Pressure

The auxiliary steam system provides steam to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the best preliminary design basis for sizing the auxiliary boiler. Upon selection of the final plant design, the selected size of auxiliary boiler should be reviewed.

2.1 COINCIDENT STEAM DEMANDS

The maximum co-incident auxiliary boiler steam demand occurs during startup when supplying maximum steam turbine sealing, fuel heating, maximum condenser sparing steam, and maximum combustion turbine inlet air heating as shown in Table 2-1.

Table 2-1 Coincident Auxiliary Steam Demands

AUXILIARY STEAM USERS	1X1 HA.01
ST Gland Sealing	[redacted]
Startup Steam to Fuel Gas Heater	[redacted]
Condenser Hotwell Sparging	[redacted]
Combustion Turbine Inlet Air Heating	[redacted]
Total Coincident Boiler Steam Flow Required	[redacted]

2.2 NON-COINCIDENT STEAM DEMANDS

During unit pre-start, there are two activities that require auxiliary steam flow, but are not co-incident with the other users. These non-coincident activities occur during HRSG pre-warming and HRSG HP pressure holding. The non-coincident auxiliary steam demands are listed in Table 2-2.

Table 2-2 Non-Coincident Auxiliary Steam Demands During Pre-Start Activities

AUXILIARY STEAM USERS	1X1 7HA.01
HRSG Warming	[redacted]
HRSG Pressure Holding	[redacted]

2.3 DESCRIPTION OF USERS

- The turbine seals require steam from the auxiliary system to provide sealing until the steam turbine increases load and becomes self-sealing. When the steam turbine exceeds the point of self-sealing, the flow from the auxiliary system will decrease to near zero.
- A startup steam to fuel gas heater is used to raise the fuel gas to the CT manufacturers specified minimum fuel temperature via a steam to water heat exchanger.
- Condenser hotwell sparging is used to heat the condensate in the condenser to normal operating temperatures prior to starting the units.
- The gas turbine inlet air heating system uses auxiliary steam to provide heat via coils in the CT inlet air structure to minimize the possibility for ice formation in the CT compressor section.
- The HRSG HP warming flow increases the metal temperature of the steam drums and the tubes, allowing for faster startup capability.
- The HRSG HP pressure holding maintains the HP evaporator at a minimum of 275 psig to maintain drum and tube temperatures for faster startup capability.

2.4 BOILER OUTLET CONDITIONS

The delivery steam pressure of the auxiliary boiler is typically 300 psig at saturation temperature to facilitate HP evaporator pressure holding of approximately 275 psig. Electric superheaters will be used to provide superheated steam to the turbine seals. Delivering saturated steam will reduce the heat input to the auxiliary boiler which is limited due to air permits.

3.0 Auxiliary Boiler Operation

3.1 PRE-START CONDITION

The auxiliary steam system should be pressurized, heated and drained up to the steam seal feed valve during pre-start activities. The operating conditions of the auxiliary boiler and system must be verified prior to initiating a unit startup. During cold pre-start activities, the steam for turbine sealing, condenser sparging steam and HP evaporator warming is supplied by the auxiliary boiler. During hot start activities, the steam demand for the HP evaporator warming steam is replaced by the steam demand for HP evaporator pressure holding. Following an HRSG outage or cold restart, the HRSG HP warming flow is set to a maximum flowrate to accelerate warming.

3.2 INITIAL STARTUP AND SHUTDOWN

During initial startup the auxiliary steam for the turbine sealing, CT air inlet heating, fuel gas heating and condenser sparging is provided from an auxiliary boiler. As the plant cycle steam from the HRSG IP drum becomes available it allows the auxiliary boiler to be shut down or unloaded to idle as plant operations allow. During normal operation the HRSG IP drum provides all required auxiliary steam flow for the plant.

During plant shutdown or trip, it is expected that there is enough residual energy in the HRSG to provide auxiliary steam until the steam turbine exhaust vacuum is broken or the auxiliary boiler can be brought online to provide sealing steam. The auxiliary boiler must remain in a ready condition at all times during combined cycle operation. During overnight plant shutdowns the aux boiler can remain in operation to provide sealing steam, condenser sparging steam and allow rapid starting in the morning.

4.0 Conclusions

The purpose of this evaluation was to determine the specific requirements for the auxiliary boiler for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed pre-start, start-up and shut down scenarios to determine the required sizing and operation of the auxiliary boiler.

This report has shown:

- Auxiliary steam users and the estimated demand.
- Non-coincident auxiliary steam users and the estimated demand
- Black & Veatch's recommendation for steam requirements listed in Table 2-1 for various plant configurations.

FINAL

EXISTING FIRE WATER SYSTEM REVIEW

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 42.1212H

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed the piping and instrumentation diagrams (P&IDs) for the existing fire protection and service water systems.

The existing system includes existing pumps and a 75,000 gallon raw water storage tank. The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. To meet the new fire water system design requirements, a third diesel motor fire pump should be added to the system and the pump arrangement modified to a 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump, which is rated for approximately 1 percent for the main pumps flow and same discharge pressure, should remain.

1.0 Existing Equipment

Based on the existing site Fire Protection and Service Water Systems P&ID (F-1024) there are 2x100 percent fire pumps (one electric driven and one diesel driven) that are rated for 1,500 gpm @ 300 FT TDH each. The fire water pumps normally take suction from existing Ranney Well pumps of adequate capacity and the Raw Water Storage Tank (75,000 gallons) via a 12" nominal diameter suction header. The fire protection water supply system is also cross tied to the River Water pumps. The Raw Water Storage Tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use. The existing site has a 10" underground fire water loop. This pipe is assumed to be ductile iron.

Per NFPA 850, the existing water source is large enough to be considered a reliable water source. The multiple pumps installed provide reliability such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. If a single pump were to be out of service, the remaining pumps will still have sufficient capacity to supply water to the existing water users as well as the maximum fire water demand of 2,500 gpm.

2.0 Design Basis and Clarifications

- A search of the NFPA codes on the Indiana State website did not include NFPA 850. However, for the purposes of this assessment and the design of the new power plant, Black & Veatch has referenced NFPA 850 – 2015.
- There is a discrepancy between some of the code years referenced on the Indiana State website and from the IBC or IFC. Our basis is the most current version when this occurs.
- It is not clear from the P&ID what the material used for the existing underground fire water supply mains. Our basis is currently ductile iron material; please clarify if different.
- Please clarify who the Authority Having Jurisdiction (AHJ) is for the A.B. Brown Site. We have identified the state fire marshal below.

    Indiana State Fire Marshal
    Stephen Cox
    317-232-2222
    http://www.in.gov/dhs/2445.htm

3.0 New Plant Fire Protection Requirements

The new plant's required fire water system supply flow is based on a worst case fire scenario, plus a hose allowance (500 gpm), and any adjacent systems in the immediate area of a potential fire area; as defined in NFPA 850, Section 6.2. The largest system demand is expected to be the Steam Turbine Building/Enclosure at 1,800 gpm in combination with the turbine generator bearings closed head sprinkler system with directional nozzles with a demand of approximately 200 gpm. This total demand will require a main fire pump rated at 2,500 gpm. The velocity limits at this flow require either a 10" DI or 12" HDPE DR 11 pipe.

To meet the new fire water system design requirements a third diesel motor fire pump (1,500 gpm @ 300ft) should be added to the system modifying the pump arrangement to 3x50 percent configuration with two pumps driven by a diesel motor and the other driven by an electric motor. This configuration allows for a fire water demand up to 3,000 gpm. The existing pressure maintenance pump which is rated for approximately 1 percent for the main pumps flow and same discharge pressure should remain. There are no elevated areas for the new or existing plant areas that require booster pumps to obtain adequate pressure for hose stations so a standard pressure rating of 300 ft-H_2O at the rated point is expected to be sufficient.

Per NFPA 850 the multiple Ranney Well pumps installed will provide a reliable source of water such that a single failure or maintenance event will not impair the ability of the system to responds to a fire event. In a single pump out of service case the two remaining Ranney Well pumps can provide up to 4,000 gpm. The preliminary water mass balance for other uses states the normal use from non-fire protection demands is approximately 150 gpm. This allows the fire water demand of 2,500 gpm to be met along with the other non-fire protection water users.

The existing 10" fire protection underground system can be reused with new 12" HDPE used for any new underground headers and around the cooling tower. Hydrants will be located as per NFPA 850 and the local code requirements.

4.0 List of Applicable Codes and Standards

675 IAC 13-2.6	Indiana Building Code, 2014 Edition (IBC, 2012 Edition, 1st printing) ANSI A117.1-2009	Effective 12/1/14
675 IAC 22-2.5	Indiana Fire Code, 2014 Edition (IFC 2012 Edition, 1st printing)	Effective 12/1/14

NFPA Standards

NFPA #	Description	Effective Date	IAC Cite
10-2010	Portable Fire Extinguishers	December 15, 2012	675 IAC 28-1-2
11-2005	Low Expansion Foam and Combined Systems	September 22, 2006	675 IAC 28-1-3
12-2005	Carbon Dioxide Extinguishing Systems	September 22, 2006	675 IAC 28-1-4
13-2010	Installation of Sprinkler Systems	September 26, 2012	675 IAC 28-1-5
14-2000	Installation of Standpipe and Hose Systems	December 13, 2001	675 IAC 13-1-9 Repealed 3/21/14
15-2001	Water Spray Fixed Systems	September 22, 2006	675 IAC 28-1-8
20-1999	Installation of Centrifugal Fire Pumps	December 13, 2001 Amended 12/26/02	675 IAC 13-1-10
25-2011	Inspection, Testing and Maintenance of Water Based Fire Protection Systems	May 12, 2013	675 IAC 28-1-12
37-2002	Installation and Use of Stationary Combustion Engines and Gas Turbines	September 22, 2006	675 IAC 28-1-15
70-2008	National Electrical Code	August 26, 2009	675 IAC 17-1.8
72-2010	National Fire Alarm Code	March 23, 2014	675 IAC 28-1-28
2001-2004	Clean Agent Fire Extinguishing Systems	September 22, 2006	675 IAC 28-1-40

5.0 Conclusions

The purpose of this evaluation was to review the existing fire water system. Black & Veatch reviewed P&IDs for both the existing fire protection and service water systems.

This report has shown:

- The raw water storage tank is sized to provide 51,000 gallons of surge capacity devoted to fire water use.
- The existing pressure maintenance pump is sufficient.
- The existing 10 inch fire protection underground system can be reused with new 12 inch HDPE used for any new underground headers and around the cooling tower.
- Black & Veatch's recommendation is to add a third diesel motor fire pump and modify the pump arrangement to a 3x50 percent configuration.

FINAL

NOISE REGULATION REVIEW

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1213H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

Table of Contents

Executive Summary

Black & Veatch reviewed the noise regulations that might apply to the new Combined Cycle Power Plant (CCPP).

Indiana, Posey County, and Marrs Township have no far field noise regulation or ordinances. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Occupational Safety and Health Administration (OSHA) standards will apply to near field noise emissions. Near field noise requirements are measured along the equipment envelope. During off-normal and intermittent operation such as startup, shutdown, and upset conditions, the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

1.0 Results of Noise Regulation Review

Noise requirements fall into two categories: far field or near field. These categories are based upon the distance from the emitter to the receptor. Far field noise requirements are generally referenced to the site boundary, property line, or other boundary limit. Near field noise requirements are measured along the equipment envelope. The envelope is defined as the perimeter line that completely encompasses the equipment package a distance of 3 feet from the face of the equipment.

1.1 FAR FIELD NOISE REQUIREMENTS

There are no extant noise regulations or ordinances for Indiana, Posey County, or Marrs Township. The expectation would be that the general environmental sound levels in the surrounding area would not be substantially different from the sound levels with the two coal units in operation, assuming the coal units will be decommissioned after the new unit is operational.

1.2 NEAR FIELD NOISE REQUIREMENTS

Near field noise requirements are limited by OSHA requirements. The near-field noise emissions for each equipment component furnished under these specifications shall not exceed a spatially-averaged free-field A-weighted sound pressure level of 85 dBA (referenced to 20 micropascals) measured along the equipment envelope at a height of 5 feet above floor/ground level and any personnel platform during normal operation.

During off-normal and intermittent operation such as start-up, shut-down, and upset conditions the equipment sound pressure level shall not exceed a maximum of 115 dBA at all locations along the equipment envelope, including platform areas, that are normally accessible by personnel.

2.0 Conclusions

Near field noise mitigation requirements will be required of equipment. Since there were no extant noise regulations specific to this site, no far field noise mitigation is required.

The attached V100 supplemental, contains the noise abatement requirements to be included with the procurement specifications. Since there were no extant noise regulations specific to this site, the V100 supplemental was developed using the near field requirements which are the typical OSHA limits.

FINAL

CONDENSATE POLISHER EVALUATION SUMMARY

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1214H

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

Executive Summary

This report provides a summary of Black & Veatch's evaluation of including a condensate polisher system in the conceptual design of the new A.B. Brown Combined Cycle. This summary of the evaluation will show that:

- Five selection criteria for Pre-Coat Condensate Polishers are present in the conceptual design. General industry practice to consider polishing is three or more.

PRE-COAT POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Steam Cation Conductivity $\leq$0.2uS/cm	**Yes – 0.2uS/cm Allowed***
Graywater Cooling	No – River Water
Air Cooled Condenser	No – Wet Surface Condenser
All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry	**Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)**
HP/Main Stream Pressure >2,400 psig	**Yes – HP/Main Steam >2,500 psig**
Cycling with Short Start-up Time	**Yes – Cycling Units with Rapid start**
LP Steam Conductivity Limit?	No
Suspended Solids (TSS) process contamination possible?	**Yes – River water contains levels of TSS**
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

[redacted]

PARAMETERS	1X1 7HA.01 (FIRED)
Condensate Design Flow, gpm	[redacted]
Estimated Equipment Costs ($450 per gpm)	[redacted]
Total Installed Capital Cost (Equipment Costs + $2.52M installation)	[redacted]

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

1.0 Introduction

1.1 GENERAL FACILITY OVERVIEW

Vectren (Company) is planning the construction of a combined cycle plant at its existing A.B. Brown Station (ABB) in Evansville, Indiana. This combined cycle configuration will utilize heat recovery steam generators (HRSG), combustion turbine generators and a single steam turbine generator to output 1,050 MW.

Condensate polishing is the process of purifying condensate before returning it to a boiler. Feedwater (condensate and boiler feed) contain various impurities. Corrosion products from the steam cycle, mostly iron, travel through the cycle and can concentrate in the boiler. Impurities in feedwater can affect HRSG performance and can be transported from the HRSG to the steam turbine, causing damage to piping and turbine components from pitting, corrosion, or scaling. They can inhibit heat transfer, cause hot spots and eventual failure of the boiler tubes. Additionally, they can carryover with the steam and degrade the steam purity to the level that it no longer meets the steam turbine suppliers steam purity guarantee requirements.

The water quality required for feedwater is defined by the HRSG manufacturers and is dependent on the unit cycling, chemistry program, and operating pressure of the plant. High pressure (1500 psi or greater) drum boilers have stringent feed water quality requirements in order to meet the steam turbine suppliers steam purity guarantee. Drum boilers meet theses water quality requirements by blowdown to eliminate impurities from the cycle and making up with fresh demineralized water. Condensate polishing provides a means to minimize blowdown and better ensure boiler water quality requirements.

In addition to improving condensate/feed water quality, condensate polishers can decrease unit startup time by minimizing chemistry related delays, minimize impacts of condenser leaks, and reduce frequency of boiler chemical cleaning. Consequently, condensate polishers are a worthy consideration in most high pressure steam cycle units, especially cycling units designed with rapid start.

1.2 EVALUATION OBJECTIVE

The purpose of this study is to:

- Identify the selection criteria for condensate polishing and determine if/which criterion is applicable to the project.
- Evaluate the capital costs associated with condensate polishing.

The following evaluation reports should be viewed in conjunction with this document:

- 41.1207H – Number of Cold, Warm and Hot Starts Analysis
- 41.1203H – Fast Start vs. Conventional Start Analysis
- 41.1217H – Demin Water Analysis Evaluation.

2.0 Condensate Polishing

2.1 SELECTION CRITERIA

Figure 1 below is a flow chart used to confirm whether or not condensate polishing is necessary in the power plant design basis. The primary and secondary factors shown in Figure 1 are used to identify, if necessary, which type of condensate polisher is to be used based on the parameters of the unit; Deep Bed type or Pre-coat type polishers.

Figure 1 –Condensate Polisher Selection Flow Chart

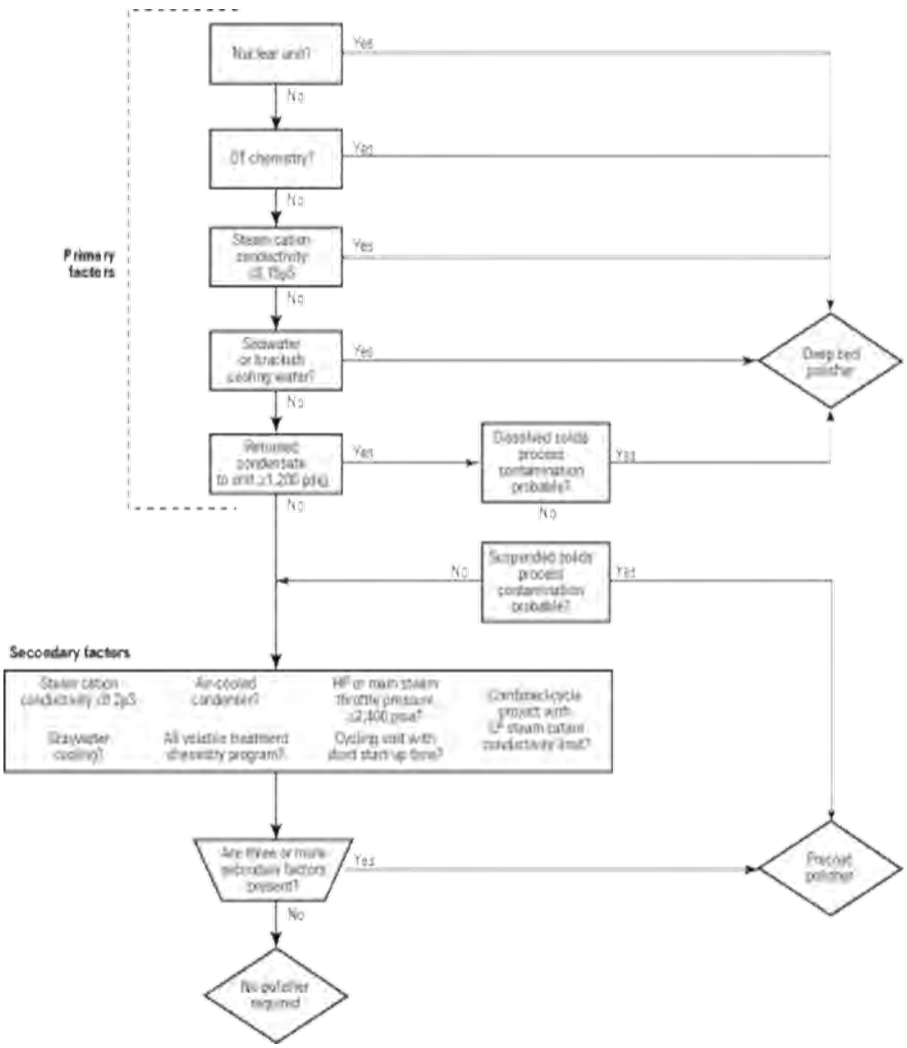


Table 1 reviews the criteria for deep bed type polishers listed and indicates if these factors apply to the project. If one or more of the selection criteria, or factors, apply to ABB, then deep bed condensate polishing should be considered.

Table 1 – Deep Bed Condensate Polisher Selection Criteria

DEEP BED POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Nuclear Plant	No – Fossil Fuel
Oxygenated Treatment (OT) Cycle Chemistry	No – All-Volatile Treatment-Oxidizing with Phosphate
Steam Cation Conductivity <0.15uS/cm	No – 0.2uS/cm Allowed*
Seawater or Brackish Cooling Water	No – Surface Water, Well Water
Returned Condensate to unit >1200 psig	No - 400 psig
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

Based on the design parameters of the plant as shown in Table 1, deep bed condensate polishing would not be considered.

Table 2 reviews the criteria for pre-coat type polishers listed and indicates if these factors apply to the project. General industry practice is if three or more factors apply to ABB, pre-coat polishers should be strongly considered.

Table 2 – Pre-Coat Condensate Polisher Selection Criteria

PRE-COAT POLISHER CRITERIA	A.B. BROWN COMBINED CYCLE PLANT
Steam Cation Conductivity ≤0.2uS/cm	Yes – 0.2uS/cm Allowed*
Graywater Cooling	No – River Water
Air Cooled Condenser	No – Wet Surface Condenser
All-Volatile Treatment – Oxidizing Treatment (AVT-O) Cycle Chemistry	Yes – All-Volatile Treatment-Oxidizing with Phosphate (no oxygen scavenger)
HP/Main Stream Pressure >2,400 psig	Yes – HP/Main Steam >2,500 psig
Cycling with Short Start-up Time	Yes – Cycling Units with Rapid start
LP Steam Conductivity Limit	No
Suspended Solids (TSS) Process Contamination Possible	Yes – River water contains levels of TSS
* GE Steam Purity for Industrial Turbine (Table 4 in document GEK 98965)	

As shown in Table 2, five factors are present in the current design of the project. As a result, pre-coat polishers or design provisions to include future polishers should be considered. The next sections review the benefits of the pre-coat polisher design.

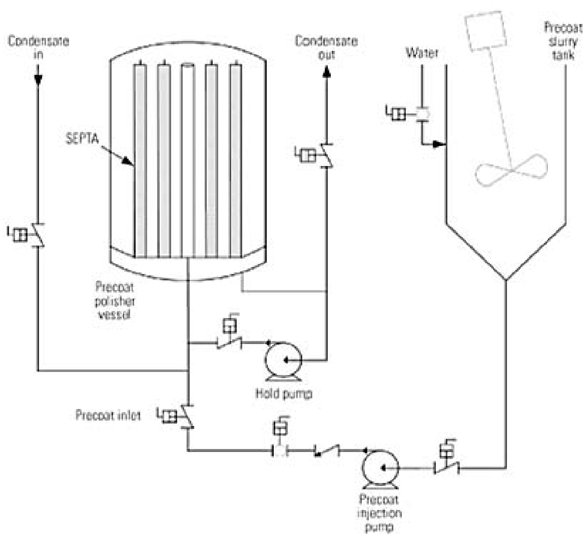
2.2 PRE-COAT TYPE CONDENSATE POLISHING

2.2.1 Overview

Pre-coat polisher is a vessel containing media-retaining filter elements. A powdered media is placed on the elements and the condensate is passed through the media coated filter element and returned to the condensate flow. Figure 2 shows a diagram of a Pre-coat polisher system.

These filter elements, combined with the ion exchanging media (powder coating), has the capability of simultaneous removal of total dissolved solids (TDS) and total suspended solids (TSS). Pre-coat polishers in particular, perform the dual purpose of straining the TSS particulates (iron oxides produced in the condensate system) and removing dissolved solids. Air in-leakage causes corrosion from oxygen pitting and to a lesser degree acidic attack from CO2. Not only does the oxygen damage the carbon steel surfaces but the iron oxides from this corrosion process, both soluble (TDS) and insoluble (TSS), will be transported into the heat recovery steam generator (HRSG) and will deposit on tube surfaces. Over time these deposits reduce unit efficiency, create an environment for under deposit corrosion (boiler tube failures) and necessitate the need for more frequent chemical cleanings.

Figure 2 – Pre-Coat Polisher Diagram



The condensate polisher improves condensate/feed water quality during steady state operations by minimizing the impacts of condenser leaks by the removal of dissolved solids and improves unit startup time by minimizing chemistry related delays by the removal of suspended solids.

2.2.2 Operational Impacts

Dissolved gases can enter the cycle as impurities in the makeup water as well as through air in-leakage to the condenser which is under vacuum. Dissolved gases, particularly uncontrolled oxygen and carbon dioxide, can cause corrosion in the cycle and are generally removed in the condenser and deaerator. However, carbon dioxide can accumulate in the condensate/feed water/boiler train because of its pH equilibrium chemistry and can only be effectively removed with condensate polishing. Particularly during startup and shutdown the condensate/feedwater cycle can and will be exposed to carbon dioxide and oxygen. Their corrosive effects on the carbon steel condensate/feedwater piping can be mitigated with the proper chemistry and blowdown over time, but a polishing unit greatly improves the amount of time necessary to reach optimal cycle chemistry.

If left untreated or detected, these impacts will lead to any number of issues including boiler tube failures, damage to the steam turbine and condenser tube failures.

A condensate polisher is warranted for combined-cycle plants where the steam turbine cation conductivity limit is ≤ 0.2 µS/cm, and especially cycling units designed with rapid start. The cation conductivity of the condensate/feedwater stream can typically reach 0.5 to 0.6 µS/cm due to carbon dioxide absorption in the water. The GE steam turbine cation conductivity requirement for A.B. Brown is <0.2 µS/cm.

Without a condensate polisher, and in the event of a major feedwater chemistry excursion, typically a plant will either dump the “out-of-spec” water and re-fill the system with “in-spec” water or operate the feedwater system without generating steam until the boiler feedwater chemical treatment system brings the water back into spec. Worst case scenario for ABB is dumping the approximate +100,000 gallons of water from the cycle (one HRSG’s and condenser).

Utilizing condensate polishing can reduce the average cycle blowdown during both startup and normal operation to approximately 0.5%-1%. For the ABB project, this blowdown reduction can save up to 1,000,000 gallons of demineralized water each year. This is based on the estimated number of starts per year and capacity factor found in 41.1207F – Number of Cold, Warm and Hot Starts Analysis. Condensate polishing can also potentially reduce the number of boiler chemical cleans over the 30 year expected life of the plant.

3.0 Risk AND Cost Analysis

3.1 RISK ANALYSIS

As stated in Section 3.0, there are several risks associated with operating a combined cycle plant with three or more of the selection factors present in the design. The risk of operating with poor steam/water quality can lead to boiler tube failures, condenser tube failures, and damage to the steam turbine. Table 3 below provides a high level risk analysis of not utilizing a condensate polisher unit.

Table 3 – Risk Analysis Without Condensate Polishing

RISK	SEVERITY	OCCURANCE	DETECTION	LENGTH OF OUTAGE	OVERALL RISK FACTOR
Boiler Tube Failure	High	Medium	High	Medium	High
Steam Turbine Damage	High	Low	Low	High	Medium
Condenser Tube Failure	Medium	Medium	Medium	Medium	Medium
Overall risk factors are indications of estimated number of failure occurrences per year: High = 1 occurrences/yr; Medium = 0.33 occurrences/yr; Low = 0.11 occurrences/yr					

The overall risk factor provides an indication of estimated number of failure occurrences per year. A high overall risk will generally indicate one occurrence per year, while the occurrences per year drop to 33 percent and 11 percent for medium and low factors, respectively.

Utilizing a condensate polisher and a good chemical conditioning program can potentially drop the overall risk factor to the next lower tier for each type of failure.

3.2 COST ANALYSIS

A budgetary cost for a full 2x100% pre-coat condensate polishing system (with pre-coating skid, slurry pumps, air receiver, and resin/precoat recovery tank) is approximately [redacted]. An estimated [redacted] for installation, project management, and risk and contingency is used to determine the total installed cost.

Table 4 – Cost Evaluation - Condensate Polishing

PARAMETERS	1X1 7HA.01 (FIRED)
Condensate Design Flow, gpm	[redacted]
Estimated Equipment Costs [redacted]	[redacted]
Total Installed Capital Cost [redacted]	[redacted]

A temporary/mobile rental condensate polisher could be considered. [redacted]

4.0 Conclusions

4.1 SUMMARY OF CONCLUSIONS

This evaluation report has shown that:

- Five selection factors for Pre-coat condensate polishers are present in the current design of the project. General industry practice to consider polishing is three or more.
- Cycling with rapid startup and <0.2 μS/cm steam cation conductivity, are the two key selection factors that are a part of this project.
- Pre-coat condensate polishers have the capability of simultaneous removal of both TDS and TSS. TSS process contamination is a possibility with any cooling water tube leak utilizing river water makeup.
- The condensate polisher, in combination with a sound cycle chemistry scheme, protects all equipment components in the steam/feedwater cycle.

Based on the selection criteria identified in the summary report, Black & Veatch's recommendation is to include provisions for a future pre-coat type condensate polisher system in the conceptual design for the project. This includes, but not necessarily limited to, [redacted] allowance in condensate pump sizing, space allocation, spare electrical capacity and connections, and condensate discharge by pass piping connections.

FINAL

AUXILIARY COOLING WATER SYSTEM ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1215H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

Table of Contents

LIST OF TABLES

Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch reviewed different design scenarios for the auxiliary cooling water system. It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated:

- Alternative 1--Auxiliary cooling from makeup and circulating water.
- Alternative 2--Circulating water to cool the closed cycle cooling water equipment.
- Alternative 3--Circulating water to cool closed cycle cooling water equipment and hydrogen and lube oil coolers.

The performance, plant area required, reliability and maintenance, and cost of both shell and tube and plate and frame heat exchangers were considered in conjunction with the three alternatives for the auxiliary cooling water system. [redacted]

1.0 Introduction

Equipment throughout the plant is cooled by water. The source of this cooling water is through a closed loop system Closed Cycle Cooling Water (CCCW) or directly from an auxiliary cooling water source. This report looks at the sources for water for equipment cooling.

The existing plant cooling system is cooled by the raw water system. The raw water system consists of three (3) 3,300 gpm river water pumps which provide cooling water for the coal units closed cooling heat exchangers. The discharge from these existing heat exchangers is then routed to the cooling towers for makeup. The heat duty of the existing closed cycle cooling water system is minimized as the circulating water system directly provides cooling water flow to the generator hydrogen coolers and lube oil coolers.

In developing this report, Black & Veatch reviewed different design scenarios for the auxiliary cooling system for the new Combined Cycle Power Plant (CCPP). It was determined that the design used for the auxiliary cooling water system on the existing units would not be practical for the CCPP. Three alternative designs were investigated.

- The first alternative uses a combination of water from the cooling tower makeup to the cooling towers and circulating water to cool closed cycle cooling water equipment. Turbine hydrogen and lube oil coolers would be cooled directly from the cooling tower makeup.
- The second alternative uses circulating water to cool the closed cycle cooling water equipment. The closed cycle cooling water equipment provides cooling water to all equipment including the turbine hydrogen and lube oil coolers.
- The third alternative uses circulating water to cool the closed cycle cooling water equipment and the turbine hydrogen and lube oil coolers. This scenario differs from the second alternative as circulating water is used to directly cool the hydrogen and lube oil coolers.

This evaluation will evaluate the different alternatives looking at the system performance and cooling capability of the different cooling configurations.

2.0 System Performance – Cooling Capability

Table 2-1 provides a table listing the pros and cons of the different auxiliary cooling water arrangements

Table 2-1 System Performance Capability

ARRANGEMENT	PROS	CONS
Aux Cooling Water from Raw Water Makeup	-	Not Practical for CCPP
Alternative 1 - Circulating water cools CCCW equipment. Aux Cooling Water cools Turbine Lube Oil and Hydrogen Cooling.	Cooler auxiliary cooling water temps. Smaller circulating water pumps. Smaller CCCW system.	Long, large diameter stainless pipe runs to generators. Warmer makeup to cooling tower. Specialized OEM heat exchangers.
Alternative 2 - Circulating water cools CCCW. CCCW cools all equipment.	Standard OEM heat exchangers. Typical CCPP design. Minimizes piping costs.	Warmer circulating water temps. Larger circ water pumps.
Alternative 3 - Circulating water cools CCCW equipment. Circulating water cools Turbine Lube Oil and Hydrogen Cooling.	Cooler auxiliary cooling water temps. Smaller circulating water pumps. Smaller CCCW system.	Long, large diameter stainless pipe runs to generators. Warmer makeup to cooling tower. Specialized OEM heat exchangers.

2.1 ALL AUXILIARY COOLING FROM RAW WATER MAKEUP

The existing raw water makeup pumps consist of three (3) pumps each having a rated a flow capability of 3,300 gpm at 176 ft of head. To maintain a N+1 sparing philosophy, two pumps would be operating and one pump would be in standby providing a cooling water flow of 6,600 gpm since pressure drop to the new cooling tower is expected to be similar to that the existing system.

If the raw water system provides all of the cooling water for the combined cycle, the temperature rise across the heat exchangers would result in an elevated summer make up temperature to the cooling tower not considered acceptable with the cooling tower fill. To limit the temperature rise across the heat exchanger, it is recommended to use the circulating water system instead of the river water for a minimum of the cooling the generator hydrogen coolers and lube oil coolers.

2.2 ALTERNATIVE 1 – AUX COOLING FROM MAKEUP AND CIRC WATER

For Alternative 1, most auxiliary cooling water would be supplied from the river water make up to cool the closed cycle cooling water system while the generator hydrogen coolers and lube oil coolers would be cooled from the circulating water system directly. This scenario would result in a temperature rise for the makeup water system to match the hot water returning from the cooling tower. The temperature rise to the generator hydrogen coolers and lube oil coolers would be designed to match the circulating water temperature rise across the condenser; additional flow to the circulating water system to cool the steam turbine and combustion turbine generator hydrogen coolers and lube oil coolers would be about 3,800 gpm.

Due to the corrosive nature of the circulating water system stainless steel pipe would be required for the piping runs to the generator hydrogen coolers and lube oil coolers. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. The advantage to supplying cooling water directly from circulating water is that auxiliary cooling water to the generator hydrogen and lube oil coolers is 10°F cooler than if supplied from the closed cycle cooling water system.

2.3 ALTERNATIVE 2 – CIRC WATER COOLS CCCW

A typical design for combined cycle plants is to supply the auxiliary cooling water from the circulating water system. Under this design, circulating water would be supplied to the closed cycle cooling water system. The design of the closed cycle cooling water heat exchangers would limit the temperature rise of the circulating water to match the temperature rise of the circulating water across the condenser; the auxiliary cooling water flow would be sized as required to reject the heat of the closed cycle cooling water system. The cold water temperature of the CCCW would have a design temperature of 105°F; this is standard for equipment provided on combined cycle power plants. Circulating water flow to supply auxiliary cooling water system would be about 6,0 00gpm.

2.4 ALTERNATIVE 3 – CIRC WATER COOLS CCCW AND HYDROGEN AND LUBE OIL COOLERS

If the 105°F cooling water is a concern for the generator hydrogen and lube oil coolers and hydrogen coolers, they could be cooled directly from the circulating water system. The design for the combustion turbine generator hydrogen coolers and lube oil coolers would need to be coordinated with OEMs. The surface area of these coolers would be approximately twice the size of the standard design to limit the pressure drop across the heat exchanger as needed to match the pressure drop across the condenser as to not adversely impact the circulating water system design. Circulating water flow to supply auxiliary cooling water system would be about 2,000 gpm.

3.0 Conclusions

Since the existing raw water pumps that provide makeup to the cooling tower do not have sufficient flow to meet the requirements of the new combined cycle, a new cooling water arrangement utilizing circulating water is recommended. Since the turbine manufacturers design their heat exchangers including turbine lube oil and hydrogen coolers for cooling water up to 105°F and the CCCW system is designed to meet this condition under the extreme hot summer day, Alternative 2 with all equipment cooling water coming from the CCCW system as it is the lowest cost and allows the use of standard OEM equipment.

FINAL

DEMIN WATER USAGE ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1217H

PREPARED FOR

Vectren

31 JANUARY 2020

Table of Contents

LIST OF TABLES

Executive Summary

In developing this report, Black & Veatch reviewed the requirements for demineralized water for the new Combined Cycle Power Plant (CCPP). Black & Veatch reviewed multiple pre-start, start-up and steady state scenarios to determine the required sizing and operation of the demineralized water system. Demineralized water storage capacity was evaluated in parallel with system operation. Black & Veatch evaluated water usage based on 1x1 7HA.01 gas turbines for this analysis:

The demineralized water system users have been summarized in the steady state demands provided in Table 2-1. Plant pre-start demands have been summarized in Table 2-2 and plant startup demands have been summarized in Table 2-3. For all scenarios, the difference between water demand and existing system capacity is compared. Based on the demineralized water requirements for the multiple scenarios, it is recommended that Vectren utilize an additional water treatment system with a water capacity of [redacted] gpm per Table 3-1. No additional demineralized water storage capacity is required.

1.0 Introduction

The purpose of this study is to determine the specific requirements for demineralized water with the new Combined Cycle Power Plant (CCPP). Based on steady state operation, the existing cycle makeup treatment system can meet water demand. However, during startup and steady state operation with the evaporative cooler in operation, water demand exceeds the existing system capacity. The following tables detail differences in water demand for each configuration and condition.

2.0 Demineralized Water System Operation Demands

The demineralized water system provides water to various users during plant startup and shutdown at multiple operating conditions. Several operating scenarios were evaluated to determine the maximum water usage for the demineralized water system. Plant pre-start activities, plant startup, and plant steady state operation was evaluated for maximum demineralized water demand. The existing demin water treatment system capacity is [redacted] gpm. Demineralized water storage will need to be sufficient to hold three (3) days storage of the CCPP steady state demineralized water demand without evaporative cooling water makeup. Demin water demands excluded in this steady state operation are evaporative cooler makeup for the CCPP, CT#3 water injection and existing Unit 3 and 4 steam cycle demands.

2.1 STEADY STATE AND NON-STEADY STATE DEMANDS

The steady state demineralized water demand occurs during operation when supplying makeup water for CCPP blowdown and sampling losses. Non-steady state demineralized water demands occur during operation when supplying makeup water for steady state CCPP users plus evaporative cooler operation, existing unit operation and CT#3 water injection operation. Demineralized water demands are shown in Table 2-1. Steady state operation assumes 2% blowdown per the water mass balances. Steady state flows are based on Hot Day Case (93.7F) heat balance. Due to the infrequent operation of existing units and CT#3, storage volume recommendations will account for the excursion in steady state demand for demineralized water.

Table 2-1 Demineralized Water Demands

DEMIN WATER USERS	1X1 7HA.01
STEADY STATE DEMANDS	
2% blowdown (gpm)	[redacted]
Sample Analytics (gpm)	[redacted]
Demand w/o Evaporative Cooler Makeup (gpm)	[redacted]
NON-STEADY STATE DEMANDS	
Existing Unit 3 steam cycle demands (gpm)	[redacted]
Evaporative Cooler Makeup on RO Permeate (gpm)	[redacted]
Demand w/ Evaporative Cooler Makeup @ 6 COC (gpm)	[redacted]
CT #3 Water Injection	[redacted]
Instantaneous Demand for Steady State Operation with CT#3 water injection (1)	[redacted]
[redacted]	

2.2 PRE-START DEMANDS

During unit pre-start, the auxiliary boiler is used to warm the HRSG and steam turbine seals. The assumption of 2% blowdown on the auxiliary boiler during this operation is included. During this operation, it is assumed all water is non recoverable. The pre-start usage demands are listed in Table 2-2.

Table 2-2 Demineralized Water Demands during Pre-Start Activities

PRESTART USAGE	1X1 7HA.01
Aux Boiler Makeup (gpm) HRSG warming	[redacted]
Difference (gpm) - Existing	[redacted]
Difference (gpm) - Proposed new	[redacted]

2.3 STARTUP DEMANDS

During unit startup, demineralized water usage is at the maximum. HRSG is warm and the condenser sparging and gland steam flows are recovered in the condenser. Steam drains are open until superheat targets are met. 5% blowdown is utilized for startup. The demineralized water demands are listed in Table 2-3.

Table 2-3 Demineralized Water Demands During Startup Activities

STARTUP DEMAND	1X1 7HA.01
Aux Boiler Makeup Fast Start (gpm)	[redacted]
Steam Drains to HRSG Blowdown Tank (gpm)	[redacted]
Blowdown (gpm)	[redacted]
Total Instantaneous Startup Demand (gpm)	[redacted]
Difference (gpm)	[redacted]
Difference (gpm) - Proposed new	[redacted]
Hot start lost capacity (gallons) (1)	[redacted]
Warm start lost capacity (gallons) (1)	[redacted]
Cold start lost capacity (gallons) (1)	[redacted]
Time to replace lost capacity during normal op (Hot Start), min	[redacted]
Time to replace lost capacity during normal op (Warm Start), min	[redacted]
Time to replace lost capacity during normal op (Cold Start), min	[redacted]
[redacted]	

3.0 Demineralized System

3.1 WATER REPLENISHMENT

The demineralized water system provides minimal margin for replenishment from startup of the combined cycle. For a typical combined cycle plant, the rule of thumb for storage is 3 days of steady state demand capacity. This relates to a 3 day outage on the demin supply. Table 3-1 details the time to replenish demineralized water capacity.

Table 3-1 Demineralized Water Volumes and Treatment Capacities

DEMINERALIZED WATER SYSTEM	1X1 HA.01
STORAGE CAPACITY	
Existing Demin storage (gallons)	[redacted]
3 day Demin storage capacity required @ steady state demand	[redacted]
Storage Surplus (+) / Storage Deficient (-) during a 3 day outage.	[redacted]
Recommended Additional Demin Storage (gallons) (1)	[redacted]
STEADY STATE TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Steady State Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
NON-STEADY STATE TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Non- Steady State Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
PEAK TREATMENT DEMAND	
Current Demin Water Treatment Capacity (gpm)	[redacted]
CCPP Peak (CT#3 + Non- Steady State) Demand (gpm)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
PROPOSED ADDITIONAL DEMINERALIZED WATER TREATMENT CAPACITY (GPM)	[redacted]
Treatment Surplus (+) / Deficient (-) (gpm)	[redacted]
Recover 3 day outage volume, Steady state after (HOURS)	[redacted]
Recover 3 day outage volume, Non-Steady state after (HOURS)	[redacted]
[redacted]	

[redacted]

Based on Black & Veatch's evaluation, the existing demineralized water storage capacity can provide sufficient storage of demineralized water based on the design parameters. Furthermore, a new demineralized water treatment system sized to supplement [redacted] gpm (coupled with the existing [redacted] gpm system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

4.0 Conclusions

Based on the evaluation Black & Veatch can conclude:

- The existing demineralized water storage capacity provides adequate storage of demineralized water based on the design parameters.
- A new demineralized water treatment system sized to supplement [redacted] (coupled with the existing [redacted] system) would be sufficient to meet various operating demands of the facility as well as replenish demineralized water volume within the design parameters.

FINAL

BLACK START ANALYSIS

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1221H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

In developing this report for the new Combined Cycle Power Plant (CCPP), Black & Veatch examined the capability of using the existing combustion turbine generator (CTG) peaking Unit 3 at A.B. Brown as a means of black starting CTG 5 of the new CCPP

Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. Two scenarios were modeled for this evaluation:

- Starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation.
- Static starting of CTG 5 with all necessary auxiliary electric loads in operation.

For analysis modeling purposes, the aggregate auxiliary electrical load necessary to start a combustion turbine were based on the preliminary conceptual design of the new CCPP. In addition, the excitation system was assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals.

Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting one combustion turbine of the new CCPP. Further analysis would be required to verify that generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator.

1.0 Introduction

The purpose of this evaluation is to examine the capability of the existing combustion turbine generator peaking Unit 3 at A.B. Brown to be utilized as a black starting means for the new combined cycle power plant (CCPP). Unit 3 is a GE 7EA turbine capable of operating with either natural gas or distillate fuel oil as the fuel source. The unit has a dedicated diesel generator and starting motor necessary to start. Unit 3 is utilized as a black starting means for existing A.B. Brown coal-fired Units 1 and 2.

Electrical power system analysis software ETAP was utilized to model and evaluate Unit 3 to verify the capability of black starting CTG 5 of the new CCPP. Figure 1-1 provides the one line diagram that was modeled in ETAP. Two scenarios were modeled for this evaluation, starting of the largest medium voltage induction motor with all necessary auxiliary electric loads in operation, and static starting of CTG 5 with all necessary auxiliary electric loads in operation.

[redacted]

[redacted]

2.0 Assumptions

In order to simulate the scenarios included in this evaluation, reasonable assumptions were made in order to model and simulate the black start capability. The assumptions are defined as follows.

2.1 LOAD LIST

It is necessary to determine the aggregate auxiliary electrical load that is necessary to start a combustion turbine of the new CCPP. Table 2-1 provides the load list of all loads considered to be in operation to support the black start. Except ACWP, BFP, CWP, CCWP & CP (major loads), all other loads were modeled as a lump load. For lump load motor power factor of 85% has been considered. A 20 percent margin was added to the lump loads of Table 2-1 for modeling purposes. The loads of Table 2-1 are based on the conceptual design of the new CCPP and are preliminary. All cooling tower fans and CWP have been modeled to show to feed from 6.9kV BUS A & existing 4.16kV BUS 1B respectively.

Table 2-1 Operating Loads during CCPP Starting

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

BLACK START ANALYSIS LOAD LIST			
LOAD	LOAD TYPE	LOAD RATING	LOAD UNITS
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

2.2 UNIT 3 EXCITATION SYSTEM

This study does not include analysis of the excitation model or transfer function for Unit 3. Therefore, the excitation system is fixed in the ETAP simulation. Additional modeling of the excitation system and transfer function would be necessary in order to more accurately simulate the response to the reactive power demands imposed when black starting one combustion turbine generator of the new CCCP, however, the excitation system is assumed to be capable of providing the necessary reactive power required by the simulated scenarios while maintaining 100 percent system voltage at a frequency of 60 Hz at the generator terminals, as long as the real and reactive demands on the Unit 3 generator do not exceed the limits of the reactive capability curve.

2.3 PROTECTION, CONTROL AND SYNCHRONIZATION

It is recommended during the detailed design phase that the turbine control system of the new CCPP is designed to be capable of allowing the new combustion turbine generator to synchronize with Unit 3 and that existing and new protection schemes are designed to permit synchronization. It also recommended during the detailed design phase that the control system of the existing Unit 3 combustion turbine generator is verified or modified as necessary to permit load sharing of the auxiliary electrical demands of the new CCPP. No investigation into the existing Unit 3 control system or switchyard protection schemes has been performed in support of this black start capability evaluation.

3.0 Static Motor Starting of Largest Motor

The starting of a large motor can have a brief, but significant, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650 percent of FLA.

In the scenario of the black start, motor starting can result in voltage and frequency sags at the generator output, which will have a corresponding impact on the capability of the motor to start and to the existing loads in operation. The ability of the generator to accommodate starting of large motors is dependent upon the generator capacity, the response of the excitation system, the rotating inertia of the generator and the characteristics of the motor at starting. Should a sag in voltage during motor starting result in the motor's inability to develop the torque necessary to accelerate to full speed, the motor could stall. It is necessary to analyze the worst-case motor starting scenario for the purpose of determining the black start capability of the Unit 3 generator.

As a worst-case scenario, static motor starting of the Boiler Feed Pump, the largest medium voltage motor, was analyzed with all other loads necessary for a black start in operation, with the exception of the Unit 5 generator static starting system. Static motor starting models the motor by locked-rotor impedance during acceleration, simulating the worst impact to loads in operation at the time of motor starting. The properties of the modeled Boiler Feed Pump is 6900 HP, 6.6 kV, 510 FLA, 0.93 power factor, 94 percent efficiency and 6.5 pu LRA.
Figure 3-1 provides the bus voltage, as a percent of nominal, at each bus during starting of the Boiler Feed Pump. The Watt and VAR demand from the Unit 3 generator and the starting motor are also displayed.

The maximum demand from the Unit 3 generator during starting of the Boiler Feed Pump is 8.58 MW and 33.75MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2. The worst-case motor terminal voltage during starting of the Boiler Feed Pump is 80.11 percent of nominal system voltage. It is typical to specify medium voltage motors rated to start at 80 percent of nameplate voltage. It is also typical to specify motor nameplate voltage below nominal system voltage. In the case of a nominal 6.9 kV system, the corresponding motor nameplate is 6.6 kV, consistent with ANSI C84.1. The result of the static motor starting analysis for the Boiler Feed Pump indicates that the momentary sag in voltage at the motor terminals is not prohibitive to the starting of the motor. The worst-case bus voltage for the BUS & MCC A is 77.43 percent during starting of the Boiler Feed Pump. This will not result in drop out of motor contactors since the nominal bus voltage is above 70%. All other medium voltage motors connected to BUS & MCC A (6.9kV) were considered to be running in this scenario. The bus voltage of BUS & MCC A recovers to 99.92 percent of nominal system voltage once the Boiler Feed Pump has accelerated to rated speed.

UAT impedance have been modeled with 6.5% for this study. The short circuit current level will be well below 40kA for 6.9kV SWGR and MCC A. UAT primary tap position has been set at -2.5% in order to achieve motor terminal voltage of higher than 80%. There is a possibility of further reducing UAT 5 impedance and motor locked rotor amperes to improve starting motor terminal voltage if necessary. A 3-3/C-500kcmil conductor has been considered to feed the BFP during this study.

[redacted]

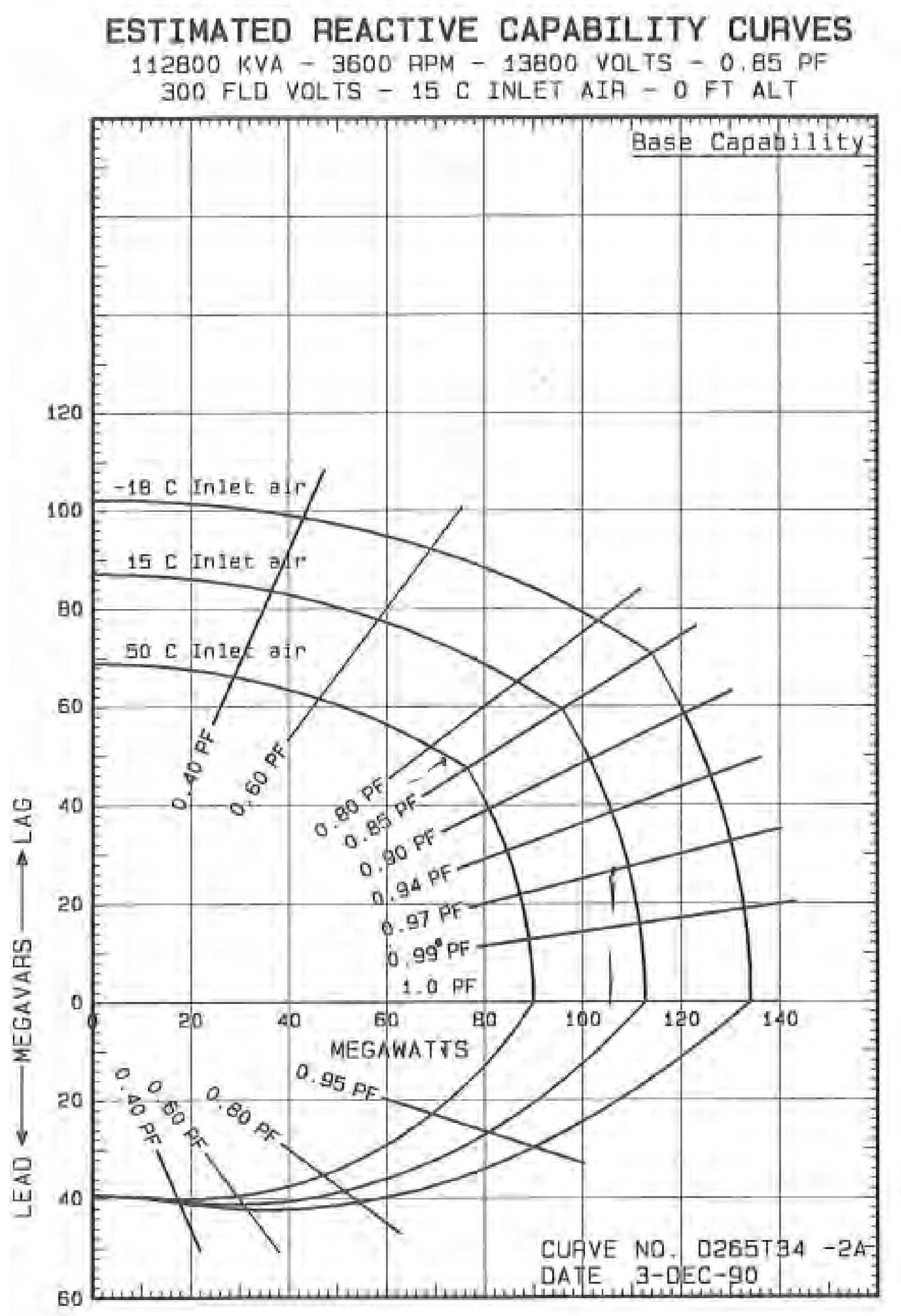


Figure 3-2 Unit 3 Generator Reactive Capability Curve

4.0 CTG 5 Static Starting Load Flow

A load flow model was analyzed during the static starting of the Unit 5 combustion turbine generator. This scenario considered all loads necessary for black starting to be in operation at the time the static starting system was energized. The maximum demand from the Unit 3 generator during static starting of Unit 5 CTG is 11.39 MW and 6.57 MVAR. This is well within the capability curve of the Unit 3 generator, considering a 0.85 lagging power factor and 15 degrees Celsius inlet air temperature, as depicted in Figure 3-2.

The worst-case bus voltage during operation of the static starting system on 6.9 kV BUS and 4.16kV BUS 1B will be 99.92 & 98.72 percent of nominal system voltage. This is well within the normal operating 'voltage range A' as per ANSI C84.1 and not considered to be a prohibitive impact to operation during black start. Additionally, the static starting system operates for a short duration until the combustion turbine reaches approximately 90 percent of rated speed, at which point it is self-sustaining and the static starting system is removed from operation and the turbine control system receives control of the turbine. This duration is approximately 30 minutes or less, dependent upon starting conditions with respect to the purging of combustible gases from the hot gas path prior to ignition.

[redacted]

5.0 Conclusions

The analyses performed in support of the black starting capabilities of the existing Unit 3 generator at A.B. Brown indicate that the generator has sufficient capacity to provide the required real and reactive power necessary to start the largest medium voltage motor as well as operate the static starting system of the new CCPP. The starting of the Boiler Feed Pump was simulated as a worst-case scenario, with all other loads necessary to support a black start in operation with the exception of the static starting system. Motor terminal voltage and bus voltages were maintained within reasonable limits for the scenario of a black start. Power requirements to support Boiler Feed Pump starting and the static starting system operation were within the capability curve of the Unit 3 generator. Both analyses assume that the Unit 3 generator excitation system is capable of responding appropriately to meet the reactive power needs, and further analysis with the excitation system modeled is necessary to confirm this response. Additionally, further analysis would be required to verify generator control and system protection would permit synchronization of the Unit 5 generator to the Unit 3 generator in order to shift auxiliary electrical loads from the Unit 3 generator to the Unit 5 generator. Within the boundaries of this evaluation, the Unit 3 generator at A.B. Brown appears to be capable of black starting the combustion turbine of the new CCPP.

FINAL

SWITCHYARD EVALUATION AND SEQUENCE

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 400278
B&V FILE NO. 41.1222H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

31 JANUARY 2020

BLACK & VEATCH

Table of Contents

LIST OF TABLES

Executive Summary

In developing this report, Black & Veatch evaluated the suitability of the existing A.B. Brown 138 kV switchyard for interconnection of a new combustion turbine generator (CTG) and steam turbine generator (STG) operating as a 1x1 Combined Cycle Power Plant (CCPP). This evaluation was performed with existing Unit 2 remaining in operation. Black & Veatch considered preliminary heat balance data for a GE 7HA.01 CCPP as a conservative approach to this evaluation. Switchyard connections and connection sequence were also evaluated.

The continuous current loading of the 3000 Ampere (A) main buses 1 and 2 as well as the 2000 A interpass conductors are not exceeded for the switchyard configurations evaluated. The loading evaluation does not identify any major bus work necessary to independently connect the generators associated with the 1x1 CCPP.

As a result of the available fault current contribution at the existing 138 kV switchyard exceeding 40 kiloampere (kA), with new generation and Unit 2 in service, circuit breakers with a symmetrical interrupting rating 40 kA require replacement. Of the existing 20 circuit breakers in the 138 kV switchyard, 13 are rated 40 kA. [redacted] Therefore, it is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

[redacted]

1.0 Introduction

The A.B. Brown 1x1 CCPP is a multi-shaft arrangement, with the combustion turbine (CT) and steam turbine (ST) individually coupled to dedicated generators rated to convert maximum turbine capabilities to electric power. The multi-shaft arrangement differs from a single shaft arrangement, with respect to electrical equipment, in that independent generators coupled to each turbine will transmit electric power via dedicated isolated phase bus duct (IPBD) to dedicated generator step-up transformers (GSU). Each GSU is sized to permit maximum real electric power to be transmitted to the electric power grid, with minimal losses, and to permit reactive electric power to be delivered to and absorbed from the electric power grid. Each turbine generator will also provide source power to 100 percent redundant unit auxiliary transformers (UAT). The high voltage side of each GSU will be independently connected to the existing 138 kV switchyard. Interconnection of the CTG and STG to the existing 138 kV switchyard requires consideration of fault current availability and system load flow relative to existing equipment ratings. Black & Veatch considered preliminary heat balance data for a GE 7HA.01 CCPP as a conservative approach for this evaluation. Configurations of a 1x1 CCPP comprised of turbine classes with lower gross megawatt (MW) output will result in additional margin with respect to switchyard loading and fault current. Each of the new generators were modelled with independent connections to the existing 138 kV switchyard, with Unit 2 remaining in operation.

The method of connection for each generator in a given configuration to the existing 138 kV switchyard is based upon the electrical ratings of the switchyard components, switchyard expansion capability, and operation of existing units. The existing 138 kV switchyard is a breaker and a half configuration with two main buses, rated 3000 A continuous [redacted] 13 of the 20 existing circuit breakers in the 138 kV switchyard are rated to interrupt 40 kA.

2.0 Switchyard Evaluation

2.1 LOAD FLOW

The interpass connections between Bus 1 and Bus 2 are rated 2,000 A, therefore a single connection to the switchyard is acceptable when the kilowatts (kW) transmitted remain below 430,000 kW at a power factor equal to 0.9. For a single connection above 430,000 kW and less than 645,000 kW, upgrades are required to the entire 138 kV switchyard, such as circuit breaker and disconnect switch replacement with 3000 A continuous rating. Generation exceeding 645,000 kW at a single connection point is not practical at a voltage level of 138 kV as equipment rated above 3000 A continuous is typically not available.

The maximum CTG and STG gross output based on the preliminary fired GE 7HA.01 1x1 considered for this evaluation are 331,500 kW and 243,950 kW and correspond to approximately 1201 A and 884 A, respectively. Detailed load flow modelling of the 138 kV switchyard with case permutations of outgoing transmission lines in and out of service is necessary in order to verify the suitability of the 138 kV switchyard to accommodate the connection of two CTGs and identify any overload cases. Initial analysis indicates that the 138 kV switchyard is generally suitable to accommodate independent connection of the new 1x1 CTG and STG while Unit 2 remains in operation.

The maximum current flow in the main and interpass busses for each analyzed case are represented in Table 2-1.

Table 2-1 Max Load in Main and Interpass Buses - 2026 Summer Peak

Case	Current in 3kA Main Bus (A)	Percent Loading (%)	Current in 2kA Interpass (A)	Percent Loading (%)
All In Service	1119	37.30	633.2	31.66
Bus 1 Outage	2017.4	67.25	1044.5	52.23
Bus 1 and Line Z95 Outage	2320.1	77.34	1228.5	61.43
Bus 1 and Line Z96 Outage	2169.9	72.33	1139.3	56.97
Bus 1 and Line Z94 Outage	2490.6	83.02	1189.5	59.48
Bus 1 and Line Z73 Outage	2125.4	70.85	1111.4	55.57
Bus 1 and Line Z98 Outage	1735.3	57.84	1133.4	56.67
Bus 1 and Line Z99 Outage	1820	60.67	1358.7	67.94
Bus 1 and Line Z93 Outage	1816.1	60.54	1204.3	60.22
Bus 1 and Line to Culley Outage	2017.4	67.25	1044.5	52.23
Bus 1 and Francisco to Gibson Outage	2333.9	77.80	1327.1	66.36
Bus 1 and AB Brown – BREC Reid Outage	2154.8	71.83	1668.4	83.42
Bus 2 Outage	2016.5	67.22	1200.47	60.02

Case	Current in 3kA Main Bus (A)	Percent Loading (%)	Current in 2kA Interpass (A)	Percent Loading (%)
Bus 2 and Line Z95 Outage	2319.2	77.31	1229	61.45
Bus 2 and Line Z96 Outage	2168.8	72.29	1199.9	60.00
Bus 2 and Line Z94 Outage	2489.9	83.00	1199.5	59.98
Bus 2 and Line Z73 Outage	2124.4	70.81	1196	59.80
Bus 2 and Line Z98 Outage	1734.1	57.80	1199.6	59.98
Bus 2 and Line Z99 Outage	1819.4	60.65	1358.2	67.91
Bus 2 and Line Z93 Outage	1814.4	60.48	1203.3	60.17
Bus 2 and Line to Culley Outage	2016.5	67.22	1200.7	60.04
Bus 2 and Francisco to Gibson Outage	2332.9	77.76	1237.9	61.90
Bus 2 and AB Brown – BREC Reid Outage	2153.90	71.80	1199.5	59.98

2.2 FAULT CAPABILITY

13 of the 20 circuit breakers in the existing 138 kV switchyard are rated to withstand and interrupt 40 kA symmetrical fault current. The interrupting capability of the 13 40 kA rated circuit breakers is marginal for three phase faults and exceeded for single phase to ground faults for this evaluated case. Due to the available fault current contribution it is recommended to replace these existing circuit breakers with circuit breakers having sufficient margin beyond maximum fault current contribution. The remaining seven existing circuit breakers are oil filled and are considered to be near the end of service life. It is recommended to replace all of the existing 138 kV switchyard circuit breakers with breakers rated 63 kA symmetrical interrupting duty. This will ensure fault interrupting capability exceeds maximum available fault contribution.

The results of the fault study are included in Table 2-2.

Table 2-2 138 kV Switchyard Fault Currents

Fault Current Availability 1x1 and Unit 2		
Fault type	**Fault Component**	**Value**
3-phase fault	Fault Current (A)	38881.2
	Phase Angle (°)	-87
	Calculated X/R	18.96
1-phase fault	Fault Current (A)	46287,2
	Phase Angle (°)	-87
	Calculated X/R	19.24

3.0 Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.0 Conclusions

The withstand and interrupting rating of 40 kA for thirteen of the twenty existing 138 kV switchyard breakers is exceeded for the fault conditions evaluated, therefore circuit breaker replacement is necessary. The remaining seven switchyard circuit breakers are oil-filled breakers and near the end of their service life. It is recommended to replace all existing circuit breakers in the 138 kV switchyard with 63 kA symmetrical withstand and interrupting rating.

The evaluated load flow of the existing 138 kV switchyard permits independent connection of the CTG and STG of the new 1x1 CCPP considering a fired GE 7HA.01 and associated preliminary heat balance gross output. In general, the existing switchyard is capable of a single point of interconnection for 430,000 kW and below. This evaluation did not identify any major bus or interpass modifications for the existing 138 kV switchyard to accommodate the new CCPP and operation of Unit 2.

Connections to the existing switchyard have been planned to permit the construction and commissioning schedule of the new CCPP, while maintaining the existing A.B. Brown Unit 1 connection as late as practical into construction of the new CCPP.

Appendix A. Switchyard Connection Sequence

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Appendix B. Construction Schedule

[redacted]

FINAL

AUXILIARY ELECTRIC SYSTEM MEDIUM VOLTAGE LEVEL COMPARISON

A.B. Brown 1x1 H-Class

B&V PROJECT NO. 195523
B&V FILE NO. 41.1223H

PREPARED FOR

VECTREN
A CenterPoint Energy Company

Vectren

19 FEBRUARY 2020

BLACK & VEATCH

Table of Contents

LIST OF TABLES

Executive Summary

This evaluation provides a summary comparison of nominal 6.9 kV and 4.16 kV auxiliary electric systems for the conceptual design (CPCN project) of the new A.B. Brown Combined Cycle Power Plant (CCPP). The medium voltage switchgear and motor controllers distribute power to large motor loads, ranging from greater than 250 HP up to several thousand HP, as well as to secondary unit substation (SUS) transformers, which derive 480V to be distributed to the low voltage system components and electrical loads.

Both nominal system voltages of 4.16 kV and 6.9 kV are commonly utilized within power generation and supported by most transformer and motor manufacturers.

Table ES-1 Advantages of 4.16kV and 6.9kV Medium Voltage Systems

MEDIUM VOLTAGE	4.16 KV	6.9 KV
Lower Running Current/Starting Current		X
Smaller Conductor Size		X
Less Heating in Below Grade Cable Ductbank		X
Reduction of Bus Short Circuit Rating		X
Overvoltage Withstand	X	
Conductor Cost Savings		X
UAT Cost Savings		[redacted]
Switchgear Cost Savings		[redacted]
Motor Cost Saving	Equal	Equal

1.0 Auxiliary Electric System Cabling Design Considerations

The cross-sectional area (CSA) of a current-carrying copper conductor is largely dependent upon the continuous current required for rated operation of the electrical load. A larger continuous current necessitates are larger CSA in order to ensure the thermal limitations of the cable insulation and the equipment terminals are not exceeded. An electrical load with a nominal system voltage rating of 6.9 kV will result in an approximate 40% reduction of running current than that of an electrical load with the same power rating, in kVA or HP, and a nominal system voltage rating of 4.16 kV.

For power cables installed in below grade duct bank, a de-rating study must be performed in order to ensure that the implications of the concrete-encased, below grade cable duct on the current-carrying capability of the conductors are properly applied during conductor sizing. The aggregate of thermal impact of the continuous current flowing through the conductors within the duct bank, depth of duct bank, and soil thermal resistivity determine the de-rating of the conductor ampacity. The ampacity of a current-carrying conductor in below grade duct bank is reduced compared to the ampacity of the same conductor in above grade raceway or free air.

It is typical in a CCPP that the electrical loads, particularly medium voltage, are not installed within proximity of the electrical distribution equipment from which the load is sourced. Voltage drop calculations must be performed in order to ensure that the voltage at the load terminals does not fall below the equipment minimum operating voltage. Voltage drop is directly proportional to current, cable length and cable impedance.

2.0 Medium Voltage Motor Starting System Impact

The starting of a large motor can have a significant, albeit brief, impact on the auxiliary electrical system. When voltage is applied to the terminals of an at rest motor, the motor will draw locked-rotor current (LRA), which decays toward full-load amps (FLA) as the motor approaches running speed. This is the result of the motor torque overcoming the combined inertia of the motor and the connected load. For an induction motor, a typical value of LRA is approximately 650% of FLA.

As voltage drop is directly proportional to current, the voltage drop at motor starting due to LRA must be analyzed in order to ensure the motor will start. It is typical to specify medium voltage motors capable of starting at 80% of rated voltage as a means of mitigating this concern.

The starting current of a motor can also have an adverse impact on equipment already in operation at the time of motor starting. Voltage sag resulting from the LRA of the starting motor can result in contactor drop-out in certain circumstances. Methods of avoiding adverse impact of large motor starting to the auxiliary electrical system include on-load tap changers (OLTC) integral to the unit auxiliary transformers for bus voltage regulation, dedicated variable frequency drives (VFD) or soft-starters for the motors of concern. The approximate 40% reduction of FLA and LRA resulting from a 6.9 kV compared to 4.16 kV provides for improved results relative to motor starting.

3.0 Short Circuit Contribution During a System Fault

During a system fault, a motor in operation will contribute current to the fault, in attempt to stabilize the decaying system voltage, as a result of the rotating magnetic field that exists in the rotor at the inception of the fault. Analyses of the auxiliary electric system during a faulted condition must be performed in order to ensure that the bus bracing of the electrical distribution equipment is appropriate relative to fault levels. The reduction of FLA of a higher system voltage correlates to reduced short circuit contribution during in a fault condition. Black & Veatch analyses of system faults utilizing Electrical Transient and Analysis Program (ETAP) indicate that motor short circuit contribution can be reduced by up to 50% by increasing the system voltage from 4.16 kV to 6.9 kV.

The reduction of bus short circuit rating of electrical distribution equipment corresponds to a reduction in capital expenditure for 6.9 kV compared to 4.16 kV.

4.0 Cost Impact of Equipment Voltage Rating

Manufacturers of switching assemblies offer various equipment voltage ratings above typical industry nominal system voltages. Metal-clad switchgear voltage ratings of 5 kV and 7.2 kV are common and correspond to nominal system voltages of 4.16 kV and 6.9 kV, respectively. Confirmation from switching assembly manufacturers indicates that bus and breaker continuous current and interrupting ratings, as well as bus bracing and short circuit rating, are the primary cost drivers. The cost difference of a line-up of metal-clad switchgear with the same continuous current rating, interrupting capability and bus bracing, but different system voltage ratings, is negligible.

Black & Veatch has received similar confirmation from motor suppliers, with respect to the negligible cost difference between 6.6 kV and 4.0 kV rated motors.

5.0 System Loading

The preliminary electrical load list associated with the 2x1 (F and H Class) configuration of the A.B. Brown CCPP conceptual design indicates a total plant running load of approximately 30 MVA. At 6.9 kV, this corresponds to approximately 2500 A of running current in combined cycle operation. The preliminary UAT required to support this auxiliary load is a two-winding transformer with a maximum forced-air cooled rating of 36 MVA. With 100% redundancy, two (2) two-winding UATs correspond to one (1) double-ended (main-tie-main) lineup of 3000A, 6.9 kV switchgear.

With the total plant running MVA, at a system voltage of 4.16 kV, the corresponding running current is approximately 4200 A. Typical switchgear manufacturers offer maximum continuous current ratings of 4000 A, which is achieved using 3000 A rated, fan cooled main circuit breakers. The condition of fan cooling required to achieve this rating is not recommended as it introduces an additional point of failure to the auxiliary electric system.

A system voltage of 4.16 kV would necessitate two (2) three-winding UATs and two (2) double-ended lineups of switchgear in order to adequately source the plant auxiliary load requirements for combined cycle operation. A budgetary cost estimate of [redacted] per UAT and [redacted] of additional metal-clad switchgear would be necessary in order to accommodate auxiliary loads at 4.16 kV system voltage.

6.0 Overvoltage Withstand

Equipment manufacturers specify maximum voltage ratings above the nominal system voltage rating. An industry typical maximum voltage rating for a 4.16 kV nominal system voltage is 5.0 kV, providing approximately 20% headroom in an overvoltage condition. Industry typical maximum voltage rating for a 6.9 kV system voltage is 7.2 kV, though some manufacturers are now offering equipment with maximum system voltage rating of up to 7.65 kV. A maximum voltage rating of 7.2 kV provides approximately 4.3% headroom in an overvoltage condition before exceeding the maximum voltage rating. Dependent upon the generator output voltage and the UAT tap, it is possible to exceed this maximum voltage rating with a 6.9 kV system. However, this is not a normal operating condition and could be mitigated with appropriate protective relaying.

7.0 Conclusions

This evaluation report has shown that:

- The design of insulated conductors is directly impacted by the medium voltage system level.
- Disturbances to the auxiliary electric system as well as motor starting concerns are mitigated by an elevated system voltage.
- Short circuit contribution from medium voltage motors is reduced by an elevated system voltage, which can correspond to a reduction in the short circuit bus rating of electrical distribution equipment.
- The cost associated with an elevated system voltage to plant equipment such as switching assemblies and motor windings is considered negligible.
- The preliminary plant auxiliary loading required for combined cycle operation of the 2x1 configuration is supported by two-winding UATs and one (1) double-ended lineup of medium voltage switchgear at a system voltage of 6.9 kV. A system voltage of 4.16 kV would necessitate three-winding UATs and two (2) double-ended lineups of medium voltage switchgear.
- 4.16 kV system voltage provides more headroom for an overvoltage condition than that of a 6.9 kV system, for industry typical maximum voltage ratings. However, this condition can be mitigated with protective relaying.

Total cost savings for using 6.9 kV medium voltage system in lieu of a 4.16 kV medium voltage system is approximately [redacted].

Attachment 6.5 Coal to Gas Conversion Study (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
A CenterPoint Energy Company

Vectren

MARCH 17, 2020

BLACK & VEATCH

Table of Contents

LIST OF TABLES

LIST OF FIGURES

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.

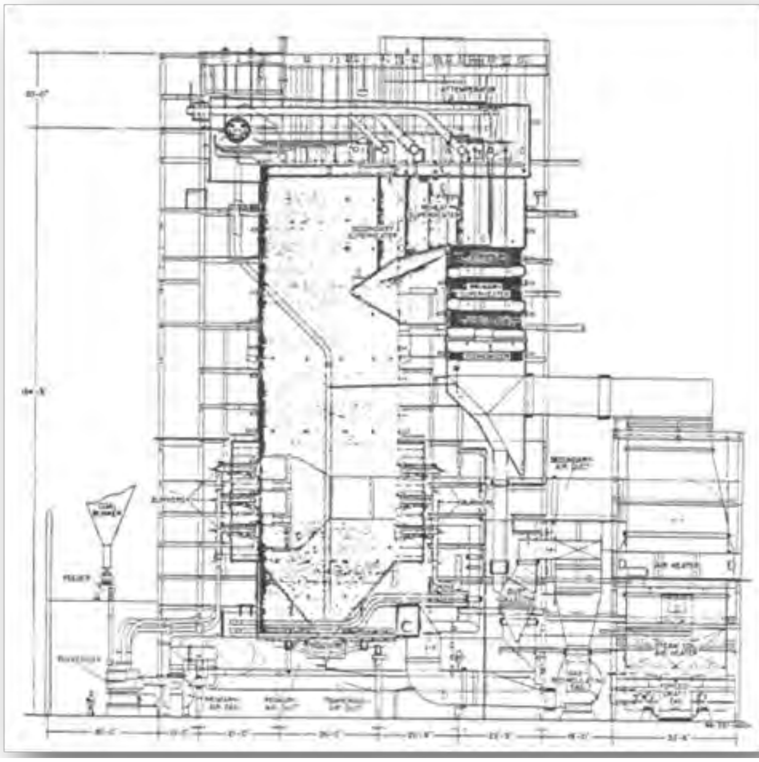


Figure 2-1 A.B. Brown Units 1 and 2 Typical Boiler Diagram

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.

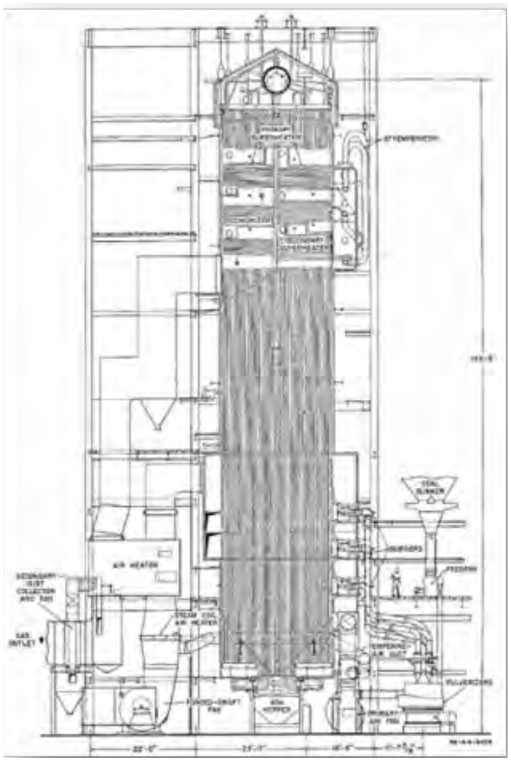


Figure 2-2 F.B. Culley Unit 2 Typical Boiler Diagram

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."

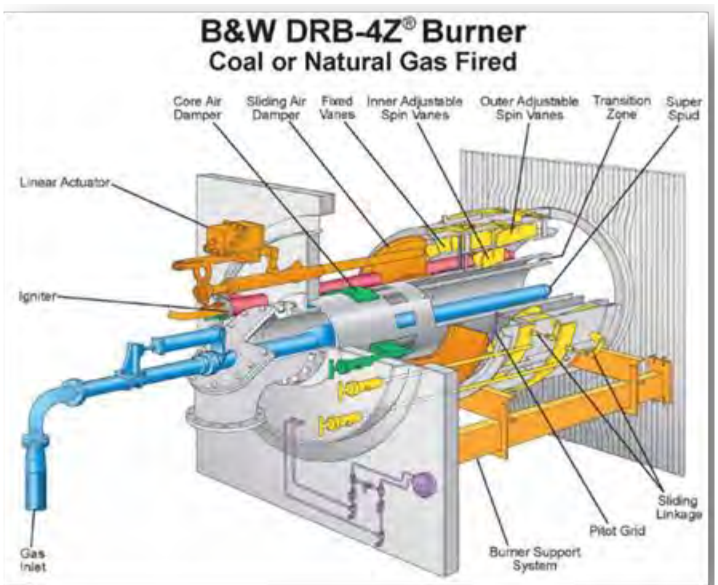


Figure 2-3 Babcock & Wilcox DRB-4Z® Burner (Coal or Gas Fired)

[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.

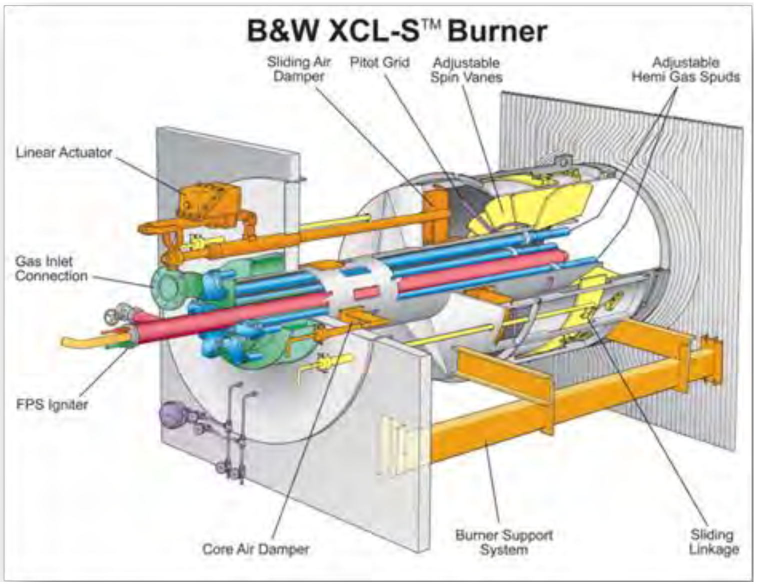


Figure 2-4 Babcock & Wilcox XCL-S™ Burner (Natural Gas Fired)

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

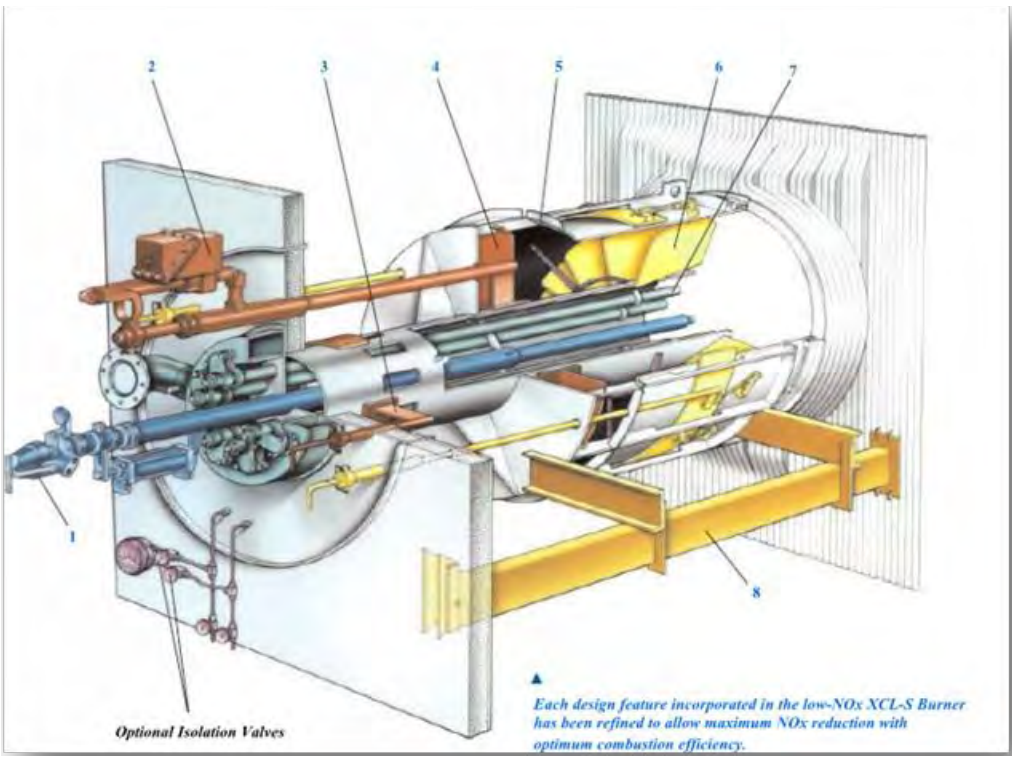


Figure 2-5 Babcock & Wilcox Low-NO_X XCL-S™ Burner[2]

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.

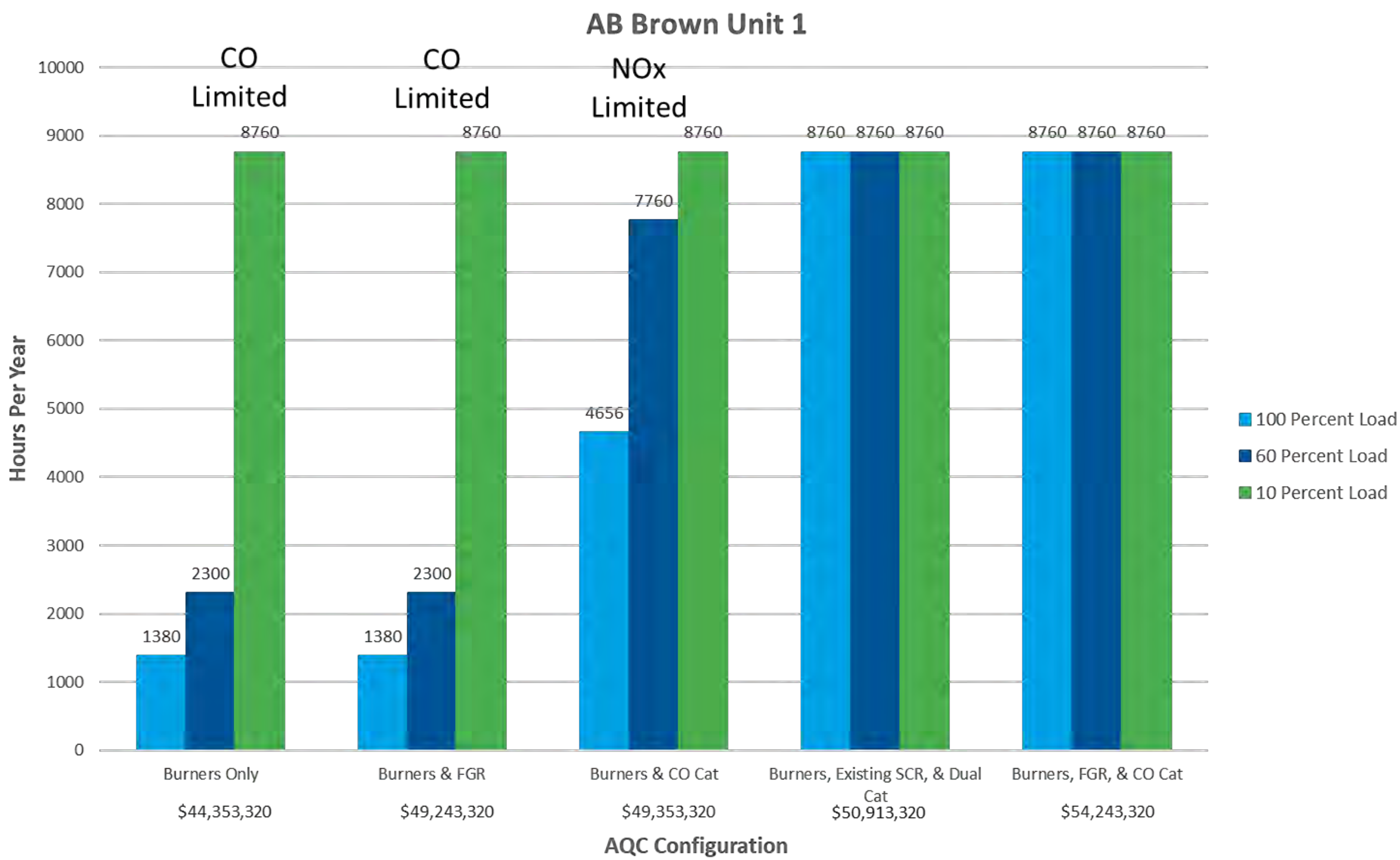


Figure 5-1 Hours of Operation Achievable without Triggering PSD – A.B. Brown Unit 1

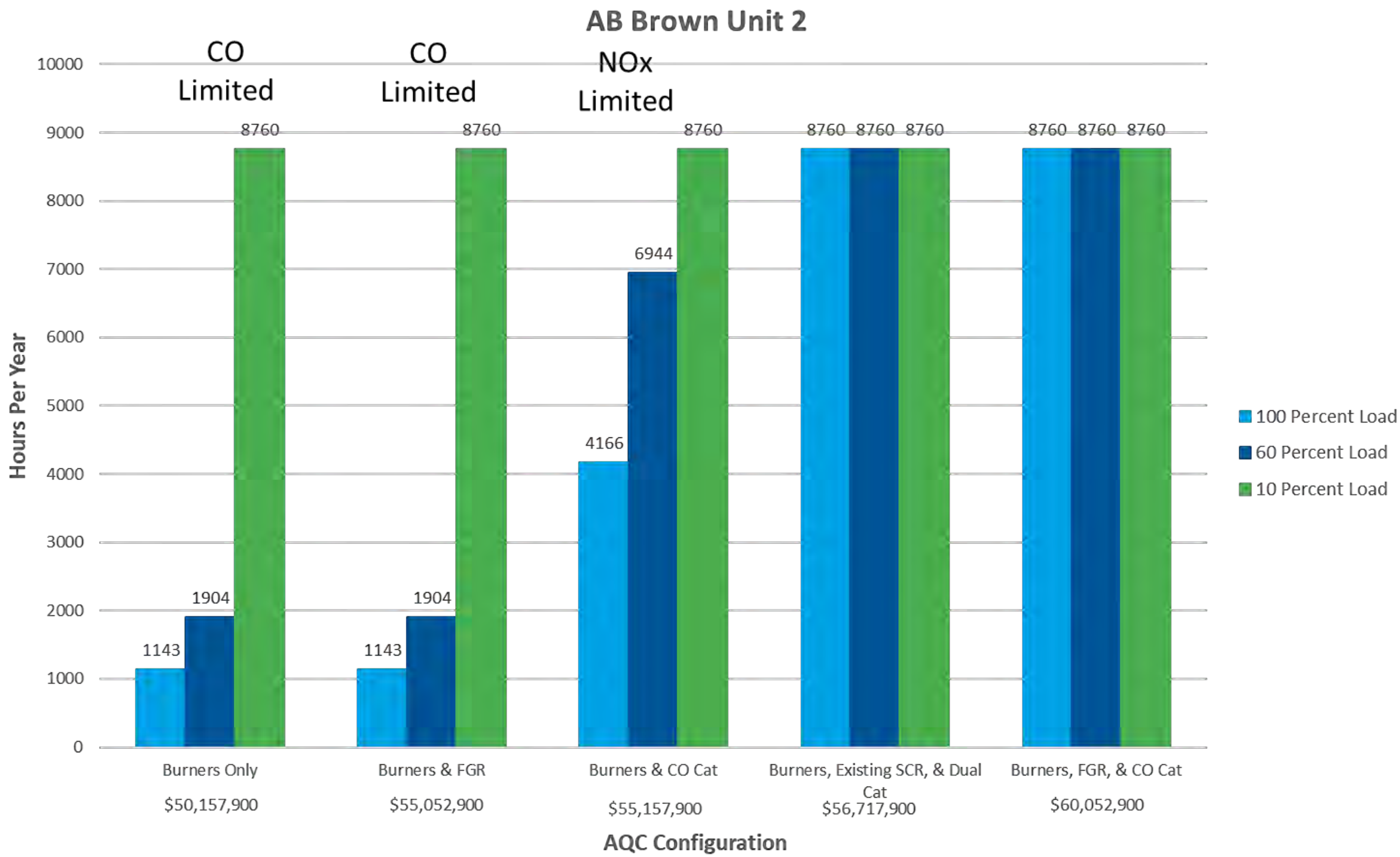


Figure 5-2 Hours of Operation Achievable without Triggering PSD – A.B. Brown Unit 2

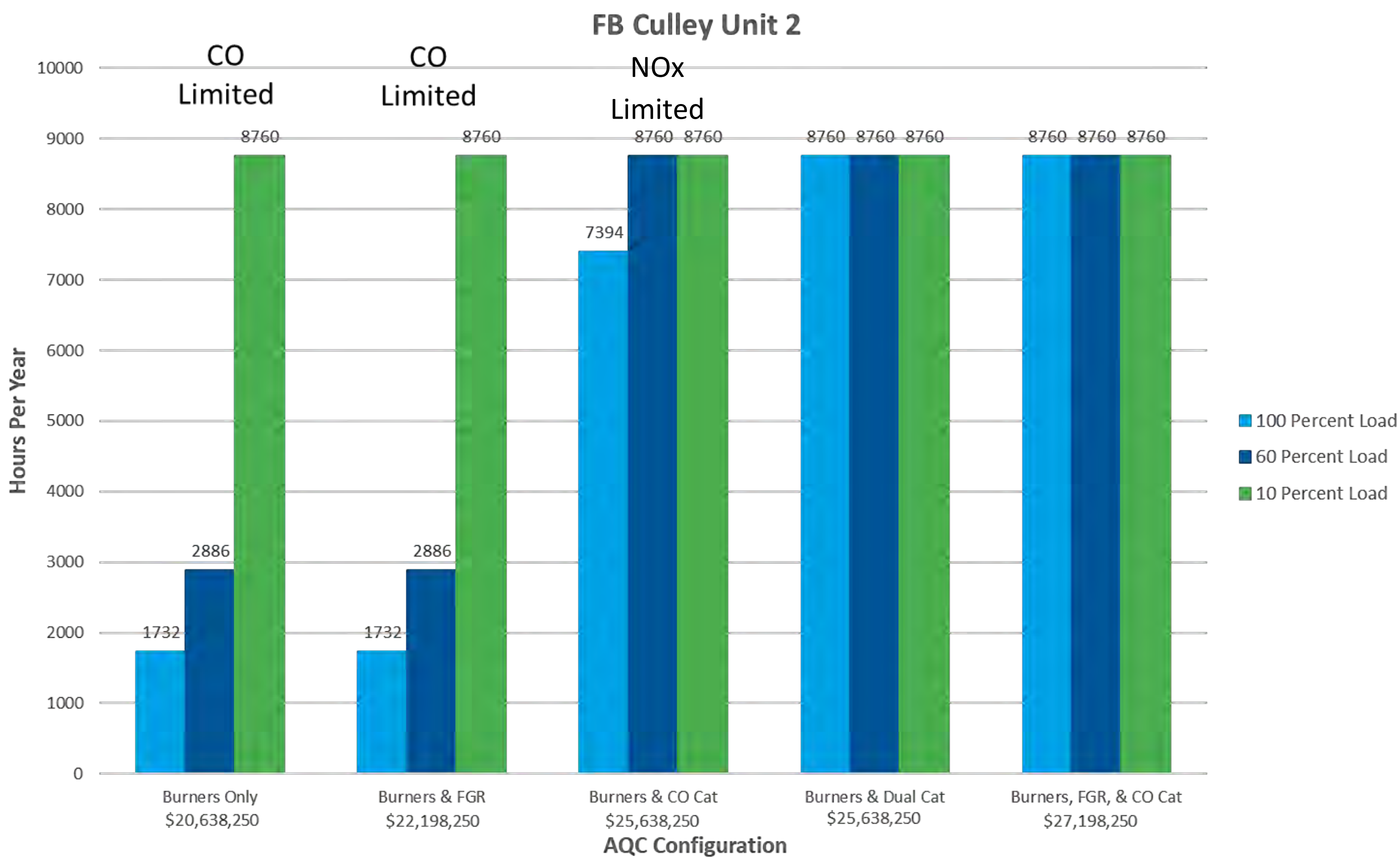


Figure 5-3 Hours of Operation Achievable without Triggering PSD – F.B. Culley Unit 2

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

TABLE OF CONTENTS

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.

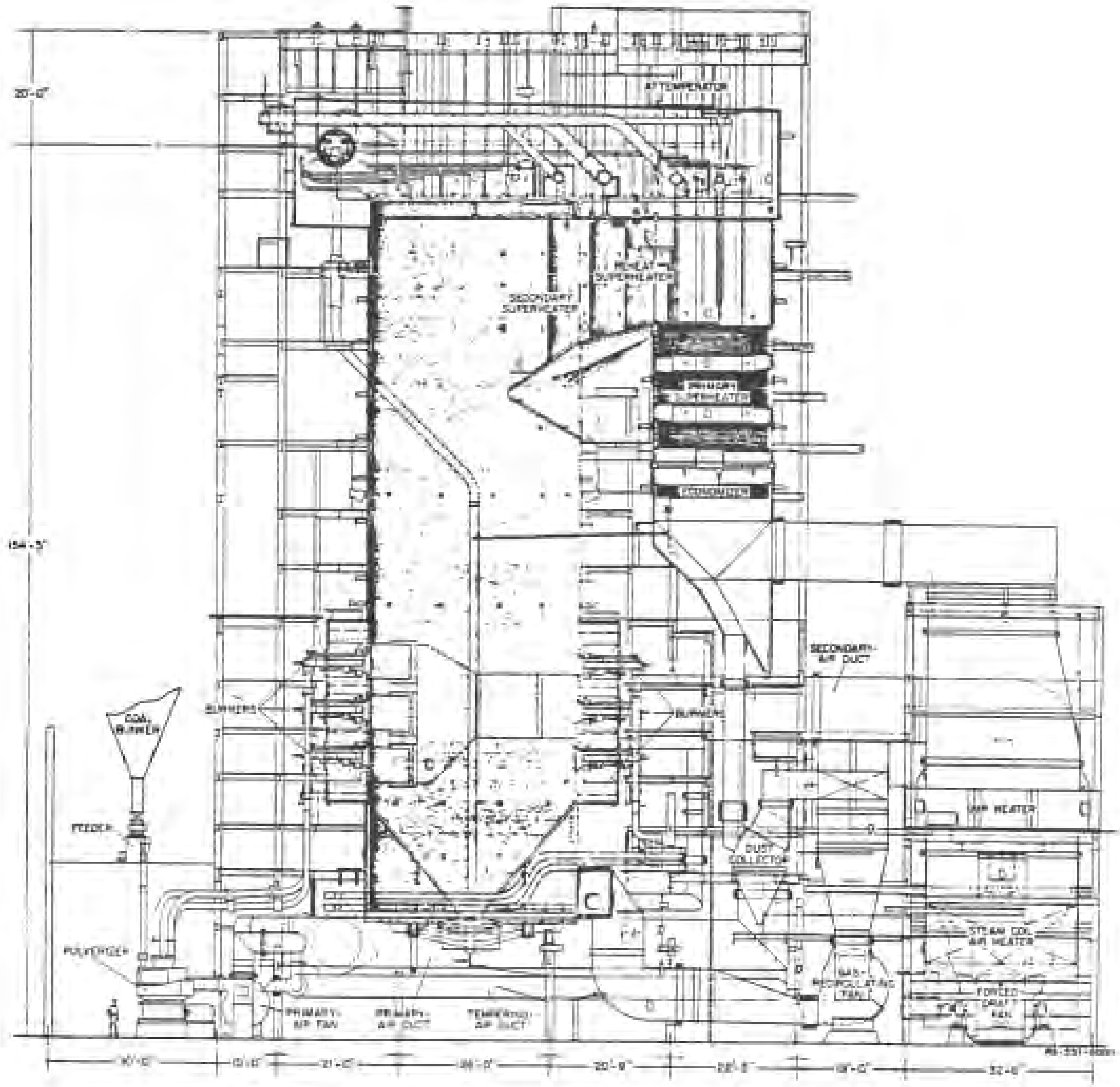
Combustion air is heated through two Ljungstrom regenerative air heaters.

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.

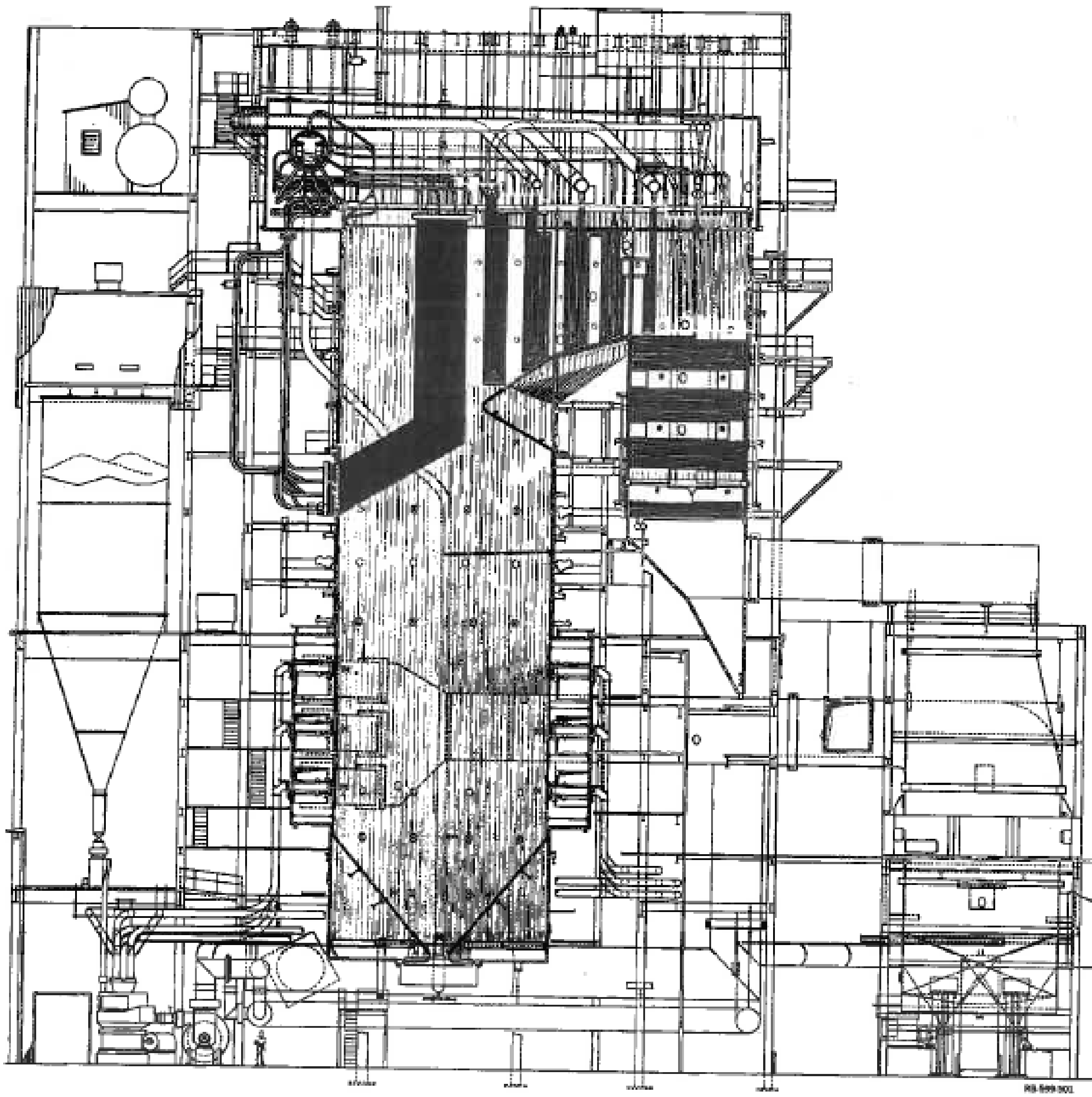
A sectional side view of the boilers is shown in Figures 1a and 1b.

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. 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. 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

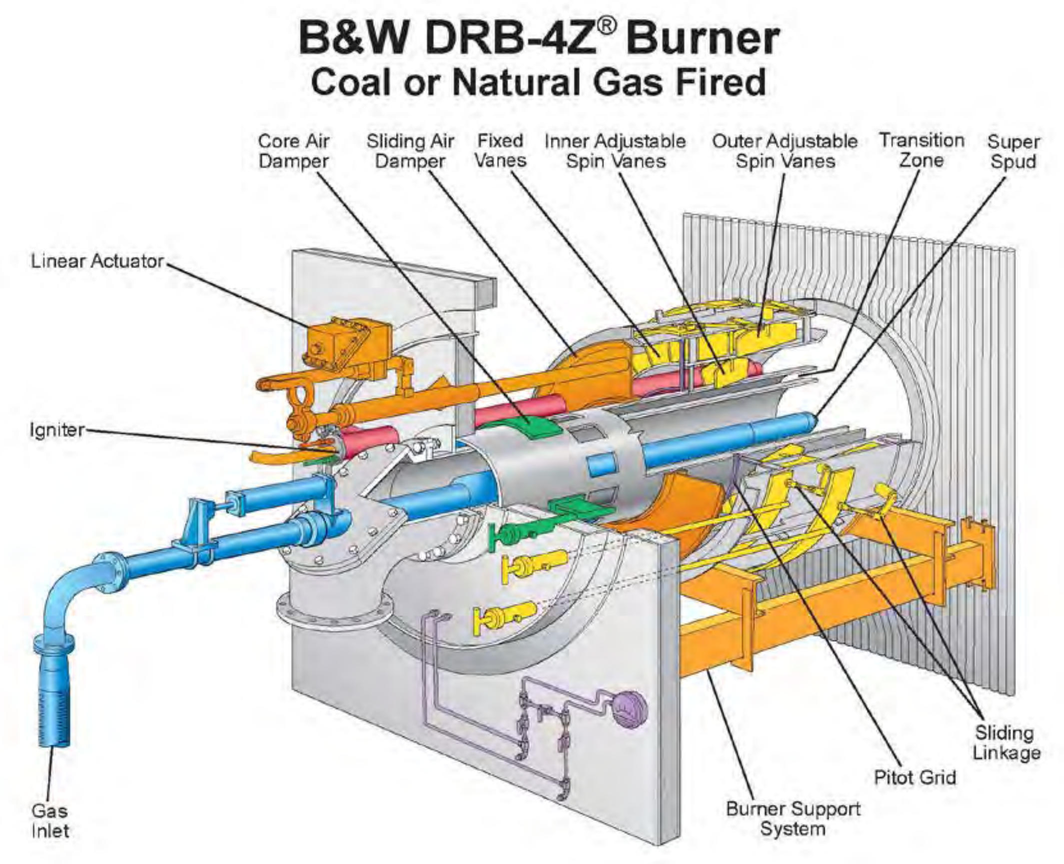
The existing induced draft fans were also analyzed to determine if they meet the requirements of 100% natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table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

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

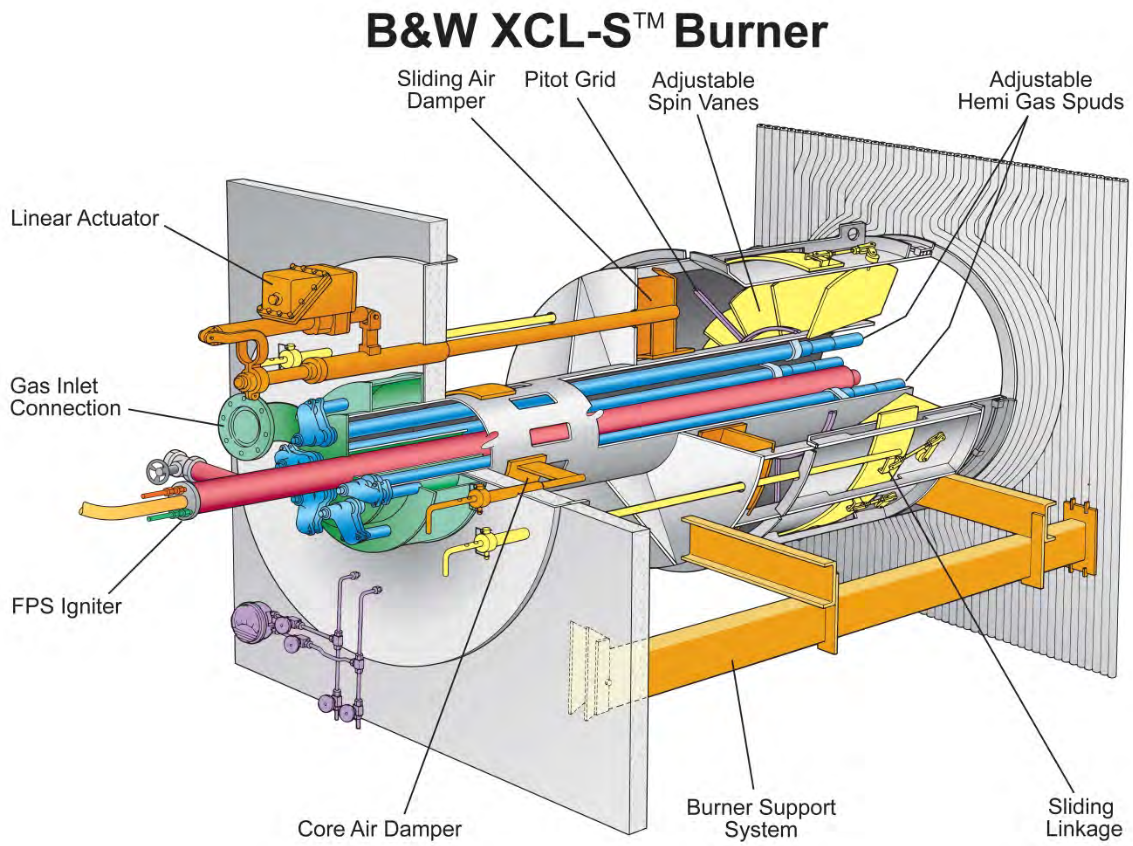
Fuel	ID Fan Test Block Unit 1	Bituminous Coal Unit 1 Original ID Fan Design Net Conditions	100% Natural Gas
Flow per fan (lb/hr)	1,380,100	1,387,610	1,199,390
Static Pressure Rise (in WC)	67.30	47.81	34.22
Temperature (F)	330	305	290

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

B&W Proprietary and Confidential

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	251		
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	85		
		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. & Mfgr. Margin		1.50	1.00		
	Total Heat Loss		12.96	15.04		
	Gross Efficiency of Unit,%		87.04	84.96		

B&W Proprietary and Confidential

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	

B&W Proprietary and Confidential

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	

B&W Proprietary and Confidential

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.

<u>Terminal Points</u>

- 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

TABLE OF CONTENTS

INTRODUCTION

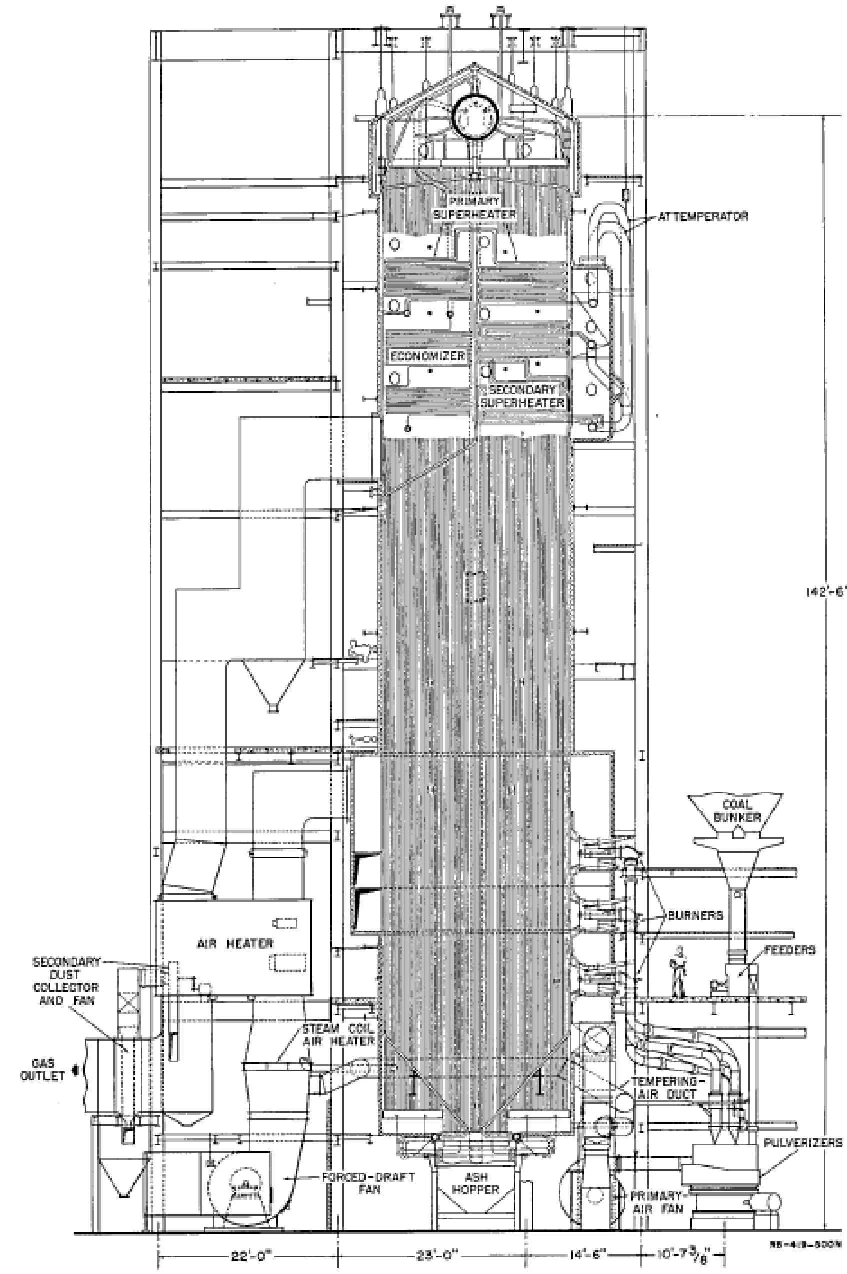
Vectren Power Supply contracted The Babcock and Wilcox Company (B&W), under B&W contract 591-1022 (293H), to evaluate natural gas firing at the Culley Station Unit #2 originally supplied by B&W under contract RB-419. The boiler performance model was reviewed at 100% MCR and 50% load when firing 100% 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:

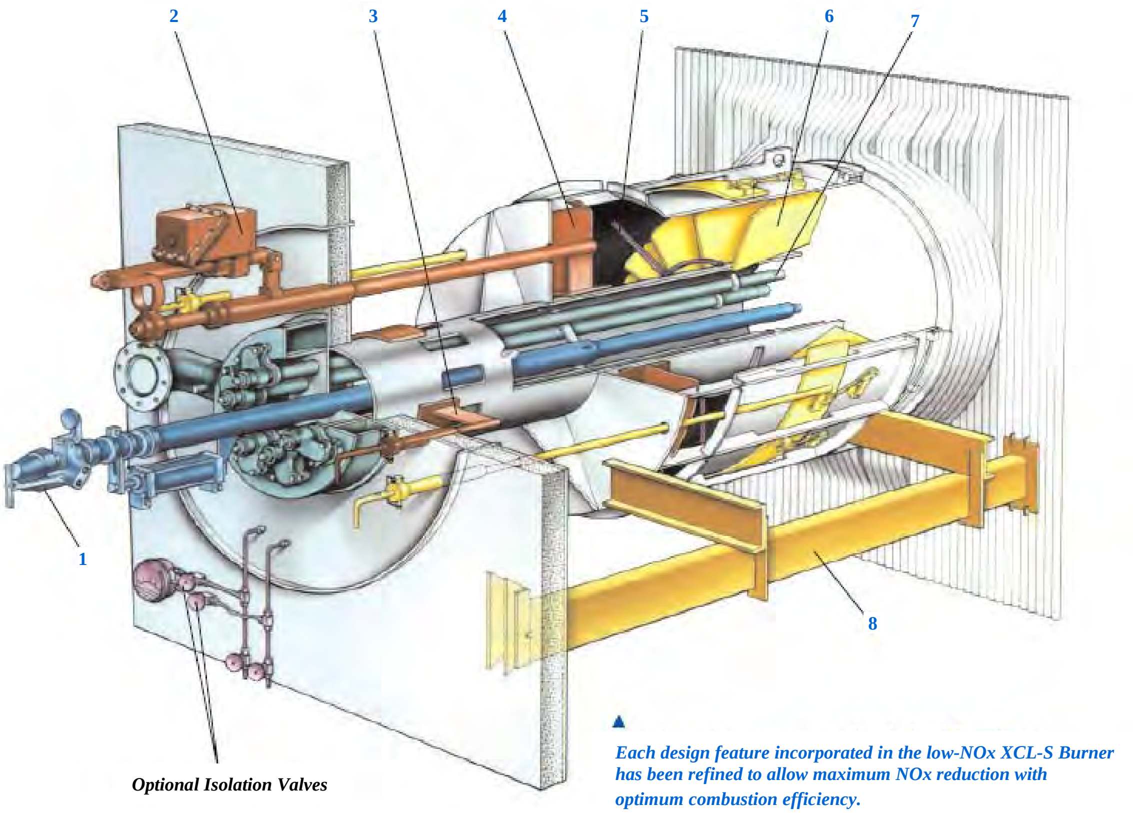
Table 8B: Induced Draft Fan Performance at MCR Load (balanced draft operation)

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

B&W Proprietary and Confidential

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

B&W Proprietary and Confidential

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

TABLE OF CONTENTS

LIST OF TABLES

Page No.

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:

<u>Boiler Front Equipment</u>

- 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

<u>Natural Gas Transport Piping and Regulating</u>

- 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

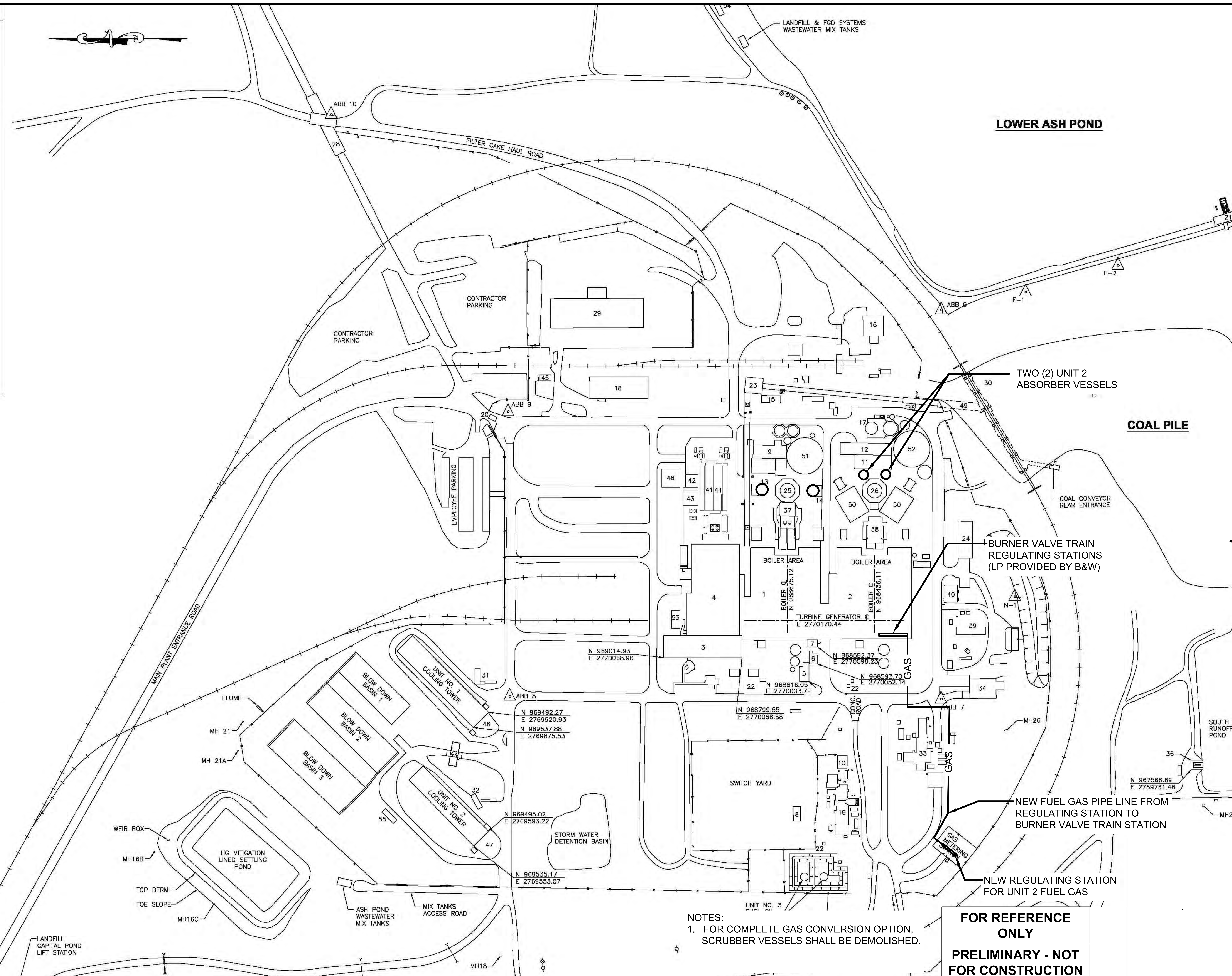
Burns & McDonnell recommends Vectren evaluate the project economics based on the cost and performances presented in this report. If the Plant economics are favorable as a future generation project, then Burns & McDonnell recommends Vectren proceed with a more detailed study to develop budget level pricing and finalize all design and cost considerations.

APPENDIX A – SITE ARRANGEMENT

BUILDING NO. DESCRIPTION

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 G-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

SCALE IN FEET: 0 – 100' – 200'

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

Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-1001.DWG 9/8/2015 9:41 AM MATHERTON

FOR REFERENCE ONLY

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
A	09/08/15	ACR	ZDL	FOR OWNER REVIEW

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

designed: A. ROOT
detailed: M. ATHERTON

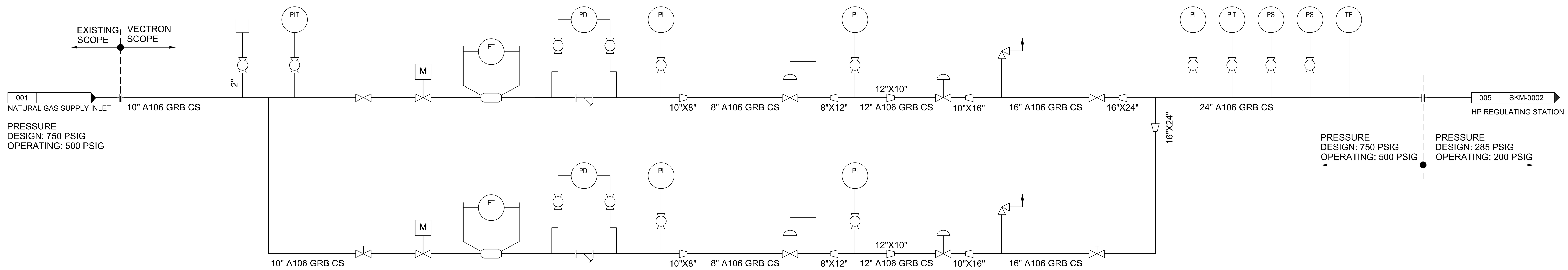
VECTREN
POSEY COUNTY, INDIANA

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

Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-1002.DWG 9/8/2015 8:43 AM MATHERTON

APPENDIX B – PROCESS FLOW DIAGRAMS



FOR REFERENCE ONLY

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
B	02/18/16	ACR	ZDL	REVISED PER B & W REPORT
A	10/29/15	ACR	ZDL	FOR OWNER REVIEW

no.	date	by	ckd	description

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

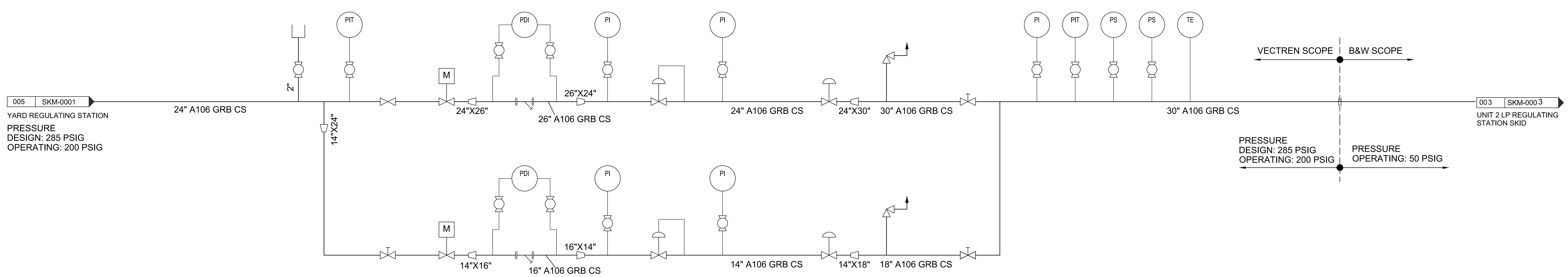
designed: A. ROOT
detailed: S. CHURCHILL

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

Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-0001.DWG 2/15/2016 10:39 AM SACHURCHILL



FOR REFERENCE ONLY

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
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

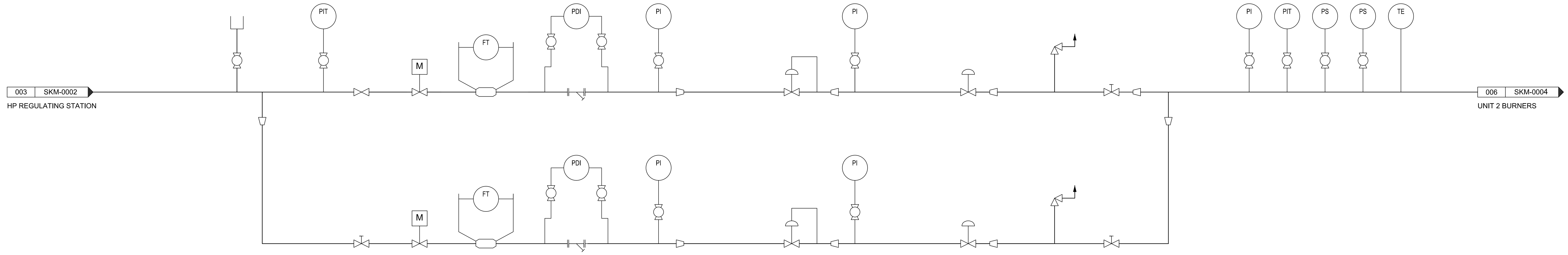
VECTREN COAL TO GAS
HP REGULATING STATION
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0002
rev.: B
sheet 1 of 1 sheets
file 86548-SMK-0002

Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-0002.DWG 2/16/2016 8:29 AM SACHURCHILL

1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19

A B C D E F G H I J K L



Millimeters

Scale For Microfilming

Inches

NOTE:

MATERIALS AND DESIGN PROVIDED BY B&W.

FOR REFERENCE ONLY

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
B	02/18/16	ACR	ZDL	REVISED PER B & W REPORT
A	10/29/15	ACR	ZDL	FOR OWNER REVIEW

no.	date	by	ckd	description

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

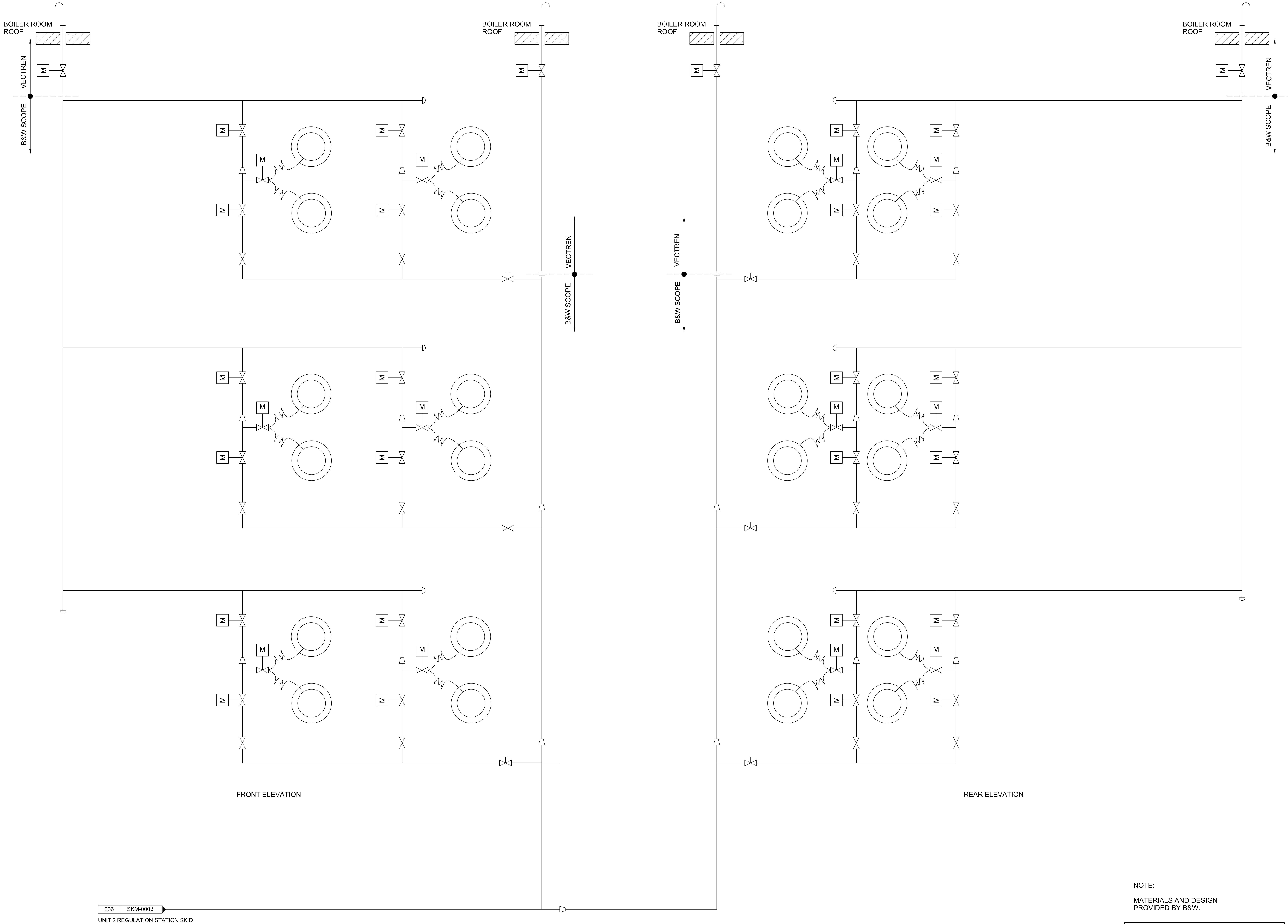
project 86548 | contract -

drawing **SKM-0003** rev. **B**

sheet 1 of 1 sheets

file 86548-SKM-0004.dwg

Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-0004.DWG 2/15/2016 10:43 AM SACHURCHILL



NOTE:

MATERIALS AND DESIGN PROVIDED BY B&W.

FOR REFERENCE ONLY

PRELIMINARY - NOT FOR CONSTRUCTION

no.	date	by	ckd	description
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

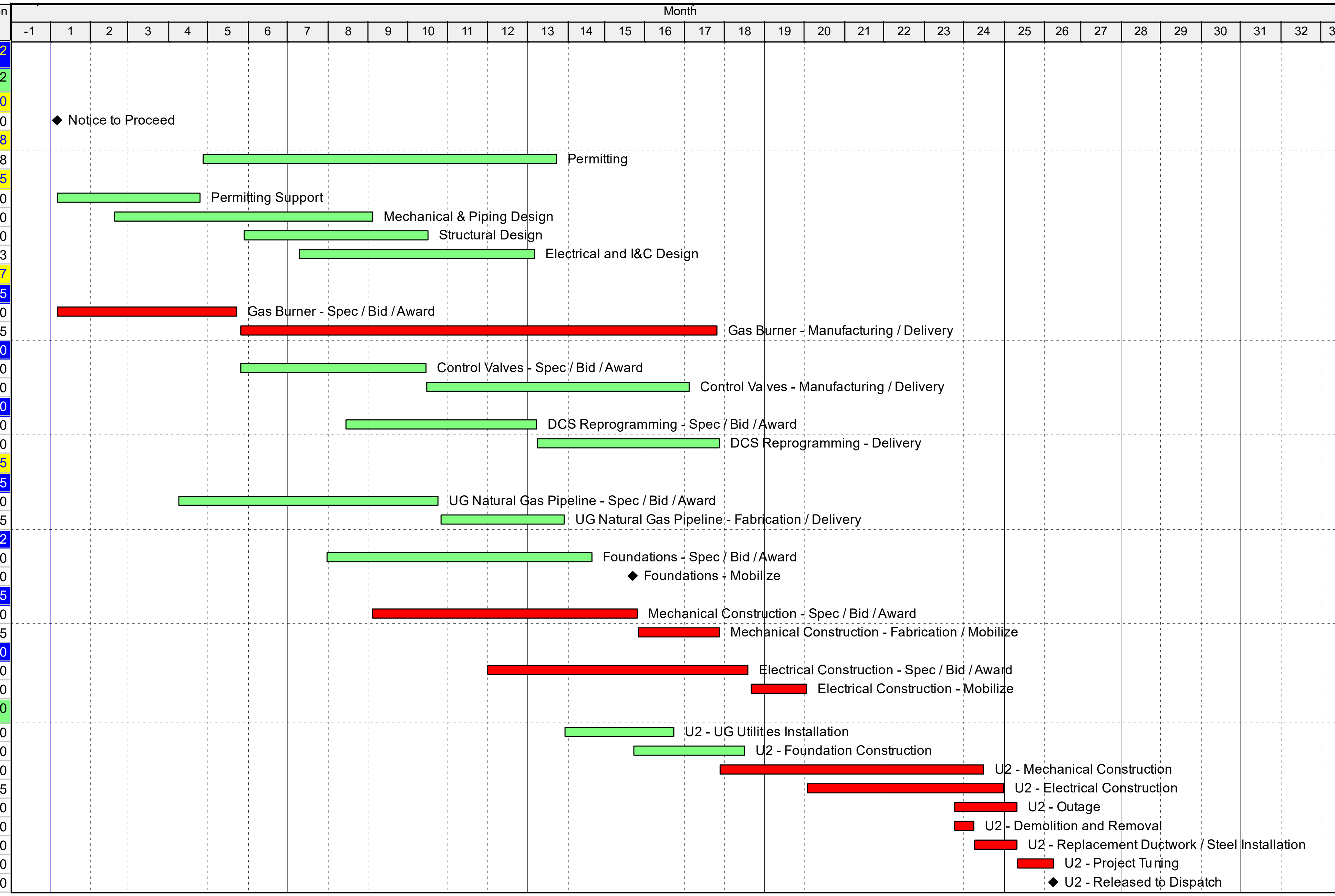
VECTREN COAL TO GAS
UNIT 2 BOILER
A. B. BROWN

project: 86548
contract: -
drawing: SKM-0004
rev.: B
sheet 1 of 1 sheets
file 86548-SKM-0006.dwg

Z:\CLIENTS\ENR\VECTREN\86548_COALTOGASCONV\DESIGN\MECH\86548-SKM-0006.DWG 2/16/2016 7:15 AM SACHURCHILL

APPENDIX C – PROJECT SCHEDULE

Activity ID	Activity Name	Duration
Vectren A B Brown Coal to Gas Conversion		532
Vectren Gas Conversion Engineering Unit 2		402
Milestones		0
A1000	Notice to Proceed	0
Permitting		188
A1010	Permitting	188
Engineering		255
A1020	Permitting Support	80
A1030	Mechanical & Piping Design	140
A1040	Structural Design	100
A1050	Electrical and I&C Design	123
Procurement		357
Gas Burner		355
A1060	Gas Burner - Spec / Bid / Award	100
A1070	Gas Burner - Manufacturing / Delivery	255
Control Valves		240
A1080	Control Valves - Spec / Bid / Award	100
A1090	Control Valves - Manufacturing / Delivery	140
DCS Reprogramming		200
A1100	DCS Reprogramming - Spec / Bid / Award	100
A1110	DCS Reprogramming - Delivery	100
Construction Contracts		335
UG Natural Gas Pipeline		205
A1120	UG Natural Gas Pipeline - Spec / Bid / Award	140
A1130	UG Natural Gas Pipeline - Fabrication / Delivery	65
Foundations		162
A1140	Foundations - Spec / Bid / Award	140
A1150	Foundations - Mobilize	0
Mechanical Construction		185
A1180	Mechanical Construction - Spec / Bid / Award	140
A1190	Mechanical Construction - Fabrication / Mobilize	45
Electrical Construction		170
A1160	Electrical Construction - Spec / Bid / Award	140
A1170	Electrical Construction - Mobilize	30
Vectren Gas Conversion Construction & Startup Unit 2		260
A1200	U2 - UG Utilities Installation	60
A1210	U2 - Foundation Construction	60
A1220	U2 - Mechanical Construction	140
A1230	U2 - Electrical Construction	105
A1240	U2 - Outage	30
A1250	U2 - Demolition and Removal	10
A1260	U2 - Replacement Ductwork / Steel Installation	20
A1270	U2 - Project Tuning	20
A1280	U2 - Released to Dispatch	0



Remaining Work
Critical Remaining Work
Milestone

Vectren - A. B. Brown
Coal to Gas Conversion Project
Page 1 of 1

Date	Revision	Checked	Approved
23-Jan-19	Gas Conversion Proposal	Y Ko	

APPENDIX D – CAPITAL COST ESTIMATE SUMMARY

CAPITAL COST ESTIMATE
VECTREN
AB BROWN
UNIT 2 ONLY NATURAL GAS CONVERSION
MT. VERNON, IN
BMcD #113003

Acct	Area / Discipline	Direct MHRS	Labor Cost	Material Cost	Engr Equip/ Subcontract Cost	Const. Equipment Cost	Total Cost
01	Engineered Equipment	960	$120,000		$7,180,000		$7,300,000
02	Civil	769	$70,000		$50,000	$10,000	$130,000
03	Deep Foundations						
04	Concrete	1,820	$190,000	$40,000	$30,000	$10,000	$270,000
05	Structural Steel	13,028	$1,580,000	$980,000		$280,000	$2,840,000
06	Architectural						
07	Piping	4,191	$550,000	$310,000	$20,000	$30,000	$910,000
08	Electrical	5,407	$680,000	$100,000		$40,000	$820,000
09	Instrument & Control				$270,000		$270,000
10	Insulation				$530,000		$530,000
11	Coatings				$20,000		$20,000
	Total Direct Cost	**26,175**	**$3,190,000**	**$1,430,000**	**$8,100,000**	**$370,000**	**$13,090,000**

Rev.	Revision Date
0	08/27/15
1	02/12/16
2	07/17/18
3	02/01/19

	Cost	Revenue	
Construction Mgmt & Indirects			$780,000
Engineering			$990,000
Start-Up			$290,000
Commercial			$250,000
Escalation (From 2016-Jan2019)			$160,000
Total Indirect Cost			**$2,470,000**
Total Direct and Indirect Costs			**$15,560,000**
	Cost	Revenue	
Project Contingency	5%	5%	$780,000
Total Project Cost			**$16,340,000**
Owner's Project Development			$250,000
Owner's Operational Personnel Prior to COD			Existing
Owner's Engineer			N/A
Owner's Project Management			$300,000
Owner's Legal Costs			$200,000
Owner's Start-up Engineering			$75,000
Temporary Utilities			$110,000
Operator Training			$50,000
Permitting and Licensing Fees			$100,000
Switchyard			Existing
Political Concessions & Area Development Fees			N/A
Startup/Testing (Fuel & Consumables)			
Startup Fuel (@$4/MMBtu)			$1,570,000
Startup Variable O&M (@$1.30/MWhr			$40,000
Startup Power (@$45/MWhr)			$20,000
Test Power Sales (@$-30/MWhr)			-$1,010,000
Initial Fuel Inventory			N/A
Site Security			Existing
Operating Spare Parts			$70,000
Permanent Plant Equipment and Furnishings			Existing
Builders Risk Insurance (0.45% of Construction Costs)			$60,000
Interest During Construction (10.2% Proj Cost)			$1,670,000
Owner Contingency		10%	$1,980,000
Total Owner Costs			**$5,485,000**
Total Project Cost Incl. Owner Costs			**$21,825,000**

V 3.5

APPENDIX E – B&W BOILER STUDY

Engineering Study for Natural Gas Firing

for

Vectren Power Supply
AB Brown Station Unit 2
Evansville, Indiana

Contract 591-1048 (317A)
April 1, 2019 - Rev. 4

TABLE OF CONTENTS

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 Unit 2, originally supplied by B&W under contract 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 Unit 2 (RB599) is presently balanced draft, subcritical Carolina type radiant boiler, 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 unit was originally designed as a front and rear wall, bituminous coal fired units. The original maximum continuous rating for 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 unit was to be operated at 5% overpressure over the load range.

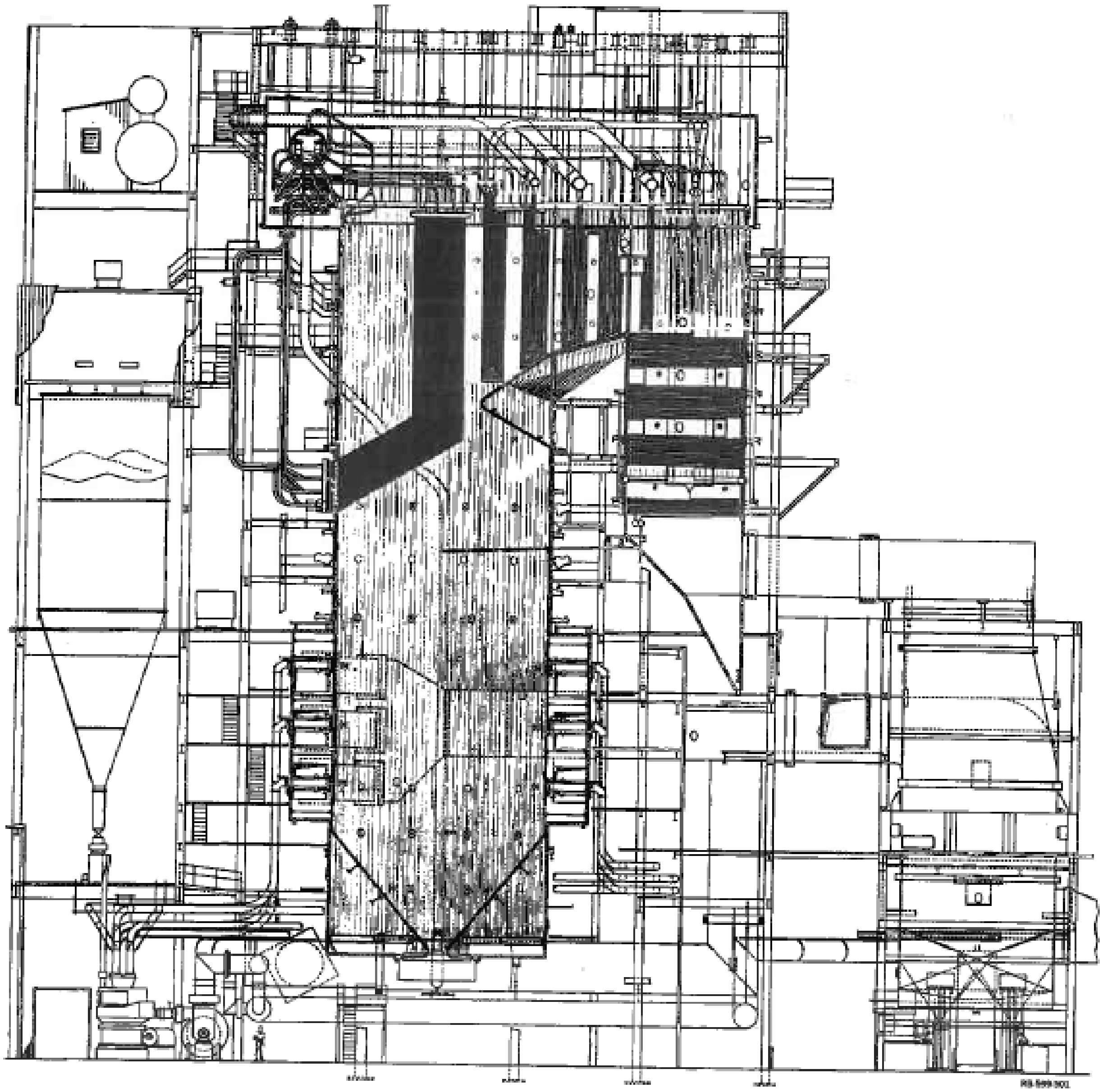
The unit is front and rear wall fired with twenty-four B&W 4Z low NO_x burners, four wide by three high. There are six B&W EL-76 pulverizers supplying coal to the burners.

Combustion air is heated through two Ljungstrom regenerative air heaters.

- Unit 2 has a furnace height of 124'-0''. The vertical burner spacing is 10'-0" for Unit 2.
- Unit 2 has six water-cooled furnace wing walls.
- Unit 2 was designed without flue gas recirculation.

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

FIGURE 1



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

*Based on original design data

Table 7b: Regenerative Air Heater Predicted Performance

Unit	2	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 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. 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. 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. 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 Unit 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 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 Unit 2
Flow per fan (lb/hr)	1,512,000	1,260,000	1,225,440	1,104,100
Static Pressure Rise (in WC)	19.8	15.8	25.1	20.3
Temperature (F)	105	80	105	80

Induced Draft Fans

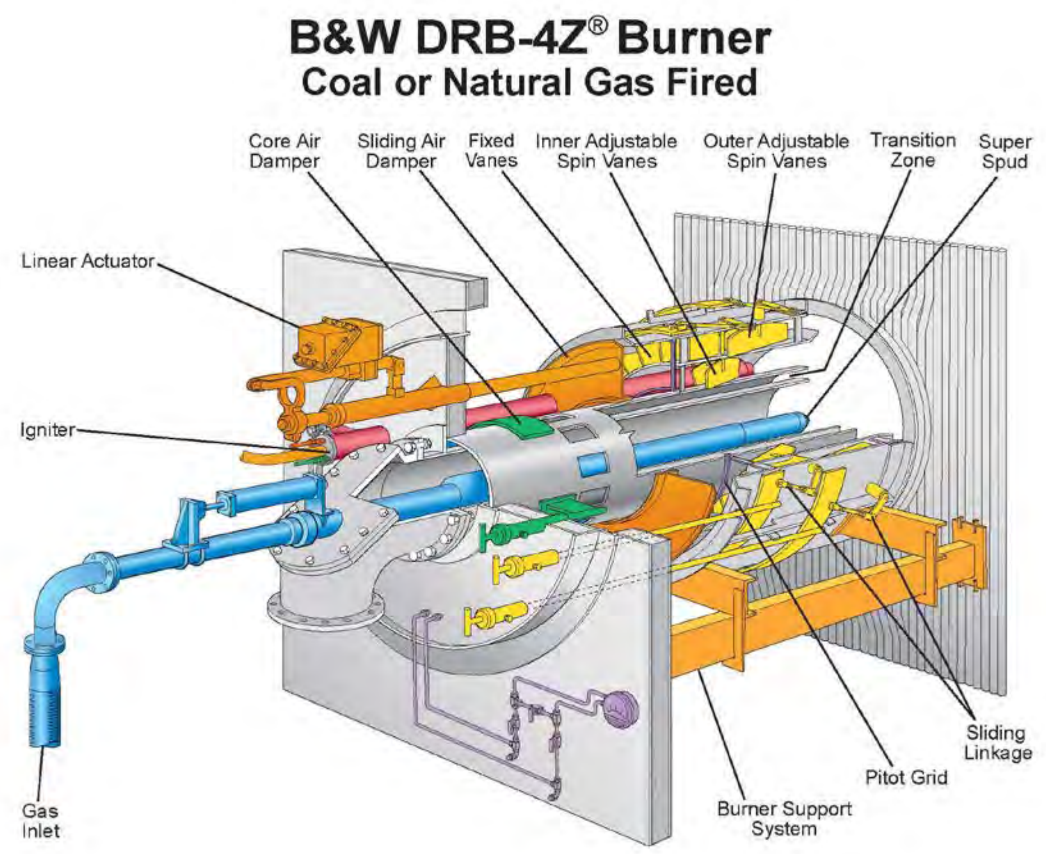
The existing induced draft fans were also analyzed to determine if they meet the requirements of 100% natural gas firing. The results showed the existing ID fans far exceed the requirements in capacity and static pressure rise for all natural gas firing cases. Predicted fan performance is shown in Table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

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

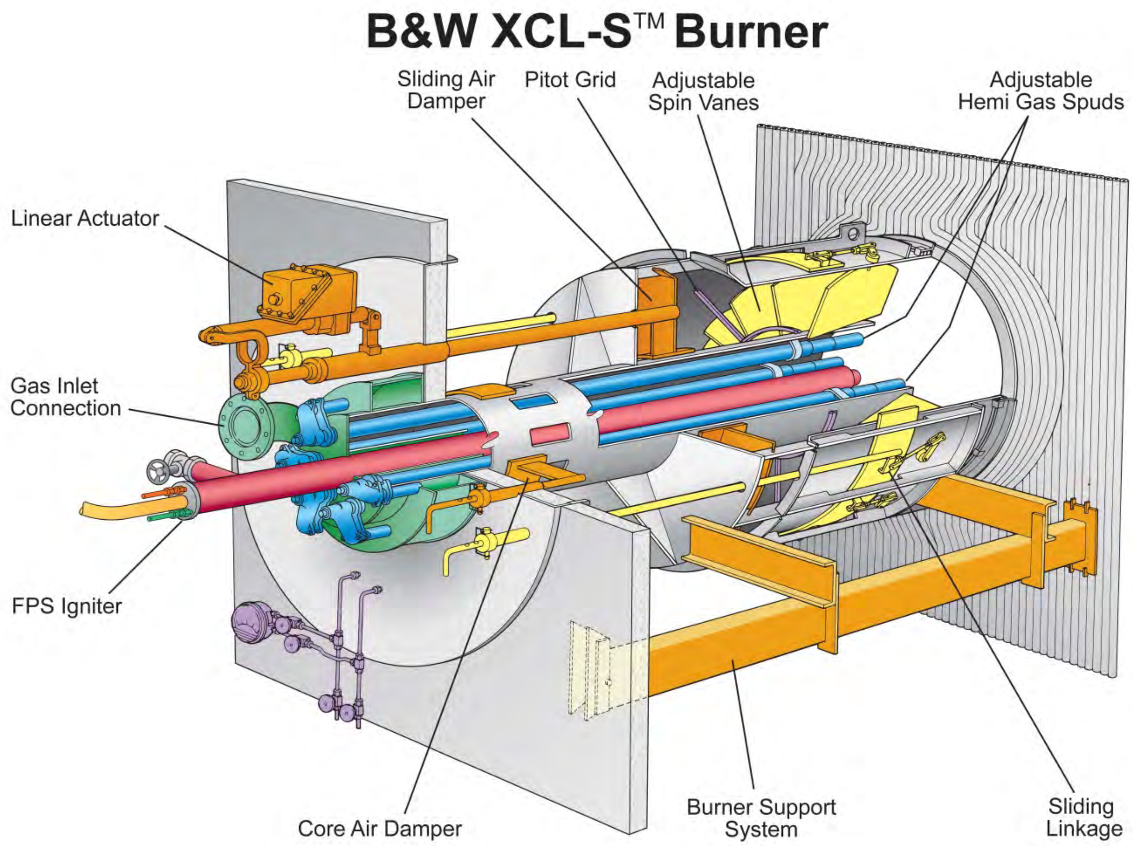
Fuel	ID Fan Test Block Unit 2	Bituminous Coal Unit 2 Original ID Fan Design Net Conditions	100% Natural Gas
Flow per fan (lb/hr)	1,380,100	1,387,610	1,199,390
Static Pressure Rise (in WC)	67.30	47.81	34.22
Temperature (F)	330	305	290

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 unit 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 unit already have SCR's, staged combustion (OFA) or flue gas recirculation (FGR) is not recommended.

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 unit are listed in Table 9.

Table 9: Predicted Full Load Emissions on Natural Gas	
	AB Brown Unit 2
NO_x ($lb/10^6$ Btu)	0.19

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

B&W Proprietary and Confidential

Table 10b:

A. B. Brown Unit 2 - Preliminary Performance Summary

Contract No.	317A		GBB	Unit 2	Unit 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

Table 10c:

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

B&W Proprietary and Confidential

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

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 2015)

Scope Item	Budgetary	
	Material	Installation
Super-Spud Option: Burner Modifications, Scanners, Valve Racks, NG Piping System	$2,244,000	$3,379,000
Hemi-Spud Option: Burner Modifications, Scanners, Valve Racks, NG Piping System	$2,463,000	$3,685,000

Lead Times

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

B&W has offered these prices in 2018 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.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
Phone: 816-333-9400
Fax: 816-333-3690
www.burnsmcd.com

Burns & McDonnell: Making our clients successful for more than 100 years

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Attachment 6.6 Brown Scrubber Assessment Study

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

11 MARCH 2020

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1.1 Executive Summary

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	 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.

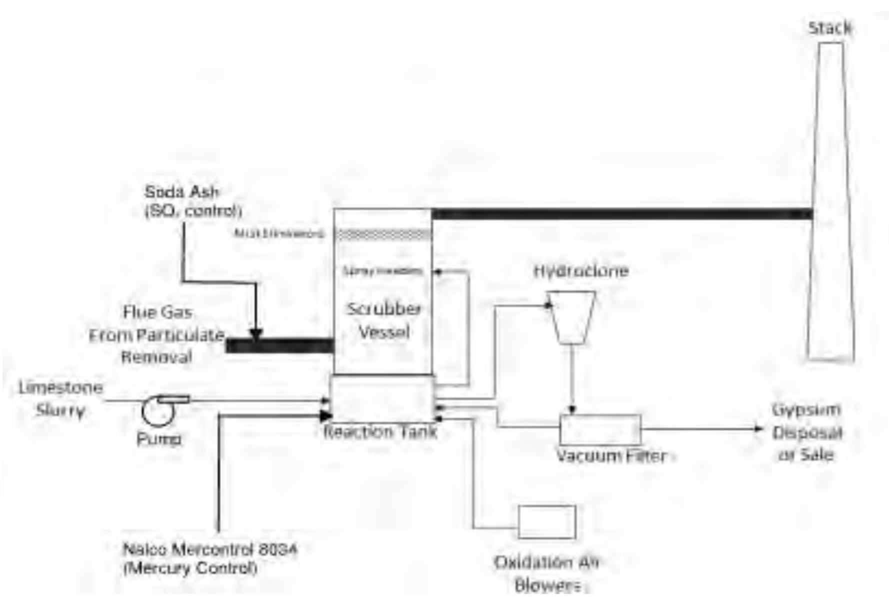


Figure 5-1 Limestone Forced Oxidation Scrubber

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.

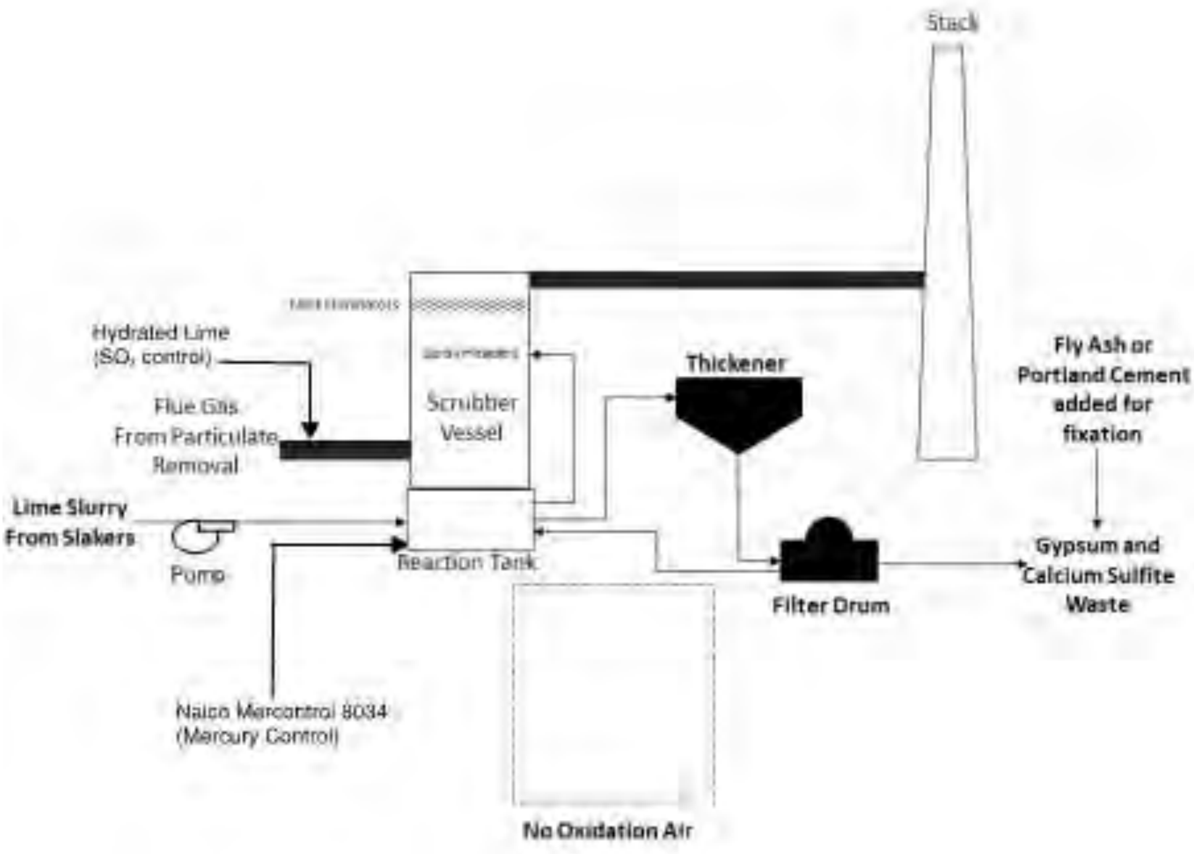


Figure 6-1 Wet Lime Inhibited Oxidation Scrubber

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.

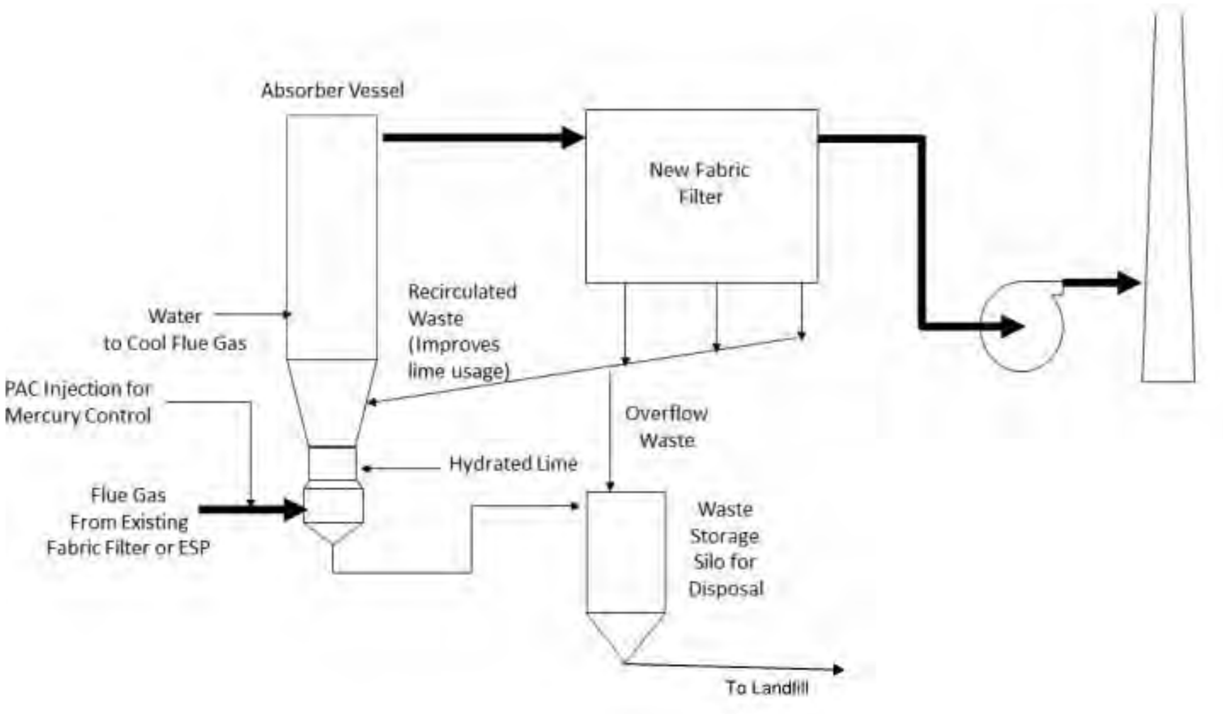


Figure 7-1 Circulating Dry Scrubber

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.

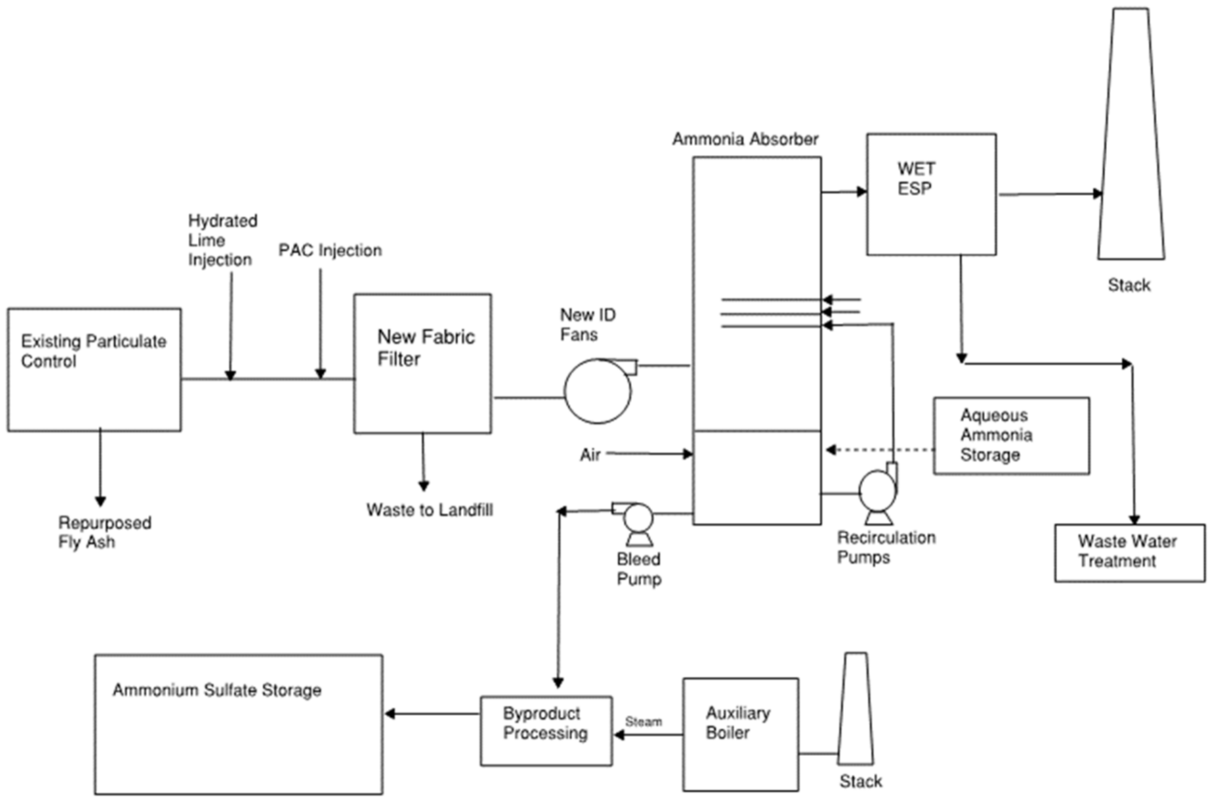


Figure 8-1 Ammonia Scrubber

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

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

TABLE OF CONTENTS

Page No.

LIST OF TABLES

Page No.

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 (inH_20)	-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

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

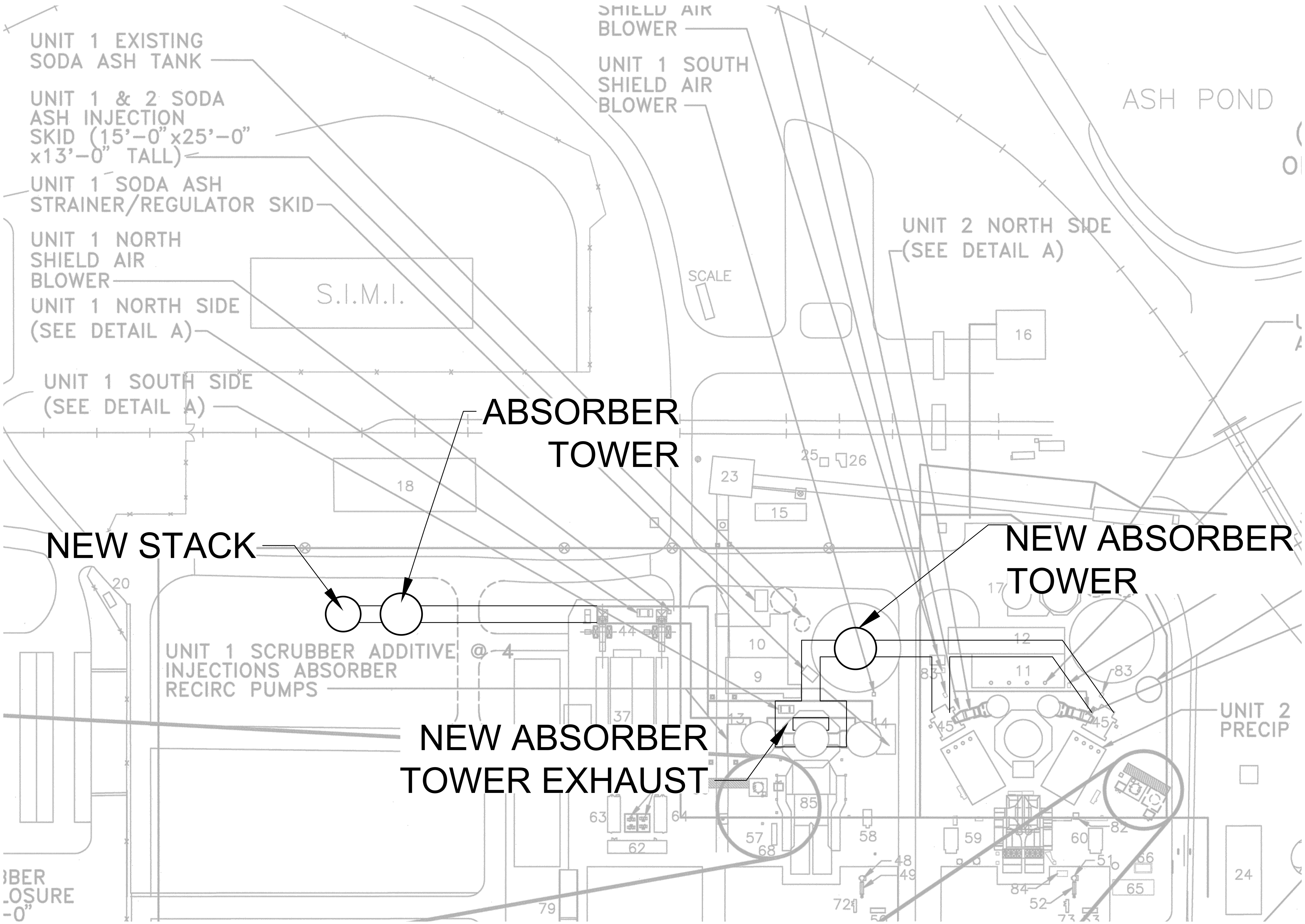
designed K. BURCHARDT
detailed R. CHANDLER

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.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
O 816-333-9400
F 816-333-3690
www.burnsmcd.com

VECTREN
A CenterPoint Energy Company

A.B. Brown Power Station
FGD Refurbishment Study
10-Year Dual Alkali Scrubber

Revised: May 11, 2020

THREE i DESIGN ENGINEERING + ARCHITECTURE
2425 WEST INDIANA ST EVANSVILLE, IN 47712 P: 812-423-6800 F: 812-423-6814 THREEIDESIGN.COM

Vectren Power Supply
A.B. Brown Power Station
FGD Refurbishment Study
10-Year Dual Alkali Scrubber

Prepared by: Three i Design

Table of Contents

A. INTRODUCTION

Three I Design (Three I Engineering) has been performing engineering and surveying support work in the A.B. Brown FGD Systems and for the A.B. Brown plant facility since the early 1980's. During the last four decades, we have worked with Vectren engineers, maintenance personnel, production personnel, contractors, and consultants, to upgrade FGD systems and plant systems, improve equipment accessibility, improve equipment handling systems, remediate Vectren safety items, and remediate corrosion damaged systems and structures. A very brief list of FGD system engineering support work is included below.

- Re-design and replace entire lime slaking system
- Re-design and replace lime conveying system
- Design and add ball mill system
- Design and add clarifier tank
- Re-design and replace unit no. 2 north and south absorber inlet ducts
- Re-design and replace unit no. 1 north and south absorber outlet ducts
- Re-design and replace unit no. 1 thickener tank rake drive support bridge
- Reinforce unit no. 2 thickener tank rake drive support bridge
- Re-design and replace unit no. 1 belt filter system
- Re-design and replace unit no. 2 belt filter system
- Re-design and replace unit no. 1 north and south absorber outlet duct support structures
- Reinforce unit no. 2 north and south absorber outlet duct support structures.
- Re-design and replace unit no. 1 rotary filter building and belt filter building siding and roofing systems (and support systems) and reinforce floor support steel and roof support steel
- Re-design and replace unit no. 2 regeneration building siding and roofing systems (and support systems) and reinforce floor support steel and roof support steel
- Re-design and replace unit no. 1 lime mixing tank and foundation
- Re-design and replace unit no. 2 lime mixing tank and foundation
- Re-design and replace unit no. 1 and 2 belt filter building ventilation systems
- Yearly unit no. 1 and unit no. 2 FGD system corrosion remediation projects

Based on experience with the A.B. Brown FGD Systems, Vectren asked Three I Design to help identify and organize the A.B. Brown FGD System Operation, Maintenance, and Remediation needs over the next ten years.

B. OBJECTIVE

The objective of this study was to identify systems, areas, and items that require regular or ongoing maintenance and/or remediation, based on historical information. This study also included identifying systems, areas, and items that are not continuous or ongoing remediation items but are expected to require maintenance and/or remediation within the next ten years. This study includes developing a ten-year project schedule for the maintenance and/or remediation, for each FGD system.

There are structures that required significant ongoing corrosion remediation work, and these structures were re-assessed in 2019. The 2019 assessment items included the four absorber vessels and the two thickener tanks.

After the work items were assembled into a ten-year project schedule (for each FGD system), budget pricing was developed for each year, as described below.

C. SCOPE OF WORK FOR FGD REFURBISHMENT STUDY

The following is a brief summary of the process that occurred and the information that was used to develop the budget pricing for Vectren's ten-year FGD plan.

Ten-year Plan - O&M Budget Pricing

The pricing provided was based on historical Vectren O&M information (provided by Vectren), for fiscal years 2011 thru 2018. Based on discussions with Vectren mechanical maintenance and electrical maintenance, the operating and maintenance expenses (2011 thru 2018) should be representative of the O&M expenses during the next ten years excluding overheads, Vectren labor, etc.

Ten-year Plan - Capital Budget Pricing

The pricing provided was based on historical Vectren capital information (provided by Vectren and Vectren's contractors), for fiscal years 2011 thru 2017. The ten-year projected costs are in 2019 dollars and exclude overheads Vectren labor, etc.

For the ten-year capital budget pricing Three I Design identified a list of projects for the first five years (2020 thru 2024). This list includes corrosion remediation items that are part of the most recent Vectren FGD system corrosion review projects (2015 thru 2018), items Vectren has included in their five-year corrosion remediation plan, and corrosion damaged items identified during recent FGD system corrosion review (2019 corrosion review during this project). In addition to corrosion remediation work, the capital project list includes replacing the absorber mist eliminators and adding mist eliminator wash systems in three absorbers (new mist eliminators and a mist eliminator wash system was installed in the Unit No. 2 south absorber at the end of 2015).

For the period 2025 thru 2026 the capital plan remained consistent with the previous 5-year period. During the period 2027-2029, the capital plan includes reductions consistent with an assumed unit retirement for study purpose at the end of 2029.

D. ESTIMATING METHODOLOGY

D.1. OEM Equipment Estimates

O&M Budget Pricing

The FGD Refurbishment Study consisted of eight years of Vectren O&M History (2011 thru 2018) and adjusting the historical information relative to current costs (2019 costs). The O&M budget pricing process also included meeting with A.B. Brown mechanical maintenance and electrical maintenance, to identify if current predictive maintenance and preventative maintenance approaches differ than the practices that were in place from 2011 to 2018. Adjustments were made to the budget pricing for 2020 thru 2029 to account for these practices.

Capital Budget Pricing

The FGD Refurbishment Study consisted of taking seven years of capital history (2011 thru 2017) and adjusting the historical information relative to current costs (2019 costs). Most historical information was provided by the contractor who performed the capital projects in the FGD system during this time. For projects performed by other contractors, this information was provided by the Vectren project managers for each project.

The capital budget pricing process also included reviewing the 2015 FGD system structural corrosion review manuals and field reviewing the equipment and structures in the FGD systems, to identify changes in performance, and to develop a list of capital projects for the 2020 to 2029 system life.

The capital budget pricing process also included performing a 2019 FGD system structural corrosion assessment of the absorber vessels and thickener tanks.

Once the FGD system reviews were complete, and the capital project list developed for 2020 thru 2029, this information was provided to Sterling Industrial, LLC a mechanical & electrical contractor familiar with the plant to develop budget pricing. Three I Design continually met with the Sterling Industrial throughout the process and provided additional concept information.

Budget pricing for 2020 thru 2029 was also compared to historical data and the age and condition of the structures and equipment in the FGD system. Changes were made to be consistent with historical data, which is generally an accurate representation of what is required to maintain these systems based on the age and condition of the structures and equipment in the FGD systems.

D.2. Balance of Plant Equipment Estimates

The descriptions below include references to previous work, previous projects, and previous capital budgets and T&M budget pricing.

The items and work described below are included in the estimates.

All estimates are 2019 dollars.

All estimates exclude overheads, escalation, and Vectren labor.

CCR compliance work was not included in this review.

Lime Silo

Exterior Walls

A corrosion remediation design package was created and bid in 2015. This work has not been completed at the time of this study and is included in the estimates going forward to avoid more extensive structural corrosion remediation work. An allowance for continual minor corrosion remediation is included each year to maintain the structure.

Roof System & Equipment

The roof system and roof mounted equipment was replaced in 2015. An allowance is included in each year for minor corrosion remediation work to maintain the systems and avoid major corrosion remediation in the future.

Ladders and Landings

The ladders and landings were replaced in 2015. An allowance is included in each year for minor corrosion remediation work to maintain the systems and avoid major corrosion remediation in the future.

Internal Walls

The internal walls were inspected, and minor repairs were made in 2015. An allowance is included in each year for minor corrosion remediation work to maintain the systems and avoid major corrosion remediation in the future.

Lime Conveyors

Ongoing Hapman conveyor equipment and conveyor tube maintenance is required, due to abrasion and wear. Regular maintenance costs and conveyor replacement costs are included in the estimate.

Lime Slaking Tank

The lime slaking tank has been replaced including the tank, foundations, platforms, and handrail systems in 1999. Regular corrosion remediation work is to be expected going forward due to the corrosive environment.

Ball Mill

The ball mill has been replaced including the primary equipment, foundations, platforms, stairs, and handrail systems in 1999 Regular corrosion remediation work is expected going forward due to the corrosive environment.

Lime Slurry Storage Tank

The lime slurry storage tank has been replaced including the tank, equipment, foundations, platforms, stairs, and handrail systems in 1996. Regular corrosion remediation work is to be expected going forward due to the corrosive environment.

Corrosion remediation work on the spiral stair to the top of the tank, the landing at the top of the tank, and the stair and the walkway to the belt filter building is included in the estimate.

Lime Slaking Building

The lime slaking building has been replaced including the building, framing, roofing, siding, equipment, foundations, doors, roofing, and siding in 1996. Regular corrosion remediation work is to be expected going forward due to the corrosive environment.

Unit No. 1 North and South Absorbers

Shell Disc & Donut, Internal Structural Repairs & Flake-glass Coating

Developed scope of work based on historical outage upgrades and repairs. Estimate includes necessary improvements and repairs based on outage schedule going forward.

Anchor Bolts and Anchor Chairs

Extensive corrosion remediation repairs were performed in 2011-2012 on the bottom of the absorbers. Based on the significant ongoing corrosion damage around the base of the absorbers these repairs will need to be performed in the future and this scope is included in the estimate.

Shell Plate

Shell replacement work was performed in 2011-2012. Based on assessment of the large number of external cover plates currently located on the absorbers, this work should be performed in 2020, and in 2025. This scope has been included in the estimate. See Corrosion Review Reports for vessel structural stability associated with external cover plates, and horizontal planes in the vessel shell that are perforated from corrosion damage.

External Stiffeners

Repairs will be needed on the external stiffeners in the next ten years. This scope is included in the estimate. The external shell stiffening work that was performed in 2011-2012 was used to develop this estimate.

Mist Eliminators, Mist Eliminator Supports, & Mist Eliminator Wash Piping

Replacement of the mist eliminators, mist eliminator supports, & mist eliminator wash piping in the north and south absorbers including the dome stiffeners, access opening in dome (and framing), access platform at dome opening, and jib crane for handling mist eliminator equipment, etc. is included in the estimate.

Access Platforms, Walkways, Stairs, and Ladders

Corrosion remediation is an ongoing process on these structures and this process is expected to continue, based on the corrosive environment. This scope is included in the estimate.

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on these vessels in 2019. In order to manage risk on these structures, Vectren should continue the current structural shell replacement process of removing damaged shell and installing new shell. This type of repair is outage work and should be performed during every outage, to replace all temporary patch plates with new in-line shell plate. This scope is included in the estimate.

In conjunction with the approach to managing risk, it is recommended that the bottom of each vessel be completely replaced. The original designer of the vessels specified the bottom of these vessels be insulated. Absorber liquid from vessel leaks and leaking expansion joint leaks filled the insulation area and held the corrosive liquid against the outside surface of the vessels. Significant metal loss occurred before Vectren understood how much damage occurred and permanently removed the insulation system.

For budgeting purposes and the replacement schedule, the vessel replacement could occur in three consecutive outages (one third of the vessel, each outage). This approach is included in the estimate.

Unit No. 1 North and South Absorber Inlet Duct

The north absorber inlet duct and nozzle has an excessive amount of liquid leaking, and this liquid is causing damage to the base of the absorber and adjacent structures. The north absorber inlet duct and nozzle needs to be repaired or replaced in 2020. This scope had been included in the estimate.

This work should also be performed on the south absorber inlet duct, so this structure doesn't cause damage to the base of the absorber or adjacent structures. This scope has been included in the estimate.

In the past, the outlet duct expansion joints have leaked onto the top of the inlet ducts and saturated the inlet duct insulation and caused significant damage to the insulation, cladding, duct shell, duct stiffeners, and duct supports. Vectren has made modifications in this area including fiberglass cladding on the areas under the expansion joints, however, if this area is saturated with scrubber liquor in the future, the resulting corrosion remediation costs have not been addressed in this ten-year estimate.

Unit No. 1 North and South Absorber Outlet Duct

The coated carbon steel elbow on the south absorber outlet duct system was replaced with a stainless steel duct elbow in 2018. This approach is planned and included in the estimate for the north absorber.

Significant corrosion remediation and shell plating work was performed on the north and south absorber outlet ducts and the breech ducts previously. This work is included in each outage estimate for the next ten years.

Unit No. 1 North and South Absorber Inlet Duct Support Structures

These structures were repaired within the last two years, but minor corrosion remediation work will be required to maintain them. This scope is included in the estimate. If the duct work is not maintained additional corrosion remediation work on the support structures will be required.

Unit No. 1 North and South Absorber Outlet Duct Support Structures

These structures have been replaced within the last two years, so only minimal work should be required to maintain them. This scope is included in the estimate. If the expansion joints are not maintained, additional corrosion remediation work will be required.

Unit No. 1 North and South Absorber Access Platforms, Stairs, Ladders, etc.

These structures have been replaced within the last two years, so only minimal work should be required to maintain them. This scope is included in the estimate. If the expansion joints are not maintained, additional corrosion remediation work will be required.

Unit No. 1 North and South Absorber Recirc. Pump Buildings

These buildings were replaced in 2013 and these structures are performing relatively well. Minor corrosion remediation work is included in each year, to avoid major corrosion remediation work in the future.

Unit No. 1 North and South Absorber Recirc. Pumps Concrete Foundations

There is cracking in the concrete and exposed reinforcing steel on the pump concrete foundations. Pump concrete foundation replacement work is included for all four concrete foundations.

Unit No. 1 North and South Absorber Bleed Piping

This 10” diameter piping system is mostly the original FMC fiberglass piping. Most of this piping is outside and exposed to UV rays (outside surfaces) and harsh chemicals on the inside surfaces. Replacement of this piping system is included in the estimate.

Unit No. 1 North and South Absorber Regeneration Return Piping

This 14” diameter piping system was replaced in 1997 and 2013. This piping system probably won’t need to be completely replaced before 2030 but will require minor corrosion remediation work. This scope is included in the estimate.

Unit No. 1 North and South Absorber Regeneration Return Valve Access Platform

Replace access platforms in 2019 or 2020. T&M Budget Pricing was developed in 2018. This scope is included in the estimate.

Unit No. 1 Alley Pipe Supports

All Supports in the Unit No. 1 Alley need to be replaced (FMC Corporation drawings 00246-608-1 thru 00246-608-3). The columns will be in new locations, so the columns can be installed before any existing structures are removed (so the existing utilities can be supported from the existing pipe support system and then transferred to the new support system, without excessive false-work). This scope is included in the estimate.

Unit No. 1 Alley Underground Drain Piping and Manholes

Vectren has performed ongoing corrosion remediation work on the underground piping and manholes. This work will need to continue, and this scope is included in the estimate.

Unit No. 1 Thickener Tank

Thickener Tank Rim

Replace top 2’-6” of rim. This work will be similar to the rim replacement work that was performed in 2008/2009, however, a new rim angle will need to be added to the entire perimeter and the angle will need to continue through the vertical structural tee shell stiffeners. Rim angle to be 4”x4”x3/8”. This scope is included in the estimate.

Thickener Tank Vertical Shell Stiffeners

The bottom portion of nearly every vertical structural tee’s is missing. Install all new vertical structural tee’s on shell. Match the existing member size. The new vertical structural tee’s will be placed mid-way between the existing vertical structural tee’s. The damaged tee’s will be abandoned in place. This scope is included in the estimate.

Thickener Tank Bridge

Entire bridge needs to be sand blasted and painted. As with previous projects, due to the amount of visual corrosion damage, this process will include a significant amount of structural discovery work/structural repairs. This scope is included in the estimate.

Thickener Tank Bridge Utility Supports, Rake Canopy, and Handrail System

Entire system needs to be sand blasted and painted. As with previous projects, due to the amount of visual corrosion damage, include a significant amount of structural discovery work/structural repairs. This scope is included in the estimate.

Thickener Tank Shell and Floor Plate

Internal corrosion remediation was performed on the thickener tank shell and floor plates in 2010. This type of work will need to be performed, at least once, during the next ten years. This scope is included in the estimate.

The outside surface of the thickener tank shell (and all shell stiffeners) should be sand blasted and coated. This scope is included in the estimate.

Thickener Tank Launder, Regeneration Return Nozzles, and Emergency Overflow

On-going corrosion remediation work is performed on these items and this repair process should continue. Most of this work requires emptying the tank (or at least lowering the liquid level). Liquid level adjustments are by Vectren. This scope is included in the estimate.

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on this tank in 2019. In order to manage risk in this million-gallon capacity tank, it was suggested that the tank be completely replaced. This remediation is appropriate. Over the last forty years, Vectren has performed a significant amount of temporary reinforcing and temporary patch plate repairs on this tank (floor cover plates, shell cover plates, corner reinforcement, partial shell replacement, etc.). The bottom portion of the vertical stiffeners, horizontal stiffening ring, and exterior floor to shell weld are also significantly damaged.

For budgeting purposes and the replacement schedule, the tank replacement is to occur in three consecutive outages (one third of the tank, each outage). This scope is included in the estimate.

Unit No. 1 Lime Mixing Tank

The lime mixing tank was completely replaced in 2013. The lime mixing tank is inspected by Vectren during each outage and the re-designed tank is performing much better than the previous tank. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 1 Soda Ash Tank

The access platform and perimeter handrail system on top of the tank will need to be replaced within the ten-year time frame. This scope is included in the estimate.

Unit No. 1 Old Rotary Filter Building

Structural Steel and Floor Support Steel

Major corrosion remediation work has been performed in this building over the last ten years. The corrosion remediation work over the next ten years should be less than the previous ten years, however, corrosion damage is expected, and corrosion remediation needed each year, to avoid major corrosion remediation work. This scope is included in the estimate.

Trench Drain System

The trench drain that runs north and south adjacent to the vacuum pump is showing significant signs of differential settlement and the old truck bay concrete foundation is cracked and shifted, which has caused a shift and cracking in the block wall that sits on the concrete foundation. This trench drain system should be replaced. The old truck bay concrete foundation and block wall should be repaired. This scope is included in the estimate.

First Floor Stair

Based on the corrosive environment and the history of this system, corrosion damage is expected, and corrosion remediation needed within the ten-year time frame. This scope is included in the estimate.

Second Floor Stair Tower

This abandoned corrosion damaged stair tower should be removed and the utilities attached to the stair tower should be re-supported. This scope is included in the estimate.

Chemical Sump

The grating, grating support steel and handrail system have been repaired numerous times. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Waste Water Sump

The grating, grating support steel and handrail system have been repaired numerous times. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 1 Belt Filter Building

South Stair Tower

This stair system was replaced in 2014. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Structural Steel and Floor Support Steel

Major corrosion remediation work has been performed in this building over the last ten years. The corrosion remediation work over the next ten years should be less than the previous ten years, however, the metal deck and concrete were not replaced (this work was postponed). There is a significant amount of corrosion damage in the metal deck. Corrosion remediation will be needed. The south edge beam (at the lime mixing tank) also needs to be reinforced or replaced. Minor corrosion damaged is also expected and corrosion remediation needed. This scope is included in the estimate.

Roof and Roof Support Steel

The roof system was supposed to be replaced, but this work was postponed for several years. This work needs to be performed (replace all roof purlins and reinforce roof support beams). Since this work has been postponed for several years, more extensive corrosion damage is expected, and more extensive corrosion remediation needed. This scope is included in the estimate.

Haul Truck Canopy

Corrosion remediation work was performed on the framing and knee brace for this canopy in 2013. There was also T&M Budget Pricing developed for replacing the purlins and roofing material for the canopy and this work was postponed for several years. This work needs to be performed. The east perimeter/edge beam and the north perimeter/edge beam need to be replaced in a similar manner to the south perimeter/edge beam that was replaced in 2013. This scope is included in the estimate.

Unit No. 1 Horizontal Belt Filter

The horizontal belt filter was completely replaced in 2015 and this system appears to be performing relatively well, however, this area is an extremely corrosive area and on-going minor corrosion remediation work should be included (every year), to avoid major corrosion remediation work in the future. This scope is included in the estimate.

Unit No. 1 Horizontal Belt Filter Drop Chute

The carbon steel horizontal belt filter drop chute was completely replaced in 2015 with a stainless steel drop chute. This system appears to be performing well, and only occasional minor corrosion remediation is anticipated. This scope is included in the estimate.

Unit No. 1 Lime Silo Enclosure

The upper portion of the north and south lime silos has been removed, but the lower portion (columns and cone) were not removed because this area is an enclosure that is still used to protect operating equipment. All wall girts, purlins, and minor support steel need to be replaced with new, and new siding and roofing installed. This scope is included in the estimate.

The main columns and bracing on the lime silos appear to be in relatively good condition and the load on these structures has been greatly reduced, therefore, only minor corrosion remediation is needed. This scope is included in the estimate.

Unit No. 1 Underflow Piping

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 1 Underflow Tunnel

The access platform and stairs into the tunnel need to be replaced. This scope is included in the estimate.

There are numerous areas where the concrete reinforcing steel is exposed and the large areas where the concrete reinforcing steel has dissolved away, completely. The tunnel needs significant corrosion remediation. This scope is included in the estimate.

Catwalk and Utility Support between Unit 1 and Unit 2

Major structural remediation work was performed in 2018, however, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed, including complete replacement of the utility supports. This scope is included in the estimate.

Unit No. 1 & Unit No. 2 Emulsified Sulfur System and Enclosure

Vectren moved the Unit No. 2 emulsified sulfur pumping system over to the Unit No. 1 emulsified sulfur tank, so this tank provides emulsified sulfur to the Unit No. 1 thickener tank and the Unit No. 2 thickener tank. The structures in this system appear to be performing well. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Minor corrosion remediation is need for the pump enclosure. This scope is included in the estimate.

The Unit No. 1 emulsified sulfur tank agitator support beams and the attachments to the fiberglass tank need to be sand blasted and coated. This scope is included in the estimate.

Unit No. 1 Switchgear Building

The roofing system on this building has been repaired several times in the past. The roof needs to be replaced and minor corrosion remediation is needed for the building structure. This scope is included in the estimate.

Unit No. 2 North and South Absorbers

Shell Disc & Donut, Internal Structural Repairs & Flake-glass Coating

Corrosion remediation is an ongoing process with a yearly budget. This scope is included in the estimate.

Anchor Bolts and Anchor Chairs

The anchor bolts and anchor chairs on the Unit No. 2 absorbers have not experienced the extensive damage that has occurred on Unit No. 1, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Shell Plate

The shell replacement work that was performed in 2012/2013 is expected to be necessary again in the next ten years, due to the corrosive environment and based on the large number of external cover plates currently located on the absorbers. This scope is included in the estimate.

External Stiffeners

The external stiffeners on the Unit No. 2 absorbers have not experienced the extensive damage that has occurred on Unit No. 1, however, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Mist Eliminators, Mist Eliminator Supports, & Mist Eliminator Wash Piping

Replace the mist eliminators, mist eliminator supports, & mist eliminator wash piping in the north absorber. Use 2015 Unit No. 2 south absorber mist eliminator replacement pricing (adjust pricing to current year). This work needs to include the absorber dome stiffeners, access opening in dome (and framing), access platform at dome opening, jib crane for handling mist eliminator equipment, etc. This scope is included in the estimate.

Access Platforms, Walkways, Stairs, and Ladders

Corrosion remediation is an ongoing process on these structures and this process is expected to continue, based on the corrosive environment. This scope is included in the estimate.

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on these vessels in 2019. In order to manage risk on these structures, Vectren should continue the current structural shell replacement process of removing damaged shell and installing new shell. This type of repair is outage work and should be performed during every outage, to replace all temporary patch plates with new in-line shell plate. This scope is included in the estimate.

Unit No. 2 North and South Absorber Inlet Duct

Unit No. 2 north and south absorber inlet duct have both been replaced in the last twenty years, along with ongoing corrosion remediation. This is an extremely corrosive area. Based on the corrosive environment, the history of this system, and the ten-year period, ongoing corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 North and South Absorber Outlet Duct

The south absorber outlet duct system was replaced in 2015 with a stainless steel. This replacement is expected for the north absorber. This scope is included in the estimate.

If the duct replacement is delayed, additional corrosion remediation work will be required.

Unit No. 2 North and South Absorber Inlet Duct Support Structures

These structures have significant corrosion damage and should be replaced. This replacement should include replacing the access platforms and ladders. This scope is included in the estimate.

Unit No. 2 North and South Absorber Outlet Duct Support Structures

Major corrosion remediation work was performed in 2016/2017, however, due to the expansion joints in the absorber outlet ducts, and the history of ongoing corrosion damage in this area, similar corrosion remediation is expected in 2025 and minor corrosion remediation in other years, to avoid major corrosion remediation work. This scope is included in the estimate.

Unit No. 2 North and South Absorber Access Platforms, Stairs, Ladders, etc.

Ongoing corrosion remediation work has been performed on these structures. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 North and South Absorber Recirc. Pump Building

The siding and roofing were replaced in 2011, but the system was not installed per the manufacturer's installation instructions and panels are not attached properly to the support steel. Some re-work was performed in 2015 when the west wall columns failed, and structure remediation work was performed on the west wall. Ongoing repair work is expected. This scope is included in the estimate.

There are several areas around the trench drains that have differentially settled. Trench drain re-work is expected in the next ten years. This work includes repairing floor areas that have settled (in addition to the areas around the trench drains). This scope is included in the estimate.

Unit No. 2 North and South Absorber Recirc. Piping

This piping system is a combination of original 1985 FMC fiberglass piping and fiberglass piping that was installed in 1998. Replacement of this piping system is expected, and this scope is included in the estimate.

Unit No. 2 North and South Absorber Bleed Piping

This 10" diameter piping system is mostly the original FMC fiberglass piping. Replacement of this piping system is expected, and this scope is included in the estimate.

Unit No. 2 North and South Absorber Regeneration Return Piping

There doesn't appear to be any coating system on the regeneration return piping. based on the number of times the Unit No. 1 regeneration return piping has been replaced, it is expected that this piping system will need to be completely replaced. This scope is included in the estimate.

Unit No. 2 North and South Absorber Regeneration Return Valve Access Platform

This platform was replaced in 2006/2007. Based on the amount of corrosion damage in this area, minor ongoing corrosion remediation will be needed on this structure to avoid a complete replacement within ten years. This scope is included in the estimate.

Unit No. 2 Pipe Supports between Absorbers

The bottom portions of the utility and pipe supports in this area were replaced a couple years ago, but the steel was never coated. Structural corrosion remediation is required for these supports and then all supports need to be sand blasted and painted. This scope is included in the estimate.

Unit No. 2 Thickener Tank

Thickener Tank Rim

Replace top 2'-0" of rim. This work will be similar to the rim replacement work that was performed in 2008/2009 Unit No. 1. This scope is included in the estimate.

Thickener Tank Bridge

Entire Bridge needs to be sand blasted and painted. Based on the corrosive environment, history of corrosion on this structure, corrosion damaged is expected to be discovered after sand blasting, and corrosion remediation needed. This work should include the bridge support columns. This scope is included in the estimate.

Thickener Tank Bridge Utility Supports, Rake Canopy, and Handrail System

Entire system needs to be sand blasted and painted. As with previous projects, due to the amount of visual corrosion damage, include a significant amount of structural discovery work/structural repairs will be needed. This scope is included in the estimate.

Thickener Tank Shell and Floor Plate

Based on the corrosive environment, the history of this system, and the ten-year period, ongoing corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

The outside surface of the thickener tank shell (and all shell stiffeners) needs to be sand blasted and coated. This scope is included in the estimate.

Thickener Tank Launder, Regeneration Return Nozzles, and Emergency Overflow

On-going corrosion remediation work is performed on these items and this repair process should continue. Most of this work requires emptying the tank (or at least lowering the liquid level). Liquid level adjustments are by Vectren. This scope is included in the estimate

Ultrasonic Thickness Testing (Corrosion Remediation)

Vectren hired Three I Design to perform ultrasonic thickness testing, temporary patch plate location work, and corrosion review work on this tank in 2019. In order to manage risk in this million-gallon capacity tank, it was suggested that the tank be completely replaced. This remediation is appropriate. Over the last thirty-five years, Vectren has performed a significant amount of temporary reinforcing and temporary patch plate repairs on this tank (floor cover plates, shell cover plates, partial shell replacement, etc.).

For budgeting purposes and the replacement schedule, the tank replacement is to occur in three consecutive outages (one third of the tank, each outage). This scope is included in the estimate.

Unit No. 2 Lime Mixing Tank

Major corrosion remediation was performed on the lime mixing tank in 2017. The lime mixing tank is inspected by Vectren during each outage and the re-designed tank is performing better than the previous tank. However, over a ten-year period, it is safe to assume some corrosion remediation will be needed. The internal roof support steel was also abandoned in place. This steel should be inspected during each outage and any compromised members should be removed. This work will require internal scaffolding. This scope is included in the estimate.

Unit No. 2 Soda Ash Tank

The access platform and perimeter handrail system on top of the tank should be replaced within the ten-year time frame. This scope is included in the estimate.

Regular minor corrosion remediation on the spiral stair to the top of the soda ash tank should be performed to avoid major corrosion remediation in the future. This scope is included in the estimate.

Unit No. 2 Belt Filter Building (Regeneration Building)

Structural Steel, Roof Support Steel, and Floor Support Steel

Major corrosion remediation work has been performed in this building over the last ten years. The corrosion remediation work over the next ten years should be less than the previous ten years, however, based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Vectren recently removed many of the masonry block walls in this building and there is corrosion damage on the beams that have been exposed, since the block walls were removed. These beams need to be sand blasted and painted. Based on the history in this building, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

The coating system for the roof support steel is not performing well. This steel needs to be sand blasted and coated. Based on the history in this building, corrosion damage is expected after sand blasting and corrosion remediation needed, prior to installing the coating system. This scope is included in the estimate.

The coating system on the center support beam in the truck bay (and center support for the filter cake drop chute) is not performing well. This steel needs to be sand blasted and coated. Based on the history in this building, corrosion damage is expected after sand blasting and corrosion remediation needed, prior to installing the coating system. This scope is included in the estimate.

The x-bracing (including connection plates) on the east face of this belt filter building, near the lime mixing tank needs to be completely replaced. This replacement process will be similar to the x-bracing replacement work that has been performed several times in the Unit No. 1 belt filter building. This scope is included in the estimate.

Siding and Roofing Systems

The siding and roofing was replaced in 2011, but the system was not installed per the manufacturer's installation instructions and panels are not attached properly to the support steel. A large area of the west wall failed and was replaced in 2017. Ongoing repair work is expected on these systems. This scope is included in the estimate.

Haul Truck Canopy

Corrosion remediation work was performed on the framing and knee braces for this canopy in 2011, but the east edge beam has corrosion damage, and this beam should be replaced (and all connection plates). This scope is included in the estimate.

Internal Stair (South)

Based on the history in this building, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

External Stair Tower (North)

Corrosion remediation has been performed several times in the last ten (plus) years, but none of the repairs have been coated. This entire structure needs to be sand blasted and painted, since some of the repairs occurred a long time ago. Based on the history, corrosion damage is expected and sand blasting and corrosion remediation is needed, prior to installing the coating system. This scope is included in the estimate.

Unit No. 2 Chemical Sump

Vectren replaced the grating support steel with stainless steel and this system appears to be performing relatively well.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 Wastewater Sump

The handrail system has been repaired over the years, and it is safe to assume that this ongoing process will continue.

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 South Horizontal Belt Filter

The south horizontal belt filter frame was completely replaced in 2013 (the north horizontal belt filter was removed last year). The coating system on the frame has completely failed. Corrosion remediation on the structural frame will be needed soon. After the major corrosion remediation is complete, minor ongoing corrosion remediation will be needed. This scope is included in the estimate.

Unit No. 2 Horizontal Belt Filter Drop Chute

The carbon steel horizontal belt filter drop chute was replaced in 2015 with a stainless steel drop chute. This system appears to be performing well, and only occasional minor corrosion remediation is anticipated. This scope is included in the estimate.

Unit No. 2 Underflow Piping

Minor ongoing corrosion remediation work has been performed on the piping and pipe supports. Based on the corrosive environment, the history of this system, and the ten-year period, corrosion damage is expected, and corrosion remediation needed. This scope is included in the estimate.

Unit No. 2 Clarifier Tank Pipe Rack

This structure is no longer used for its intended purpose (the 24” diameter and 36” diameter pipes are empty and abandoned in place). The structure is at a reduced structure loading, however, there is significant amount of corrosion damage to the two columns that support this tall structure. This pipe rack should be removed and the SBS compressor utilities routed on a new support system. Any other piping and electrical utilities that are still in use should also be relocated. This process would be similar to the 2016/2017 removal of the Unit No. 2 FMC CEMS building platform and re-supporting the piping and electrical utilities that were attached to the platform columns. This scope is included in the estimate.

Unit No. 2 Switchgear Room

See Section on absorber recirc. pump building.

D.3. List of Major Corrosion Remediation Projects

Unit 1 – 2020

- North and South Absorber Access Platforms, Stairs, Ladders, etc. - Remediation
- Replace North and South Regen. Return Valve Access Platforms
- Replace Alley Pipe Supports
- Alley Underground Drain Piping - Corrosion Remediation
- Alley Drainage Manhole - Corrosion Remediation
- Haul Truck Canopy - Replace Beams, Purlins, and Roof Panels
- Lime Silo Enclosure - Replace Siding System and Roof System
- Underflow Access Platform and Stairs - Corrosion Remediation
- Underflow Tunnel Repair - Concrete & Reinforcing Steel - Corrosion Remediation
- Thickener Tank - Replace Exterior Coating
- Thickener Tank - Corrosion Remediation/Discovery Work
- Thickener Tank Vertical Shell Stiffeners
- Old Rotary Filter Building Trench Repair
- Old Rotary Filter Building Truck Bay Block Wall Repair

Unit 2 – 2020

- Thickener Tank - Replace Exterior Coating System
- Thickener Tank - Corrosion Remediation/Discovery Work
- North Outlet Duct Repairs
- Replace North and South Inlet Duct Support Structures
- North and South Absorber Access Platforms, Stairs and Ladders, Etc. - Remediation
- North and South Recirc. Pump Building Trench Drains and Floor - Remediation
- North and South Absorber Regen. Return Valve Access Platform - Replace Coatings
- Regen. Return. Platform - Discovery Work
- Pipe Supports Between Absorbers - Corrosion Remediation
- Regen. Building Siding and Roofing - Corrosion Remediation
- Belt Filter Building Internal Stairway (South) - Coating
- Belt Filter Building Internal Stairway (South) - Corrosion Remediation/Discovery Work
- Belt Filter Building External Stairway (North) - Coating
- Belt Filter Building External Stairway (North) - Corrosion Remediation/Discovery Work
- Lime Silo Exterior Walls - Corrosion Remediation
- Disc & Donut, Shell, Sump, and Duct Repair
- Thickener Tank Bridge Coating
- Regeneration Building Southeast X Bracing - Replace
- Regeneration Building Grit Pit Area Perimeter Beams - Coating Replacement
- Misc. Piping Replacement
- North and South Absorber Shell Plates

- Replace Top Landing on Lime Slurry Storage Tank
- Lime Slurry Storage Tank Roof Support Steel - Corrosion Remediation
- Clarifier Tank - Dome Top - Corrosion Remediation
- Clarifier Tank - Rake Drive Support Steel and Access Platform - Corrosion Remediation
- Clarifier Tank - Walkway and Stairs - Corrosion Remediation

<u>Unit 1 – 2021</u>

- North and South Inlet Duct at Scrubbers - Replace
- North and South Outlet Duct Repairs - Partial Replacement & Remediation
- North and South Inlet Duct Support Structures - Replace Posts
- Replace North Quench Sprays
- Replace South Quench Sprays
- North and South Absorber Outlet Duct Structures - Remediation
- North Absorber Inlet Expansion Joint Replacement 1-15
- North Absorber Inlet Expansion Joint Replacement 1-23
- North Absorber Inlet Expansion Joint Replacement 1-18B
- South Absorber inlet Expansion Joint Replacement 1-17
- South Absorber Inlet Expansion Joint Replacement 1-18A
- North Absorber Outlet Expansion Joint Replacement
- South Absorber Outlet Expansion Joint Replacement
- Alley Underground Drain Piping - Corrosion Remediation
- Alley Drainage Manhole - Corrosion Remediation
- Thickener Tank Bridge - Corrosion Remediation/Discovery Work
- Thickener Tank Bridge and Utility Supports, Rake Canopy, and Handrail System - Replace Coating
- Soda Ash Tank Install Drains and piping
- Soda Ash Tank Grating (Remove and Install)
- Switch Gear Building - Remediation
- Disc & Donut, Shell, Sump, and Duct Repair
- North and South Absorber Access Platforms, Stairs, ladders, Etc.
- Replace Thickener Tank Rim and Launder - Shop Fabrication
- Replace Thickener Tank Rim and Launder - Exterior and Interior Coating
- Replace Thickener Tank Rim and Launder
- Misc. Piping Replacement
- North and South Absorber Shell plates

<u>Unit 2 – 2021</u>

- North Absorber Inlet Expansion - Replace
- South Absorber Inlet Expansion - Replace
- North Absorber Outlet Expansion (1st one off scrubber) - Replace
- North Absorber Outlet Expansion (At Stack) - Replace
- South Absorber Outlet Expansion (1st one off scrubber) - Replace
- South absorber Outlet Expansion (At Stack) - Replace

- North Outlet Duct Repairs - Remediation
- North and South Inlet Duct Support Structures - Remediation
- North and South Absorber Access Platforms, Stairs and Ladders, etc. - Remediation
- Thickener Tank Rim - Remediation
- Regen Building Siding and Roofing - Remediation
- Clarifier Tank Pipe Rack - Remove & Replace SBS Air Compressor Utilities
- Lime Silo Fill Lines - Replace
- Disc & Donut, Shell, Sump, and Duct Repair
- Misc. Piping Replacement
- North and South Absorber Shell plates
- Replace Walkway From Lime Slurry Storage Tank to Regen. Building
- Clarifier Tank - Shell and Floor - Corrosion Remediation
- Clarifier Tank - Enclosure - Corrosion Remediation
- Clarifier Tank - Tank Floor Support Steel - Corrosion Remediation

Unit 1 – 2022

- North and South Absorber Anchor Bolts and Chairs
- North and South Absorber Shell plates
- North and South Absorber External Stiffeners
- North and South Tower - Replace Flake Glass Liner (Complete Replacement)
- North and South Tower Patching, Vertical Supports And Plates (Drawing 70 thru 74)
- North and South Absorbers Support Post (Drawing 76)
- North and South Absorber Supports (Drawing 77)
- North and South Absorber Alloy Bands and External Stiffening (drawing 78)
- North and South Absorber Repairs to Inlet Duct and Absorber Interface And Internal Awning
- North and South Absorber wall repairs after cleaning
- Replace North Absorber Mist Eliminators
- Replace South Absorber Mist Eliminators
- North Absorber Cone Repair and Reinforcement
- South Absorber Cone Repair and Reinforcement
- North and South Inlet Duct at Scrubbers
- North and South Outlet Duct - Corrosion Remediation
- North and South Inlet Duct Support Structures - Corrosion Remediation
- North and South Absorber Outlet Duct Structures
- North Absorber Outlet Elbow Duct
- Thickener Tank Shell and Floor Plate
- Disc & Donut, Shell, Sump, and Duct Repair
- North and South Absorber Access Platforms, Stairs, Ladders, Etc. - Remediation
- Belt Filter Roof Support Steel - Corrosion Remediation
- Replace Belt Filter Roof System (including purlins and roofing panels)
- Replace Acid Brick Liner in Absorber Sumps

Unit 2 – 2022

- North and South Absorber Access Platforms, Stairs and Ladders, Etc.
- Regen Building Siding and Roofing
- Haul Truck Canopy - Remediation
- Replace Soda Ash Tank Stairway
- Purchase Material for North Absorber Mist Eliminators
- Purchase Material for North Absorber Duct Replacement

Unit 1 – 2023

- Alley Underground Drain Piping - Remediation
- Alley Drainage Manhole - Remediation
- North and South Absorber Access Platforms, Stairs, ladders, Etc.
- Old Rotary Filter Building Coating
- Horizontal Belt Filter Building Coating
- Old Rotary Filter Building - Remediation
- Horizontal Belt Filter Building Coating - Remediation
- Belt Filter Building Floor Replacement
- Soda Ash Tank Access Platform and Perimeter Handrail system

Unit 2 – 2023

- Absorbers Inside Liner Replacement
- North and South Absorber Anchor Bolts and Chairs
- North and South Absorber Shell Plates
- North and South Absorber External Stiffeners
- North Mist Eliminators - Install
- North and South Mist Eliminators Wash Access Platforms and Walkways Corrosion
- North Outlet Duct Replacement - Install
- North and South Inlet Duct Support Structures
- North Quench Spray Piping
- South Quench spray Piping
- North and South Absorber Access Platforms, Stairs and Ladders, Etc.
- North and South Bleed Piping - Replace
- Thickener Tank Shell and Floor Plate Internal Remediation
- Regen Building Siding and Roofing
- South Horizontal Belt Filter - Replace Frame and Main Rollers
- Disc & Donut, Shell, Sump, and Duct Repair
- Replace Absorber Recirc. Piping
- Replace Acid Brick Liner in Absorber Sumps

Unit 1 – 2024

- North and South Inlet Duct at Scrubbers
- North and South Outlet Duct Repairs

- North and South Inlet Duct Support Structures
- North Quench Sprays
- South Quench Sprays
- North and South Absorber Outlet Duct Structures
- North Absorber Inlet Expansion Replacement 1-15
- North Absorber Inlet Expansion Replacement 1-23
- North Absorber Inlet Expansion replacement 1-18B
- South Absorber inlet Expansion Replacement 1-17
- South Absorber Inlet Expansion Replacement 1-18A
- North Absorber Outlet Expansion Replacement
- South Absorber Outlet Expansion Replacement
- Alley Underground Drain Piping - Remediation
- Alley Drainage Manhole - Remediation
- Thickener Tank Bridge Utility Supports, Rake Canopy, and Handrail System Coating
- Disc & Donut, Shell, Sump, and Duct Repair
- North and South Absorber Access Platforms, Stairs, ladders, Etc.
- Lime Mixing Tank - Remediation
- Misc. Piping Replacement
- North and South Absorber Shell plates

<u>Unit 2 – 2024</u>

- North and South Inlet Duct Support Structures
- North and South Absorber Access Platforms, Stairs and Ladders, Etc.
- Regen Building Siding and Roofing
- Replace Thickener Tank Bridge
- Disc & Donut, Shell, Sump, and Duct Repair
- Lime Mixing Tank - Remediation
- Misc. Piping Replacement
- North and South Absorber Shell plates

E. ESTIMATE ASSUMPTIONS & CLARIFICATIONS

- The project list contains major projects and major tasks.
- Budget pricing for all years is in 2019 dollars.
- The capital projects have not been designed or engineered; therefore, all budget pricing is conceptual only.
- The cost for each outage year includes $1,000,000 for absorber disc and donut repairs and interior shell repairs. This is based on the current Vectren repair approach.
- The cost for the major outage year for unit no. 1 includes $3,500,000 for the north and south absorber mist eliminator and mist eliminator wash system replacement. This is a Vectren planned replacement.
- The cost for the major outage year for unit no. 2 includes $1,700,000 for north absorber mist eliminator and mist eliminator wash system replacement. This is a Vectren planned replacement.
- An engineering cost of 20% for all capital work is included in the budget pricing.
- Costs for planned work were estimated using historical costs from 2011 – 2017 and contractor budget pricing.
- The budget pricing is based on Vectren's current operating practices, maintenance practices, outage approaches, corrosion remediation practices, management practices, etc. If Vectren management, engineering, maintenance, and/or operations, change their practices, the changes may affect the projected costs.
- The budget pricing does not include allowances for changes in EPA requirements, changes in CCR regulations, etc.
- The budget pricing is based on good maintenance and repair practices, which includes quickly repairing all leaks.
- The historical Vectren O&M and capital (2011 thru 2018) was used as reference information for budget pricing data.

F. RISKS ASSOCIATED WITH OPERATION BEYOND TEN ADDITIONAL YEARS

Unit No. 1 was designed and installed in 1977/1978 and Unit No. 2 was designed and installed in 1983/1984. In 2030, Unit No. 1 will be older than fifty years and Unit No. 2 will be almost fifty years old.

FMC Corporation, who designed the original FGD Systems, didn't identify a service life for the systems or the components. Generally, if no system life is identified, the expected service life would be less than fifty years. Many system components can have a ten to twenty-year service life. In excessively corrosive environments, the expected service life needs to be de-rated, consistent with the corrosion rate.

The FGD system is a very corrosive environment, and even though there has been ongoing repair work and major repair work in numerous areas of the Unit No. 1 and Unit No. 2 FGD systems, the infrastructure is still basically the original FMC Corporation infrastructure.

Operating a system beyond its design service life or anticipated service life results in reduced structural capacity and integrity, increased occurrences of equipment failure, increased Operating and Maintenance Costs, reduced system reliability, reduced system availability, and increased safety risks.

APPENDIX: COST TABLES

10 Year O&M/CapEx Estimate
9/27/2019

ABB DA Summary	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
O&M - Scheduled Outage	$700,000	$1,000,000	$700,000	$700,000	$1,100,000	$800,000	$900,000	$1,500,000	$1,200,000	$1,400,000	$2,300,000
O&M - Base Non-Labor	$2,900,000	$3,100,000	$3,200,000	$3,400,000	$3,600,000	$3,800,000	$4,100,000	$4,700,000	$5,700,000	$7,000,000	$7,300,000
Total O&M Costs	$3,600,000	$4,100,000	$3,900,000	$4,100,000	$4,700,000	$4,600,000	$5,000,000	$6,200,000	$6,900,000	$8,400,000	$9,600,000
Capital - Direct Unit	$9,400,000	$15,500,000	$18,100,000	$13,800,000	$11,900,000	$8,200,000	$6,900,000	$9,200,000	$7,400,000	$7,300,000	$8,300,000
Capital - Construction	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	$9,400,000	$15,500,000	$18,100,000	$13,800,000	$11,900,000	$8,200,000	$6,900,000	$9,200,000	$7,400,000	$7,300,000	$8,300,000
20 Yr Total	$13,000,000	$19,600,000	$22,000,000	$17,900,000	$16,600,000	$12,800,000	$11,900,000	$15,400,000	$14,300,000	$15,700,000	$17,900,000

ABB1 Dual Alkali Re-Furbish	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage	$200,000	$500,000	$500,000	$200,000	$600,000	$600,000	$300,000	$800,000	$900,000	$400,000	$1,200,000
O&M - Base Non-Labor	$1,500,000	$1,600,000	$1,700,000	$1,800,000	$1,900,000	$2,000,000	$2,200,000	$2,500,000	$3,000,000	$3,700,000	$3,800,000
Total O&M Costs	$1,700,000	$2,100,000	$2,200,000	$2,000,000	$2,500,000	$2,600,000	$2,500,000	$3,300,000	$3,900,000	$4,100,000	$5,000,000
Capital - Direct Unit	$2,700,000	$9,200,000	$15,900,000	$2,200,000	$7,200,000	$4,600,000	$2,500,000	$4,800,000	$5,000,000	$2,700,000	$4,800,000
Capital - Construction											
Total Capital Costs	$2,700,000	$9,200,000	$15,900,000	$2,200,000	$7,200,000	$4,600,000	$2,500,000	$4,800,000	$5,000,000	$2,700,000	$4,800,000
20 Yr Total	$4,400,000	$11,300,000	$18,100,000	$4,200,000	$9,700,000	$7,200,000	$5,000,000	$8,100,000	$8,900,000	$6,800,000	$9,800,000

ABB2 Dual Alkali Re-Furbish	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage	$500,000	$500,000	$200,000	$500,000	$500,000	$200,000	$600,000	$700,000	$300,000	$1,000,000	$1,100,000
O&M - Base Non-Labor	$1,400,000	$1,500,000	$1,500,000	$1,600,000	$1,700,000	$1,800,000	$1,900,000	$2,200,000	$2,700,000	$3,300,000	$3,500,000
Total O&M Costs	$1,900,000	$2,000,000	$1,700,000	$2,100,000	$2,200,000	$2,000,000	$2,500,000	$2,900,000	$3,000,000	$4,300,000	$4,600,000
Capital - Direct Unit	$6,700,000	$6,300,000	$2,200,000	$11,600,000	$4,700,000	$3,600,000	$4,400,000	$4,400,000	$2,400,000	$4,600,000	$3,500,000
Capital - Construction											
Total Capital Costs	$6,700,000	$6,300,000	$2,200,000	$11,600,000	$4,700,000	$3,600,000	$4,400,000	$4,400,000	$2,400,000	$4,600,000	$3,500,000
20 Yr Total	$8,600,000	$8,300,000	$3,900,000	$13,700,000	$6,900,000	$5,600,000	$6,900,000	$7,300,000	$5,400,000	$8,900,000	$8,100,000

ABB BPT	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											$0
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB LF Leachate	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB Selenium	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											$0
Capital - Construction		$0	$0	$0							
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB DBA	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030

O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB DFA	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

ABB By-Products Landfill	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
O&M - Labor											
O&M - Scheduled Outage											
O&M - Base Non-Labor											
Total O&M Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Capital - Direct Unit											
Capital - Construction											
Total Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20 Yr Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Assumptions

1. All costs are expressed in 2019 dollars. No Escalation is included.
2. Total Capital costs are +/- 50% and include the costs associated with the purchase of equipment, erection, and all contractor services.
3. Total Capital costs do not include contingency, owners cost, taxes, insurance, spare parts, or construction utility interconnections/consumables.
4. BPT and Selenium treatment is common equipment for both units
5. Leachate and WW Hg Treatment is included in BPT treatment Total Capital Costs
6. O&M Base Non-Labor cost for BPT and Selenium treatment assumed 2% equipment capital costs for maintenance items, consumables and spare parts. Variable O&M costs are not included.
7. Capital Direct cost for BPT and Selenium treatment assumed 4% equipment capital cost for equipment replacement during major outage
8. BPT treatment Total Capital Costs includes all common water treatment infracture.
9. Selenium treatment Total Capital costs includes only biological treatment which requires the BPT treatment system and entire infrastructure upstream for effluent compliance
10. DBA and DFA rates to be established by Vectren

BPT Reagent Data				
Reagent	**Unit Pricing**		**Usage Rate**	
Coagulant Feed	1.4	$/gal	15	gal/MWhr
Polymer	7.5	$/gal	5	gal/MWhr
Dewatering Polymer	7.5	$/gal	5	gal/MWhr
Sodium Hypochlorite	0.95	$/gal	2.1	gal/MWhr
Sodium Bisulfite	2.4	$/gal	1.1	gal/MWhr
Organosulfide	3	$/gal	15	gal/MWhr

Landfill Assumptions/Clarifications

ADDITIONAL COSTS NOT REFLECTED ABOVE:

Closure (calendar year 2040) = $6M

Post-Closure (30 years) beginning in 2041 = $0.2M per year.

*Closure costs move up if landfill is no longer used.

A wastewater treatment facility is constructed at the AB Brown Station. Those costs are not included here. Internal treatment cost assumed to be $0.05 per gallon.

No inflation escalator has been included. All etimates are based on 2019 prices.

ESTIMATES DO NOT INCLUDE:

Mitigation of wetland areas disturbed by construction.

Project management/supervision by Vectren.

Legal costs associated with zoning.

Purchase of property.

Investigations and/or remediation associated with groundwater impact.

Waste delivery to landfill costs.

Attachment 6.7 Environmental Compliance Options Study

FINAL

REVIEW OF ENVIRONMENTAL COMPLIANCE

A.B. Brown Unit 1 and 2

F.B. Culley Unit 2

B&V PROJECT NO. 400278
B&V FILE NO. 40.0003

PREPARED FOR

Vectren

20 MAY 2020

Table of Contents

LIST OF TABLES

1.0 Executive Summary

Southern Indiana Gas and Electric Company d/b/a Vectren Power Supply, Inc. (Company) has contracted with Black & Veatch Corporation (Consultant) to serve as an Owner's Engineer (OE) in the evaluation of coal combustion residuals (CCR) and effluent limit guideline (ELG) regulations for A.B. Brown (ABB) and F.B. Culley (FBC) Power Stations.

On April 17, 2015, the Environmental Protection Agency (EPA) published in the Federal Register the final CCR rule. The CCR rule contains specific requirements that are to be met to continue operation of the CCR unit(s). Failure to meet specific requirements will require operation to cease and closure or retrofit of the CCR unit to begin. For units that are required to close, the CCR rule allows for two options: (1) leave the CCR in place and install a final cover system or (2) remove the CCR and decontaminate the unit.

The EPA finalized an update to the ELG rule on September 30, 2015. The final rule strengthens the technology based ELGs by introducing more stringent discharge restrictions on toxic pollutants. Changes include new standards for flue gas desulfurization (FGD), flue gas mercury control (FGMC), gasification, and landfill leachate waste streams that were previously included under low volume wastes. Additionally, it establishes a zero-discharge standard for fly and bottom ash transport waste streams for both new and existing point sources. The final rule did not include any changes to the previously specified cooling tower blowdown, once-through cooling, or coal pile runoff effluent standards.

On September 18, 2017, the EPA postponed compliance dates in the 2015 rule for best available technology (BAT) effluent limitations and pretreatment standards for existing sources (PSES) for FGD wastewater and bottom ash transport water until new rulemaking could be completed. On May 23, 2019, the EPA released its rulemaking timeline, indicating a new proposed rule would be issued in June 2019, with the final rule issued in August 2020. On November 22, 2019, EPA published the new proposed rule which would revise requirements to FGD wastewater and bottom ash transport water.

The National Pollutant Discharge Elimination System (NPDES) permit issued to A.B. Brown Station in 2017 (effective date of April 1, 2017) by the Indiana Department of Environmental Management (IDEM) was subsequently modified in 2018 and contains new, more strict effluent limitations for copper, chloride, and selenium. Pursuant to the permit, the facility must comply with the final effluent limitations for these constituents by April 1, 2020.

1.1 A.B. BROWN STATION

A.B. Brown Station is a two unit, 530 megawatt (MW) coal fired electricity generating power facility, located on the northern bank of the Ohio River, 5 miles southwest of Evansville, Indiana. The station includes Unit 1 with a rated capacity of 265 MW and Unit 2 with a rated capacity of 265 MW. A.B. Brown Station currently utilizes an ash pond for ash handling and settling pond for wastewater treatment, as well as collection of metal cleaning, FGD wash water, other process wastewaters, treated sanitary wastewaters, and storm water.

Closure of the ash pond because of the CCR ruling represents a significant reduction in reuse water, storage, and settling capabilities for A.B. Brown. Of the wastewater streams regulated under the EPA's revised ELG rule, only fly ash transport, bottom ash transport, low volume wastewater, and leachate apply to A.B. Brown. Discharge of ash transport water is no longer permissible and, as such, a new means of transport and storage of CCR materials will be necessary. All wastewater flows into the ash pond will now need to be re-directed, collected, and properly treated prior to discharge.

1.2 F.B. CULLEY STATION

F.B. Culley Station is a two unit, 387 MW coal fired electricity generating power facility, located on the northern bank of the Ohio River, southeast of Newburgh, Indiana. The station includes Unit 2 with a rated capacity of 100 MW and Unit 3 with a rated capacity of 287 MW.

As with the A.B. Brown units, the CCR regulations require F.B. Culley to discontinue the use of the Unit 2 and Unit 3 ponds, referred to as east and west, respectively. The elimination of both CCR units represents a significant reduction in storage and settling capabilities for F.B. Culley.

F.B. Culley Unit 3 is planned for a dry bottom ash conversion in 2020 utilizing a submerged chain conveyor. This report discusses the upgrade options for F.B. Culley Unit 2 to also meet CCR and ELG regulations.

1.3 OBJECTIVE

The focus of the ELG/CCR Compliance Program is to identify alternative ash handling and water treatment options as well as any water reclamation or elimination options for each regulated discharge stream to bring A.B. Brown and F.B. Culley Stations into future compliance with the updated CCR and ELG regulations.

This report provides the following:

- A review of the updated CCR for both A.B. Brown Units 1 and 2 and F.B. Culley Unit 2.
- ELG regulations and NPDES permit limitations and their impact on A.B. Brown Units 1 and 2, including timing of the respective rules and application.
- An evaluation of bottom ash and fly ash solutions, design concepts, feasibility, and present worth of capital and operating expenses for each option for both A.B. Brown Units 1 and 2 and F.B. Culley Unit 2.
- An evaluation of treatment technology options for A.B. Brown Units 1 and 2 with respect to the updated ELG rulings including design concepts, feasibility, and present worth of capital and operating expenses.

1.4 SUMMARY OF RECOMMENDATIONS

The following recommendations are proposed for each unit.

Table 1-1 Summary of Recommended Technologies – A.B. Brown Station

OPTION	TECHNOLOGY DESCRIPTION	CAPITAL COST	O&M COST
ELG Equipment (Table 4-1)	Physical/Chemical and Biological, Collection and Filtration, Location 2	$43,072,000	$1,378,000
Bottom Ash	Modified SCC Bottom Ash Handling	$29,927,200	$1,260,500
Fly Ash	Dry Pneumatic Fly Ash Handling	$22,652,300	$3,679,300

Table 1-2 Summary of Recommended Technologies – F.B. Culley Station

OPTION	TECHNOLOGY DESCRIPTION	CAPITAL COST	O&M COST
Wet-to-Dry Ash Handling	Indoor Dewatering Tanks	$3,868,000	$300,300

2.0 Summary of Evaluations

This section summarizes the ELG/CCR Compliance Program (“Projects”) for A.B. Brown (ABB) and F.B. Culley (FBC) Stations.

2.1 COAL COMBUSTION RESIDUALS RULING

2.1.1 Background

On April 17, 2015, the Environmental Protection Agency (EPA) published in the Federal Register the final CCR rule. As expected, the rule regulates CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA). The rule was published in the Federal Register on April 17, 2015, and it was effective on October 19, 2015.

The CCR rule contains specific requirements that are to be met to continue operation of the CCR unit(s). These requirements include the following:

- Location restrictions.
- Design criteria, including liner design and structural integrity.
- Operating criteria including air criteria, hydrologic and hydraulic capacity requirements, and inspection requirements.
- Groundwater monitoring and corrective action.
- Closure and post-closure care.
- Recordkeeping, notification, and internet posting.

Failure to meet or document the above items generally results in requirements to cease operation and begin closure or retrofit of the CCR unit. For units that are required to close, the CCR rule allows for two options; either to leave the CCR in place and install a final cover system (i.e., close in place) or remove the CCR and decontaminate the unit (i.e., clean closure). Regardless of the selected closure option, in the event of groundwater contamination, closure is not deemed complete until groundwater is no longer exceeding groundwater protection standards

Clean closure requires dewater and excavation of all CCR, removal of the underlying impacted soil, and final backfill with clean soil. This option removes any groundwater contamination risks so any groundwater remediation (if required) is limited to treating the residual contamination. The option also requires only top soil, which eliminates the need for an engineered cap or any post-closure care. The drawbacks are the significant construction costs associated with the dewatering, excavation, and backfill efforts in addition to long construction durations.

Close in place requires dewatering and regrading of the existing surface, backfill efforts, and an engineered cap. This option results in minimal disturbance of the existing CCR, reduced backfill with relatively short construction schedule, and lowered costs. This option does require an engineered cap, typically a geosynthetic layer, and regularly scheduled post-closure care including groundwater monitoring for 30 years. There are more risks involved with this option because the potential for groundwater contamination remains and there is a significant cost for groundwater remediation if groundwater is incised with CCR.

2.1.2 Implementation and Enforcement

The rule is self-implementing; therefore, affected facilities must comply with the new regulations irrespective of whether a state adopts the rule. Even if a state promulgates its own rule and incorporates the federal criteria into the state's solid waste management program, the federal rule remains in place as an independent set of federal criteria that must be met (although the EPA states in the preamble that facilities in compliance with an EPA-approved state CCR solid waste management plan that is identical to or more stringent than the federal criteria should be viewed as meeting or exceeding the federal criteria). Because the rule is promulgated under Subtitle D, it does not require regulated facilities to obtain permits, does not require the states to adopt and implement the new rules, and cannot be enforced by the EPA. The rule's only compliance mechanism is for a state or citizen group to bring an RCRA citizen suit in federal district court under RCRA Section 7002 against any facility that is alleged to be in noncompliance with the new requirements.

2.1.3 Applicability

The rule applies to new and existing landfills and surface impoundments used to manage CCR generated by coal fired electric utility plants in North American Industry Classification System (NAICS) Industry Code 221112. The rule also applies to inactive surface impoundments (i.e., impoundments not receiving CCR on or after October 19, 2015, but that still contain CCR and liquid) located at power plants producing electricity regardless of fuel type.

2.2 EFFLUENT LIMITATION GUIDELINE RULE

2.2.1 Background

As authorized by the Clean Water Act (CWA), the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating discharge point sources into bodies of water in the United States. Wastewater discharges from Vectren facilities are regulated under the Indiana Department of Environmental Management (IDEM) NPDES program that incorporates the standards set forth in the 40 Code of Federal Regulations (CFR) 423, Steam Electric Power Generating Point Source category.

Guidelines set forth under 40 CFR 423 establish wastewater discharge standards for existing point sources that represent the degree of effluent reduction that can be achieved by application of the best available technology (BAT) that is economically achievable. Guidelines for discharges from new point sources are set forth in new source performance standards (NSPS). In addition, guidelines for existing and new sources that discharge into a publicly owned treatment works (POTW) are established for pretreatment standards for existing sources (PSES) and/or pretreatment standards for new sources (PSNS). These guidelines and standards are to be used by the NPDES permitting authority (IDEM in Indiana) in setting applicable discharge limits for specified effluents in new and renewed NPDES and pretreatment permits for steam electric generation facilities.

In 2015, the EPA released a final rule updating the ELGs in 40 CFR 423. The updated rule strengthened the technology based ELGs by introducing more stringent discharge restrictions on toxic pollutants. Changes included new standards for flue gas desulfurization (FGD), flue gas mercury control (FGMC), gasification, and landfill leachate waste streams that were previously included under low volume wastes. In November 2019, the EPA released a proposed rule to further update the ELGs in 40 CFR 423, which is only applicable to FGD wastewater and bottom ash transport water. The proposed rule would establish BAT effluent limitations for total suspended solids (TSS), mercury (Hg), arsenic (As), selenium (Se), and nitrate/nitrite as nitrogen in FGD wastewater discharges. For bottom ash, the proposal includes a TSS BAT effluent limitation and a not-too-exceed 10 percent volumetric purge limitation. The proposed rule proposes subcategories with separate requirements, including high flow facilities (>4 MGD of FGD wastewater), low utilization boilers (876,000 MWh per year or less), and boilers retiring by 2028.

2.2.2 Review of ELG Final Rule

The 2015 ELG rule update was applicable to Vectren facilities that established separate definitions and categories for FGD wastewater and combustion residual leachate, which were previously considered low volume waste sources.

The EPA's rulemaking sets forth technology-based effluent standards for discharges from these new wastewater streams to surface waters and POTW sewer systems. NPDES permitting authorities (IDEM in Indiana) have been incorporating the 2015 ELG standards as applicable into each existing facility's NPDES permit renewals.

The 2015 ELG rule established more stringent BAT effluent limitation guidelines and standards for the various waste streams generated by new and existing steam electric facilities (i.e., FGD wastewater, bottom ash transport water, combustion residual leachate, flue gas mercury control wastewater, fly ash transport water and gasification wastewater). The new proposed rule proposes to amend the more stringent effluent limitations guidelines and pretreatment standards for existing sources in the 2015 rule that apply to FGD wastewater and bottom ash transport water. Where BAT limitations are more stringent than previously established, the new rule proposes that those limitations would not apply until a date determined by the permitting authority (IDEM in Indiana) that is as soon as possible on or after November 1, 2020, but that is no later than December 31, 2023, (for bottom ash transport water) or December 31, 2025 (for FGD wastewater).

The proposal also includes a voluntary incentives program that provides the certainty of more time (until December 31, 2028) for plants to adopt additional process changes and controls that achieve more stringent limitations on mercury, arsenic, selenium, nitrate/nitrite, bromide, and total dissolved solids in FGD wastewater. The optional program provides plants more flexibility, such as additional time, that previous incentives programs.

The technology basis for discharges from existing point sources applicable to the subject Vectren facilities set forth in the proposed 2019 ELG rule are shown in Table 2-1.

Table 2-1 Technology Basis for BAT/PSES and NSPS/PSNS Effluent Limitation Guidelines

WASTE STREAMS	EXISTING BAT AND PSES	NEW NSPS AND PSNS
Fly Ash Transport Water	Dry Handling	Dry Handling
Bottom Ash Transport Water	Dry Handling/Closed Loop Bottom ash transport water on not-too-exceed 10 percent volumetric purge	Dry Handling/Closed Loop Bottom ash transport water on not-too-exceed 10 percent volumetric purge
Wet FGD Wastewater	Chemical Precipitation + Biological Treatment Low residence Biological treatment Membranes	Evaporation
Combustion Residual Leachate	Gravity Settling Impoundment	Chemical Precipitate

2.3 A.B. BROWN--IMPACT OF CCR REGULATIONS

A.B. Brown Station currently utilizes one ash pond. The pond is designed as a surface impoundment. The pond receives bottom ash and fly ash water and the FGD wash water flows, as well as process wastewater, treated sanitary wastewaters and stormwater.

Future closure of the ash pond represents a significant reduction in reuse water, storage, and settling capabilities for A.B. Brown. In conjunction with the ELG ruling, discharge of ash transport water will no longer be permissible and, as such, a new means of transport and storage of CCR materials will be necessary.

2.4 A.B. BROWN--TECHNOLOGY OPTIONS FOR CCR COMPLIANCE

Black & Veatch worked with Vectren to evaluate different cost-effective concepts of bottom ash handling at A.B. Brown Units 1 and 2.

Following the evaluation, Black & Veatch recommended incorporation of a submerged chain conveyor (SCC) underneath the boiler to replace the current sluicing system at A.B. Brown. An SCC uses a submerged drag chain to collect ash and discharge the dewatered ash into a bunker for final dewatering and storage. Subsequently, the ash would be managed for beneficial reuse or disposal. Conversion to SCC may require cooling water depending on final design parameters. The basis for the SCC for the A.B. Brown units is based on the current design, which is in progress for F.B. Culley Unit 3. This design is a United Conveyor Corporation (UCC) submerged flight conveyor (SFC) system. The installed cost to retrofit both A.B. Brown Unit 1 and Unit 2 boilers with SCC equipment has been incorporated into the treatment options in Section 4.0, Table 4-3.

A technology comparison matrix for the bottom ash alternatives described for A.B. Brown Units 1 and 2 is provided in Table 2-2.

Table 2-2 A.B. Brown Units 1 and 2 Bottom Ash Technology Comparison Matrix

ALTERNATIVE	SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 1)	DEWATERING BUNKER (ALTERNATIVE 2)	REMOTE SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 3)
Description	Alternative 1 consists of a new submerged chain conveyor under the existing bottom ash hopper and existing grinders. The submerged chain conveyor will be routed out of the Boiler Building, discharging on an exterior pile or waiting truck.	Alternative 2 is a concrete dewatering bunker. The bottom ash is sluiced through piping to a remote bunker location. A concrete bunker is used to separate the larger particles while a settling tank is used to separate the smaller fines.	Alternative 3 provides a remote closed loop system outside of the existing Boiler Building. The existing bottom ash hopper and sluicing pump would deliver the ash to the new remote dewatering containment equipped with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.
Technical Feasibility	A submerged chain conveyor is often used for removing and dewatering bottom ash from boilers and is a sound technical approach.	The dewatering bunker system is complex with many pumps, piping, and concrete bunkers.	Remote recirculation systems are often used for bottom ash conversions. The technical feasibility is sound but may not be financially viable for small units.
Total Contracted Cost	$29,927,200	$36,448,900	$41,656,700
Operations and Maintenance Cost	$1,260,500	$1,539,400	$1,463,500
Estimated Additional Manpower	1.8	3.6	2.4
Estimated Footprint (sq. ft.)	400	20,000	6,000
Major Equipment	• Submerged chain conveyor. • Hydraulic power unit. • Instrumentation and controls. • Quench water overflow tank, pump, and heat exchanger. • Chain wash spray system. • Three-sided concrete bunker. • Motor control center (MCC) to feed new motors and pumps.	• Transfer tank with jet pump. • Water supply tank and sluice transfer pumps. • Dewatering bunker. • Bunker sump pumps. • Settling tank and sludge pumps. • Surge tank and sluice recirculation pumps. • New overhead door on operating floor. • Instrumentation and controls. • MCC to feed new motors and pumps.	• New remote hopper with new submerged chain conveyor. • Hydraulic power unit. • Instrumentation and controls. • Return water pumps and piping. • Chain wash spray system. • Distribution sluice piping. • MCC to feed new motors and pumps.
Advantages	• Allows for the continued use of existing bottom ash hopper and grinders. • Ash quench water is treated as low volume wastewater.	• Allows for continued use of existing ash hopper. • Minimal outage time for modification of the existing boiler.	• Minimal outage time for modification of the existing boiler.
Disadvantages	• Requires truck operators throughout the day, but could be reduced if three-sided concrete structure were included. • Requires modification of the existing Boiler Building foundation.	• This alternative has a large amount of footprint needed for the separation tanks and dewatering bunker. Therefore, the only available location is the long distance north of the unit. • Due to this length, excessive piping and larger pumps are involved. • Requires front-end loaders with support crews for bottom ash removal from dewatering bunker. • Ash sluicing water needs to be maintained in a closed loop or treated prior to discharge.	• Requires new foundations for remote equipment. • Requires weather protection for the collection trough. • Requires a three-sided concrete containment structure with weather protection. • Requires freeze protection. • Requires lengthy sluice piping and potential for booster pumps. • Ash sluicing water needs to be maintained in a closed loop or treated prior to discharge.
Reliability	The reliability of the submerged chain conveyor is proven	The dewatering tanks, bunker, and sluice piping are a proven approach to ash dewatering.	Remote recirculation systems are often used for bottom ash conversions. The technical feasibility is sound but may not be financially viable for small units.
Recommended for Further Review	Yes	No	No

2.4.1 Existing System and Conceptual Design Basis

The bottom ash system will be designed to receive bottom ash from the existing Units 1 and 2, each rated at 265 MW per pulverized coal fired unit.

The existing ash collection hopper consists of two pyramidal hoppers with two clinker grinders. Jet pumps located at the discharge of the clinker grinders are used to sluice the bottom ash from the bottom ash hopper to the ash storage pond using a single sluice pipe. The existing hopper cooling water overflows from the bottom ash hopper by gravity to an existing plant drain for the alternatives proposed below.

The conceptual design for this study is based on a maximum ash production rate of 3 tons per hour.

2.4.2 Bottom Ash Conceptual Design Alternatives

The following conceptual design alternatives were developed for A.B. Brown Units 1 and 2.

2.4.2.1 Submerged Chain Conveyor (Alternative 1)

Alternative 1 consists of a new submerged chain conveyor under the existing bottom ash trough and existing grinders. The submerged chain conveyor will be routed out of the Boiler Building, discharging to a CCR rule-compliant storage area or transport truck.

Refer to Drawing 190507-PFD-4004 for the material flow. Table 4-4 outlines the estimated cost. The major equipment for this alternative includes the following:

- Submerged chain conveyor.
- Hydraulic power unit.
- Programmable logic controller (PLC) control system and instrumentation.
- Motor control center (MCC) to feed new motors.
- Chain wash spray system.

The submerged chain conveyor consists of a water filled lower trough with submerged drag chain flights attached to two chains to move the ash. The inclined conveyor section dewaters the ash and discharges the ash directly into a dump truck. The dump truck can then haul the dewatered ash for beneficial reuse or disposal.

This operation may require two trucks, with one truck located under the discharge point of the conveyor and another truck to haul ash to a storage location. Dump truck operators would be required 7 days per week with full shift coverage on a 24-hour basis to maintain shifts for around-the-clock manpower coverage. A three-sided concrete bunker could be installed outside the plant building to reduce the number of trucks and operators required. In this case, a front-end loader could be used to remove ash from the bunker and load the dump trucks on a single shift per day.

The existing seal troughs have been modified to a dry seal configuration that will eliminate the need for cooling water usage.

Key comparisons for Alternative 1 include the following:

- Disadvantages of the submerged chain conveyor:
  - Requires truck operators throughout the day.
  - Requires a weather structure over the exterior storage pile/truck loading platform.
  - May require front-end loaders.
- Advantages of the submerged chain conveyor:
  - Comparatively minimal new equipment.
  - Continuous removal of ash.

2.4.2.2 Dewatering Bunker (Alternative 2)

Alternative 2 is a dewatering bunker for the dewatering technology. The reason for the selection is the expected lower capital cost with this alternative, as compared to other dewatering alternatives such as a dewatering bin system, dewatering basin system, and remote closed loop systems.

Refer to Drawing 190507-PFD-4005 for the material flow. Table 4-4 outlines the estimated cost. The major equipment for this alternative includes the following:

- Transfer tank with jet pump.
- Water supply tank.
- Sluice transfer pumps.
- Dewatering bunker and sump.
- Bunker sump pumps.
- Settling tank.
- Surge tank.
- Sludge pumps.
- Sluice recirculation pumps.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.

The difference between a dewatering bunker and a dewatering basin is that a dewatering bunker is used to collect only heavy ash particles (above 1/16 inch) whereas a dewatering basin system with both an ash dewatering basin and a polishing basin is used to capture both the heavy or large ash particles in the ash dewatering basin and the fine particles in the polishing basin. The dewatering bunker is sized for only 1 day of ash storage, so the size of the bunker is small and the capital cost is low. A front-end loader is required to remove ash from the bunker 7 days per week for each day that the unit is at full load and ash is pulled to the bunker. The sump adjacent to the bunker collects the sluice water.

The dewatering bunker system pulls the bottom ash from the bottom ash hoppers and it sluices to the new bottom ash transfer tank using the existing ash sluice pump.

The water from the transfer tank gravity flows to the new water supply tank to supply water to one of two redundant sluice transfer pumps; bottom ash is conveyed from the bottom ash transfer tank to the dewatering bunker. The jet pump at the discharge of the transfer tank removes the ash from the tank. The sluice water flows by gravity from the dewatering bunker to the dewatering bunker sump over the concrete weir located between the bunker and the sump. The bottom ash in the dewatering bunker is segregated from the sump by the concrete weir and a perforated metal screen to keep lumps of ash (over approximately 1/4 to 1/16 inch in size) from entering the sump.

The bunker sump pump is used to pump the sluice water to the settling tank where the fine ash solids are settled in the tank. The sludge is pumped from the settling tank to the storage pile in the bottom ash bunker. The water in the settling tank gravity flows to the surge tank to supply water to the sluice recirculation pumps, recycling the water back to the plant and the existing ash sluice pump.

The bottom ash bunker is sized for 1 day of storage (72 tons). The water level in the dewatering bunker is kept at a constant level and does not require draining to remove the ash from the bunker. A front-end loader removes the ash from the bunker (while there is water in the bunker) and fills dump trucks hauling ash to the intermediate storage location at the plant site. The front-end loader needs to have a wheel axle height higher than the water level in the bunker.

Key comparisons for Alternative 2 include the following:

- Disadvantages of the dewatering bunker:
  - Since this alternative requires pumps, tanks, and concrete structures, a large site area is needed.
  - Numerous pieces of new equipment are required.
  - A lengthy amount of sluice piping is required to deliver the ash to the remote location for the new bunker.
  - Front-end loaders with support crews are required.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the dewatering bunker:
  - Allows for the continued use of existing bottom ash hopper, grinders, and sluice pumps.

2.4.2.3 Remote Submerged Chain Conveyor (Alternative 3)

Alternative 3 provides a remote closed loop system outside of the existing Boiler Building. The existing bottom ash trough and sluicing pump would deliver the ash to the new remote dewatering containment with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.

Refer to Drawing 190507-PFD-4006 for the material flow. Table 4-4 outlines the estimated cost. The major equipment for this alternative includes the following:

- Existing bottom ash trough and existing grinders.
- Existing sluice pumps but may need a booster pump if located a long distance from the Boiler Building.
- New remote hopper with new submerged chain conveyor for dewatering.
- Hydraulic power unit.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.
- Chain wash spray.
- Return water pumps and piping.

Key comparisons for Alternative 3 include the following:

- Disadvantages of the remote closed loop system:
  - A new foundational support for the remote equipment is required.
  - Weather protection for remote collection trough is required.
  - A weather protection structure may be required to control the ash in the three-sided concrete containment structure.
  - Freeze protection is required for winter operation.
  - More expensive new equipment is required, especially if the remote system is located so far away that a booster pump is required to deliver the wet ash.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the remote closed loop system:
  - No outage time is required for modification of the existing boiler.

2.4.3 Fly Ash

A.B. Brown utilizes dry ash handling a majority of the time for beneficial reuse, but resorts to wet fly ash handling when beneficial reuse transport is unavailable. For the dry fly ash system, the low-pressure ash pond water is used to draw a vacuum on various ash hoppers through the hydroveyor and move the fly ash to a filter/separator that is then pressurized and blows the ash to a storage silo near the river for barge loading. For sluicing the wet fly ash, the vacuum portion does not change but the ash is dropped into a combine tube prior to reaching the filter/separators that mixes it with water and moves it to the ash pond for storage when the dry fly ash storage silo is full.

When the ash pond is closed, the source of water for the vacuum will be lost, and the ability to wet the fly ash and move it to the ash pond will be lost. To solve the loss of the vacuum source, a new mechanical exhauster system will be required. Essentially these are vacuum pumps that will use the existing infrastructure to replace the hydroveyor. The ash will still be pulled from the ash collection hoppers to the filter/separator system for pressurized transport to the existing dry fly ash storage silo and new day bin silo. F.B. Culley Station purchased (from UCC), installed, and has been operating mechanical exhausters for several years. The technology and product have proven to be reliable. A.B. Brown has identified the same vendor and equipment to perform a similar function.

Currently the dry fly ash storage silo is located near the river and accepts the pneumatically conveyed ash from the A.B. Brown units as well as trucked ash from F.B. Culley and Warrick. This silo has equipment for pneumatically unloading tank trucks into the silo and a tube conveyor for moving ash to the river for barge loading from the silo. However, it does not have equipment for loading over-the-road trucks for transport of dry fly ash.

New mechanical exhausters and a day bin silo have been identified for installation at the plant site instead of at the river silo area to take advantage of the auxiliaries available for cost reduction. The day bin silo would be a smaller silo with a paddle mixer (pug mill) to wet the ash to control fugitive dust and would be capable of loading into over-the-road trucks. The fly ash handling equipment cost estimate is included in Table 4-4.

2.5 A. B. BROWN--IMPACT OF ELG REGULATIONS

The critical aspect of this review is the impact these regulations will have on the wastewater point source discharges at A.B. Brown. Black & Veatch's scope of work for this review was to identify the target areas for specific pollutants that are included in the final ruling and determine which wastewater discharge streams, if any, are affected by the updated ELG regulations.

Of the new wastewater streams regulated under the EPA's revised rule, only fly ash transport, bottom ash transport, low volume wastewater, and leachate apply to A.B. Brown. The EPA and IDEM have determined that the dual alkali scrubber discharge wastewater at A.B. Brown, as it is defined in the 2015 ELG rulemaking, is not subject to the FGD standards in the ELG rule. The EPA established numerical effluent limits that would correspond to the level of treatment that could be achieved based on application of these treatment technologies. While the scrubber wastewater is not subject to ELG standards, the current NPDES permit contains final effluent limitations for copper, selenium, and chloride.

Wastewater at A.B. Brown is considered direct discharge from an existing source. The current ELGs for the steam electric power generating existing sources and their applicability to A.B. Brown are shown in Appendix A.

2.5.1 Operation Evaluation

A.B. Brown currently utilizes sluicing systems to transport fly ash and bottom ash to the ash pond for settling. The EPA's final rule on wastewater effluent regulation standards requires zero discharge for fly and bottom ash transport water (refer to Table 2-1). For fly and bottom ash transport, the final ELG rule specifies dry handling or closed-loop systems as the technology basis.

The removal of ash sluice water and closure of the ash pond would comply with the CCR rule requirements. All waste streams currently discharged to the ash pond were sampled to determine water quality. The sampled waste stream data indicate that A.B. Brown is expected to achieve the new direct discharge limits from an existing source imposed by the final rule if the settling capability of the ash pond were to be sufficiently substituted.

2.6 A.B. BROWN--TECHNOLOGY OPTIONS FOR ELG/NPDES COMPLIANCE

Based on review of the final ELG, NPDES permit, and capabilities of the existing plant wastewater systems to achieve these standards, Black & Veatch has identified potential modifications to the existing wastewater system as well as additional treatment that could be implemented to comply with wastewater effluent limitations. A summary and breakdown of the conceptual cost estimate can be found in Section 4.0.

2.6.1 Ash Pond Elimination

Elimination of the ash pond represents a significant reduction in reuse water, storage, and settling capabilities for A.B. Brown. Ash sluice water and FGD makeup are the major consumers of reuse water and sources of wastewater. The pending ash pond closure and conversion to a closed loop SCC for bottom ash handling represents a large reduction in wastewater generation and storage requirements, which would minimize the size of any downstream treatment equipment. However, the new treatment equipment would still need to be capable of handling approximately 2.5 million gallons per day (mgd) of treated low volume wash water streams from FGD wash water and coal pile runoff.

It is important to note that the FGD wash water is not an FGD wastewater as defined in the ELG rule. The 2015 ELG rule added the following clarifying sentence to the definition of FGD wastewater:

"Wastewater generated from cleaning the FGD scrubber, cleaning FGD solids separation equipment, cleaning FGD solids dewatering equipment, or that is collected in floor drains in the FGD process area is not considered FGD wastewater."

Therefore, the dual alkali scrubber does not discharge FGD wastewater as it is defined in the ELG rule, and the scrubber is not subject to the FGD ELG standards.

While this report focuses on ELG compliance, elimination of the ash pond will impact NPDES permit compliance. Therefore, final effluent limitations for parameters such as copper, chloride and selenium, are being considered in evaluation of treatment options. Treatment options evaluated for compliance with the ELG rule (and NPDES permit) include physical/chemical treatment, settling and dewatering processes, and CCR compliant basins or tanks for reduction of suspended solids.

2.6.2 Design Concept

The basic design concept includes treating scrubber wastewater and collecting and re-directing all existing flows that discharge to the ash pond. Collected wastewater would be transferred to the necessary users for reuse demands with the accumulated wastewater. Water not reused would be filtered and transferred to the existing wastewater mercury treatment system and subsequent lined pond. The basic design concept would still utilize a significant portion of the existing equipment while providing a physical/chemical/biological system for heavy metals and suspended solids reduction, a basin for collection and flow equalization, a filter system for final suspended solids reduction in the combined basin wastewater, and a sludge dewatering system for solids handling and removal.

Using A.B. Brown's water qualities and a water mass balance provided by Vectren, Black & Veatch developed a proposed water mass balance outlining influent and effluent flows around pieces of equipment impacted by the pending closure. Black & Veatch's proposed water mass balance is contained in Appendix D.

2.6.3 FGD Treatment

2.6.3.1 Physical/Chemical Treatment

Physical/chemical treatment is a process used for heavy metals and total suspended solids (TSS) reduction. On the basis of the effluent limitations identified in the current NPDES permit, the heavy metals of concern are mercury, copper, and selenium. To achieve the desired level of metals removal and TSS reduction, the FGD blowdown would be pumped to a new continuously mixed sulfide reaction tank, followed by a coagulation reaction tank, to allow for chemical addition of organosulfide and coagulant. An organosulfide would be fed to achieve high removal of heavy metals by converting the soluble metals to an insoluble precipitate.

The reaction tanks are sized to allow sufficient reaction time for the chemical precipitation reactions to occur. The reaction tanks feed a clarifier where polymer is added to increase the particle size of the insoluble particles and allow settling for solids removal with traditional clarification techniques. Settled solids from clarification would be directed to dewatering equipment. While the physical/chemical treatment will reduce mercury and copper in the FGD wastewater, additional treatment will be required to reduce selenium.

2.6.3.2 Biological Treatment

Selenium typically exists in one of two forms, selenite (Se^{+4}) or selenate (Se^{+6}), which are both soluble in water. Selenite can typically be removed from wastewater through chemical precipitation, where selenate is more soluble, requiring reduction to a less soluble form for removal. Selenium in FGD wastewater typically exists in both forms and the concentration of each form depends on plant operation and the type of coal being combusted. Therefore, a biological treatment process is required downstream of the physical/chemical treatment system to reduce selenium.

Anaerobic biological treatment is an industry-proven technology for selenium and is the basis for the ELG limits. Biological treatment involves the growth of naturally occurring microorganisms that act as selenium reducing agents. A food source (nutrient) is oxidized by the microorganisms, which in turn reduces both selenate and selenite and precipitates solid elemental selenium. Biological treatment typically consists of a series of fixed-film biofilters in a controlled, anaerobic environment for the proper reactions and reduction of selenium to occur.

Periodically, biomass and elemental selenium are backwashed from the system. During backwash, treated effluent is used as a counterflow wash to remove entrained solids and gases from the biofilter substrate. Backwash wastewater is allowed to degas and is recycled to the inlet of the secondary pretreatment system where the solids are settled in the clarifier and dewatered with the pretreatment sludge. The treated water is discharged downstream to the collection basin for storage and use within the facility.

2.6.3.3 Sludge Handling

Accumulated sludge from the clarifier is collected in a sludge holding tank. The sludge holding tank is sized to hold 12 hours of sludge accumulation. Two 100 percent capacity filter press feed pumps supply sludge from the holding tank to two 100 percent capacity recessed plate and frame filter presses that dewater the sludge. Sludge conditioning polymer, supplied from a chemical tote, is fed upstream of the filter presses to improve dewatering. Dewatered solids can be deposited in the landfill at A.B. Brown. Removal of solids provides further metals reduction.

2.6.4 Collection Basin

A concrete, below grade collection basin will serve the purpose of equalizing wastewater flow rates from the coal pile runoff pond and treated effluent from the new FGD treatment system. The collection basin will provide a reservoir from which to draw reuse water to supply existing high-pressure water recirculation users and makeup water for dry bottom ash system. The collection basin is sized to accommodate 20 minutes of retention time for all flows indicated on the water mass balance. A mixer is included with the collection basin to prevent the settling and accumulation of solids within the collection basin.

Two 100 percent capacity, vertical sump pumps will draw suction from the collection basin to supply existing users of high-pressure ash pond recirculation pumps. New piping from the collection basin will tie into existing high-pressure water piping. Additional piping will be included to direct recirculation water as cooling makeup water for dry bottom ash system from the high-pressure recirculation supply pumps.

While TSS reduction occurs in the upstream FGD treatment system, the combined wastewater in the collection basin will have increased TSS levels because of the contribution from the untreated coal pile runoff pond discharge. To meet the NPDES permit limits for TSS, a new filter system will be installed on the discharge from the collection basin. Two 100 percent capacity discharge pumps controlled based on level in the collection basin will forward wastewater from the collection basin to the filter system for suspended solids removal. Periodically, the filter system is backwashed to remove accumulated solids. The backwash waste stream will be discharged to the sludge handling system further thickening and dewatering prior to disposal. Filtered water is sent to the existing Ash Pond Mercury Treatment System, existing lined settling pond, and finally to Outfall 001.

2.6.5 Operations and Maintenance Costs of A.B. Brown NPDES Compliance

Black & Veatch has developed estimated costs for the operations and maintenance (O&M) of the proposed treatment. Costs include consumption of chemical feeds, cost to dispose of solids, power consumption, and staffing costs. The O&M costs are presented in Section 4.0.

2.7 F.B. CULLEY--IMPACT OF CCR REGULATIONS

The F.B. Culley facility has two CCR units: the east and west. The west pond is now an inactive surface impoundment undergoing closure. The east pond is an active pond. The elimination of CCR units represents a significant reduction in storage and settling capabilities for F.B. Culley.

2.8 F.B. CULLEY--TECHNOLOGY OPTIONS FOR CCR COMPLIANCE

Black & Veatch worked with Vectren to evaluate different cost-effective concepts of bottom ash handling at F.B. Culley Unit 2. These alternatives focus on meeting the ELG regulations by converting the bottom ash system either to a dry system or a closed loop wet system. Each alternative proposed will allow the bottom ash to be dewatered sufficiently and truck transported off-site.

Following the evaluation, Black & Veatch recommended incorporation of a dewatering tank system for F.B. Culley Unit 2. A project is currently in progress to install the SCC at F.B. Culley Unit 3 with installation scheduled for 2020. The installed cost to retrofit the F.B. Culley Unit 2 boiler with dewatering tank equipment has been incorporated into the treatment options in Section 4.0, Table 4-4.

A technology comparison matrix for the bottom ash alternatives described for F.B. Culley Unit 2 is provided in Table 2-3.

Table 2-3 F.B. Culley Unit 2 Bottom Ash Technology Comparison Matrix

ALTERNATIVE	BUCKET ELEVATOR (ALTERNATIVE 1)	INDOOR DEWATERING TANKS (ALTERNATIVE 2)	DRY PNEUMATIC SYSTEM (ALTERNATIVE 3)	REMOTE SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 4)
Description	Alternative 1 utilizes a new vertical bucket elevator connected under the existing ash trough at the existing grinder discharge. The bucket elevator concept will dewater the material as the ash is raised above the water level.	Alternative 2 delivers the bottom ash from the existing ash trough through the existing pumps to a dewatering tank located on the operating floor near the northeast corner of the Boiler Building. The new dewatering tank will require properly sized filters or screens to separate the water from the bottom ash. The separated water would be recycled back to the existing bottom ash trough. The dewatering tank will discharge bottom ash into a container for a forklift to haul outside of the building. Once outside the Boiler Building, the material can be loaded into trucks for transport off-site.	Alternative 3 is a completely dry system but will require an entirely new dry bottom ash trough and a new exterior dry hopper storage bin. The replacement of the existing bottom ash trough will be a major construction effort requiring a long outage for the unit. There are various options to collect the ash at the bottom of the new trough such as a vacuum conveyor, a vibratory oscillatory conveyor, or a mesh screen drag conveyor.	Alternative 4 provides a remote closed loop system outside of the existing Boiler Building. The existing bottom ash trough and sluicing pump would deliver the ash to the new remote dewatering containment with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.
Technical Feasibility	This concept utilizes a bucket elevator for dewatering, which is rarely used in the power industry. The design would need thorough investigation to ensure the elevator will handle the fines in the allotted space. As well as assurance that the wet ash would discharge from the bucket effectively. Based on the highly conceptual nature of the design and lack of industry specific equipment available, this option was determined technically not feasible.	This concept of using dewatering tanks has been used in the past. Further design refinement will be required to determine if one or two tanks are necessary to accomplish complete dewatering.	Dry bottom ash troughs are being used in the industry but usually they are intended for larger boilers with more height. Special design will be required to fit the troughs in the shallow height of Unit 2.	Remote recirculation systems are often used for bottom ash conversions. The technical feasibility is sound but may not be financially viable for small units.
Total Contracted Cost	NA	$3,868,000	$7,636,600	$17,059,600
Operations and Maintenance Cost	NA	$300,300	$311,100	$471,000
Estimated Manpower	0.4	0.4	0.4	0.8
Est. Footprint (sq. ft.)	400	1,000	2,000	6,000
Major Equipment	• Vertical bucket elevator. • Hydraulic power unit. • Instrumentation and controls. • Forklift container. • Quench water overflow tank, pumps, separator, and heat exchanger. • MCC to feed new motors and pumps.	• Distribution piping. • Dewatering tank. • Quench water overflow tank, low- and high-pressure pumps, and heat exchanger. • Instrumentation and controls. • Forklift container. • MCC to feed new motors and pumps.	• New dry trough and conveyor. • New grinders. • Pneumatic power unit. • Exterior dry storage tank. • Wet conditioning equipment. • Instrumentation and controls • MCC to feed new motors and pumps.	• Remote submerged chain conveyor. • Hydraulic power unit. • Quench water overflow tank and pump. • Instrumentation and controls. • Recycle water pumps and piping. • Chain wash spray system. • Distribution sluice piping. • MCC to feed new motors and pumps.
Advantages	• Minimal new equipment. • Utilizes the existing bottom ash trough. • Outage time minimized if foundation modifications can be completed prior to outage.	• Lowest comparative capital costs. • Allows for continued use of existing ash trough, grinders, and jet pumps. • Minimal outage time required.	• Quench water removed from system, but still may require water for a wet conditioner system for loading open top trucks.	• Minimal outage time required for modification of the existing boiler. • Cost prohibitive for a small unit; but may show financial benefit if utilized for multiple units.
Disadvantages	• Requires a larger pit to be excavated in the existing ground floor of the Boiler Building. • The use of a bucket elevator as a dewatering device is rare and will require additional design refinements and coordination with the equipment supplier. • The ash discharged from the bucket elevator may not be completely dewatered due to the equipment and space constraints. Additional dewatering may be required after the bottom ash prior to truck loading.	• Water from the dewatering tank and forklift container must be recycled in a closed recirculating loop back to the existing bottom ash trough. • The water tank may require special internal screens to dewater sufficiently. Laboratory tests may need to be conducted to ensure this design. • If the dewatering tank is located outside the equipment and piping will require heat trace and insulation for winter operation.	• Requires a lengthy outage period to replace the existing bottom ash trough. • Major modification to boiler requiring expensive new equipment.	• Requires new foundations for remote equipment. • Requires weather protection for the collection trough. • Requires a three-sided concrete containment structure with weather protection. • Requires freeze protection. • Requires lengthy sluice piping. • Ash sluicing water maintained in a closed loop or treated prior to discharge.
Reliability	The reliability of the bucket elevator is dependent on the ability to properly dewater. Since this is not	The dewatering tanks are a proven approach to bottom ash dewatering.	Dry pneumatic ash handling is a proven approach for large units.	Remote recirculation systems are often used for bottom ash conversions.

ALTERNATIVE	BUCKET ELEVATOR (ALTERNATIVE 1)	INDOOR DEWATERING TANKS (ALTERNATIVE 2)	DRY PNEUMATIC SYSTEM (ALTERNATIVE 3)	REMOTE SUBMERGED CHAIN CONVEYOR (ALTERNATIVE 4)
	a common use of bucket elevators, the reliability is difficult to predict.			
Recommended for Further Review	No	Yes	No	No

2.8.1 Existing System and Conceptual Design Basis

The bottom ash system will be designed to receive bottom ash from the existing Unit 2, 100 MW pulverized coal fired unit.

The existing ash collection hopper consists of one longitudinal hopper with one clinker grinder mounted at the west end. The hopper is located in the basement area of the Boiler Building while the operating floor is 37 feet above the basement. The east side of the operating floor exits at the grade level, while the west side is over the one story Administration Building. The longitudinal bottom ash hopper has three segments with flat bottoms that are stair-stepped in elevation toward the grinder. Jet pumps located at the discharge of the clinker grinder and jet pump piping located at each step-in elevation are used to sluice the bottom ash from the bottom ash hopper to the bottom ash storage pond. The existing hopper cooling water overflows from the bottom ash hopper by gravity to an existing plant drain.

The conceptual design for this study is based on a maximum ash production rate of 1 ton per hour.

2.8.2 Bottom Ash Conceptual Design Alternatives

The following conceptual design alternatives were developed for F.B. Culley Units 2.

2.8.2.1 Bucket Elevator (Alternative 1)

The proposed bucket elevator bottom ash system utilizes a new vertical bucket elevator connected under the existing ash trough at the existing grinder to transport bottom ash away from the existing bottom ash hopper. The bucket elevator will dewater the bottom ash as it lifts it up above the ash flush water level to a waiting container on the basement floor. The existing water level in the ash hopper is approximately 8 feet above the basement floor, while the water level during ash flushing is approximately 2 feet above the basement floor.

The bucket elevator will need at least a 4 foot height above the water level to support adequate dewatering. The elevator requires another 2 feet above this point for the head pulley and drive. Therefore, the total minimum length for the bucket elevator above the basement floor must be 14 feet. There appears to be a number of existing pipes approximately 8 feet above the basement floor in this area that must be rerouted. It is assumed this arrangement is workable and will be refined during final design.

In addition, a sloped transition chute to slide the ash out of the grinder and into the elevator must be provided to properly load the bucket elevator. Therefore, it is estimated that the bottom of the bucket elevator will be a minimum of 5 feet below the basement floor. The existing grinder pit is only 3 feet deep.

After the ash is dewatered, the bucket elevator will discharge into a forklift-sized container. The container could be a large manual wheelbarrow, a customized container for a motorized wheelbarrow, or a container designed for a forklift. This type of container can be moved across the basement floor to the existing exterior door in the southwest corner of the Boiler Building; the bottom ash can then be transported with a dump truck to a new landfill.

Because the new bucket elevator system no longer utilizes the ash quench water in the sluicing operation, it will be required to capture and recycle the quench water in a closed loop back to the bottom ash hopper. The ash quench water recycle system would consist of a quench water overflow tank that is gravity-fed from a new bottom ash hopper overflow connection. This tank would be sized so that it can hold all the ash quench discharged over the duration of the bottom ash removal operation. After the bottom ash flush operation is complete, the flush water would then be pumped back to the hopper via a new quench water recycle pump. However, before the water can enter the hopper it may be necessary to both remove some of the bottom ash fines in a separator and cool the water in a heat exchanger. The need for the quench water system separator and heat exchanger will require additional investigation and potential testing during the next phase.

Drawing 190507-PFD-4000 shows a simplified material flow block diagram for the bucket elevator bottom ash system concept. The major equipment for this alternative includes a vertical bucket elevator, hydraulic power unit, bottom ash container, ash flush water recirculation system, instrument and controls, new MCC, and mobile equipment to move the ash (e.g., forklift, dump truck).

The most critical issue with this alternative is the ability to properly load the bucket elevator in a manner that will not overload the buckets. To prevent possible plugging of the individual buckets, the elevator must operate continuously while the ash trough is evacuated; otherwise, fine material will build up around the tail pulley and overfill the lower section of the elevator with compacted fines.

Other concerns may be the fines that tend to float because the water level in the bucket elevator will be level with the water in the bottom ash trough. The water level is 12 to 14 feet above the bottom of the vertical elevator. If the buckets are traveling at an inappropriate speed, the floating material may spill over the edge of the buckets.

In conclusion, the bucket elevator design is sensitive to the proper sizing of the buckets and the number of dewatering openings, combined with the speed at which the buckets travel. All of these factors must match the actual physical properties of the bottom ash to ensure dewatering over the travel height of the elevator. Based on the highly conceptual nature of the design and lack of industry specific equipment available, this option was determined technically not feasible.

Key comparisons for Alternative 1 include the following:

- Disadvantages of vertical elevator:

    - It requires an excavated large pit of approximately 8 feet by 8 feet by 5 feet in the existing foundation to allow for proper loading of the bottom ash into the bucket elevator. This will require extensive foundation modification.
    - There will be a design balance between elevator speed and material density, possibly requiring laboratory scale testing to finalize the design. Also, an additional pump will be required to remove the flush water in the excavated pit. The new pump may also draw some bottom ash fines. Therefore, a filter/separator may be inserted to assist in removing these fines before the water is recycled.
    - The use of a bucket elevator to dewater bottom ash is rare; it will require buckets with screen material to accomplish dewatering. The lower portion of the elevator will be submerged in water. The number and size of dewatering holes in the buckets must match the properties of the actual ash produced at the plant. If, during the final design phase, it is found that the bucket elevator cannot effectively load the ash, other options within this alternative could be a screw conveyor or drag chain.
    - The bucket elevator may have difficulty starting because of the settlement of ash fines around the tail end pulley. If too much ash collects, it may tend to plug/overload the buckets. To help prevent buildup of fines, the bucket elevator may require startup before the bottom ash is flushed from the boiler.
    - The ash discharged on the operating floor may not be completely dewatered. A watertight collection hopper/container may also require screens to ensure that, by the time the material is dumped into a dump truck, it is sufficiently dry.
- Advantages of vertical elevator:
    - Minimal new equipment is required.
    - The option allows for the continued use of existing bottom ash hoppers.
    - The installation of equipment requires minimal outage time as long as the foundation modification can be complete without an outage.

2.8.2.2 Indoor Dewatering Tanks (Alternative 2)

Alternative 2 delivers the bottom ash from the existing ash trough through the existing pumps to a dewatering tank located on the operating floor near the northeast corner of the Boiler Building. This new dewatering tank will require properly sized filters or screens to separate the water from the bottom ash. The separated water would be recycled back to the existing bottom ash trough. The dewatering tank will discharge into a container for a forklift to haul outside the building. Once outside the Boiler Building, the material can be dumped into a dump truck.

Depending on the actual physical properties of the bottom ash, the forklift container may also require filters or screens to ensure that the material discharged into the dump trucks is dry.

Refer to Drawing 190507-PFD-4001 for the material flow. Table 4-2 outlines the estimated cost. The major equipment for this alternative includes the following:

- Sluice piping.
- Dewatering tank.
- Overflow tank with recirculation pump(s) and heat exchanger.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.
- Forklift container, along with the use of a forklift and dump truck.

Key comparisons for Alternative 2 include the following:

- Disadvantages of the dewatering tank:
  - Water from the dewatering tank and forklift container must be recycled in a closed recirculating loop back to the existing bottom ash trough. In the event there is a discharge stream it will require the utilization of a zero liquid discharge treatment. One possible ZLD solution would be the utilization of the spray dry evaporator planned for future installation on F.B. Culley Unit 3.
  - If the dewatering tank must be located outside the existing Boiler Building, the dewatering and the water discharge piping must be heat traced for winter operation. The current assumption is that the tank can be located in the turbine deck area.
  - The water tank may require special internal screens to dewater sufficiently. Laboratory tests may need to be conducted to ensure this design.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the dewatering tank:
  - Minimal new equipment is required because the existing sluice pumps will be enough for reuse.
  - Minimal capital costs are required.

Minimal outage will be needed for installation because much of the existing equipment will be reused.

2.8.2.3 Dry Pneumatic System (Alternative 3)

Alternative 3 is a completely dry system but will require an entirely new dry bottom ash trough and a new exterior dry hopper storage bin. The replacement of the existing bottom ash trough would be a major construction effort and would cause a long outage for the unit. There are various options for collecting the ash at the bottom of the new trough such as a vacuum conveyor, a vibratory oscillatory conveyor, or a mesh screen drag conveyor. The exterior storage bin would require new pneumatic equipment to draw the ash out of the Boiler Building to a location north of the plant. This storage bin would require a sizable foundation because the bin would be elevated to allow unloading the material into either an open truck or a pneumatic tanker truck. If an open truck is used, a wet conditioner may be required to prevent fugitive dust.

Refer to Drawing 190507-PFD-4002 for the material flow. Table 4-2 outlines the estimated cost. The major equipment for this alternative includes the following:

- New dry trough and conveyor.
- New grinders.
- Pneumatic power unit.
- Exterior dry storage tank.
- Possible wet conditioning equipment to load open dump trucks.
- PLC control system and instrumentation.
- MCC to feed new motors and pumps.

Key comparisons for Alternative 3 include the following:

- Disadvantages of pneumatic ash removal:
    - A lengthy outage period is required because existing ash hopper must be removed.
    - Additional equipment for a vacuum conveying system is required.
    - A major amount of expensive new equipment is required.
    - If unloaded to an open truck, a wet conditioning system may be required to control dust. This will affect the water balance for the system.
- Advantages of pneumatic ash removal:
    - It does not require water under the boiler but may still require water for a wet conditioner system under the storage bin to properly load open trucks.

2.8.2.4 Remote Submerged Chain Conveyor (Alternative 4)

Alternative 4 provides a remote closed loop system outside the existing Boiler Building. The existing bottom ash trough and sluicing pump would deliver the ash to the new remote dewatering containment with a new submerged chain conveyor that would dewater and deliver the ash to a three-sided bunker for truck removal.

Refer to Drawing 190507-PFD-4003 for the material flow. Table 4-2 outlines the estimated cost. The major equipment for this alternative includes the following:

- Utilizes existing bottom ash trough and existing grinders.
- Utilizes existing slice pumps but may need a booster pump if located a large distance from the Boiler Building.
- New remote hopper with new submerged chain conveyor for dewatering.
- Hydraulic power unit.

- PLC control system and instrumentation.
- MCC to feed new motors and pumps.
- Chain wash spray.
- Return water pumps and piping.

Key comparisons for Alternative 4 include the following:

- Disadvantages of the remote closed loop system:
  - A new foundational support for the remote equipment is required.
  - Weather protection for the collection trough is required.
  - A weather protection structure might be required to control the ash in the three-sided concrete containment structure.
  - Freeze protection for winter operation is required.
  - More expensive new equipment is required, especially if the remote system is located so far away that a booster pump is required to deliver the wet ash.
  - Ash sluicing water must be 100 percent accounted for and maintained in a closed loop or treated prior to discharge.
- Advantages of the remote closed loop system:
  - No outage time required for modification of the existing boiler.
  - May be cost prohibitive for a small unit; but may show financial benefit if utilized for multiple units.

2.8.3 Fly Ash

The dry ash handling system is already in service at F.B. Culley using mechanical exhausters. The alternative wet sluicing line will need to be capped and abandoned in place so the capability of sluicing fly ash no longer exists to meet compliance.

3.0 Economic Criteria

The economic criteria shown in Table 3-1 was used to develop the cost estimates presented in this report. The present worth discount rate, capital recovery factor, and present worth values listed do not represent Vectren's actual or proposed values. These values represent relative values that have been applied to technology scenarios to determine the most economical alternative. The results of these evaluations are summarized in Section 4.0.

Table 3-1 A.B. Brown ELG Compliance - Summary of Economic Criteria

ECONOMIC INPUTS - ALL UNITS	VALUE	UNITS
Present Worth Discount Rate	6.00	%
Economic Life	20	years
Capital Recovery Factor (Calculated)	8.72	%
Present Worth Factor (Calculated)	11.47	
Salary – Full Time O&M Employee	100,000	$/year
Power Price	0.098	$/kWh
Plant Capacity – Brown Unit 1	65	%
Plant Capacity – Brown Unit 2	65	%
Plant Capacity – Culley Unit 2	25	%
Balance of Plant Treatment (BPT) Reagent-Coagulant Feed (Ferric Chloride)	0.12	$/lb
Organosulfide	1.36	$/lb
BPT Reagent - Flocculant Aid (polymer)	0.60	$/lb
Filter Press Polymer Costs	0.60	$/lb
Selenium Reagent - Sulfuric Acid	0.20	$/lb
Selenium Reagent - Nutrient Feed	1.98	$/lb
Selenium Reagent - Lime	0.10	$/lb
On-site Landfill Costs	24	$/load
On-site Landfill Haul Capacity	30	tons/load
Off-site Landfill Costs	990	$/load
Off-site Landfill Haul Capacity	25	tons/load

4.0 Conceptual Cost Estimate Cases

Tables 4-1 and 4-2 present the ±50 percent cost estimates for A.B. Brown separated into treatment options for CCR and ELG compliance, respectively. Table 4-3 presents the ±50 percent cost estimate for CCR compliance at F.B. Culley. Table 4-4 presents the ±50 percent fly ash cost estimate for A.B. Brown Units 1 and 2. Each scenario presents the capital cost and O&M costs for its respective treatment technologies.

Table 4-1 Cost Estimate Summary for ELG Compliance – A.B. Brown Station

DESCRIPTION		PHYSICAL/CHEMICAL AND BIOLOGICAL TREATMENT
Direct Cost		
Pumps and Drivers		$163,000
Water Treatment - Physical/Chemical		$7,598,000
Water Treatment - Biological		$6,990,000
Water Treatment - Filtration		$222,000
Mechanical Equipment, Piping and Piping Specials		$1,432,000
Electrical Equipment		$3,502,000
Civil/Structural Works		$3,375,000
Total Direct Cost (DC)		**$23,282,000**
Indirect Cost		
Construction Management	20% x DC	$4,657,000
Construction Indirects	15% x DC	$3,492,000
Engineering	15% x DC	$3,492,000
Contingency	20% x DC	$4,657,000
Overhead and Profit	15% x DC	$3,492,000
Total Indirect Cost Including Material and Labor (IC)		**$19,790,000**
Total Direct and Indirect Costs = (DC + IC)		**$43,072,000**
ANNUAL OPERATING COST		
Power		$27,000
Chemical Feed		$906,000
Off-site Landfill Costs		$95,000
Equipment Operator Labor (FTE)		$50,000
Maintenance		$300,000
Total Direct Annual Costs (DAC)		**$1,378,000**

Table 4-2 Summary of Unit 2 F.B. Culley Bottom Ash Cost Estimate (100 MW; 1 tph Ash Production)

DESCRIPTION	BUCKET ELEVATOR	INDOOR DEWATERING TANKS	DRY PNEUMATIC SYSTEM	REMOTE SUBMERGED CHAIN CONVEYOR
Alternative	1	2	3	4
CAPITAL COST **Direct Costs**				
Weather Structure Remote Structures	NA	NA	NA	$213,400
Weather Structure 3-Sided Conc. Contain	NA	NA	NA	$106,700
New Dry Bottom Ash Trough	NA	NA	$1,067,000	NA
Dewatering Tank Support and Access	NA	$426,800	NA	NA
Emergency Drain Tank for Meeting Plant ZLD Requirement	NA	$400,100	NA	NA
Heat Exchanger	NA	$213,400	NA	NA
New Grinders	NA	NA	$853,600	NA
New Exterior Vacuum System	NA	NA	$533,500	NA
New Wet Conditioning for Dump Truck	NA	NA	$213,400	NA
New Remote Wet Trough w/Submerge Chain Conveyor/Overflow Tank	NA	NA	NA	$4,268,000
Vertical Bucket Elevator w/ Drive Unit	NA	NA	NA	NA
Subtotal: Equipment Costs	NA	$1,040,300	$2,667,500	$4,588,100
Electrical, Instr. and Controls Equipment	NA	$233,700	$249,700	$602,900
Mechanical Equipment, Piping and Valves	NA	$266,800	$298,800	$1,760,600
Foundations and Civil Works	NA	-	$266,800	$1,067,000
Miscellaneous Equipment	NA	$277,400	$106,700	-
Demolition Works	NA	$87,200	$393,000	$87,200
Existing BOP System Modifications	NA	$185,400	$145,300	$115,600

DESCRIPTION		BUCKET ELEVATOR	INDOOR DEWATERING TANKS	DRY PNEUMATIC SYSTEM	REMOTE SUBMERGED CHAIN CONVEYOR
Site Earth Works		NA	-	-	$1,000,000
Subtotal: Miscellaneous Costs		NA	$1,050,500	$1,460,300	$4,633,300
Total Direct Costs (DC)		**NA**	**$2,090,800**	**$4,127,800**	**$9,221,400**
Indirect Costs					
Construction Management	20% x DC	NA	$418,200	$825,600	$1,844,300
Construction Indirects	15% x DC	NA	$313,600	$619,200	$1,383,200
Engineering	15% x DC	NA	$313,600	$619,200	$1,383,200
Contingency	20% x DC	NA	$418,200	$825,600	$1,844,300
Overhead and Profit	15% x DC	NA	$313,600	$619,200	$1,383,200
Total Indirect Costs (IC)		**NA**	**$1,777,200**	**$3,508,800**	**$7,838,200**
Total Contracted Costs (CC) DC + IC		**NA**	**$3,868,000**	**$7,636,600**	**$17.059.600**
ANNUAL OPERATING COST **Operating Costs**					
Power		NA	$38,300	$14,300	$42,900
Off-site Landfill Costs		NA	$182,300	$182,300	$182,300
Equipment Operator Labor (FTE)		NA	$42,700	$42,700	$85,400
Maintenance		NA	$37,000	$71,800	$160,400
Total Direct Annual Costs (DAC)		**NA**	**$300,300**	**$311,100**	**$471,000**

Table 4-3 Summary of Units 1 and 2 A.B. Brown Bottom Ash Cost Estimate (265 MW each; 3 tph Ash Production)

DESCRIPTION	SUBMERGED CHAIN CONVEYOR (1)	DEWATERING BUNKER (1)	REMOTE SUBMERGED CHAIN CONVEYOR (1)
Alternative	1	2	3
CAPITAL COST **Direct Costs**			
Weather Structure for Remote System	NA	$426,800	$4,300,000
Weather Structure for 3-Sided Conc. Storage	$406,200	NA	$406,200
Dewatering Bunker/Sump	NA	$853,600	NA
Settling and Surge Tanks	NA	$2,500,000	$373,500
Submerged Chain Conveyor	$5,000,000	NA	NA
Bottom Ash Tank w/Jet Pump and Water Supply Tank	NA	$917,600	NA
Sluice, Recirculation and Sump Pumps	NA	$3,128,400	NA
Seal Water Pumps	NA	$640,200	NA
New Remote Wet Trough w/Submerge Chain Conveyor/Overflow Tank	NA	NA	$5,400,000
Mechanical Pump and Piping Modification	NA	$320,100	$1,600,500
Subtotal: Equipment Costs	$5,406,200	$8,786,700	$12,080,200
Electrical, Instrumentation and Controls Equipment	$2,942,800	$1,557,800	$2,500,000
Mechanical Equipment, Piping and Valves	$3,776,900	$3,190,300	$3,000,000
Foundations and Civil Works	$1,941,100	$3,000,000	$2,000,000
Miscellaneous Equipment Installation	-	$597,500	-
Demolition Works	$1,454,000	$440,000	$440,000
Existing BOP System Modifications	$655,900	$379,900	$646,900

DESCRIPTION		SUBMERGED CHAIN CONVEYOR (1)	DEWATERING BUNKER (1)	REMOTE SUBMERGED CHAIN CONVEYOR (1)
Site Earth Works		-	$1,750,000	1,850,000
Subtotal: Miscellaneous Costs		$10,770,700	$10,915,500	$10,436,900
Total Direct Costs (DC)		**$16,176,900**	**$19,702,200**	**$22,517,100**
Indirect Costs				
Construction Management	20% x DC	$3,235,400	$3,940,400	$4,503,400
Construction Indirects	15% x DC	$2,426,500	$2,955,300	$3,377,600
Engineering	15% x DC	$2,426,500	$2,955,300	$3,377,600
Contingency	20% x DC	$3,235,400	$3,940,400	$4,503,400
Overhead and Profit	15% x DC	$2,426,500	$2,955,300	$3,377,600
Total Indirect Costs (IC)		**$13,750,300**	**$16,746,700**	**$19,139,600**
Total Contracted Costs (CC)	**DC + IC**	**$29,927,200**	**$36,448,900**	**$41,656,700**
ANNUAL OPERATING COST **Operating Costs**				
Power		$22,300	$89,200	$126,300
Off-site Landfill Costs		$946,100	$946,100	$946,100
Equipment Operator Labor (FTE)		$192,100	$384,100	$256,100
Maintenance		$100,000	$120,000	$135,000
Total Direct Annual Costs (DAC)		**$1,260,500**	**$1,539,400**	**$1,463,500**

Note 1: Costs in the Table 4-3 are provided as a total cost for both A.B. Brown Unit 1 and Unit 2.

Table 4-4 Summary of Units 1 and 2 A.B. Brown Fly Ash Cost Estimate

DESCRIPTION		DILUTE PHASE, VACUUM PNEUMATIC CONVEYING SYSTEM
Direct Cost		
Civil and Structural Costs		$5,439,300
Mechanical Costs		$4,328,000
Electrical and Control Costs		$2,477,100
Total Direct Cost (DC)		**$12,244,400**
Indirect Cost		
Construction Indirects	15% x DC	$1,836,700
Engineering	15% x DC	$1,836,700
Construction Management	20% x DC	$2,448,900
Contingency	20% x DC	$2,448,900
Overhead and Profit	15% x DC	$1,836,700
Total Indirect Cost Including Material and Labor (IC)		**$10,407,900**
Total Contracted Costs (CC) DC + IC		**$22,652,300**
ANNUAL OPERATING COST **Operating Costs**		
Power		$37,200
Offsite Landfill Costs		$3,574,400
Equipment Operator Labor (FTE)		$42,700
Maintenance		$25,000
Total Direct Annual Costs (DAC)		**$3,679,300**

5.0 Conclusions and Recommendations

The analysis covered by this comprehensive report has shown ash pond closure options and alternative ash handling and water treatment options to bring A.B. Brown and F.B. Culley Stations into future compliance with the updated CCR and ELG regulations (NPDES compliance). Flue gas desulfurization wastewater treatment for heavy metals and suspended solids reduction will be required at A.B. Brown.

Recommendations for each station are summarized below with associated cost estimates shown in Tables 5-1 and 5-2.

5.1 A.B. BROWN

Based on the evaluations reported in Sections 2.3 through 2.6, Black & Veatch recommends the following:

- **Submerged Chain Conveyor for Bottom Ash Removal**. The modified SCC is technically feasible with less modification to existing equipment and reduced outage time.
- **Mechanical Exhausters for Fly Ash Removal**. The mechanical exhausters match the design at F.B. Culley.
- **Scrubber Treatment and Collection Basin**. The recommended location for the basin and equipment is south of the capital pond. This option avoids expensive impacts to the railway, undergrounds, and is in close proximity to the power block.

5.2 F.B. CULLEY

Based on the evaluations reported in Sections 2.7 through 2.8, Black & Veatch recommends the following:

- **Indoor Dewatering Tanks for Bottom Ash Removal.** The indoor dewatering tank is technically feasible and is a proven approach to bottom ash dewatering and ash removal.

Table 5-1 Summary of Recommended Technologies – A.B. Brown Station

OPTION	TECHNOLOGY DESCRIPTION	CAPITAL COST	O&M COST
ELG Equipment (Table 5-2)	Physical/Chemical and Biological, Collection and Filtration, Location 2	$43,072,000	$1,378,000
Bottom Ash	Modified SCC Bottom Ash Handling	$29,927,200	$1,260,500
Fly Ash	Dry Pneumatic Fly Ash Handling	$22,652,300	$3,679,300

Table 5-2 Summary of Recommended Technologies – F.B. Culley Station

OPTION	TECHNOLOGY DESCRIPTION	CAPITAL COST	O&M COST
Wet-to-Dry Ash Handling	Indoor Dewatering Tanks	$3,868,000	$300,300

Appendix A. Applicable Effluent Guidelines and Standards

WASTE STREAM/POLLUTANT	EXISTING SOURCE DIRECT DISCHARGE		APPLICABILITY A.B. BROWN
	BPT[a]	BAT[a]	
All Waste Streams	pH: 6-9 S.U. PCBs[b]: Zero Discharge.	PCBs: Zero Discharge.	Yes
Low Volume Wastes	TSS: 100 ppm[1] / 30 ppm[2]. Oil & Grease: 20 ppm[1] / 15 ppm[2].		Yes
Flue Gas Desulfurization (FGD) Wastewater	TSS: 100 ppm[1] / 30 ppm[2]. Oil & Grease: 20 ppm[1] / 15 ppm[2].	Arsenic: 11 ppb[1] / 8 ppb[2]. Mercury: 788 ppt[1] / 356 ppt[2]. Nitrate/Nitrite as N: 17 ppm[1] / 4.4 ppm[2]. Selenium: 23 ppb[1] / 12 ppb[2].	No[c]
Flue Gas Mercury Control (FGMC) Wastewater	TSS: 100 ppm[1] / 30 ppm[2]. Oil & Grease: 20 ppm[1] / 15 ppm[2].	Zero Discharge.	No
Gasification Wastewater	TSS: 100 ppm[1] / 30 ppm[2]. Oil & Grease: 20 ppm[1] / 15 ppm[2].	Arsenic: 4 ppb[1]. Mercury: 1.8 ppt[1] / 1.3 ppt[2]. Selenium: 453 ppb[1] / 227 ppb[2]. TDS: 38 ppm[1] / 22 ppm[2].	No
Combustion Residual Leachate	TSS: 100 ppm[1] / 30 ppm[2]. Oil & Grease: 20 ppm[1] / 15 ppm[2].	TSS: 100 ppm[1] / 30 ppm[2]. Oil & Grease: 20 ppm[1] / 15 ppm[2].	No
Fly Transport	TSS: 100 ppm[1] / 30 ppm[2]. Oil & Grease: 20 ppm[1] / 15 ppm[2].	Zero Discharge.	Yes
Bottom Ash Transport	TSS: 100 ppm[1] / 30 ppm[2]. Oil & Grease: 20 ppm[1] / 15 ppm[2].	Zero Discharge.	Yes
Once-Through Cooling	Free Available Chlorine: 0.5 ppm[3] / 0.2 ppm[4].	Total Residual Chlorine if ≥25 MW: 0.2 ppm[5]. If ≤25 MW: equal to BPT.	No
Cooling Tower Blowdown	Free Available Chlorine: 0.5 ppm[3] / 0.2 ppm[4].	Free Available Chlorine: 0.5 ppm[3] / 0.2 ppm[4]. 126 Priority Pollutants: Zero discharge except: Chromium: 0.2 ppm[3] / 0.2 ppm[4]. Zinc: 1.0 ppm[3] / 1.0 ppm[4].	Yes
Coal Pile Runoff	TSS: 50 ppm[5].		Yes
Chemical Metal Cleaning Wastes	TSS: 100 ppm[1] / 30 ppm[2]. Oil & Grease: 20 ppm[1] / 15 ppm[2]. Copper, total: 1 ppm[1] / 1 ppm[2]. Iron, total: 1 ppm[1] / 1 ppm[2].	Copper: 1.0 ppm[3] / 1.0 ppm[4]. Iron: 1.0 ppm[3] / 1.0 ppm[4].	Yes

Source: [40 CFR Part 423]

[1]Maximum concentration for any one day.

[2]Average daily values for 30 consecutive days.

[3]Maximum concentration.

[4]Average concentration.

[5]Instantaneous maximum.

[a]The pH of all discharges, except once-through cooling water, shall be within the range of 6.0 – 9.0. For all effluent guidelines, where two or more waste streams are combined, the total pollutant discharge quantity may not exceed the sum of allowable pollutant quantities for each individual waste stream. BAT, BPT, NSPS allow either mass or concentration-based limitations.

[b]Polychlorinated biphenyl compounds (PCBs) commonly used in transformer fluid.

[c] The EPA has ruled that the type of wet FGD system utilized at ABB, dual alkali scrubber, produces only low volume wastewater.

BPT – Balance of Plant Treatment

BAT – Best Achievable Technology

Appendix B. List of Assumptions for A.B. Brown

The conceptual cost estimate is provided for alternative treatment options for each stream that discharges into the ash pond to bring A.B. Brown into compliance with ELG regulations. The A.B. Brown site includes existing coal fired plants.

The cost estimate is based on the assumptions in the following sections:

B.1 GENERAL ASSUMPTIONS

- Ash pond will be closed in place. No costs associated with its closure are included in the estimate.
- All underground pipe will be buried so that the top of pipe is below frost depth. All aboveground pipe will be supported on sleepers.
- Pipe that is running under an existing rail track is assumed to be jack and bored into place.
- Existing buried pipe under 12 inches that will no longer be in service will be capped and abandoned in place. Existing pipe greater or equal to 12 inches will be backfilled. An allowance is also included to remove some large bore piping when in the area of installation of any new piping. No other demolition of any existing structures is included.
- Existing soil will have sufficient strength to support the new basins and building. Cost is added to include a geotechnical survey to confirm this assumption.
- No cost is included for existing gravel road repair or new roads.
- One railroad crossing would be required for Option 2 for new access road.
- A liner was assumed to be needed under collection basin and settling basins. A liner was not assumed to be needed under new piping.
- A new 80 foot by 50 foot metal building with heating, ventilating, and air conditioning (HVAC) is included for new water treatment equipment. A 2 foot thick slab was assumed to be sufficient to support any equipment needed inside the metal building. Piles are not included. There are 2 tons of support steel for miscellaneous equipment inside of the metal building.
- A 2.5 ton jib crane is included for the settling basin.
- No site leveling or raising is 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.
- Wastewater treatment will include one clarification and sludge handling train. All transfer pumps, sludge pumps and chemical feed pumps will be designed with 2x100 percent redundancy. Wastewater treatment will include programmable logic controller (PLC) control panel, input/output (I/O) cabinets, and motor control center (MCC) all located in the metal building.

- Sludge hauling dumpster is not included in the estimate.
- No provisions for future expansion of the new wastewater treatment equipment are included.
- An emergency generator is not provided.
- Construction power will be provided by Vectren.
- The existing fire protection hydrant loop from the existing facility will be extended as required to serve the new metal building and water treatment areas. It is assumed that existing fire water pressure and volume are sufficient, therefore, no new fire pumps are included.
- Existing auxiliary power system can supply a minimum 100 amperes at 4160 volts.
- A new distributed control system (DCS) remote input/output (RIO) cabinet is located in the new electrical room in the metal building.
- There is fiber-optic connection to plant DCS.
- Add 30 percent for DCS programming engineering, arc flash coordination study.
- Uninterruptible power supply (UPS) feeds are based on typical primary/backup feed to DCS cabinets; other option is local mini-UPS located in Electrical Building. Power provided by available plant UPS.
- Heat trace loads that are nonfreeze protection lines (nonwater) are allowed off 120/208V panel in the power distribution center (PDC) in accordance with previous project work.
- Building will have 20 foot hi-bay ceilings, with potential second floor open grated level.
- All cables fed from plant; not from cooling tower area based on lack of information.
- New collection basin and wastewater treatment equipment sizing is based on two operating units.
- No changes to the current FGD wastewater mercury treatment equipment or any upstream piping or devices from either unit.
- Current coal pile runoff pump capacity is adequate to reach new collection basin based on topography, pump curve, and Black & Veatch flow modeling.
- New collection basin sizing is based on 20 minutes retention time for all flows identified on the Vectren water mass balance (WMB).
- Proposed treatment is based on flows in the A.B. Brown Plant Water Balance, Drawing F-2025.1, and water quality data provided by Vectren.
- Cooling tower blowdown flow rate and water quality assumes the cooling tower operates at six cycles of concentration. Copper content in the cooling tower blowdown is assumed to be reduced to 0.02 ppm after treatment in the existing cooling tower blowdown settling basins. This is consistent with existing plant water quality data.

- Proposed treatment assumes 60 gpm of SCC wastewater total for both units. SCC wastewater quality is assumed to be the same as the quality of the combined collection basin water, except with 1,000 ppm TSS.
- The coal pile runoff pond discharge will improve in quality as a result of the new FGD treatment system. The water quality for the coal pile runoff pond discharge is assumed to be a flow-proportioned blend of non-SCC wastewater (water quality of A.B. Brown's coal pile runoff sample) and the SCC wastewater.
- Proposed physical/chemical treatment assumes 99 percent removal of mercury, removal to 10 ppm TSS in clarifier effluent, and removal to 0.02 ppm copper in clarifier effluent.
- Proposed biological treatment assumes selenium removal to 0.01 ppm in system effluent.
- Proposed dewatering system assumes 99 percent of solids in feed will be removed in filter cake for disposal. Precipitated metals are included in this assumption.
- Treatment vessel will flow by gravity to the existing ash pond wastewater mercury treatment system.
- No electrical equipment or storage building provided at Location No. 3.
- Treatment system is not designed to handle chemical cleaning wastes.
- Required instrumentation is included in cost of treatment system.
- A.B. Brown Station bottom ash handling equipment costs are based on F.B. Culley Unit 3 design and recent proposals from United Conveyor Corporation for submerged chain conveyor.
- New high-pressure and low-pressure recirculation pumps will tie in to existing piping within plant.
- Existing excavated dirt is assumed to be suitable for backfill material. No imported fill is included.

B.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 are based on a turnkey construction approach. Construction is assumed to be performed based on a 50 hour workweek. Local union rates are used that include payroll, payroll taxes, and benefits. The consolidated labor rate used is about $75 per man-hour.

- Total capital costs are ±50 percent and include the costs associated with the purchase of equipment, erection, and all contractor services.
- Construction costs are based on an EPC construction approach.
- Capital direct cost for balance of plant treatment (BPT) assumed 4 percent equipment capital cost for equipment replacement during major outage.
- BPT treatment total capital costs include all common water treatment infrastructure.
- Selenium treatment total capital costs include only biological treatment that requires the BPT treatment system and entire infrastructure upstream for effluent compliance.
- BPT and selenium treatment is common equipment for both units.
- Leachate and WW Hg treatment is included in BPT treatment total capital costs.
- FBC selenium treatment includes all necessary equipment for effluent compliance; physical chemical treatment with biological.

B.3 INDIRECT COST ASSUMPTIONS

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

- 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.
- Transportation costs for equipment and materials delivery to the jobsite.
- Startup/commissioning spare parts. Only miscellaneous parts used during the startup process are included. All major equipment long-term spare parts should be included in Vectren's costs.
- Construction contractor contingency costs.
- Construction contractor typical profit margin.
- Total capital costs do not include contingency, owner's cost, taxes, insurance, spare parts, or construction utility interconnections/consumables.

- O&M base non-labor cost for BPT assumed 2 percent equipment capital costs for maintenance items, consumables, and spare parts. Variable O&M costs are not included.

The following additional items of cost are not included in the construction estimate. These costs shall be determined by Vectren and are 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.
- Furniture, maintenance and office equipment, supplies, consumables, communications and plant IT systems, and startup fuel.
- Emissions credits.
- Environmental mitigation.

Appendix C. List of Process Flow Diagrams

C.1 PROCESS FLOW DIAGRAMS FOR F.B. CULLEY UNIT 2

Bucket Elevator (Alternative No. 1) – 190507-PFD-4000

Indoor Dewatering Tanks (Alternative No. 2) – 190507-PFD-4001

Dry Pneumatic System (Alternative No. 3) – 190507-PFD-4002

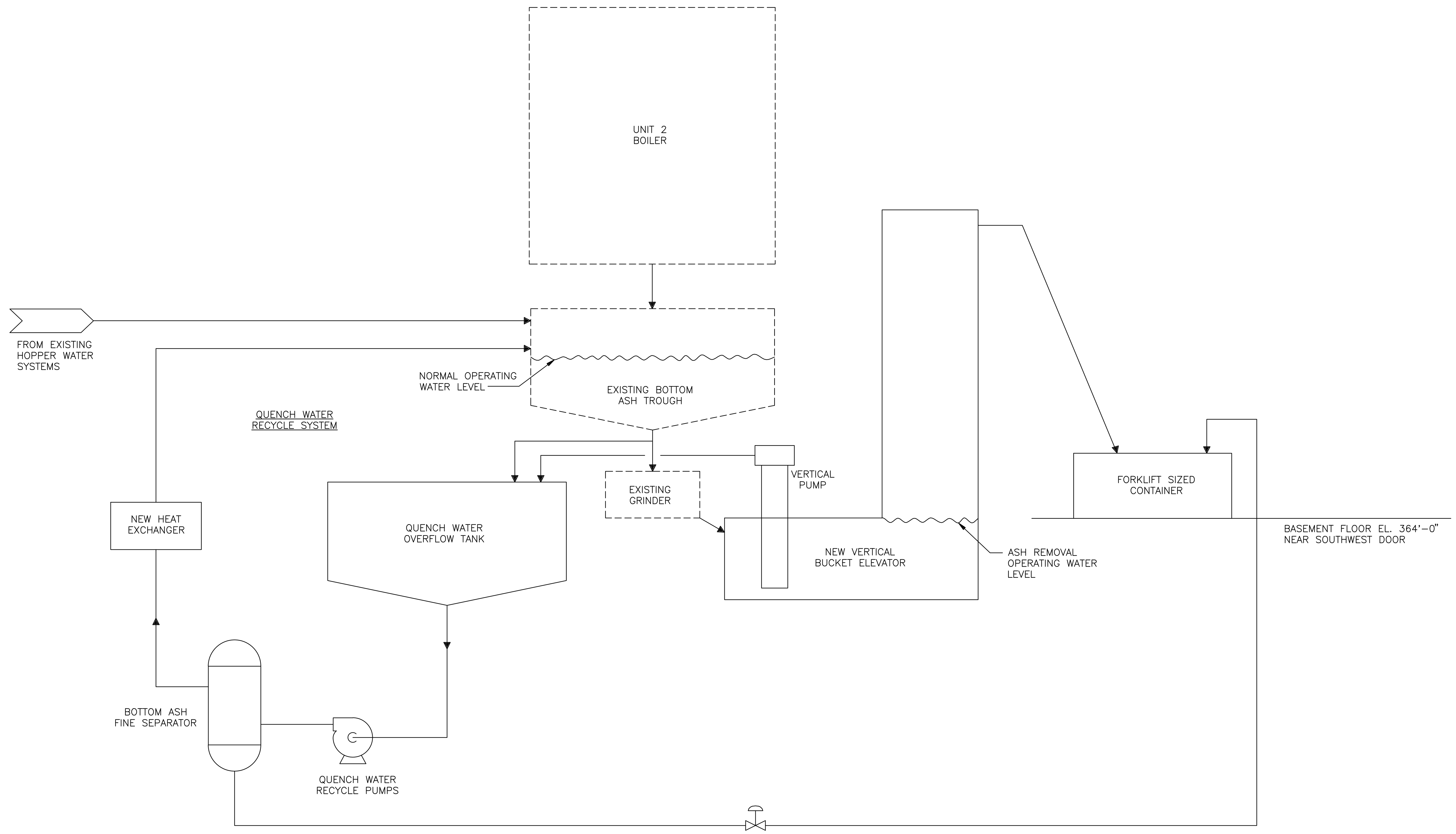
Remote Submerged Chain Conveyor (Alternative No. 4) – 190507-PFD-4003

C.2 PROCESS FLOW DIAGRAMS FOR A.B. BROWN UNITS 1 AND 2

Submerged Chain Conveyor (Alternative No. 1) – 190507-PFD-4004

Dewatering Bunker (Alternative No. 2) – 190507-PFD-4005

Remote Submerged Chain Conveyor (Alternative No. 3) – 190507-PFD-4006



NOT TO BE USED
FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	28/JUL/16	ISSUED FOR CLIENT REVIEW	DRE	EGC		LRK	

BLACK & VEATCH
Building a world of difference®

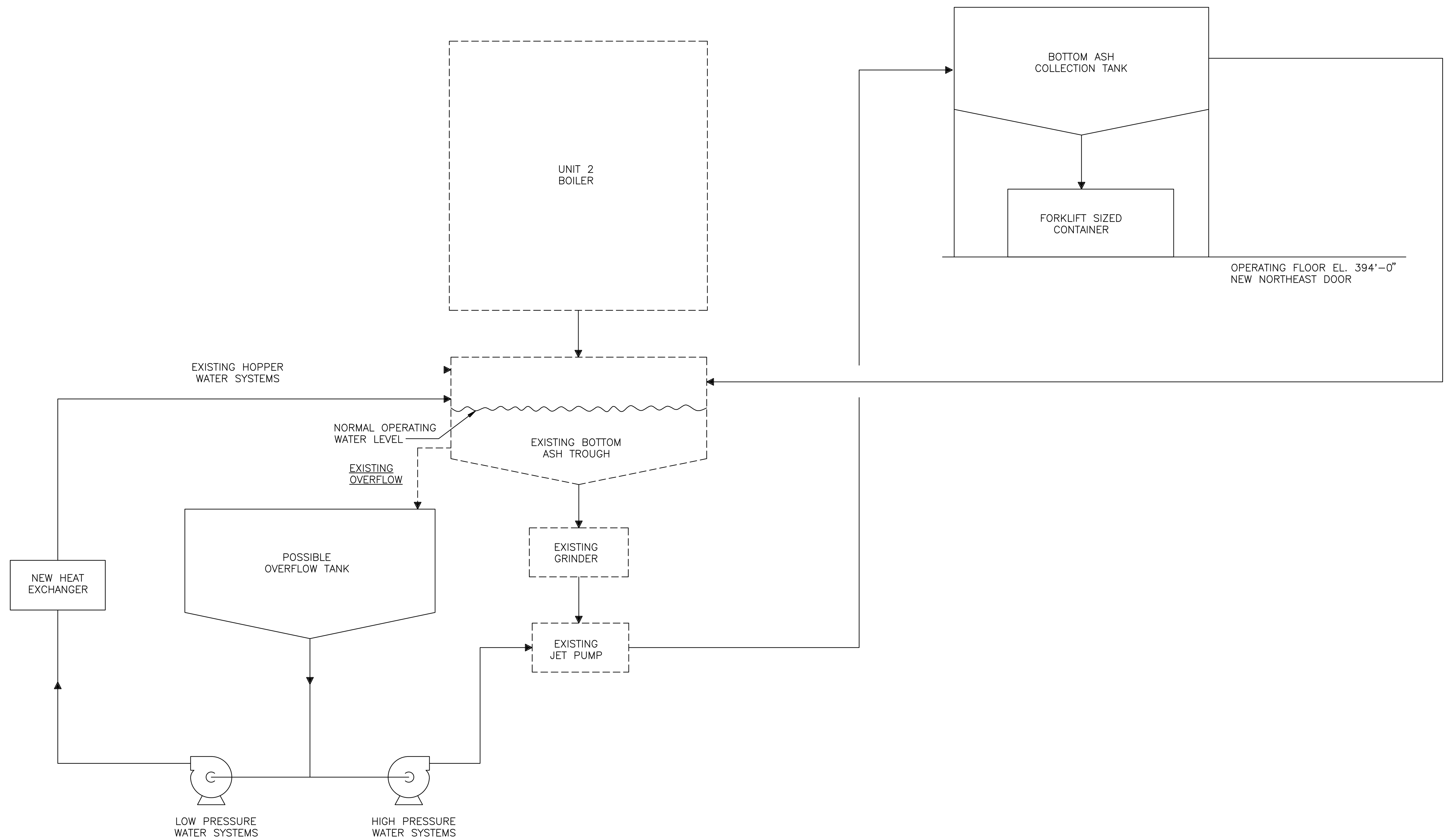
DESIGNER LRK | DRAWN DRE
CHECKED | DATE

VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 1
VERTICAL BUCKET ELEVATOR FLOW DIAGRAM

PROJECT | DRAWING NUMBER 190507-PFD-4000 | REV A
CODE
AREA

ELY65172 D1 1=1
A1ASL028
08/02/16 15:24:16
ACAD 18.2s (LMS Tech)



NOT TO BE USED
FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	28/JUL/16	ISSUED FOR CLIENT REVIEW	DRE	EGC		LRK	

BLACK & VEATCH
Building a world of difference®

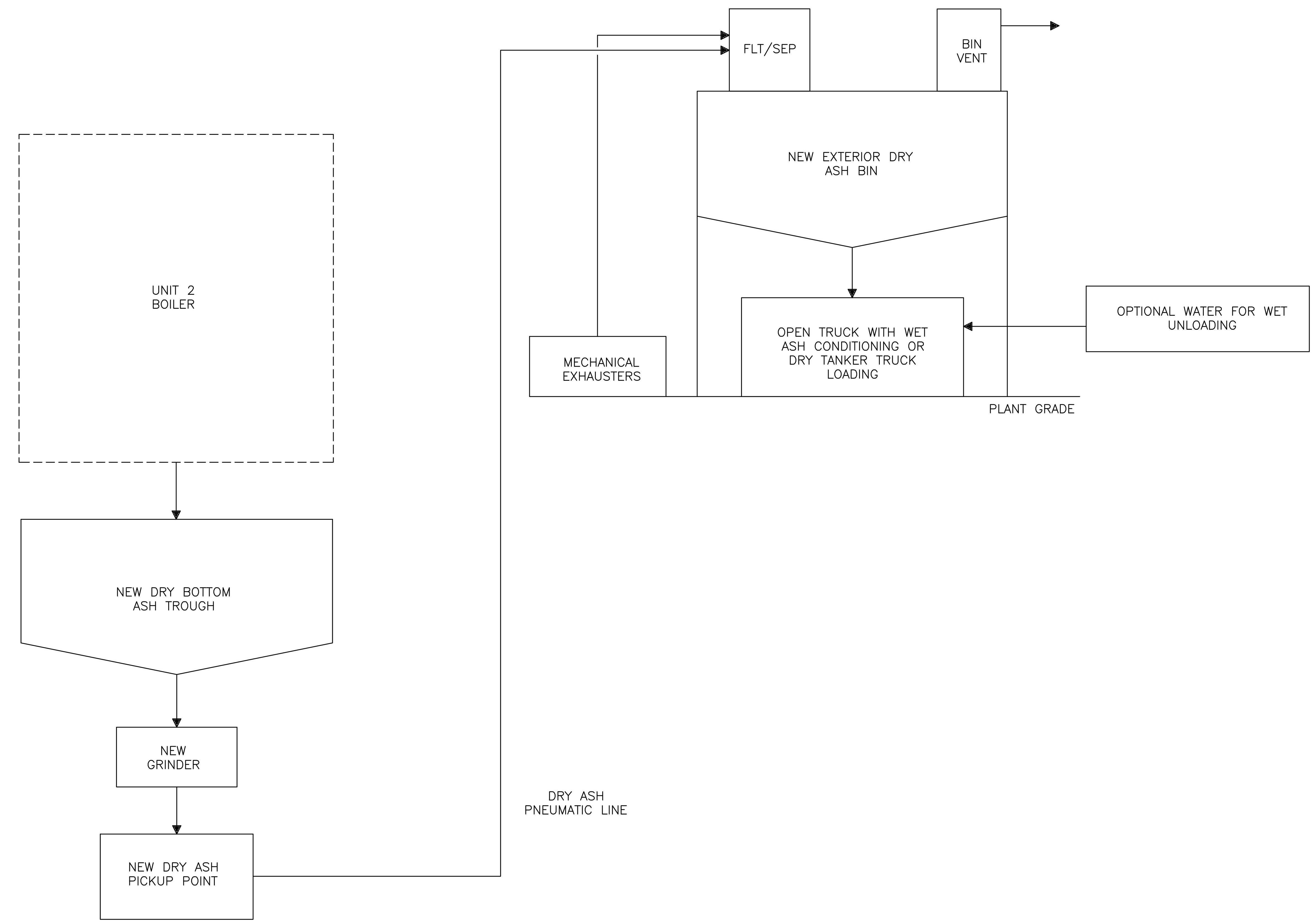
DESIGNER LRK | DRAWN DRE | CHECKED | DATE

VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 2
INTERIOR DEWATERING TANK FLOW DIAGRAM

PROJECT / DRAWING NUMBER: 190507-PFD-4001 | REV: A
CODE
AREA

ELY65172 A1ASL028 08/03/16 08:40:25 D1 1=1 ACAD 18.2s (LMS Tech)



NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	28/JUL/16	ISSUED FOR CLIENT REVIEW	DRE	EGC		LRK	

BLACK & VEATCH
Building a world of difference®

DESIGNER LRK | DRAWN DRE | CHECKED | DATE

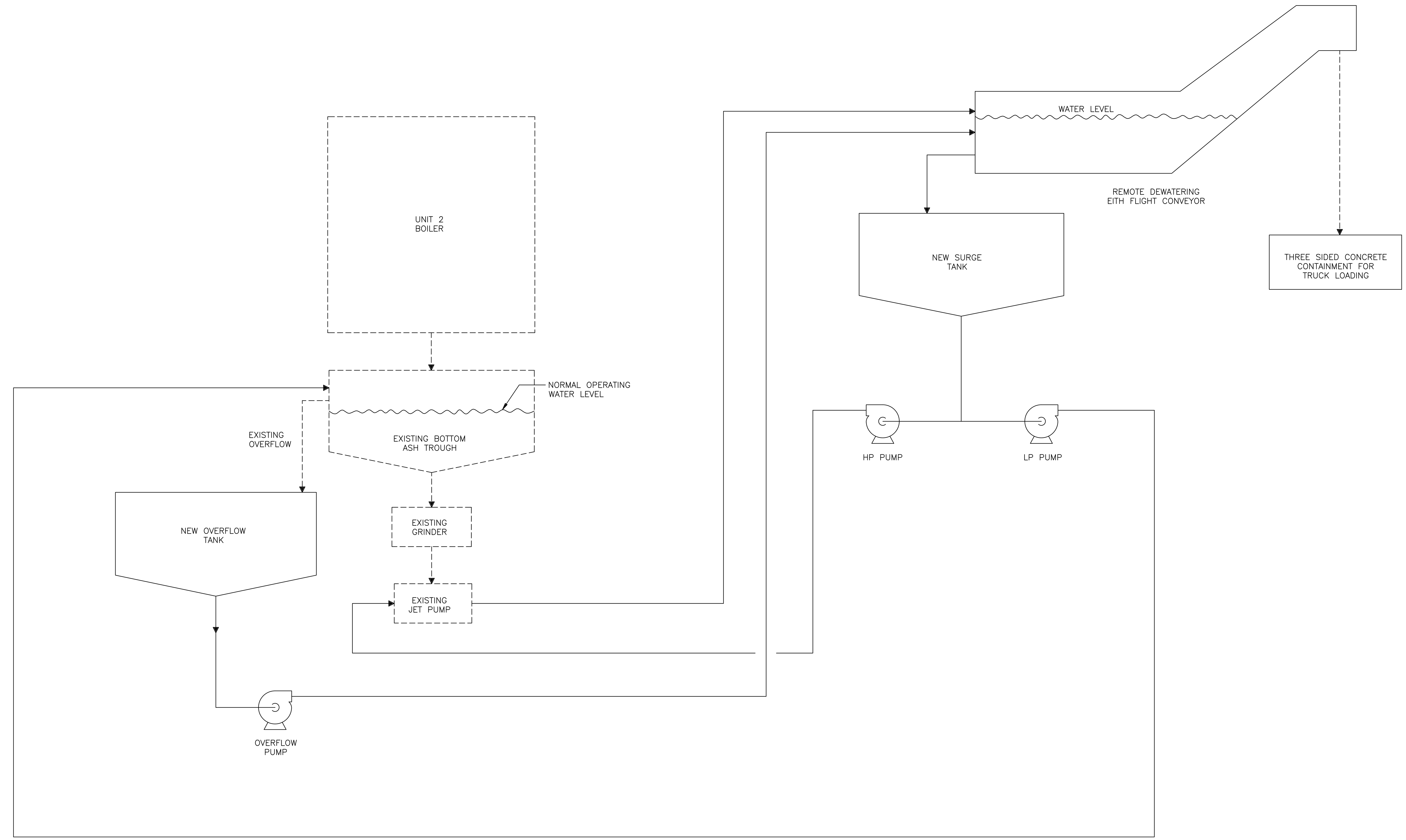
VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 3
PNEUMATIC ASH REMOVAL FLOW DIAGRAM

PROJECT | DRAWING NUMBER: 190507–PFD–4002 | REV: A

CODE | AREA

ELY65172 D1 ACAD 18.2s (LMS Tech)
A1ASL028 1=1
08/03/16 08:21:04



NOT TO BE USED
FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	28/JUL/16	ISSUED FOR CLIENT REVIEW	DRE	EGC		LRK	

BLACK & VEATCH
Building a world of difference®

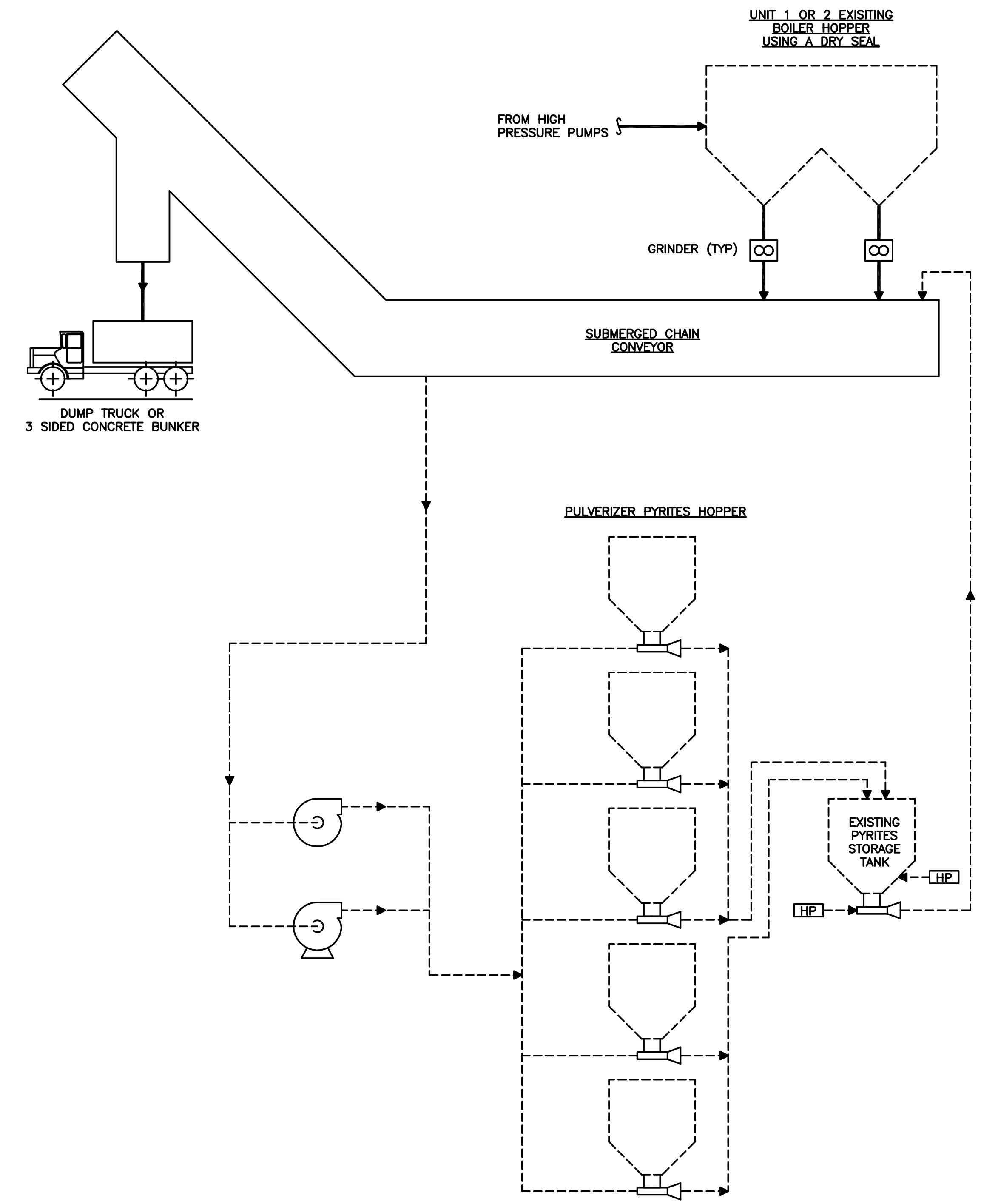
DESIGNER LRK | DRAWN DRE
CHECKED | DATE

VECTREN POWER SUPPLY
CULLEY STATION UNIT 2

ALTERNATIVE 4
REMOTE DEWATERING FLIGHT CONVEYOR FLOW

PROJECT | DRAWING NUMBER: 190507–PFD–4003 | REV: A
CODE
AREA

ELY65172 D1 1=1
A1ASL028
08/03/16 08:57:09
ACAD 18.2s (LMS Tech)



NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	03/JUL/19	ISSUED FOR CLIENT REVIEW	JLH	MWE		KMK	

BLACK & VEATCH Building a world of difference.

DESIGNER MWE DRAWN JLH
CHECKED DATE

VECTREN POWER SUPPLY
A.B. BROWN STATION (UNIT 1 OR 2)

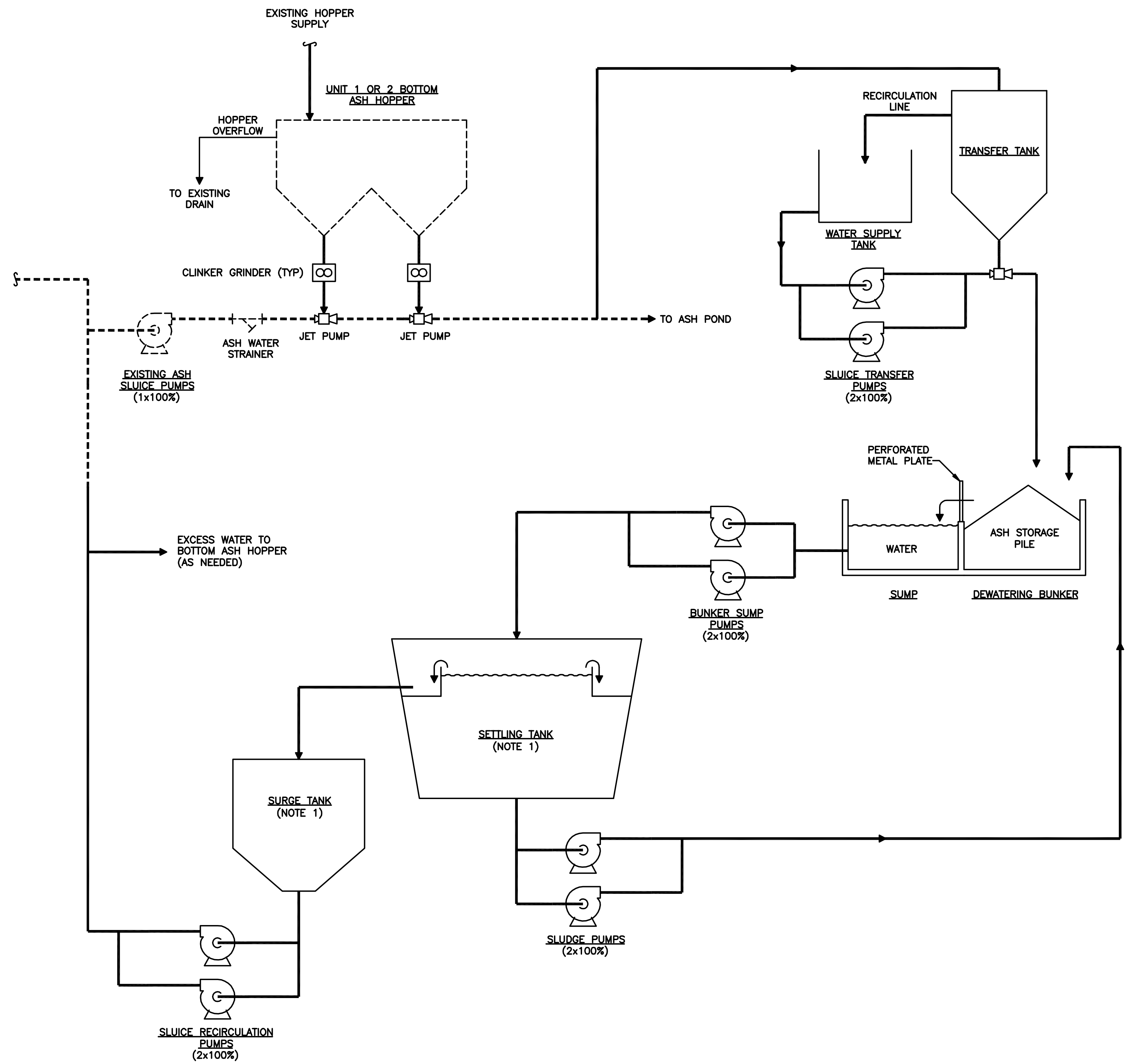
ALTERNATIVE 1
SUBMERGED CHAIN CONVEYOR

PROJECT / DRAWING NUMBER: 190507-PFD-4004
REV: A
CODE
AREA

ELY65172 A1A5L028 11/14/16 09:48:42 D1 1=1 ACAD 18.2s (LMS Tech)

NOTES:

1. SETTLING TANK & SURGE TANK NEED FURTHER INVESTIGATION.



NOT TO BE USED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	03/JUL/19	ISSUED FOR CLIENT REVIEW	JLH	MWE		KMK	

BLACK & VEATCH Building a world of difference.

DESIGNER MWE | DRAWN JLH | CHECKED | DATE

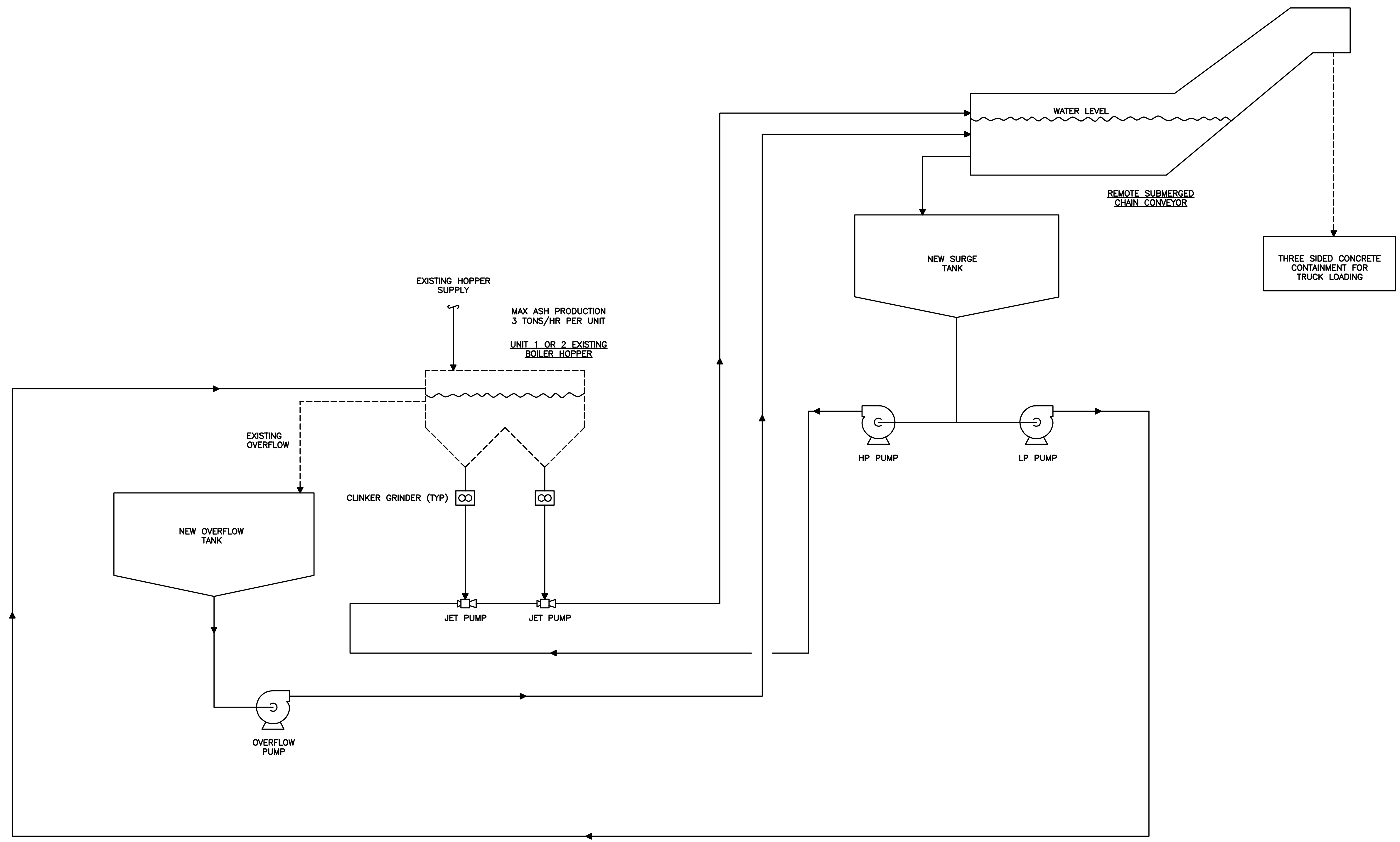
VECTREN POWER SUPPLY
A.B. BROWN STATION (UNIT 1 OR 2)

ALTERNATIVE 2
BOTTOM ASH DEWATERING BUNKER

PROJECT | DRAWING NUMBER: 190507-PFD-4005 | REV: A

CODE | AREA

ELY65172 A1ASL028 08/04/16 10:48:15 D1 1=1 ACAD 18.2s (LMS Tech)



NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
A	03/JUL/19	ISSUED FOR CLIENT REVIEW	JLH	MWE		KMK	

BLACK & VEATCH
Building a world of difference.

DESIGNER MWE | DRAWN JLH
CHECKED | DATE

VECTREN POWER SUPPLY
A.B. BROWN STATION (UNIT 1 OR UNIT 2)
ALTERNATIVE 3
REMOTE SUBMERGED CHAIN CONVEYOR FLOW

PROJECT 190507 | DRAWING NUMBER PFD-4006 | REV A

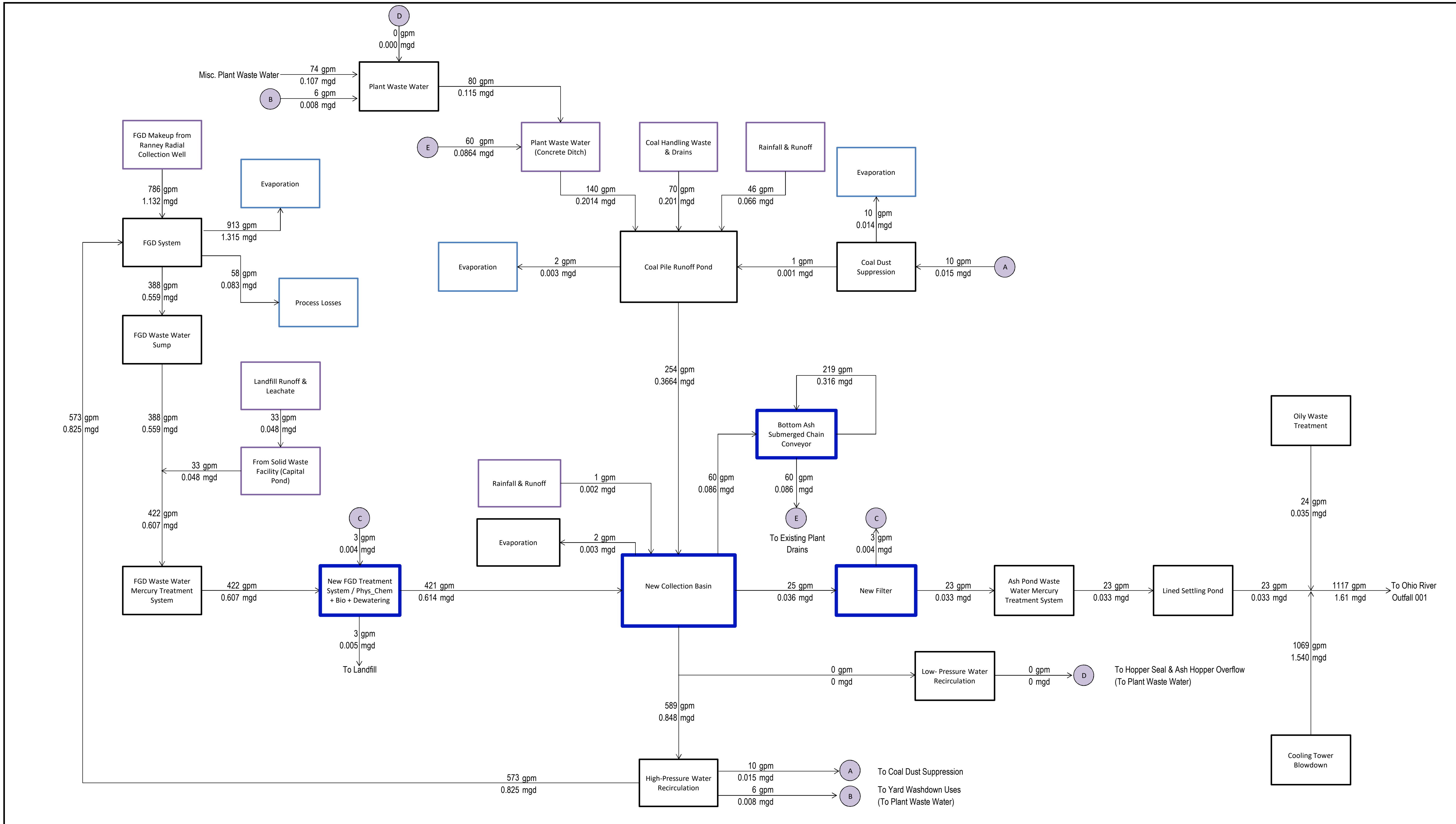
CODE
AREA

ELV65172 A1ASL028 08/22/16 D1 1=1 16:16:10 ACAD 18.2s (LMS Tech)

Appendix D. Water Mass Balance Diagram

D.1 WATER MASS BALANCE DIAGRAM FOR A.B. BROWN

ELG / CCR REPORT
APPENDIX D - WATER BALANCE



NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	ENG
A	2/21/20	ELG - CCR Compliance Report	VMM	AJF

BLACK & VEATCH
Building a world of difference.

Vectren Corp.
A.B. Brown Station
WATER MASS BALANCE - Dual Alkali Scrubber

Eng:
Dwg:
Date: 2/21/2020
REV
A

Attachment 6.8 ACE Rule Heat Rate Study

FINAL

EPA ACE HEAT RATE STUDY

B&V PROJECT NO. 402338
B&V FILE NO. 40.0004

PREPARED FOR

Vectren

16 JANUARY 2020

Table of Contents

LIST OF TABLES

LIST OF FIGURES

Executive Summary

The Affordable Clean Energy (ACE) rule, finalized by the United States Environmental Protection Agency (EPA) on June 19, 2019, establishes new standards for reducing greenhouse gas (GHG) emissions for coal-fired electric utility generating units (EGUs) based on the "best system of emission reduction" (BSER). First proposed in August 2018, the rule, Docket ID No. EPA-HQ-OAR-2017-0355: FRL-9995-70-OAR, "Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations," focuses on measures that can be implemented within the fence line of existing EGU facilities. As such, the EPA concluded that BSER be limited to heat rate improvements (efficiency improvements) for existing coal-fired EGUs. Within ACE, the EPA identified a list of candidate technologies and measures to achieve heat rate improvements (HRI).

In anticipation of the final rule, Vectren requested that Black & Veatch assess these candidate technologies for improvements at four coal fired plants (A.B. Brown Unit 1, A.B. Brown Unit 2, Culley Unit 2, and Culley Unit 3) to meet the goals of the ACE rule. Black & Veatch reviewed the characteristic of the four plants and examined each plant according to several BSER alternatives:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive (VFD) deployment.
- Neural networks.
- Intelligent sootblowing (ISB).
- Various improved operations and maintenance (O&M) practices.

Several factors influenced the recommendations for upgrades at the four plants; these factors are discussed in detail in Section 3.0. A summary of Black & Veatch's assessment and recommendations is as follows:

- The existing steam turbines at A.B. Brown Units 1 and 2 have been upgraded to full dense pack and no significant improvement in heat rate would result in additional upgrades; a turbine blade path upgrade would improve heat rate at F.B. Culley Unit 3 (1.4 to 1.6 percent). Steam turbine blade path upgrades options for F.B. Culley Unit 2 would improve heat rate by 1.3 to 1.5 percent, at a cost of $10.4 million.
- Economizer upgrades are not recommended for A.B. Brown Units 1 and 2 or F.B. Culley Unit 3 at this time; upgrades at F.B. Culley Unit 2 would require significant investment and require further study. A boiler modeling study of the potential benefits of reducing economizer surface area at A.B. Brown Units 1 and 2 or F.B. Culley Unit 3 found that although there was a potential reduction in natural gas use for the gas burners, the net impact upon the units was negative.
- Recommendations were provided for improving unit air heaters at all four units.

- Estimated costs are provided for VFD improvements for the FD and ID Fans at A.B. Brown Units 1 and 2. VFD improvements were studied for the FD fans at F.B. Culley Units 2 and 3 as both units ID fans have already been upgraded with VFDs.
- The deployment of VFDs for circulating water pumps was studied at all four units, but in no instance was it found to be a cost-effective HRI option.
- Estimated costs are provided for neural network deployment at all four units.
- F.B. Culley Unit 2 is the only unit that could benefit from ISB; the other units already use this technology.
- Improved O&M practices include heat rate improvement training, on-site heat rate appraisals, and improved condenser cleanliness strategies; these techniques may result in improvements at all four units.

Overall, many opportunities exist for heat rate improvement at the A.B. Brown and F.B. Culley units in compliance with the EPA-ACE rule. The decision of which heat rate improvements should be pursued must be based upon the long-term plans for the continued operation of the units, and the specific cost/benefit factors for each improvement found in Appendix B.

Recommendations

The following recommendations have been made for the units, based upon their past performance and current operations, as well as the expected future payback potential.

- For the A.B. Brown 1, A.B. Brown 2, and F.B. Culley 3 units upgrades to the air heaters and repair and remediation of ductwork and air quality control systems leakage appears to have a high value to the plants. In the case of air heater upgrades the improvement in heat transfer will improve the boiler efficiency, and the reduction in air heater leakage will reduce station service by reducing the air and gas main fan flow requirements. Reductions in duct leakage and leakage in air quality control equipment leakage will significantly improve induced draft fan performance and will reduce station service. There will also be the ancillary benefit of improved operations and efficiency of the air quality control equipment for emissions reduction.

  F.B. Culley Unit 2 was found to have a poor cost/benefit ratio for these upgrades due to its very low capacity factor and net generation, as well as its relatively short remaining useful life. F.B. Culley Unit 3 on the other hand was found to have the best potential benefit from air heater and duct leakage improvements from the standpoint of improvement per capital dollar spent.

- Steam turbine and blade path upgrades were analyzed for F.B. Culley Units 2 and 3 (A.B. Brown Units 1 and 2 were judged not to benefit from them sufficiently to warrant further upgrades, due to their relatively recent dense pack refurbishments) but only upgrades respective to F.B. Culley Unit 3 were found to be technically feasible and cost-effective at this time. However, as the New Source Review (NSR) exemption portion of EPA-ACE has been deferred and will be proposed in a separate action at a later date, pursuing steam turbine upgrades at this time should be done under the consideration of the potential for triggering NSR.

- Variable frequency drive deployment was found to be only advantageous for the induced draft fans on A.B. Brown Units 1 and 2. For all other systems and the F.B. Culley units, either VFDs had already been deployed to critical systems, or there was no acceptable cost/benefit to further deployment.
- Deploying a neural network or other boiler optimization system was found to be beneficial for all units except F.B. Culley Unit 2, which again was excluded due to its low capacity factor and output. Even modest improvements in optimization could result in significant improvements to heat rate and overall unit control and emissions.
- Heat rate awareness training was found to be a very good cost/benefit for all the units and could yield significant improvements in operations practices and responses to controllable losses at both plants. Targeted heat rate assessment, while difficult to quantify exactly, is expected based upon Black & Veatch experience to have a very high return on investment, and numerous examples have been provided in the text from past projects.
- The addition of more circulating water temperature measurements leaving the condenser would also improve accuracy of results by better capturing temperature stratification in the return piping.

Summary of Costs

The following table provides a summary of costs associated with the recommended ACE technologies for each unit. Additional detailed cost estimates for each unit can be found in Appendix B.

Table ES-1 A.B. Brown Unit 1 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	57.88
Air Heater (Steam Coil) System Repairs	350	0.10	11.6

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Circulating Water Pumps	2,100	N/A	N/A
Induced Draft Fans VFD Deployment	2,900	2.39	276.5
Forced Draft Fans VFD Deployment	2,000	0.43	50.3
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.23 to 0.60	26.6 to 69.5
Heat Rate Improvement Training	15	0.30	34.7
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	0.15	17.4

Table ES-2 A.B. Brown Unit 2 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	55.0
Air Heater (Steam Coil) System Repairs	350	0.10	11.0
Circulating Water Pumps	2,100	N/A	N/A
Induced Draft Fans VFD Deployment	2,900	1.33	146.3
Forced Draft Fans VFD Deployment	2,000	0.26	28.6
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.30 to 0.60	25.3 to 66.0
Heat Rate Improvement Training	15	0.30	33.0
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	Negligible	Negligible

Table ES-3 F.B. Culley Unit 2 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
Air Heater Basket, Seal, and Sector Plate Replacement	476	0.50	63.2
Circulating Water Pumps	900	N/A	N/A
Forced Draft Fans VFD Deployment	2,000	0.48	60.9
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.26 to 0.62	32.9 to 78.4
Boiler Feed Pump VFD Deployment	600	0.6	75.8
Synchronized Controlled Sootblowing System Designed to Alleviate Excessive Use of Steam, Air or Water That Have A Negative Effect on Heat Rate.	350	0.10	12.64
Heat Rate Improvement Training	15	0.30	37.9
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	0.42	53.1

Table ES-4 F.B. Culley Unit 3 Summary of ACE Technology Costs

Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)
HP/IP Upgrades	19,900	1.5	158.3
Air Heater Basket, Seal, and Sector Plate Replacement	750	0.50	52.8
Air Heater (Steam Coil) System Repairs	350	0.10	10.6
Circulating Water Pumps	2,100	N/A	N/A
Forced Draft Fans VFD Deployment	2,000	0.51	54.3
Deployment of A Neural Network for Combustion Control and Boiler Excess Air Reduction. (0.25% to 0.75% Reduction in Excess O_2)	500	0.25 to 0.62	26.4 to 65.4
Heat Rate Improvement Training	15	0.30	31.7
On-Site Heat Rate Appraisals	Variable	Variable	N/A
Improved Condenser Cleaning Strategies	N/A	0.44	46.4

1.0 Introduction

Vectren requested that Black & Veatch support its efforts to analyze a potential response to the United States Environmental Protection Agency (EPA) Docket ID No. EPA-HQ-OAR-2017-0355: FRL-9995-70-OAR, "Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations;" known as the Affordable Clean Energy (ACE) rule. Vectren operates the A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 coal-fired electric generating units (EGUs) and specifically requested that Black & Veatch develop a high-level assessment report identifying opportunities to improve plant efficiency to meet ACE rule goals.

To meet these goals, Black & Veatch prepared a high-level description of four primary heat rate improvement (HRI) projects that have been proposed by the EPA as the best system of emission reduction (BSER). Estimates of HRI, annual carbon dioxide (CO_2) reduction, and a rough order-of-magnitude capital cost estimate were developed for each alternative.

Black & Veatch performed a high-level assessment to consider the technical and economic feasibility of items that have been seen as beneficial in previous ACE studies. Financial benefits would be confirmed by integrated resource plan (IRP) modeling; specific modifications would then be reviewed in a detailed effort to confirm the performance and financial benefits.

1.1 AN OVERVIEW OF EPA-ACE

On June 19, 2019, EPA issued the ACE rule, a replacement to the previous presidential administration's Clean Power Plan (CPP) to regulate CO_2 emissions from existing coal-fired power plants. ACE regulates EGUs based on the BSER. Unlike the CPP, ACE focuses on only those measures which can be implemented within the fence line of existing EGU facilities. As such, EPA has determined BSER to be limited to heat rate improvement (HRI) measures (efficiency improvements) for existing coal-fired EGUs at the individual unit level. The lower a unit's heat rate, the more efficiently it will convert heat input to electrical output, consuming less fuel per kilowatt-hour (kWh) and emitting lower amounts of CO_2. To aid operators and state agencies in determining which measures should be considered when determining BSER, EPA developed a list of 7 HRI candidate technologies. According to EPA, these technologies have been shown to be reliable, efficient, cost-effective, and broadly achievable for a source category across the country. The technologies include:

- Steam turbine blade path upgrades.
- Redesign or replacement of the economizer.
- Air heater and duct leakage control.
- Variable frequency drive (VFD) deployment.
- Neural networks/Intelligent sootblowing (ISB).
- Boiler feed pump upgrade/overhaul
- Various improved operations and maintenance (O&M) practices.

The EPA has responsibility under the CAA to provide a range of reductions and costs associated with each of the candidate technologies. The ranges of expected reductions for each technology are to be used as guidance, but the states will be expected to evaluate each affected unit individually. For reference, EPA's summary of HRI measures and the range of their HRI potential (%) by EGU size is included in Table 1-1. These ranges represent the degree of emission reduction achievable for each technology, however the EPA acknowledges that a specific unit may have the potential for more or less emission reduction based on the unit's specific characteristics. According to the preamble to the final rule, HRI potential will be determined by source-specific factors including, but not limited to, the EGU's past and projected utilization rate, maintenance history, and remaining useful life[1].

Table 1-1 EPA's Summary of HRI Measures and Range of HRI Potential (%) by EGU Size

HRI MEASURE	<200 MW		200-500 MW		>500 MW	
	MIN	MAX	MIN	MAX	MIN	MAX
Neural Network/Intelligent Sootblowers	0.5	1.4	0.3	1.0	0.3	0.9
Boiler Feed Pumps	0.2	0.5	0.2	0.5	0.2	0.5
Air Heater & Duct Leakage Control	0.1	0.4	0.1	0.4	0.1	0.4
Variable Frequency Drives	0.2	0.9	0.2	1.0	0.2	1.0
Blade Path Upgrade (Steam Turbine)	0.9	2.7	1.0	2.9	1.0	2.9
Redesign/Replace Economizer	0.5	0.9	0.5	1.0	0.5	1.0
Improved Operating and Maintenance (O&M) Practices	Can range from 0 to >2.0% depending on the unit's historical O&M practices.					

Ultimately, it is the EPA's role to determine the possible BSERs and the degree of emission control achievable for each technology, and it is the states' role to create plans establishing unit-specific standards (in a lbm CO_2/MWh format) that reflect the application of the BSER. Each state will be required to submit plans (or a State Implementation Plan [SIP]) to the EPA explaining how the state applied the BSER to each source and what other factors were considered when developing the unit-specific standards. In addition to the performance standards, states will also propose compliance deadlines for each EGU, as well as monitoring, recordkeeping and reporting requirements in their plans. These plans will be due to the EPA in three years (July 2022). Upon submittal, the EPA will have 12 months to determine whether or not to approve the plan.

[1] This could have the most significant implications for F.B. Culley Unit 2.

The emission limits and requirements for Vectren's affected EGUs will ultimately be established by IDEM. States are afforded considerable flexibility in determining emission standards for each unit as each state is more familiar with the existing sources within their jurisdictions. States are to use the guidelines EPA provided to evaluate each applicable EGU within its jurisdiction with regards to the utilization of each of the candidate technologies, equipment upgrades, and best O&M practices in establishing a standard of performance for that source. Physical and cost considerations will limit or prevent full implementation of the listed technologies and each state will consider these factors when establishing the standards of performance required. The remaining useful life of the source and other source-specific factors will also be considered by the states when establishing the standards of performance for each unit.

It will be the states' responsibilities to determine how these factors will be taken into consideration when establishing the standards. One approach that states may use is a top-down analysis that examines technical feasibility and cost effectiveness when determining an appropriate standard. Black & Veatch notes that variations of this type of analysis have been used by EPA in multiple regulatory programs to determine appropriate controls (e.g., BACT, RACT, BART, etc.). Such an analysis of the candidate BSER technologies could entail the following steps:

1. Identify all technologies (This step has already been done by the rule);
2. Eliminate technically infeasible options;
3. Rank remaining technologies by effectiveness;
4. Evaluate the most effective controls – entails energy, environmental, and economic impacts – cost effectiveness could entail a consideration of remaining useful life to ultimately determine the cost of a technology on the basis of dollars per lbm CO_2/MWh improvement.
5. Select the appropriate technology and set a standard of performance in terms of a lbm CO_2/MWh emission rate.

Black & Veatch notes that such an approach could provide state agencies such as IDEM with the defensible approach that they seek to avoid potential legal vulnerabilities while at the same time allowing Vectren to implement the most cost-effective option. Given the lack of specificity in the Rule, IDEM and their stakeholders have been afforded a great deal of latitude in designing the SIP. Therefore, early engagement with IDEM is encouraged in order to influence and assist in their determinations of the appropriate performance standard to include in the SIP for Vectren's affected units.

Numerous lawsuits have already been filed against the ACE rule, however, no stay (delay in rule administration) has been requested to this point. As with many environmental rules, industry sentiment is that the Rule's fate could be determined by the 2020 presidential election. In the meantime, however, Black & Veatch would expect that states will begin to gather information in order to begin designing their SIPs.

1.2 EPA'S INTEGRATED PLANNING MODEL

To assess the potential costs and benefits associated with the ACE rule, the EPA used the Integrated Planning Model (IPM) in support of final rulemaking. According to EPA documentation on the latest version of the model (EPA Platform v6, November 2018), "IPM is a multi-regional […] model of the U.S. electric power sector" that provides "[…] forecasts of least cost capacity expansion, electricity dispatch, and emission control strategies while meeting energy demand, environmental, transmission, dispatch, and reliability constraints." Historically, EPA has used the IPM to forecast power sector behavior and examine the impact of potential air pollution control policies. The EPA has used this model for over two decades to evaluate the economic and emission impacts of potential environmental regulations. Specifically, EPA has used v6 to develop regulatory impact analyses in support of the Cross-State Air Pollution Rule (CSAPR), the greenhouse gas New Source Performance Standard (NSPS) for new, modified, and reconstructed electric utility generating units (NSPS Subpart TTTT), the Mercury and Air Toxics Rule (MATS), the Regional Haze Rule, 316b, and ELG/CCR regulations.

The EPA IPM is quite complex and utilizes numerous inputs to characterize the power sector including:

- Power System Operation
- Generation Resources
- Emission Control Technologies
- CO_2 Capture, Transport, and Storage
- Coal Characteristics (i.e., Supply Curves and Transportation Matrix)
- Natural Gas Market Characteristics
- Other Fuel Assumptions
- Financial Assumptions

These inputs are processed in the model in order to arrive at outputs quantifying sector-wide emissions, costs, capacity expansion, retrofit decisions, fuel consumption and prices, and electricity generation and prices. Finally, these outputs can be fed into a post-processor in order to forecast individual boiler-level data, retail electricity price projections, and outputs needed to assess the impacts on air quality via air quality modeling. According to the model documentation, "The model has been tailored to meet the unique environmental considerations important to EPA, while also fully capturing the detailed and complex economic and electric dispatch dynamics of power plants across the country."

The IPM model was not designed to evaluate the technological or economic feasibility of the various BSER technologies for a single ACE-affected unit, but, rather, is intended to be used to holistically evaluate the impacts of EPA rulemakings on the entire power sector. Additionally, the model appears overly complex, such that it could be time-consuming and provide a false sense of accuracy when used to evaluate the technologies as part of an ACE study. As such, it is unlikely that the IPM would/should ever be utilized to evaluate the BSER technologies as a part of a state ACE compliance plan.

1.3 POTENTIAL NEW SOURCE REVIEW CHANGES

To accommodate and facilitate the HRI projects associated with the ACE rulemaking, EPA has proposed changes to the New Source Review (NSR) permitting program. Under the current regulations, modifications to stationary sources, such as EGUs, that increase annual emissions of regulated pollutants at or above certain regulatory thresholds are subject to NSR permitting requirements. EPA is now proposing to incorporate a comparison of hourly emissions into the NSR applicability assessment for EGUs. Under this approach, the maximum actual emissions values measured on an hourly basis before the project and the projected hourly emission rate that will occur after the proposed modification would be compared to determine if an emission increase would result. If no *hourly* emissions increase will occur, NSR would not be applicable.

However, if hourly emissions were determined to increase, the emissions analysis must continue per the traditional methodology where an assessment of both project-specific overall emissions increases, and plant-wide net emissions increases on an annual basis would need to be calculated to determine if NSR permitting requirements would apply. Black & Veatch notes that this proposed rule-making is considered particularly vulnerable to legal challenges. Therefore, an evaluation of the potential applicability of NSR to each of the BSER options examined in this report may be prudent in order to provide Vectren a full picture of the costs project timeline associated with the various options. Additionally, EPA has noted in the final rule, that costs associated with permitting NSR applicable projects can be included in the economic evaluation of the various ACE technologies.

2.0 Existing Plant Characteristics

This section briefly describes the baseline characteristics of each unit. The average and summary annual performance data for each unit that were used to calculate the potential heat rate benefits of applicable technologies can be found in Section 4.0.

A.B. Brown Units 1 and 2 are “sister units” in that they share many common characteristics. Each unit is a nominal 265-megawatt (MW) gross and 245 MW net unit, featuring a subcritical pulverized coal furnace with reheat steam and designed for bituminous coal from the Illinois Basin. A.B. Brown Unit 1 was commissioned in 1979, and A.B. Brown Unit 2 in 1986. Each unit employs low-nitrogen oxide (NO_X) burners and a selective catalytic reduction system (SCR) for NO_X control, and a scrubber for sulfur dioxide (SO_2) control. Unit 1 uses a pulse-jet fabric filter baghouse, and Unit 2 uses a cold-side electrostatic precipitator for particulate removal. Heat rejection is provided by mechanical draft cooling towers.

F.B. Culley Unit 2 is a nominal 100 MW gross and 90 MW net unit, featuring a non-reheat subcritical pulverized coal furnace designed for bituminous coal from the Illinois Basin. F.B. Culley Unit 2 was commissioned in 1966. The unit employs low-NO_X burners for NO_X control and a scrubber for SO_2 control. The unit uses a cold-side electrostatic precipitator for particulate removal. Cooling water is provided by the Ohio River.

F.B. Culley Unit 3 is a nominal 287 MW gross and 270 MW net unit, featuring a subcritical pulverized coal furnace with reheat steam and designed for bituminous coal from the Illinois Basin. F.B. Culley Unit 3 was commissioned in 1973. The unit employs low-NO_X burners and an SCR system for NO_X control and a scrubber for SO_2 control. The unit uses a pulse-jet fabric filter (PJFF) baghouse for particulate removal. Cooling water is provided by the Ohio River.

3.1 Description of Heat Rate Improvement Alternatives

This preliminary heat rate project screening was based on a high-level analysis of A.B. Brown Unit 1 and on Black & Veatch's experience with similar projects. The projects depicted herein were selected from HRI projects detailed by the EPA in its ACE rule as BSER projects. A detailed table summarizing the benefits and costs is included in Appendix B.

3.2 UNIT STEAM TURBINE BLADE PATH UPGRADES

Black & Veatch reviewed the steam turbine blade path upgrade option for each of the existing plants. The specific steam turbine upgrades are described for each individual plant in the following subsections.

3.2.1 A.B. Brown Unit 1 Steam Turbine Blade Path Upgrades

Black & Veatch reviewed steam turbine blade path upgrade. The A.B. Brown Unit 1 steam turbine had a full dense pack upgrade installed in 2012. In 2016, extensive high-pressure/ intermediate-pressure (HP/IP) repairs were made because of a main stop valve bypass failure. Black & Veatch estimates that there would not be any significant improvement with a steam turbine upgrade now, considering the relatively shorter duration since the last steam path upgrade and the potential cost associated with it.

3.2.2 A.B. Brown Unit 2 Steam Turbine Blade Path Upgrades

Black & Veatch reviewed the steam turbine blade path upgrade. The A.B. Brown Unit 2 steam turbine had a full dense pack upgrade installed in 2013. Black & Veatch estimates that there would not be any significant improvement with a steam turbine upgrade now, considering the relatively shorter duration since the last steam path upgrade and the potential cost associated with it.

3.2.3 F.B. Culley Unit 2 Steam Turbine Blade Path Upgrades

The Culley Unit 2 steam turbine is a GE non-reheat steam turbine with a two-flow low-pressure turbine with 20 inch last stage blades. Black & Veatch performed a review of the steam turbine blade path upgrade. As a result of this investigation, two heat balance model of the Culley Unit 2 steam turbine were developed:

- Base: Best match of the Culley Unit 2 Thermal Kit heat balance 328 HB 706 rating flow (guarantee) +5%. (Valve-Wide-Open, Normal Pressure (VWO-NP) case).
- Upgrade Scenario: The entire steam path HP/LP (High-Pressure and Low-Pressure turbines) are upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance is more important than the absolute performance. The performance improvements and pricing estimates are based on in house data and past project experience. However, steam turbine manufacturers should be contacted to confirm performance and pricing.

3.1.3.1 Base Case

The Base case model is matched to the original thermal kit heat balance 328 HB 706, which is the rating flow (guarantee) +5%. The condenser pressure was set to 1.5 in HgA to keep the basis consistent across the models for comparison against various upgrade options. This Base model was then used to run four cases: Rating flow + 5%, guarantee load (rated pressure and rated flow, corresponding to thermal kit heat balance 332 HB 827), 80% of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 332 HB 829), and 60% of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 332 HB 831).

3.1.3.2 Upgrade Scenario: HP/LP Steam Path Upgrades

In this model, the HP and LP sectional efficiencies were increased from approximately 86.9% and 69.9%, to approximately 87.9% and 71.9% respectively. The advanced age of the Culley Unit 2 steam turbine makes it difficult to estimate exactly how much efficiency could be gained in each section and further analysis should be completed by a steam turbine manufacturer. This model was then used to run four cases: Rating flow + 5%, guarantee load, 80% of guarantee load, and 60% of guarantee load. In each of the cases the boiler steam generation was reduced such that the steam turbine power output matches the value found in the corresponding cases in the original design (STG OEM Thermal Kit).

Tables 3-1 through 3-4 show the results of the turbine modeling conducted by Black & Veatch for this study. For comparison purposes, it was assumed that a boiler efficiency of 88.3% (HHV basis) applies regardless of the magnitude and type of boiler upgrades that may be required. This boiler efficiency is provided by the Vectren data in the Culley Unit 3 snapshot data and was assumed to be the same for Culley Unit 2 for the purposes of this modeling to allow for a comparison between the units.

Table 3-1 Culley Unit 2 Steam Turbine Modeling Results – Rating Flow + 5%

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	99,765	99,766
Gross Turbine Heat Rate	Btu/kWh	9,012	8,881
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-131
Turbine Heat Rate Improvement	%	N/A	1.5%
Boiler Heat Input (HHV)	MBtu/h	1,018.4	1,003.6
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-14.8
Boiler Heat Input (HHV) Improvement	%	N/A	1.5%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,208	10,060
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-136
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.5%
*See the explanation above regarding the choice of the boiler efficiency value.			

Table 3-2 Culley Unit 2 Steam Turbine Modeling Results – Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	95,500	95,501
Gross Turbine Heat Rate	Btu/kWh	9,002	8,870
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-131
Turbine Heat Rate Improvement	%	N/A	1.5%
Boiler Heat Input (HHV)	MBtu/h	973.8	959.6
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-14.2
Boiler Heat Input (HHV) Improvement	%	N/A	1.5%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,197	10,048
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-136
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.5%
* See the explanation above regarding the choice of the boiler efficiency value.			

Table 3-3 Culley Unit 2 Steam Turbine Modeling Results – 80% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	76,239	76,239
Gross Turbine Heat Rate	Btu/kWh	8,977	8,856
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-121
Turbine Heat Rate Improvement	%	N/A	1.4%
Boiler Heat Input (HHV)	MBtu/h	775.3	764.8
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-10.5
Boiler Heat Input (HHV) Improvement	%	N/A	1.4%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,169	10,032
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-138
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.4%
* See the explanation above regarding the choice of the boiler efficiency value.			

Table 3-4 Culley Unit 2 Steam Turbine Modeling Results – 60% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
Gross STG Gross Output	kW	56,672	56,672
Gross Turbine Heat Rate	Btu/kWh	9,133	9,020
Turbine Heat Rate Change	Btu/kWh	N/A	-113
Turbine Heat Rate Improvement	%	N/A	1.2%
Boiler Heat Input (HHV)	MBtu/h	586.3	579.0
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-7.3
Boiler Heat Input (HHV) Improvement	%	N/A	1.2%
Gross Plant Heat Rate (HHV)	Btu/kWh	10,346	10,217
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-129
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.2%
* See the explanation above regarding the choice of the boiler efficiency value.			

The estimate capital cost and HRI for the turbine upgrade option is as follows:

Full Steam Path Upgrade

Total Installed Capital Cost:	$10.4 million
Heat Rate (efficiency) Improvement:	1.3-1.5%

3.1.4 F.B. Culley Unit 3 Steam Turbine Blade Path Upgrades

The F.B. Culley Unit 3 steam turbine is a GE reheat steam turbine with a two-flow LP turbine and 26-inch last stage blade length for the LP end. Black & Veatch reviewed the steam turbine blade path upgrade. As a result of this investigation, heat balance cases were developed for the F.B. Culley Unit 3 steam turbine:[2]

- Base Case: Best match of the F.B. Culley Unit 3 thermal kit heat balance 534 HB 894 (guarantee).
- Upgrade Scenario: The entire HP/IP/LP steam path is upgraded.

This analysis is based on the incremental improvement in steam turbine efficiency, and the differential performance is more important than the absolute performance. The performance improvements and pricing estimates are based on in-house data and past project experience and are believed to be achievable. However, steam turbine manufacturers should be contacted to confirm performance and pricing.

3.1.4.1 Base Case

The Base Case model is matched to the thermal kit heat balance 534 HB 894, which is the guarantee case. The condenser pressure was set to 3.5 in. HgA to keep the basis consistent across the models for comparison against various upgrade options. This Base Case model was then used to run three cases: Guarantee load (rated pressure and rated flow, corresponding to thermal kit heat balance 534 HB 894); 80 percent of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 170X450-21); and 60 percent of guarantee load (rated pressure and reduced flow, corresponding to thermal kit heat balance 170X450-22).

3.1.4.2 Upgrade Scenario: HP/IP/LP Steam Path Upgrades

In this model, the HP, IP, and LP sectional efficiencies were increased from approximately 86.7 percent, 88.2 percent, and 89.3 percent to approximately 90 percent, 90 percent, and 92 percent, respectively[3]. This model was then used to run three cases: Guarantee load; 80 percent of guarantee load; and 60 percent of guarantee load. In each of the cases, the boiler steam generation was reduced so that the steam turbine power output matched the values found in the corresponding cases in the original design (STG OEM thermal kit).

---

[2] Additional cases could be evaluated which look at the difference between current performance if the blades and turbine are newly overhauled, versus a new upgrade. Another possibility is developing a map of turbine performance over an expected life between major turbine outages and maintenance activities. Those require more detailed studies which mandate input from the STG OEM with a reference upgrade design, which is beyond the scope of this EPA-ACE analysis.

[3] Based upon OEM data.

Tables 3-5 through 3-7 show the results of the turbine modeling conducted by Black & Veatch for this study. For comparison purposes, it was assumed that a boiler efficiency of 88.3 percent (HHV basis) applies regardless of the magnitude and type of boiler upgrades that may be required.

Table 3-5 F.B. Culley Unit 3 Steam Turbine Modeling Results – Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/IP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	288,360	288,367
Gross Turbine Heat Rate	Btu/kWh	8,219	8,085
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-134
Turbine Heat Rate Improvement	%	N/A	1.6%
Boiler Heat Input (HHV)	MBtu/h	2,684.7	2,640.9
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-43.8
Boiler Heat Input (HHV) Improvement	%	N/A	1.6%
Gross Plant Heat Rate (HHV)	Btu/kWh	9,310	9,158
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-152
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.6%

*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.

Table 3-6 F.B. Culley Unit 3 Steam Turbine Modeling Results – 80% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/IP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	236,806	236,817
Gross Turbine Heat Rate	Btu/kWh	8,254	8,129
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-125
Turbine Heat Rate Improvement	%	N/A	1.5%
Boiler Heat Input (HHV)	MBtu/h	2,214.1	2,180.7
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-33.4
Boiler Heat Input (HHV) Improvement	%	N/A	1.5%
Gross Plant Heat Rate (HHV)	Btu/kWh	9,350	9,208
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-142
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.5%

*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.

Table 3-7 F.B. Culley Unit 3 Steam Turbine Modeling Results – 60% of Guarantee Load

		ORIGINAL HEAT BALANCE	UPGRADE HP/IP/LP
Boiler Efficiency (HHV)*	%	88.3	88.3
STG Gross Output	kW	178,684	178,683
Gross Turbine Heat Rate	Btu/kWh	8,451	8,333
Gross Turbine Heat Rate Change	Btu/kWh	N/A	-118
Turbine Heat Rate Improvement	%	N/A	1.4%
Boiler Heat Input (HHV)	MBtu/h	1,710.6	1,686.7
Boiler Heat Input (HHV) Change	MBtu/h	N/A	-23.9
Boiler Heat Input (HHV) Improvement	%	N/A	1.4%
Gross Plant Heat Rate (HHV)	Btu/kWh	9,573	9,440
Gross Plant Heat Rate (HHV) Change	Btu/kWh	N/A	-134
Gross Plant Heat Rate (HHV) Improvement	%	N/A	1.4%
*This boiler efficiency takes its basis from the F.B. Culley Unit 3 data snapshot, collected on May 27, 2019.			

The estimate capital cost and HRI for the turbine upgrade options is as follows:

Full Steam Path Upgrade

Total Installed capital cost: $19.9 million

Heat Rate (efficiency) improvement: 1.4-1.6%

3.2 UNIT ECONOMIZER REDESIGN OR UPGRADES

3.2.1 Economizer Upgrades Under EPA ACE

One of the primary BSER under the EPA ACE is the prospect of upgrades to, or even complete replacement of, the economizer. The overarching goal in economizer upgrades or replacement is to improve heat transfer from the flue gas to add heat to the boiler water/steam circuit and, thus, improve boiler efficiency. According to the performance estimates included in the EPA ACE proposal, redesign or replacement of the economizer should yield a heat rate improvement from 0.5 percent to 0.9 percent for units under 200 MW, and from 0.5 percent to 1.1 percent for units ranging from 200 MW to 500 MW. The EPA specifically states that economizer replacements are often avoided because of concerns over triggering New Source Review (NSR); for this reason, the EPA ACE is intended to provide power plants with the flexibility to make these changes.

However, there are many risks associated with redesign or replacement of the economizer:

- Most commonly, projects that consider increasing economizer tube surface area are ones which consider adding tube passes to either the upstream or the downstream portion of the economizer(s). This is because most economizers have a dense tube packing that disallows addition of tube assemblies across the furnace width. However, in the boiler backpass region, space constraints often limit the ability to add more than 2 or 3 tube passes. Thus, making significant changes to the economizer may not be possible at many units.
- Even the addition of a single pass of tubes requires an extended boiler outage; significant construction preparation and welding/tie-in work are required to add tubes to the economizer. The replacement power cost and lost opportunity/contract cost of this outage can be significant if it is not combined with a previously planned outage (such as, for steam turbine upgrades).
- Replacement of entire economizers is not generally done within the industry because of the large expense involved. When it has been undertaken in recent years, the most common reasons are either to replace a badly eroded economizer, or to replace an economizer with spiral-finned tubes with one with bare tubes to reduce tube fouling (especially after conversions to Powder River Basin coals).
- Changing tube surface area will often change the balance of heat transfer between the radiative and connective sections, as well as the main steam and reheat steam circuitry. This is especially true in the case of units that employ a split backpass design with gas biasing reheat control. Prediction of the complex interactions between the water, main steam, and reheat steam circuits in both the radiative and convective sections typically requires detailed boiler modeling.
- Adding tube surface to an economizer will reduce the flue gas temperature exiting the economizer, which could reduce operations flexibility if an SCR is positioned downstream of the economizer. Reduced flue gas temperatures will increase the minimum load possible with the SCR in service and could require a system such as an economizer gas bypass or in-duct burners to allow for SCR operation with these reduced temperatures. Both of these reparative measures will worsen the plant heat rate, thus negating the benefit of the upgraded economizer.
- Reduced flue gas temperatures entering the air heater will help improve the overall boiler efficiency but can also lead to operations problems should the cold-end average temperature be reduced below the recommended point for the type of fuel that is being burned and its sulfur content. In addition, ammonium bisulfate deposition can be increased in some cases where the flue gas inlet temperature at the air heaters is reduced from normal.
- In some cases, flue gas temperatures could be reduced to the point where other downstream air quality control equipment (such as an electrostatic precipitator or fabric filter baghouse) could be at risk for corrosion damage.

- While it is possible to add an economizer downstream of the SCR system to reduce the impact on the flue gas temperature entering the SCR, such installations are unusual and often require variable water bypass circuitry to maintain good temperature control.

Assessment of the ability of a unit to accommodate changes in the economizer tube surface area typically requires plant modeling of some sort, whether utilizing a combined first-principles and empirical model (such as the Electric Power Research Institute's [EPRI's] Vista program), or even a highly detailed (and expensive) computation fluid dynamics model of the entire boiler circuit and downstream affected equipment. The following section is a high-level overview of economizer upgrades, while the further sections provide more detail through the use of Vista modelling software.

Cost estimation for economizer upgrades is highly variable and depends on the amount of work conducted, the site spacing and access, other boiler or plant modifications that are required, etc. The EPA ACE rule advises in Table 2 that the cost to redesign or replace an economizer can be up to $3.74 million for a 200 MW unit or up to $6.35 million for a 500 MW unit.

3.2.2 A.B. Brown Units 1 and 2 Economizer Redesign or Upgrades

Plant personnel report that because of low SCR inlet temperatures, A.B. Brown Units 1 and 2 require natural gas duct burners to be operated to maintain temperatures over the minimum SCR inlet temperature of 625° F. An example of the gas duct burner operation as a function of gross output is shown for Unit 1 on Figure 3-1.

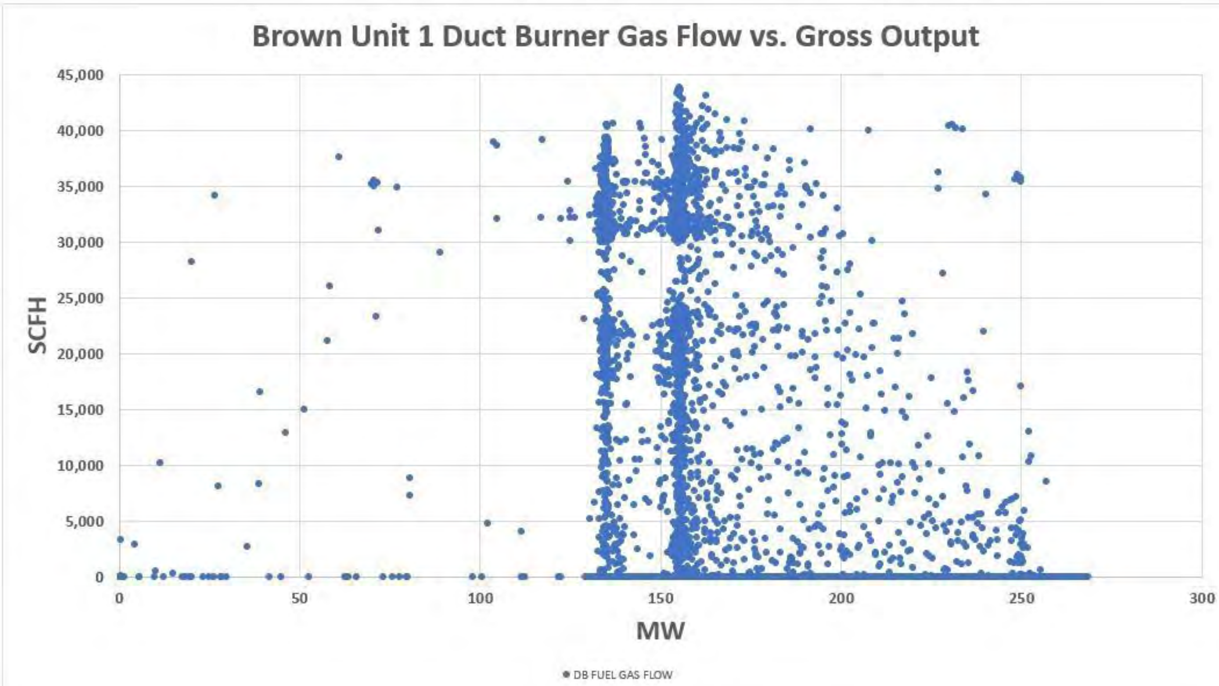


Figure 3-1 A.B. Brown Unit 1 Economizer Gas Flow vs. Gas Outlet

Plant personnel stated that the high gas use of the duct burners is a concern from a heat rate standpoint, although, unlike the case of F.B. Culley Unit 3, there was no estimate on the overall annual heat rate impact. Given this situation at A.B. Brown Units 1 and 2, adding economizer tube surface area is not recommended at this time. It is possible that reducing the economizer tube surface area could improve the plant heat rate by reducing the natural gas usage, and a next-phase study could easily determine this by employing coordinated plant modeling with a boiler-SCR-air heater model across the typical operating load ranges of the units.

3.2.3 F.B. Culley Unit 2 Economizer Redesign or Upgrades

F.B. Culley Unit 2 has maintained its original economizer design, and as it does not have an SCR system, it does not suffer from the constraint of reduced flue gas temperatures limiting operation. As a result, it is possible that economizer modifications could result in a significant heat rate benefit to the unit, especially as the F.B. Culley Unit 2 economizer gas outlet temperature appears to be high at higher loads (over 700° F at times). Refer to Figure 3-2.

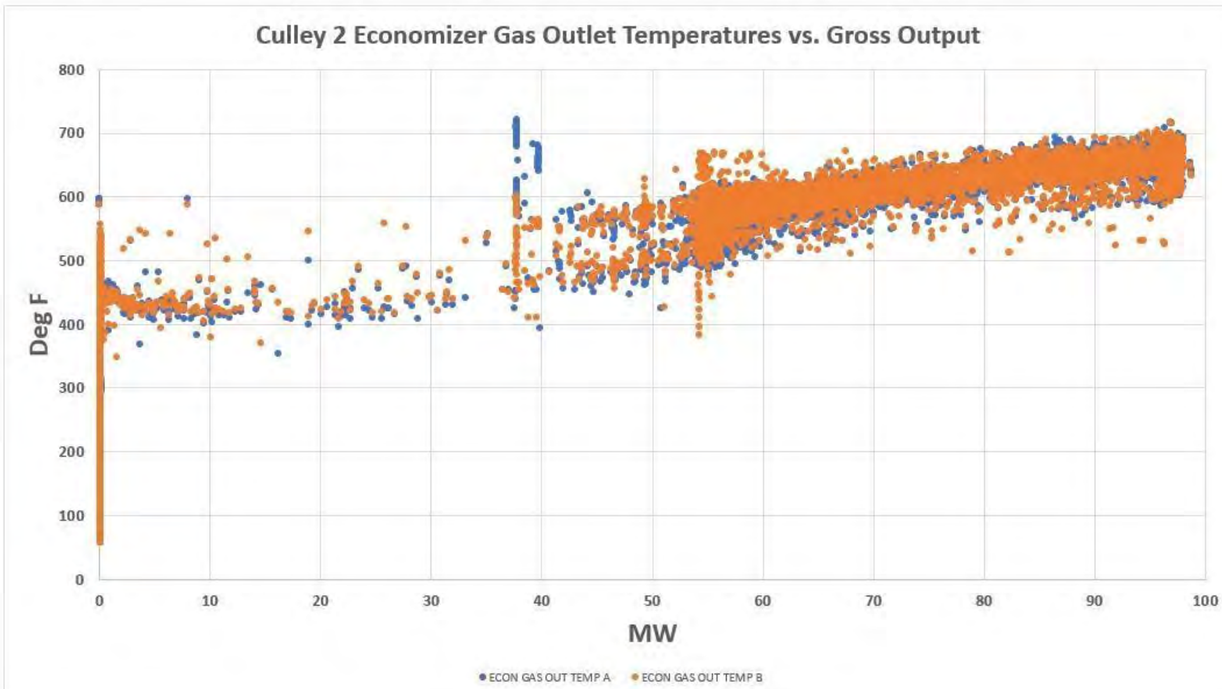


Figure 3-2 F.B. Culley Unit 2 Economizer Gas Outlet Temperature Versus Gross Output

The estimated costs and logistics of such a change to the economizers requires significant investigation as a next-phase effort. Assuming no header relocation is needed, and neglecting the loss of contract availability, such a cost is estimated at about $40,000 to 50,000 per British thermal unit per kilowatt-hour (Btu/kWh) for the improvement, or between $2 million to $4 million. For a small, non-reheat unit such as F.B. Culley Unit 2, such an investment may not be warranted at this juncture unless the unit was expected to operate for a significant length of time so that a sufficient payback period could be realized. When the expected future load factor and remaining plant life are taken into account, it is nearly impossible to justify an investment in this area of the plant.

3.2.4 F.B. Culley Unit 3 Economizer Redesign or Upgrades

According to plant personnel, the F.B. Culley Unit 3 economizer was replaced in 1994 with a tube configuration that had additional tube surface area relative to the original design. The goal of this upgrade was to reduce flue gas exit temperatures and improve cycle efficiency, and in that respect, it was successful. However, when the SCR system was added in 2003, the lower flue gas temperatures exiting the economizer resulted in the need for natural gas duct burners to maintain the minimum SCR flue gas inlet temperature of 625° F. The economizer was replaced again in 2008 but was not changed to the original design because of concerns about triggering NSR. Refer to Figure 3-3.

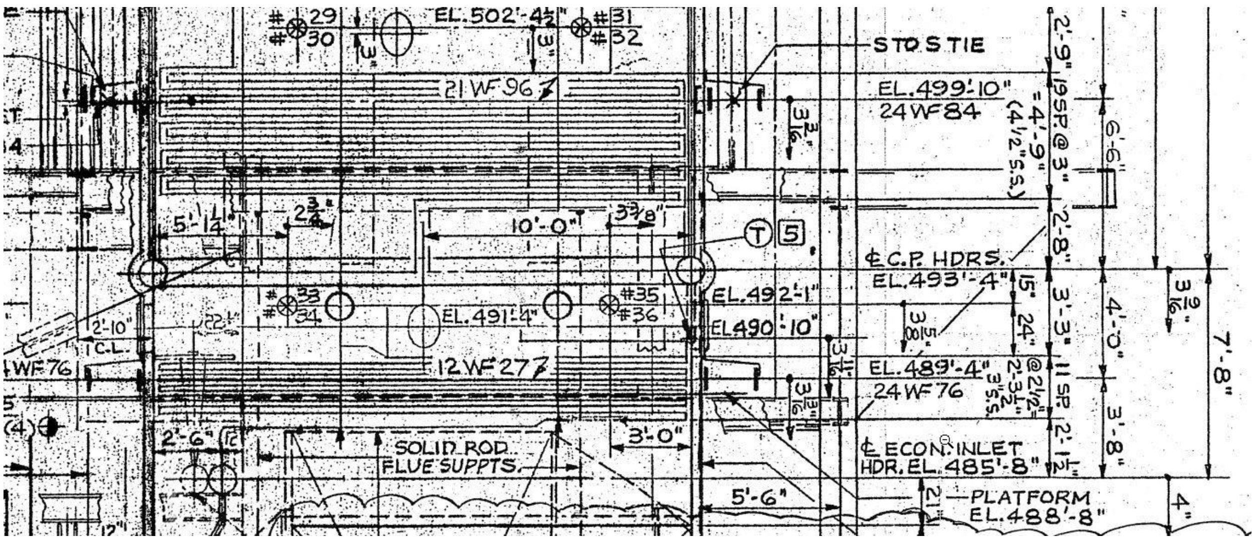


Figure 3-3 F.B. Culley Unit 3 Original Economizer Design

F.B. Culley Unit 3 is required to utilize significant amounts of natural gas via in-duct burners upstream of the SCR system to maintain SCR operating temperatures at anything less than 75 to 80 percent of full load. A plot of operational data, comparing the natural gas burner fuel flow rate versus the unit gross output, is shown by Figure 3-4.

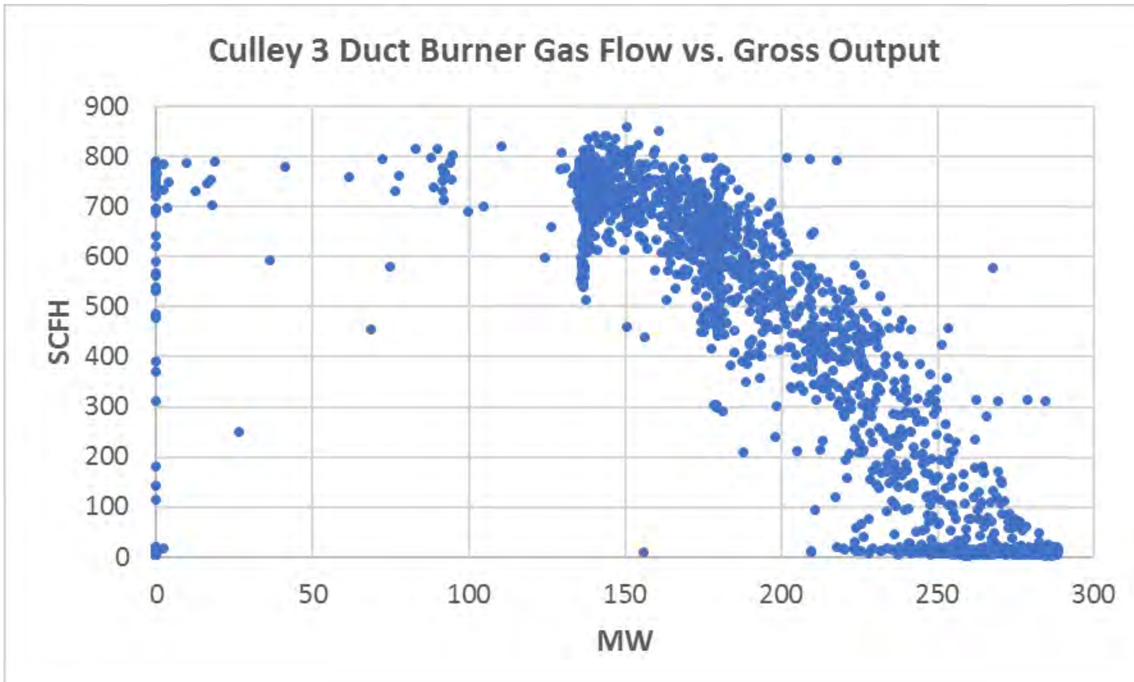


Figure 3-4 F.B. Culley Unit 3 Duct Burner Gas Flow Versus Gross Output

Given this situation at F.B. Culley Unit 3, adding economizer tube surface area is not recommended at this time. It is possible that reducing the economizer tube surface area could improve the plant heat rate by reducing the natural gas usage, and a next-phase study could easily determine this by employing coordinated plant modeling with a boiler-SCR-air heater model across the typical operating load ranges of the units. Plant personnel report that natural gas heat input to the duct burners comprised nearly 2 percent of the total heat input to the unit for 2018 and 2019 to date.

3.2.5 Economizer Analysis using Vista

Based on the analysis and discussion in the above sections, an analysis of the benefit of reducing natural gas flow to the duct burners by reducing the size of the economizer section was performed for A.B. Brown 1 and F.B. Culley 3. To assess the economizer, Black &Veatch created a base case and then investigated three options: removing 1, 2, and 3 tube passes.

Using data provided by Vectren engineering personnel, an EPRI Vista fuel quality impact model was created for A.B. Brown 1 and F.B. Culley 3. The Vista program contains a detailed linear heat transfer model that has the power to conduct “what if” analyses upon tube banks surface area configurations, and this model was utilized successfully for this study. Several simulations of tube configurations that would decrease the heat transfer area of the economizer were analyzed, and these are detailed in this section. A schematic of the current economizer for A.B. Brown 1 is depicted below (F.B. Culley 3 is depicted in Figure 3-3):

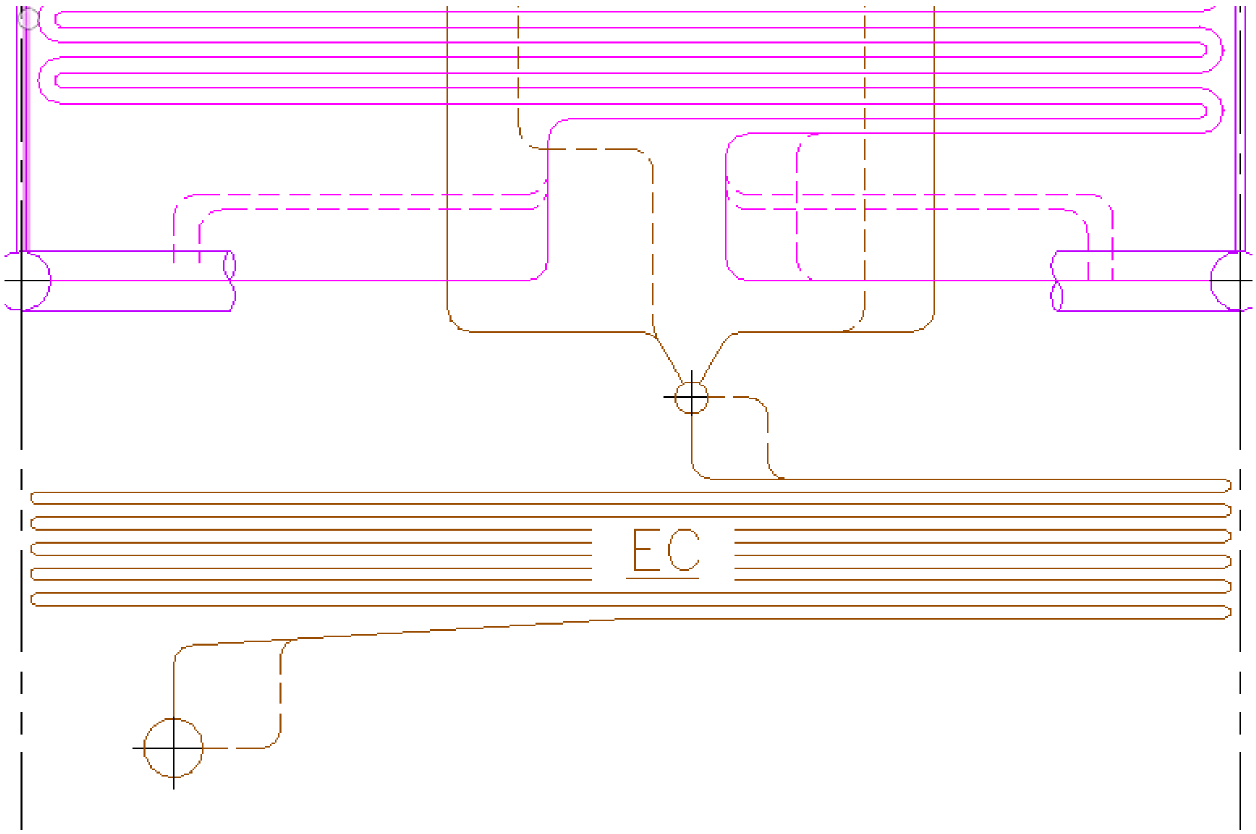


Figure 3-5 A.B. Brown 1 Economizer

3.2.5.1 A.B. Brown Units 1 and 2 Economizer Analysis Results

After calibrating the Vista model of A.B. Brown 1 to 264 MW gross from data collected on August 9, 2018, the following scenarios were run, with the following results.

- Baseline case – SCR inlet temperature = 651 °F.
- Removing 1 pass to the lower economizer – SCR inlet temperature = 662 °F.
- Removing 2 pass to the lower economizer – SCR inlet temperature = 675 °F.
- Removing 3 passes to the lower economizer – SCR inlet temperature = 690 °F.

The results above were from running the model at full load. The graph below shows the unit load vs. the duct burner natural gas flow.

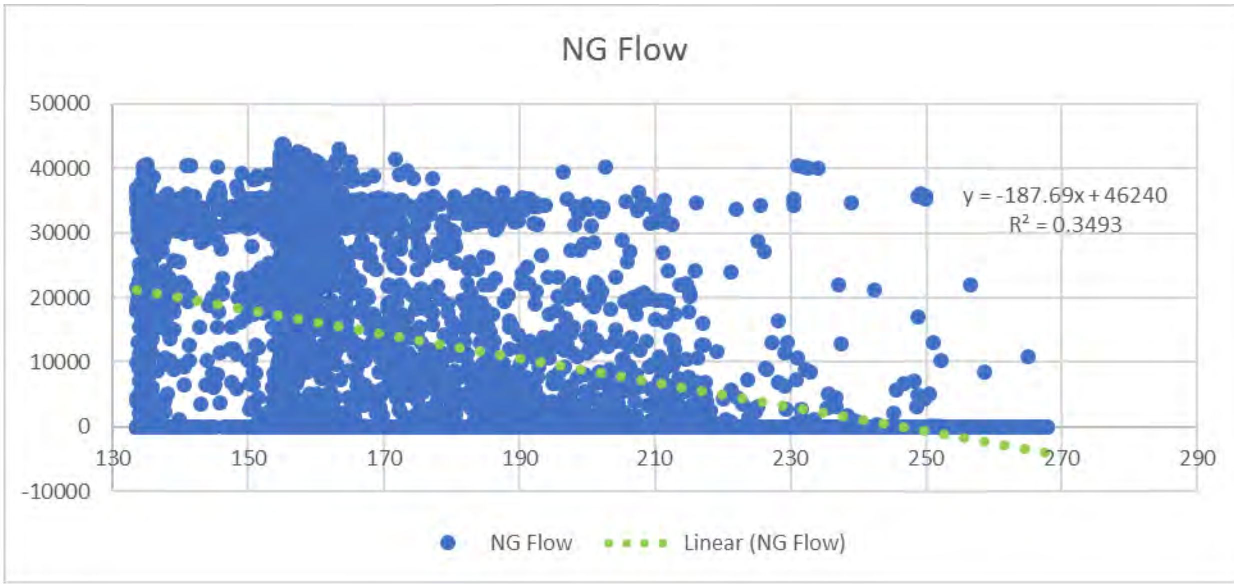


Figure 3-6 Load vs. Temperature and Flow

Linear regression was used to determine the natural gas flow; however, the correlation between natural gas flow and load was poor (R^2 of 0.35). This may warrant further investigation into the measurement or control methodology of the natural gas flow for the duct burners. Also, A.B. Brown 1 does not have an online measurement for the economizer flue gas outlet temperature. If this temperature was measured and tracked in the data historian, it would significantly improve the analysis of the data.

This reduction in economizer surface area comes at a cost in heat rate. From the analysis a reduction in the economizer surface area produces the following heat rate impacts on an overall basis:

- Baseline case – 0% difference.
- Removing 1 pass to the lower economizer – 0.17 % worsening.
- Removing 2 passes to the lower economizer – 0.36 % worsening.
- Removing 3 passes to the lower economizer – 0.61 % worsening.

This heat rate impact had the following effects on fuel burn rate at full load:

- Removing 1 pass to the lower economizer – 4.23 MMBtu/hr increase.
- Removing 2 passes to the lower economizer – 8.91 MMBtu/hr increase.
- Removing 3 passes to the lower economizer – 15.06 MMBtu/hr increase.

Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change to the economizers, assuming no header relocation is needed and neglecting the loss of contract availability, are expected to range from $750,000 to $1,400,000 depending upon the amount of modification. Complete replacement of the economizer was not estimated during this effort, nor was any addition to hot reheat surface or any other modifications.

3.2.5.2 F.B. Culley Unit 3 Economizer Analysis Results

After calibrating the Vista model of F.B. Culley 3 to 286 MW gross from data collected on May 27, 2019, the following scenarios were run, with the following results.

- Baseline case – SCR inlet temperature = 649 °F.
- Removing 1 pass to the lower economizer – SCR inlet temperature = 656 °F.
- Removing 2 pass to the lower economizer – SCR inlet temperature = 663 °F.
- Removing 3 passes to the lower economizer – SCR inlet temperature = 670 °F.

The results above were from running the model at full load. The graph below shows unit load vs. SCR inlet temperature, economizer gas outlet temperature, and duct burner natural gas flow. The delta-temperature below the minimum acceptable SCR inlet temperature of 625 °F was also plotted.

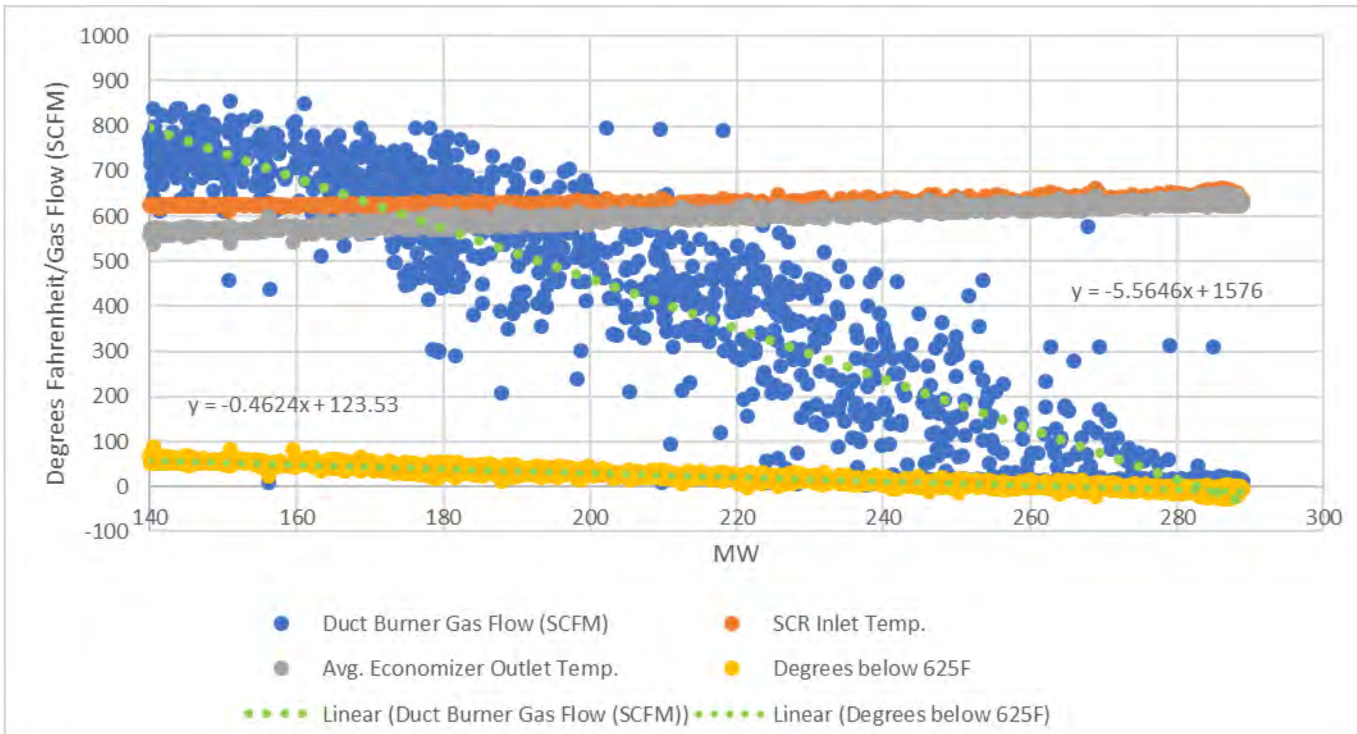


Figure 3-7 Load vs. Temperature and Flow

Using linear regression, the temperature difference calculated from Vista was used to determine new loads without using the duct burner and the gas flow savings for each economizer pass reduction"

- Removing 1 pass to the lower economizer – New load without duct burner use - 252MW, Gas Flow savings - 174 SCFM (10.6 MMBtu).

- Removing 2 passes to the lower economizer – New load without duct burner use- 237MW, Gas Flow savings - 257 SCFM (15.7 MMBtu).
- Removing 3 passes to the lower economizer – New load without duct burner use- 222MW, Gas Flow savings - 341 SCFM, (20.8 MMBtu).

This reduction does come at a cost in heat rate. From the analysis a reduction in the economizer surface area produces the following heat rate impacts on an overall basis:

- Baseline case – 0% difference.
- Removing 1 pass to the lower economizer - 0.14% worsening.
- Removing 2 passes to the lower economizer – 0.28% worsening.
- Removing 3 passes to the lower economizer – 0.43% worsening.

This heat rate impact had the following effects on fuel burn rate at full load:

- Removing 1 pass to the lower economizer – 3.22 MMBtu/hr increase.
- Removing 2 passes to the lower economizer – 6.6 MMBtu/hr increase.
- Removing 3 passes to the lower economizer – 10.16 MMBtu/hr increase.

From examining the results listed above, removing a portion of the economizer would results in an energy savings. Given the cost differential of $3.00 per MMBtu for natural gas compared to Vectren's $2.22 per MMBtu for coal, the savings in natural gas flow at full load would be approximately $5.76 per hour for the 1 pass case and $8.30 per hour for the 3-pass case. Assuming that savings would be realized over 70% of the year (8760 hours). This would result in $151k in savings for the first year for the base case and $244k in savings for the first year for the alternate case.

Should a change be made to the economizer tube surface area, the estimated costs and logistics of such a change to the economizers, assuming no header relocation is needed and neglecting the loss of contract availability are expected to range from $750,000 to $1,400,000 depending upon the amount of modification. Complete replacement of the economizer was not estimated during this effort, nor was any addition to hot reheat surface or any other modifications.

3.3 AIR HEATER AND LEAKAGE CONTROL UPGRADES

A core opportunity for net plant heat rate (NPHR) improvement is solidifying the operational reliability and process integrity of the combustion air draft system and flue gas draft system. The gas-to-air regenerative air heaters are a critical nexus between these two subsystems. Similarly, balanced draft units are susceptible to the effects of air in-leakage in the flue gas draft system because of the negative (internal) operating pressure of the flue gas ductwork. The following sections outline the NPHR improvement initiatives targeting the existing regenerative air heaters and mitigating the detrimental effects of flue gas draft system duct air in-leakage. The A.B.

Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 considerations are addressed in the following sections.

3.3.1 A.B. Brown Unit 1 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is due to reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas and causing corrosive flue gas acid gasses to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair and reduce operation and maintenance (O&M) costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of pulse jet fabric filter (PJFF) bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout the flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of HRI projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefits. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.1.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas induced draft fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reduce the temperature of the flue gas, and increase the mass and volumetric flow of the flue gas, which results in a higher flue gas-induced draft fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of A.B. Brown Unit 1 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The A.B. Brown Unit 1 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the A.B. Brown Unit 1 air heaters was approximately 7 percent to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared). Additionally, the hot end sector plates have been replaced for A.B. Brown Unit 1, and the OEM recommendation is to replace the cold-end sectors plates. Air heater leakage is closely monitored for A.B. Brown Unit 1 because of the detrimental effect of oxygen on the dual alkali scrubbers within the air quality control system (AQCS).

According to feedback from Vectren operations personnel, positive contact seals have been attempted for the A.B. Brown Unit 1 air heaters in the past but were removed from service because of failures during operation. The air heaters now utilize the original seal types. More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the induced draft (ID) fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. To achieve this, upgrades to the air preheat system and air-side and/or gas-side air heater bypasses would likely be required to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the A.B. Brown Unit 1 air heaters is the potential reduction of the air heater cold-end setpoint temperature for A.B. Brown Unit 1.

According to unit operating data provided by Vectren, A.B. Brown Unit 1 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for A.B. Brown Unit 1). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages. While plant personnel report that generally speaking dew point temperatures have not been a problem at the unit, they nonetheless would be concerned about any significant reduction in air heater gas outlet temperature which takes the unit into an unfamiliar operating regime.

Air heater bypasses have been installed on the A.B. Brown Unit 1 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

3.3.1.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas ID fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

The ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The A.B. Brown Unit 1 forecast for scheduled maintenance outages is outlined in Table 3-8.

Table 3-8 A.B. Brown Unit 1 O&M Scheduled Outage Intervals (2020-2039)

YEAR	A.B. BROWN UNIT 1 O&M - SCHEDULED OUTAGE
2020	--
2021	3 weeks
2022	Major
2023	--
2024	3 weeks
2025	3 weeks
2026	--
2027	3 weeks
2028	3 weeks
2029	--
2030	3 weeks
2031	Major
2032	--
2033	3 weeks
2034	3 weeks
2035	--
2036	3 weeks
2037	3 weeks
2038	--
2039	3 weeks

To determine the overall cost associated with improving the ductwork leakage rates, field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air forced draft/primary air [FD/PA]) fans or areas closer to the inlet of the flue gas induced draft fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for A.B. Brown Unit 1 were not available for review or incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$850,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20 °F air heater gas outlet temperature improvement)

Air Preheater (Steam Coil) System Repairs

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.1% (applicable to intermittent periods when steam coils would be used)

3.3.2 A.B. Brown Unit 2 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades results from reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas and causing corrosive flue gas acid gasses to condense on air heater cold end baskets and ductwork components, resulting in degradation of equipment materials. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow reducing the ability of an electrostatic precipitator to capture ash.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be

closer to acid dew point increasing the potential for equipment corrosion throughout flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.2.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of A.B. Brown Unit 2 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The A.B. Brown Unit 2 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the A.B. Brown Unit 2 air heaters was approximately 7 to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared). Additionally, the hot end sector plates have been replaced for A.B. Brown Unit 2, and the OEM recommendation is to replace the cold-end sectors plates. Air heater leakage is closely monitored for A.B. Brown Unit 2 because of the detrimental effect of oxygen on the dual alkali scrubbers within the AQCS.

According to feedback from Vectren operations personnel, positive contact seals have been attempted for the A.B. Brown Unit 2 air heaters in the past but were removed from service because of failures during operation. The air heaters now utilize the original seal types. More frequent in-situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage trends over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. Upgrades to the air preheat system and air-side and/or gas-side air heater bypasses are expected to be likely, however, to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the A.B. Brown Unit 2 air heaters is the potential reduction of the air heater cold-end setpoint temperature for A.B. Brown Unit 2.

According to unit operating data provided by Vectren, A.B. Brown Unit 2 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for A.B. Brown Unit 2). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

Air heater bypasses have been installed on the A.B. Brown Unit 2 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

3.3.2.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas ID fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The A.B. Brown Unit 2 forecast for scheduled maintenance outages is outlined in Table 3-9.

Table 3-9 A.B. Brown Unit 2 O&M Scheduled Outage Intervals (2020-2039)

YEAR	A.B. BROWN UNIT 2 O&M - SCHEDULED OUTAGE
2020	3 weeks
2021	3 weeks
2022	--
2023	Major
2024	3 weeks
2025	--
2026	3 weeks
2027	3 weeks
2028	--
2029	3 weeks
2030	3 weeks
2031	--
2032	3 weeks
2033	Major
2034	--
2035	3 weeks
2036	Major
2037	--
2038	3 weeks
2039	Major

To determine the overall cost associated with improving the ductwork leakage rates field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for A.B. Brown Unit 2 were not available for review/incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits could likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$850,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20° F air heater gas outlet temperature improvement)

Air Preheater (Steam Coil) System Repairs

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.1% (applicable to intermittent periods when steam coils would be used)

3.3.3 F.B. Culley Unit 2 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is a result of reducing the duty of the unit's combustion air and flue gas induced draft fans, thus reducing the unit's overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas, causing corrosive flue gas acid gases to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of PJFF bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak by of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout flue the gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.3.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The F.B. Culley Unit 2 air heater is a regenerative Ljungström type air heater with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The F.B. Culley Unit 2 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate from a dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency because the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent.

The F.B. Culley Unit 2 air preheater (steam coil) units are reportedly in good condition and operate reliably; because of this, there were no recommendations or perceived improvements to unit performance as a result of additional capital budget spending for the air preheater units.

It should be noted that an internal air heater conditional assessment should also be made to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the F.B. Culley Unit 2 air heaters is the potential reduction of the air heater cold-end setpoint temperature for F.B. Culley Unit 2.

According to unit operating data provided by Vectren, F.B. Culley Unit 2 maintains a consistent air heater cold-end temperature near 325 to 330°F (measured at the ID fan inlet for F.B. Culley Unit 2). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature, which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to setpoints within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

3.3.3.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas induced draft fan auxiliary load, thus negatively impacting the units NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The F.B. Culley Unit 2 forecast for scheduled maintenance outages is outlined in Table 3-10.

Table 3-10 F.B. Culley Unit 2 O&M Scheduled Outage Intervals (2020-2039)

YEAR	F.B. CULLEY UNIT 2 O&M - SCHEDULED OUTAGE
2020	3 weeks
2021	--
2022	3 weeks
2023	--
2024	Major
2025	--
2026	3 weeks
2027	--
2028	3 weeks
2029	--
2030	3 weeks
2031	--
2032	3 weeks
2033	--
2034	Major
2035	--
2036	3 weeks
2037	--
2038	3 weeks
2039	--

To determine the overall cost associated with improving the ductwork leakage rates field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Draft system leakage testing data for F.B. Culley Unit 2 were not available for review or incorporation into this analysis. Therefore, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities can be implemented to improve the existing air heater units and find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$476,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20° F air heater gas outlet temperature improvement)

3.3.4 F.B. Culley Unit 3 Air Heater and Leakage Control Upgrades

The main NPHR benefit of air heater and flue gas ductwork leakage control repairs/upgrades is as a result of reducing the duty of the unit's combustion air and flue gas induced draft fans thus reducing the units overall auxiliary load demand.

Excessive air heater and flue gas duct leakage presents additional issues beyond degradation in NPHR, however. Air in-leakage can also result in tempering of flue gas, causing corrosive flue gas acid gases to condense on air heater cold end baskets and ductwork components. Reduction in air heater and flue gas duct leakage can improve overall equipment life, reduce capital investment for repair, and reduce O&M costs caused by flue gas acid gas corrosion. Additionally, the following are some other characteristics of air in-leakage that can negatively impact draft system and air quality control equipment performance:

- Higher velocities from additional mass flow, potentially reducing the life expectancy of PJFF bags.
- Higher pressure drops through combustion air and flue gas draft system equipment.
- Reduced air heater gas outlet temperatures (due to additional leak-by of cold combustion air mixing with hot flue gas out of air heater), causing flue gas to be closer to acid dew point and increasing the potential for equipment corrosion throughout the flue gas draft system.

The following subsections provide further discussion of air heater and leakage control upgrades. The discussions are based on Black & Veatch prior experience in heat rate assessments and implementation of heat rate improvement projects. The typical information and results provided for such projects can be used to assess and further screen the potential benefit. Future efforts would be required to assess the in-service condition of the air heaters and ductwork to determine the definitive benefits of potential improvement projects.

3.3.4.1 Air Heater

As previously noted, air heater leakage rates have the effect of increasing the duty of the combustion air fans and flue gas ID fans. Higher pressure combustion air passing through the air heater will leak past air heater seals to the flue gas side (on the cold-side of the air heater for the most part), reducing the temperature of the flue gas, and increasing the mass and volumetric flow of the flue gas, resulting in a higher flue gas ID fan duty. The combustion air leakage within the air heater also increases the duty of the combustion air fans since additional combustion air needs to be supplied at the outlet of the combustion air fan to account for the combustion air lost across the air heater.

The two air heaters of F.B. Culley Unit 3 are regenerative Ljungström type air heaters with rotating baskets. Radial, axial, and circumferential seals provide sealing between the combustion air and flue gas paths across and around the air heater baskets as they rotate within the air heater casing. Deterioration of seals from typical usage, corrosion, many large temperature swings such as unit trips, or damage of seals that are misaligned or out of adjustment will result in increased air heater leakage rates. The F.B. Culley Unit 3 air heaters are regularly inspected by the OEM, including an assessment of the air heater seals and replacement if required during all planned outages. Prior to the SCR installation, the original design air leakage for the F.B. Culley Unit 3 air heaters was approximately 7 to 8 percent. The installation of the SCR units has resulted in a corresponding increase of the full load air-to-gas side differential pressure by several inches of water column (when combustion air and flue gas pressures are compared).

Air in-leakage testing (measuring the oxygen content rise in discrete sections of the F.B. Culley Unit 3 draft system) was performed in 2017. This testing indicated a 16 to 17 percent leakage across each of the F.B. Culley Unit 3 air heaters (with the unit at full load). The leakage data across the PJFF and SCR units indicated no significant air infiltration. These data are outlined in Table 3-11 and Figure 3-8.

Table 3-11 F.B. Culley Unit 3 Draft System and Air Heater Air In-Leakage Test Data (July 2017)

TESTING LOCATION	DESCRIPTION	F.B. CULLEY UNIT 3 DRAFT SYSTEM – WEST SIDE	F.B. CULLEY UNIT 3 DRAFT SYSTEM – EAST SIDE
SCR Inlet	SCR inlet after duct burner; duct burner out of service at during full load test	4.0	3.5
SCR Outlet	SCR outlet/AH inlet duct section	4.0	3.7
AH Outlet	AH outlet/PJFF inlet duct section	6.4	6.3
FF Outlet	PJFF outlet/ID fan inlet(s) duct section	6.5	6.2
Calculated AH Leakage (%)	Calculated from "SCR Out" and "AH Out" data provided above	16.9	17.8
AH - air heater			

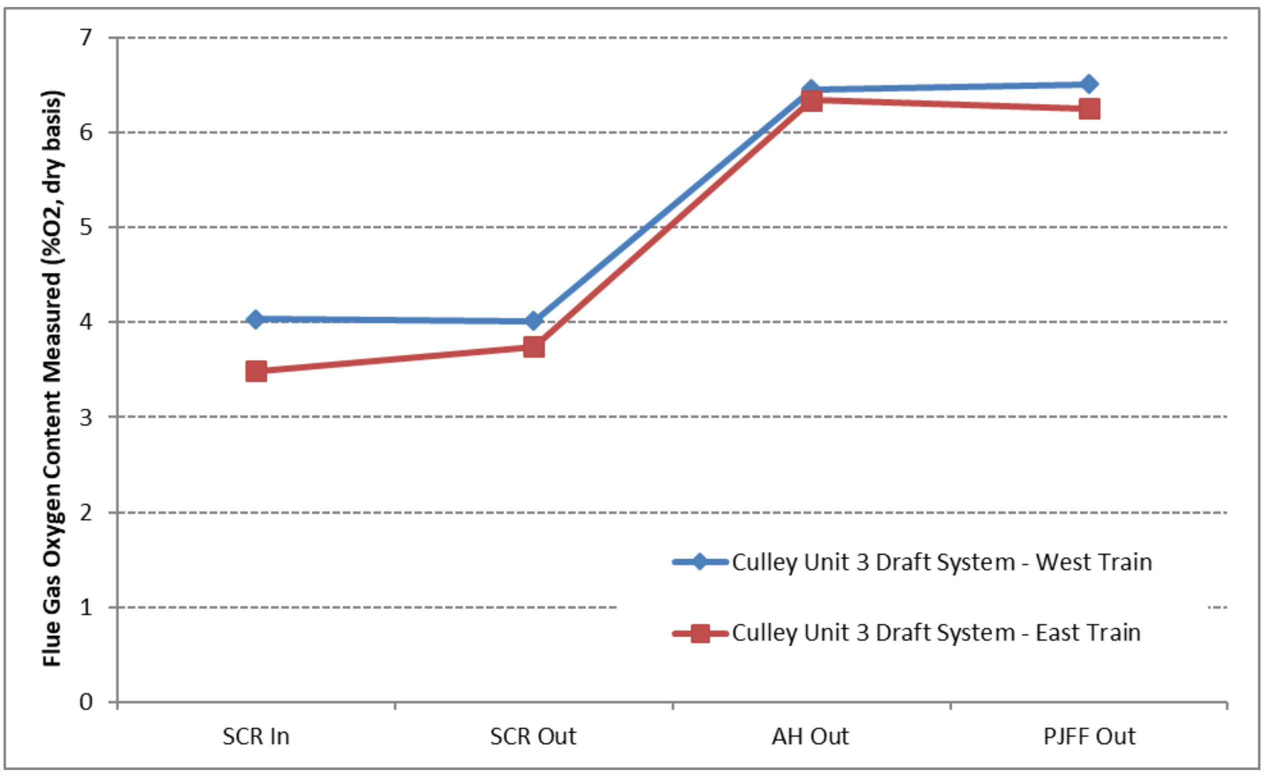


Figure 3-8 F.B. Culley Unit 3 Draft System Air Leakage Test Data (July 2017)

As a result of the air heater leakage test data, all sector plates and seals were replaced at the recommendation of the OEM during the recently completed 2019 planned outage for F.B. Culley Unit 3.

More frequent in situ monitoring or installation of permanent probes measuring flue gas oxygen content at the ID fan inlet would allow for more accurate trending of the air in-leakage over time. This information would assist with planned outage maintenance and would provide ancillary benefits such as reducing ID fan power consumption and improved heat rate due to dry gas loss reduction.

In addition to improving air heater leakage, replacing worn air heater baskets with new ones can improve draft system losses and air heater effectiveness. The replacement of the existing air heater baskets with new ones that are more thermally efficient could be beneficial because the average flue gas temperature leaving the unit could be decreased with minimal, if any, impact to pressure drop. As a rule, for every 40° F decrease in air heater gas outlet temperature, a 1.0 percent increase in boiler efficiency can be expected. The reduction in leakage previously discussed is expected to increase the measured average air heater gas outlet temperature. This increase would not be expected to negatively impact boiler efficiency as the air heater no-leak gas outlet temperature would remain the same. Black & Veatch expects that air heater upgrades that could lower the no-leak temperature by 20° F are attainable without an in-depth analysis of the air preheat system and acid gas dew points. This would increase boiler efficiency by about 0.5 percent.

However, if additional efficiency gains are desired, additional analyses of the air preheat system and acid gas dew points with the air heater performance would be required to ensure the average gas temperature does not encroach upon the acid gas dew point at all loads. It is expected that the air heater gas outlet temperature could be lowered by another 10 to 15° F, improving boiler efficiency by another 0.25 percent. The F.B. Culley Unit 3 air preheater (steam coils) are located in the FD fan room to maintain a minimum air inlet temperature setpoint, controlled by the FD fan outlet temperature. To achieve this, upgrades to the air preheat system and air-side and/or gas-side air heater bypasses would likely be required to maintain air heater gas outlet temperatures above the acid dew point at lower loads and during colder times of the year.

It should be noted that internal air heater condition should also be assessed to help in the decision-making process for upgrading or refurbishing air heater components to improve unit NPHR.

An additional area of opportunity for NPHR improvement related to the F.B. Culley Unit 3 air heaters is the potential reduction of the air heater cold-end setpoint temperature.

According to unit operating data provided by Vectren, F.B. Culley Unit 3 maintains a consistent air heater cold-end temperature near 325 to 330° F (measured at the ID fan inlet for F.B. Culley Unit 3). This temperature target is considered above the recommended setpoint, given the potential acid gas dew point temperature which is likely below 300° F. The gradual reduction of the air heater cold-end setpoint (e.g., reduction by 5 degrees every few months) would be a zero-cost (i.e., can be implemented via changes to set points within the existing control system) means of improving NPHR and not negatively impacting beneficial reuse of the fly ash. Changes to the condition of the draft system could be monitored during the regularly scheduled maintenance outages.

Air heater bypasses have been installed on the F.B. Culley Unit 3 draft system. This system provides a backup for the existing air preheating steam coil systems for cold-end temperature control for periods of extreme cold weather or a coil being taken out of service. Upgrades to the steam coil system would allow for fewer uses of the air heater (air-side) bypass during the year and fewer instances of the associated heat rate penalty during the intermittent use of the bypass.

In October 2018, Ljungström (F.B. Culley Unit 3 air heater OEM, a division of Arvos Group) provided information regarding a proposed air heater upgrade to improve heat rate as part of Vectren's ongoing heat rate improvement initiatives. According to a preliminary review of Ljungström's proposed air heater upgrade options, a 0.4 percent heat rate improvement was estimated. Black & Veatch recommends additional review of the proposed upgrades and potential balance-of-plant impacts (ID fan, ductwork, etc.). The basis of this improvement is relocating the DSI system upstream of the air heater, which would also need to be considered in the project costs.

3.3.4.2 Ductwork

The ductwork system can be divided between the combustion air and the boiler flue gas ductwork systems. Excessive leakages in either ductwork system will negatively impact the overall NPHR of the unit and long-term equipment health.

The combustion air ductwork system operates at a pressure greater than atmosphere and will experience combustion air leakages to atmosphere. Excessive combustion air duct leakages will increase the duty of the combustion air fans and result in an increase in the combustion air fan auxiliary load, thus negatively impacting the unit's NPHR.

The flue gas ductwork system will operate at a pressure slightly below atmosphere and will experience air in-leakage. For balanced draft units, the differential in flue gas ductwork internal pressure compared to ambient increases (i.e., becomes more negative) as the flue gas progresses from the furnace, through the draft system, and to the inlet of the ID fans. Excessive air in-leakage to the flue gas ductwork will increase the duty of the flue gas ID fans and result in an increase in the flue gas induced draft fan auxiliary load, thus negatively impacting the unit's NPHR.

Air in-leakage to the flue gas duct work will also have the result of tempering the flue gas. A reduction in flue gas temperature (overall or localized) below that of the dew point of acid gases of the flue gas will result in acid gasses condensing on ductwork components. Condensed acid gasses will result in corrosion and degradation of ductwork components. Reducing air in-leakage of the ductwork system will also provide a capital and O&M expense benefit by improving equipment life and mitigating O&M issues resulting from ductwork corrosion. Information provided to assess the flue gas duct work leakage is provided in Table 3-11 and Figure 3-8 above.

Ductwork inspection activities and the air heater upgrades discussed in the previous section would be expected to be incorporated during the regularly scheduled O&M outages. The F.B. Culley Unit 3 forecast for scheduled maintenance outages is outlined in Table 3-12.

Table 3-12 F.B. Culley Unit 3 O&M Scheduled Outage Intervals (2020-2039)

YEAR	F.B. CULLEY UNIT 3 O&M - SCHEDULED OUTAGE
2020	3 weeks
2021	--
2022	3 weeks
2023	3 weeks
2024	--
2025	3 weeks
2026	Major
2027	--
2028	3 weeks
2029	3 weeks
2030	--
2031	3 weeks
2032	3 weeks
2033	--
2034	3 weeks
2035	Major
2036	--
2037	3 weeks
2038	3 weeks
2039	--

To determine the overall cost associated with improving the ductwork leakage rates, field examinations and tests must be carried out to pinpoint ductwork leakage locations. Utilization of a smoke generator (or similar system) to locate and catalog the leaks would be required. Leakage quantities should then be estimated for each leakage source to quantify an impact to fan duty and associated auxiliary load increase. The initial field examination should focus on high impact areas where the differential between the inside duct pressure and atmosphere is greater (i.e., areas closer to the discharge of the combustion air fans or areas closer to the inlet of the flue gas ID fans). In addition, the initial review should focus on expansion joints, expansion joint health, expansion joint sealing gaskets, duct door gaskets, duct gaskets, or potentially failing duct jointing seal welds.

Because the age of the previous leakage testing data and the subsequent air heater maintenance performed by Vectren, Black & Veatch has not assessed any NPHR impacts regarding reducing flue gas draft system leakage other than that discussed for the air heaters. The following activities described in this section can be implemented to continue to find draft system leakage points. With the availability of additional data, the following estimates could be further refined, and the following heat rate benefits would likely increase.

Air Heater Basket, Seal, and Sector Plate Replacement

Total Installed Capital Cost:	$750,000
Heat Rate (efficiency) Improvement:	0.5% (assumes 20° F air heater gas outlet temperature improvement)

Air Preheater (Steam Coil) System Repairs

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.1% (applicable to intermittent periods when steam coils would be used)

3.4 UNIT VARIABLE FREQUENCY DRIVE UPGRADES

Variable-frequency drives (VFDs) function by controlling electric motor speed by converting incoming constant frequency power to variable frequency, using pulse width modulation. VFD upgrades for main plant electric motors provide many co-benefits, the largest one of which is improved part-load efficiency and performance. The benefit is greatest at low load. The more part load and unit cycling that is done, the greater the benefit.

In addition to the reduced auxiliary power consumption, other benefits that are gained from the installation of VFDs on rotating equipment are as follows:

- Reduced noise levels around the equipment.
- Lower in-rush current during startups.
- Decreased wear on existing auxiliary power equipment.

Disadvantages of the installation of VFDs include the high capital cost plus a minimal amount of increased electrical equipment maintenance associated with the VFD system.

Output power signal quality and reliability of VFD equipment has increased significantly in the last 10 to 15 years. Part of this increased reliability comes from the development of technology to allow the VFD equipment to remain in operation if one or multiple insulated-gate bipolar transistor (IGBT) power cells fail by automatically bypassing the bad cell, or cells, until an outage when repairs can be made. Additionally, output power signals meet Institute of Electrical and Electronics Engineers (IEEE) 519 1992 requirements, eliminating the need for harmonic filters.

VFD installation typically requires about 2 months of total pre-outage work, with a 1-week outage (per device) for the final tie-in. To support installation of the VFDs, the following changes are necessary:

- Replacement of existing rotating equipment coupling with resilient elastomeric block shaft couplings to accommodate the shaft misalignment and absorb the high torque loads during rapid load changes. This means the existing equipment must be de-coupled from the motor and then realigned with the new coupling.
- Upgrades to lube oil system as necessary.
- New VFD enclosure foundations.
- New VFD enclosures and heat exchangers.
- Replace the power supply cables from existing switchgear to the new VFD cabinet. Install new cables from the VFD cabinet to the motor.
- For smaller units, the VFD control enclosure and cabinets will also be smaller with reduced pre-outage time requirements.

A high-level assessment of the technical and economic feasibility of VFD modifications that have been seen as beneficial in previous ACE studies were considered as part of this study. With financial benefits confirmed by integrated resource plan (IRP) modeling, specific modifications can then be reviewed in a detailed effort to confirm the performance and financial benefits of VFD modifications.

3.4.1 A.B. Brown Unit 1 Variable Frequency Drive Upgrades

The A.B. Brown Unit 1 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, cooling tower fans, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the ID fans.

3.4.1.1 Boiler Feed Pumps

The A.B. Brown Unit 1 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

3.4.1.2 Circulating Water Pumps

The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by 1,750 horsepower motors. The impellers on the circulating water pumps were replaced with new impellers in 2008. According to the A.B. Brown Unit 1 operating data provided by Vectren, during the period of January 2017 through September of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicates that the unit operated between 40 percent load and 60 percent load for approximately 52 percent of the time, a significant period where Unit 1 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 15 percent of the time and between 80 percent load and 100 percent load for approximately 33 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). These studies have shown that, for the majority of time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature circulating water to the condenser with the resulting lowest condenser pressure possible. This operating scenario typically provides a better plant heat rate than lowering the auxiliary power requirements with a resulting increase in condenser back pressure.

As an example, for every 0.1 in. Hg increase in condenser pressure for A.B. Brown Unit 1, the turbine generator output is expected to decrease by about 0.3 to 0.8 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.3 to 0.4 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-13 summarizes the rated circulating water pump design conditions, as provided in the A.B. Brown Unit 1 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-13 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	65,000	64,350	61,750
Total head, ft	84	82.3	75.8
Pump brake horsepower, hp	1,558	1,512	1,336
Pump speed, rpm	514	509	488
gpm – gallons per minute; ft – feet; hp – horsepower; rpm – revolutions per minute Note: The above operating data is for one of two (2x50%) circulating water pumps.			

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

The only scenarios that Black & Veatch has assessed where the installation of VFD systems on circulating water pumps has been beneficial is with once-through circulating water systems that use river or lake water that cools during winter months and there is no concern of freezing. Since the heat rejection system on A.B. Brown Unit 1 involves the use of a cooling tower, the installation of VFD systems on the circulating water pumps does not appear to be cost effective.

Lastly, the costs of adding VFDs to large motors is significant. The estimated costs for adding VFDs to the two Unit 1 circulating water pumps is $2,100,000.

3.4.1.3 Cooling Tower Fans

Cycle heat rejection is via a seven-cell mechanical draft cross-flow cooling tower with seven mechanical draft cooling tower fans. Each cooling tower fan is driven by a 200 hp motor equipped with a VFD system to control both de-icing and to control condenser backpressure. As the cooling tower fans are already equipped with VFDs, the fans will not be investigated further.

3.4.1.4 Large Draft Fans

According to available information and operating data, the A.B. Brown Unit 1 ID fan auxiliary power consumption benefit is estimated to be a total of 3.3 MW for both fans at full load and 4.1 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0473 pounds per cubic foot (lbm/ft^3) at 322° F.

The estimated furnish and erect price for a VFD system for the A.B. Brown Unit 1 ID fans includes the VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for ID Fans

Total Installed Capital Cost:	$2,900,000 for both fans
Auxiliary Power Reduction:	Full load: 3.3 MW
	Low Load: 4.1 MW
Heat Rate (efficiency) improvement:	Full Load: 1.4%
	Low Load: 3.0%

Estimated Additional Annual O&M Cost: $2,000 per unit

The A.B. Brown Unit 1 FD fan auxiliary power consumption benefit is estimated to be a total of 0.85 MW for both fans at full load and 0.7 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0726 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the A.B. Brown Unit 1 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.85 MW
	Part load: 0.7 MW
Heat Rate (efficiency) Improvement:	Full Load: 0.37%
	Low Load: 0.54%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.2 A.B. Brown Unit 2 Variable Frequency Drive Upgrades

The A.B. Brown Unit 2 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, cooling tower fans, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the ID fans.

3.4.2.1 Boiler Feed Pumps

The A.B. Brown Unit 2 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

3.4.2.2 Circulating Water Pumps

The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by 1,750 hp motors. The impellers on the circulating water pumps were replaced with new impellers in 2008. According to A.B. Brown Unit 2 operating data provided by Vectren, during the period of January 2017 through September of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 40 percent load and 60 percent load for approximately 44 percent of the time, a significant period where Unit 2 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 19 percent of the time and between 80 percent load and 100 percent load for approximately 37 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). These studies have shown that, for the majority of time, it is more advantageous to operate the circulating water pumps and cooling tower fans at full capacity to maintain the lowest temperature circulating water to the condenser with the resulting lowest condenser pressure possible. This operating scenario by and large provides a better plant heat rate than lowering the auxiliary power requirements with a resulting increase in condenser back pressure.

As an example, for every 0.1 in. Hg increase in condenser pressure for A.B. Brown Unit 2, the turbine generator output is expected to decrease by about 0.3 to 0.8 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.3 to 0.4 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-14 summarizes the rated circulating water pump design conditions, as provided in the A.B. Brown Unit 2 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-14 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	65,000	64,350	61,750
Total head, ft	84	82.3	75.8
Pump brake horsepower, hp	1,558	1,512	1,336
Pump speed, rpm	514	509	488
Note: The above operating data is for one of two (2x50%) circulating water pumps.			

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

The only scenarios that Black & Veatch has assessed where the installation of VFD systems on circulating water pumps has been beneficial is with once-through circulating water systems that use river or lake water that cools during winter months and there is no concern of freezing. Since the heat rejection system on A.B. Brown Unit 2 involves the use of a cooling tower, the installation of VFD systems on the circulating water pumps does not appear to be cost effective.

Lastly, the costs of adding VFDs to large motors is significant. The estimated costs for adding VFDs to the two Unit 2 circulating water pumps is $2,100,000.

3.4.2.3 Cooling Tower Fans

Cycle heat rejection is via a seven-cell mechanical draft cross-flow cooling tower with seven mechanical draft cooling tower fans. Each cooling tower fan is driven by a 200 hp motor equipped with a VFD system. As the cooling tower fans are already equipped with VFDs, the fans will not be investigated further.

3.4.2.4 Large Draft Fans

According to available information and operating data, the A.B. Brown Unit 2 ID fan auxiliary power consumption benefit is estimated to be a total of 1.7 MW for both fans at full load and 2.3 MW on the basis of the density of the inlet air to the fans of 0.048 lbm/ft^3 at 321° F.

The evaluated impacts of this project are as follows:

VFD Deployment for ID Fans

Total Installed Capital Cost:	$2,900,000 for both fans
Auxiliary Power Reduction:	Full load: 1.7 MW
	Part Load: 2.3 MW
Heat Rate (efficiency) improvement	Full Load: 0.73%
	Low Load: 1.7%

Estimated Additional Annual O&M Cost: $2,000 per unit

The estimated furnish and erect price for a variable frequency drive system for the A.B. Brown Unit 2 ID fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The Brown Unit 2 FD fan auxiliary power consumption benefit is estimated to be a total of 0.3 MW for both fans at full load and 0.45 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0726 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the Brown Unit 2 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.3 MW
	Part load: 0.45 MW
Heat Rate (efficiency) improvement	Full Load: 0.13%
	Low Load: 0.34%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.3 F.B. Culley Unit 2 Variable Frequency Drive Upgrades

The F.B. Culley Unit 2 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the circulating water pumps.

3.4.3.1 Boiler Feed Pumps

F.B. Culley Unit 2 includes one 100 percent capacity motor driven boiler feed pumps. The pump is driven by a 2,500 hp single-speed electric motor, which indicates that this system is amenable to a VFD deployment. The boiler feed pump has a design capacity of 1,980 gpm. Feedwater flow at full load is 1,550 gpm and 960 gpm at low load.

Table 3-15 Boiler Feed Water Pump Operating Conditions

	RATED OPERATING CONDITIONS	FULL LOAD	LOW LOAD	FULL LOAD WITH VFD	LOW LOAD WITH VFD
Flow, gpm	1,980	1,550	960	1,550	960
Total head, ft	3,980	4,375	4,550	3,700	3,307
Pump brake horsepower, hp	2,388	2,146	1,690	1,771	1,133
Pump speed, rpm	3,750	3,750	3,750	3,310	3,050

The evaluated impacts of this project are as follows:

VFD Deployment for Boiler Feed Pump

Total Installed Capital Cost: $600,000

Auxiliary Power Reduction: Full load: 0.3 MW
Part load: 0.4 MW

Heat Rate (efficiency) improvement 0.6%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.3.2 Circulating Water Pumps

Unit cooling is provided via a once-through circulating water system utilizing river water as the cooling water supply. Circulating water pump installation is two 50 percent capacity vertical turbine wet pit circulating water pumps. The pumps are driven by 450 hp motors. The circulating water pumps take suction directly from the Ohio River. According to F.B. Culley Unit 2 operating data provided by Vectren, during the period of January 2017 through January of 2019, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 40 percent load and 60 percent load for approximately 45 percent of the time, a significant period where Unit 2 was operating at a relatively significant part load. The operating data also indicate that the unit operated between 60 percent load and 80 percent load for approximately 23 percent of the time and between 80 percent load and 100 percent load for approximately 32 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser back pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). However, Black & Veatch has assessed some coal fired plants where the installation of VFD systems on circulating water pumps has been beneficial when unit cooling was provided by once-through circulating water systems using river or lake water. The impact is particularly beneficial during winter months when the water supply is cold and there is no concern of freezing.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-16 summarizes the rated circulating water pump design conditions, as provided in the F.B. Culley Unit 2 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-16 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	34,920	33,947	32,576
Total head, ft	43.7	42.8	39.4
Pump brake horsepower, hp	443	430	380
Pump speed, rpm	505	500	480
Note: The above operating data is for one of two (2x50%) circulating water pumps.			

This is not strictly true for systems with a high static head, and the savings could be somewhat less when the pump speed differences are fully accounted for. Detailed pump modeling should be conducted to improve the accuracy of these predictions as part of a next-phase effort.

Variations in pump speed and circulating water flow can have a significant impact on condenser pressure, particularly when the reduced speed and corresponding decrease in flow result in an increased circulating water temperature to the unit. As an example, for every 0.1 in. Hg increase in condenser pressure for F.B. Culley Unit 2, the turbine generator output is expected to decrease by about 0.1 to 0.5 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.09 to 0.1 MW, and the condenser pressure is expected to increase by more than 0.2 in. Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months, creating a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

However, when unit cooling is provided by once-through circulating water systems using river water, such as the F.B. Culley Unit 2, the water supply can be provided with little day-to-day variation in temperature. This is particularly beneficial during the winter months when the water supply is very cold and any reduction in circulating water pump speed, with the corresponding decrease in flow, can have little effect on the condenser pressure.

Evaluating the impact to condenser pressure and auxiliary load by the addition of VFDs to circulating water pumps on units with once-through cooling is an involved assessment. It is necessary to determine a temperature profile of the river water over at least one annual operating period since the cooling water temperature directly impacts condenser back pressure. Additionally, the circulating water flow rate impacts heat transfer, which also directly impacts condenser back pressure. The assessment basically requires creating condenser back pressure curves as a function of the two different variables but must also consider the river water temperature profile as a function of time. The assessment would then identify the auxiliary power savings on the basis of the operating profile of the VFD speed controlled circulating water pumps. Still another concern is that low water flow velocities can cause silting and drop-out of suspended particles in piping.

The costs of adding VFDs to large motors is significant, but in the case of once-through cooling water systems, the investment can prove beneficial. The estimated costs for adding VFDs to the two Unit 2 circulating water pumps is $900,000.

3.4.3.3 Large Draft Fans

Vectren personnel informed Black & Veatch that F.B. Culley Unit 2 has already installed VFDs on the ID fans, which are typically the motors that can gain the most HRI benefit.

The Culley Unit 2 FD fan auxiliary power consumption benefit is estimated to be a total of 0.3 MW for both fans at full load and 0.3 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0727 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the Culley Unit 2 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.3 MW
	Low load: 0.3 MW
Heat Rate (efficiency) improvement:	Full Load: 0.34%
	Low Load: 0.57%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.4.4 F.B. Culley Unit 3 Variable Frequency Drive Upgrades

The F.B. Culley Unit 3 rotating equipment evaluated for the possible addition of VFD systems in this study include the boiler feed pumps, circulating water pumps, and the large draft fans for handling combustion air and flue gas.

After discussion with Vectren personnel, the best potential application for further VFD upgrades appears to be the circulating water pumps.

3.4.4.1 Boiler Feed Pumps

The F.B. Culley Unit 3 boiler feed pump is a turbine driven feed pump that already provides high efficiency variable speed capability. The installation of a VFD system on the boiler feed pump will therefore not be evaluated further.

3.4.4.2 Circulating Water Pumps

Unit cooling is provided via a once-through circulating water system utilizing river water as the cooling water supply. The circulating water system includes two 50 percent capacity vertical turbine circulating water pumps driven by electric motors. The circulating water pumps take suction directly from the Ohio River. According to F.B. Culley Unit 3 operating data provided by Vectren, during the period of January 2017 through June of 2018, the unit was off-line at times and operated as high as 100 percent load. Excluding any hours when the unit was off-line or appeared to be ramping up to load, the operating data indicate that the unit operated between 60 percent load and 80 percent load for approximately 14 percent of the time and between 80 percent load and 100 percent load for approximately 60 percent of the time. The operating data also indicate that the unit operated at less than 60 percent load for approximately 26 percent of the time. The addition of VFDs on the circulating water pumps would allow variation in pump operating speed and circulating water flow over the operating load ranges experienced during normal operation of the unit. However, variations in pump speed and circulating water flow can have a significant impact on condenser back pressure.

Past studies performed by Black & Veatch on similar coal fired plants have shown that condenser back pressure has a higher impact on plant heat rate than changes in auxiliary power associated with the circulating water system (i.e., circulating water pumps and cooling tower fans). However, Black & Veatch has assessed some coal fired plants where the installation of VFD systems on circulating water pumps has been beneficial when unit cooling was provided by once-through circulating water systems using river or lake water. The impact is particularly beneficial during winter months when the water supply is cold and there is no concern of freezing.

For reference, the impact on the circulating water pump power consumption at lower pump speeds and flow rates can be estimated utilizing the pump affinity laws. Table 3-17 summarizes the rated circulating water pump design conditions, as provided in the Culley Unit 3 documentation, and the reduced operating pump brake horsepower at a 1 percent and a 5 percent reduction in circulating water flow rate per pump. Estimations of pump speed have also been provided if these pumps were to be equipped with VFD systems.

Table 3-17 Predicted Circulating Water Pump Operating Conditions at Reduced Flows

	RATED OPERATING CONDITIONS	1% REDUCED FLOW OPERATING CONDITIONS	5% REDUCED FLOW OPERATING CONDITIONS
Flow, gpm	69,000	68,310	65,550
Total head, ft	57	55.9	51.4
Pump brake horsepower, hp	1170	1135	1,003
Pump speed, rpm	300	297	285
Note: The above operating data is for one of two (2x50%) circulating water pumps.			

Variations in pump speed and circulating water flow can have a significant impact on condenser pressure, particularly when the reduced speed and corresponding decrease in flow result in an increased circulating water temperature to the unit. As an example, for every 0.1 in. Hg increase in condenser pressure for F.B. Culley Unit 3, the turbine generator output is expected to decrease by about 0.4 to 0.9 MW, according to past experience. Decreasing circulating water flow by 5 percent will decrease the circulating water pump auxiliary load by about 0.25 MW, and the condenser pressure is expected to increase by more than 0.2 in Hg for the vast majority of operating scenarios and unit loads, especially during the warmer months. This creates a significant loss in turbine generator output, more so than the gains that would be seen in modulating circulating water pump flow.

However, when unit cooling is provided by once-through circulating water systems using river water, such as the F.B. Culley Unit 3, the water supply can be provided with little day-to-day variation in temperature. This is particularly beneficial during the winter months when the water supply is very cold and any reduction in circulating water pump speed, with the corresponding decrease in flow, can have little effect on the condenser pressure.

Evaluating the impact to condenser pressure and auxiliary load by the addition of VFDs to circulating water pumps on units with once-through cooling is an involved assessment. It is necessary to determine a temperature profile of the river water over at least one annual operating period since the cooling water temperature directly impacts condenser back pressure. Additionally, the circulating water flow rate impacts heat transfer, which also directly impacts condenser back pressure. The assessment basically requires creating condenser back pressure curves as a function of the two different variables but must also consider the river water temperature profile as a function time. The assessment would then identify the auxiliary power savings on the basis of the operating profile of the VFD speed controlled circulating water pumps. Moreover, plant personnel have expressed concerns about silting problems due to low water velocity, which is already a known issue at the plant, where, extended periods of operation at low flows have led to silting in the condenser tubes and associated corrosion.

The costs of adding VFDs to large motors is significant, but in the case of once-through cooling water systems, the investment can prove beneficial. The estimated costs for adding VFDs to the two Unit 3 circulating water pumps is $2,100,000.

3.4.4.3 Large Draft Fans

Vectren personnel informed Black & Veatch that F.B. Culley Unit 3 has already installed VFDs on the ID fans, which are typically the motors that can gain the most HRI benefit at a coal fired power plant.

The only other large rotating equipment identified for this F.B. Culley Unit 3 study that has the potential for significant HRI benefits from a VFD retrofit are the FD fans. The F.B. Culley Unit 3 FD fan auxiliary power consumption benefit is estimated to be a total of 0.6 MW for both fans at full load and 0.9 MW for both fans at low load on the basis of the density of the inlet air to the fans of 0.0727 pounds per cubic foot (lbm/ft^3) at 74° F.

The estimated furnish and erect price for a VFD system for the Culley Unit 3 FD fans includes VFD, VFD enclosure, enclosure foundations, fan coupling, new power cabling and any new raceway required, engineering, installation, and contingency. If there is limited available space immediately around the rotating equipment, the installation of VFD systems would not be affected because the VFD equipment can be placed virtually anywhere on the plant site and still provide adequate, clean power to the equipment.

The evaluated impacts of this project are as follows:

VFD Deployment for FD Fans

Total Installed Capital Cost:	$2,000,000 for both fans
Auxiliary Power Reduction:	Full load: 0.6 MW
	Low load: 0.9 MW
Heat Rate (efficiency) improvement:	Full load: 0.23%
	Low Load: 0.69%

Estimated Additional Annual O&M Cost: $2,000 per unit

3.5 BOILER FEED PUMP UPGRADES, REBUILDING, OR REPLACEMENT

The purpose of this project would be to reduce the energy consumed by the boiler feed pumps by exploring whether upgrades or repairs to the pump internal components, or replacement in kind with a new boiler feed pump would be warranted. As steam-driven boiler feed pumps are inherently much more efficient than any electric-driven boiler feed pumps, no analysis of a conversion to VFD use will be assessed on A.B. Brown Units 1 and 2, or Culley Unit 3.

3.5.1 A.B. Brown Unit 1 Boiler Feed Pumps

A.B. Brown 1 has one Pacific, 5 stage, Type BFIDS, Size 12” RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. With the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

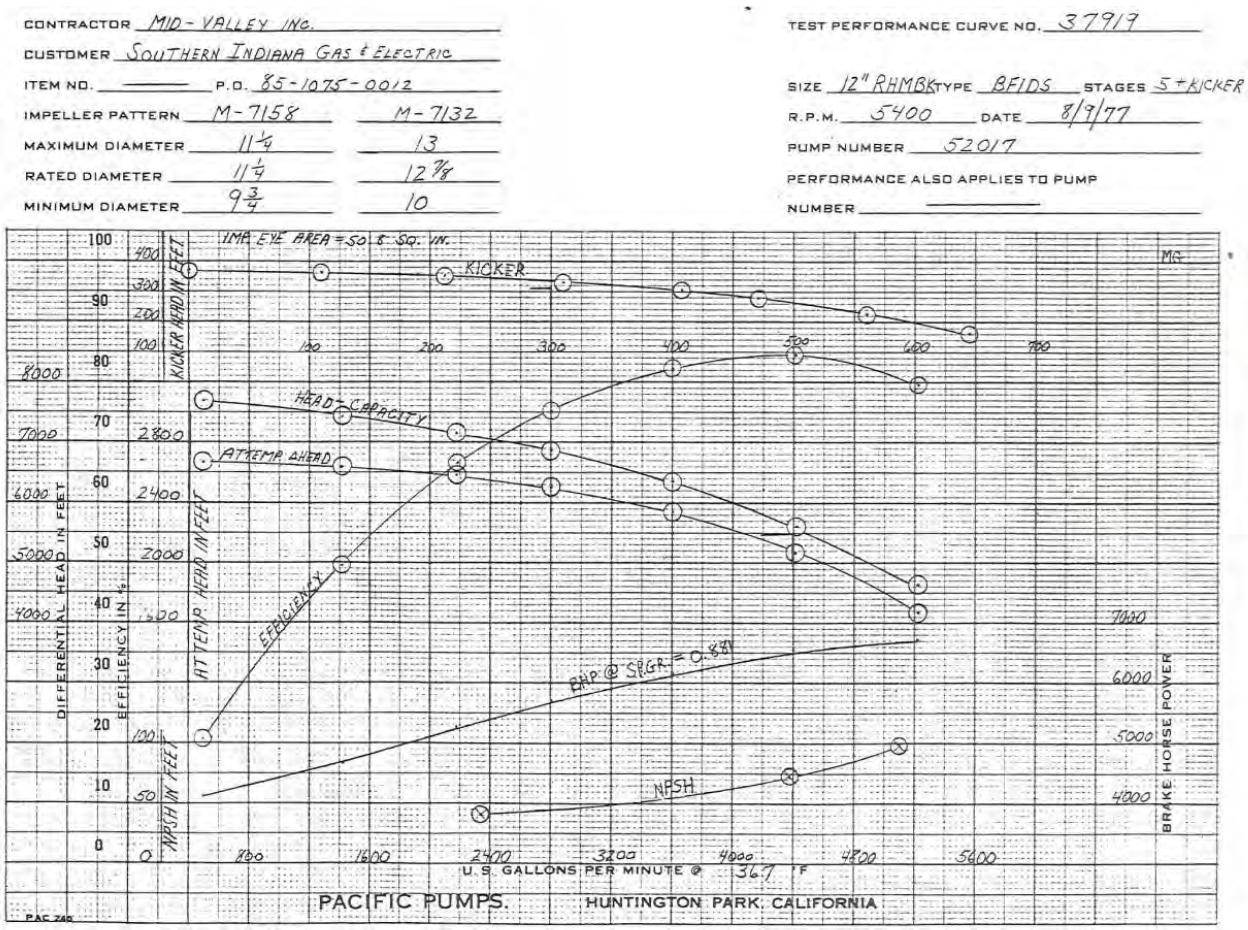


Figure 3-9 Brown 1, Brown 2, and Culley 3 Boiler Feed Pump Performance Curve

3.5.2 A.B. Brown Unit 2 Boiler Feed Pumps

A.B. Brown 2 has one Pacific, 5 stage, Type BFIDS, Size 12” RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. As in the case of Unit 1, with the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

3.5.3 F.B. Culley Unit 2 Boiler Feed Pumps

F.B. Culley 2 has one Byron Jackson, double volute, 7 stage multiplex, Type DVMX, Size 6x8x11B pump. The pump has a rated capacity of 1,980 gpm at 3,980 feet of head, 3,750 rpm, and 220 °F water. The full load operating data set Black & Veatch was provided has the BFP operating with a discharge flow rate of 1,550 gpm and a total developed head of 3,980 ft. The pump curve shows that the pump should have a TDH of 4,380 ft. The actual developed head of the BFP is 9.2% less than that of the design curve. The pump no longer lies on the initial operating curve which suggest that degradation has occurred. Please see the section on VFD deployment for further information on upgrades that are possible for F.B. Culley Unit 2's boiler feed pump.

3.5.4 F.B. Culley Unit 3 Boiler Feed Pumps

F.B. Culley 3 has one Pacific, 5 stage, Type BFIDS, Size 12" RHBK pump. The pump has a rated capacity of 4,400 gpm at 5,470 feet of head, 5,400 rpm, for 367 °F water. With the current data available, there is no indication that any significant improvement could be made to the overall unit heat rate by upgrading this pump. Discussions with one boiler feed pump retrofit vendor indicated that at best a 1-1.5% drive turbine efficiency could be realized, which would only translate to a very small efficiency improvement on a unit basis.

3.6 UNIT NEURAL NETWORK DEPLOYMENT

The purpose of this project would be to tune the system to allow for the reduction of boiler outlet oxygen concentration without increasing NO_X or carbon monoxide (CO) emissions. Adaptive neural net systems have the greatest effect when controlling air flow and fuel mixtures down to a fine level. The full benefits are realized only if the plant has adequate feedback signals to allow the neural net to sense changes made to the available controls. For instance, individual fuel and air controls at each burner provide tremendous levers for a neural net system; however, the effect of the levers is reduced if the neural net does not receive feedback about the air/fuel mixture through a grid of CO measurements.

3.6.1 A.B. Brown Unit 1 Neural Network Deployment

The unit has the ability to bias individual mills as well as compartmented windboxes. Each burner row has an independent windbox with a damper for air control on each end, but there is only manual secondary air adjustment at each individual burner. CO measurement is located at the outlet of the reheat section, but this requires regular maintenance for reliable operation.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance. Still another benefit would be the ability to better control the balance of O_2 across the furnace, which is known to be a current concern.

For A.B. Brown Unit 1, the excess oxygen varies roughly from between 2 percent to 4.5 percent at gross output levels above 250 MW, with an average level approximating 3.0 to 3.3 percent. No online correlation of NPHR or boiler efficiency from distributed control system (DCS) system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess O_2: 0.10 percent gain in boiler efficiency, 0.23 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.21 percent gain in boiler efficiency, 0.43 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.27 percent gain in boiler efficiency, 0.60 percent improvement in net plant heat rate.

Utilization of a specific Vista model of A.B. Brown Unit 1 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it would be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent, then the NPHR improvement would be about 0.23 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.23%

3.6.2 A.B. Brown Unit 2 Neural Network Deployment

The unit has the ability to bias individual mills as well as compartmented windboxes. Each burner row has an independent windbox with a damper for air control on each end, but there is only manual secondary air adjustment at each individual burner. There is no valid CO measurement [4]; thus, the unit must be restricted to an arbitrary O_2 lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels

[4] Lack of a valid CO measurement would significantly hamper the ability of a neural network system to affect positive change in unit operations.

improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance.

For A.B. Brown Unit 2, the excess oxygen varies roughly from between 2 percent to 4.5 percent at gross output levels above 250 MW, with an average level approximating 3.1 to 3.3 percent. No online correlation of NPHR or boiler efficiency from DCS system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate (these are the same as A.B. Brown Unit 1):

- 0.25 percent reduction in excess O_2: 0.10 percent gain in boiler efficiency, 0.23 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.21 percent gain in boiler efficiency, 0.43 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.27 percent gain in boiler efficiency, 0.60 percent improvement in net plant heat rate.

Utilization of a specific Vista model of Brown 2 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent then the NPHR improvement would be about 0.23 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.23%

3.6.3 F.B. Culley Unit 2 Neural Network Deployment

The unit has the ability to bias individual mills, and each burner has an air shroud that can be biased; fuel biasing is available at each burner. Also, there is no valid CO measurement; thus, the unit must be restricted to an arbitrary O_2 lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance.

The excess oxygen varies roughly from between 3.5 percent to 5.2 percent at gross output levels above 80 MW, with an average level approximating 4.3 percent. No online correlation of

NPHR or boiler efficiency from DCS system calculations was readily available from which to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess O_2: 0.15 percent gain in boiler efficiency, 0.26 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.29 percent gain in boiler efficiency, 0.47 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.43 percent gain in boiler efficiency, 0.62 percent improvement in net plant heat rate.

Utilization of a specific Vista model of F.B. Culley 2 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by approximately 0.25 percent, then the NPHR improvement would be approximately 0.26 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.26%

3.6.4 F.B. Culley Unit 3 Neural Network Deployment

The unit has the ability to bias individual mills, and each burner has an air shroud that can be biased; there is no fuel biasing available at each burner. Also, there is no valid CO measurement[5]; thus, the unit must be restricted to an arbitrary O_2 lower limit to avoid typical low oxygen combustion issues such as slagging and tube wastage.

Reducing excess oxygen levels in the boiler increases the boiler efficiency by reducing sensible heat losses, although in some cases, unburned carbon losses can be increased (but almost never more than the sensible heat losses are reduced). In addition, reducing excess oxygen levels improves the NPHR by reducing both FD and ID fan flow requirements and can also benefit emissions control systems performance. Plant personnel have commented that this could also help to control the O_2 balance across the furnace, which would yield better combustion control and help reduce slagging.

For F.B. Culley Unit 3, the excess oxygen varies roughly from between 2.5 percent to 4.2 percent at gross output levels above 270 MW, with an average level approximating 3.5 percent. No online correlation of net plant heat rate NPHR or boiler efficiency from DCS system calculations was

[5] Lack of a valid CO measurement would significantly hamper the ability of a neural network system to affect positive change in unit operations.

readily available to draw a plant-specific correlation, but from examining the plant air heater temperature data, boiler temperature data, and other factors, it was estimated by utilizing representative plant models within the EPRI Vista fuel quality impact model that reducing the excess oxygen would result in the following improvements to boiler efficiency and heat rate:

- 0.25 percent reduction in excess O_2: 0.13 percent gain in boiler efficiency, 0.25 percent improvement in net plant heat rate.
- 0.50 percent reduction in excess O_2: 0.24 percent gain in boiler efficiency, 0.46 percent improvement in net plant heat rate.
- 0.75 percent reduction in excess O_2: 0.32 percent gain in boiler efficiency, 0.62 percent improvement in net plant heat rate.

Utilization of a specific Vista model of F.B. Culley 3 would result in improved heat rate benefit estimates and should be considered as a next-phase effort. Hypothetically, it could be assumed that a modest reduction in boiler excess oxygen would be possible; therefore, if the unit could lower boiler outlet oxygen concentration by about 0.25 percent, then the NPHR improvement would be about 0.25 percent. The effects on NPHR were not linear because they varied as a function of auxiliary power changes, as well as changes in steam temperatures, which were affected by reduced excess O_2 levels.

Total Installed Capital Cost:	$500,000
Heat Rate (efficiency) Improvement:	0.25%

3.7 UNIT INTELLIGENT SOOTBLOWING DEPLOYMENT

The purpose of this project would be to reduce the required sootblowing flow by installing an integrated intelligent sootblowing (ISB) control system. This system would utilize heat flux sensors, hanger strain gauges, and process data to determine the areas needing to be cleaned. By cleaning only “dirty” areas, sootblowing flow would be reduced and tube life potentially extended.

3.7.1 A.B. Brown Unit 1 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because A.B. Brown Unit 1 already has ISB installed.

3.7.2 A.B. Brown Unit 2 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because A.B. Brown Unit 2 already has ISB installed.

3.7.3 F.B. Culley Unit 2 Intelligent Sootblowing Deployment

The plant uses air as the sootblowing media, but currently, no heat flux sensors or hanger strain gauges are installed. Sootblowing is currently based on operator observation, attemperation, and control operator judgement. In addition to current sootblower O&M, it is estimated that an ISB could reduce sootblowing by approximately 10 percent or greater.

Total Installed Capital Cost:	$350,000
Heat Rate (efficiency) Improvement:	0.10%

3.7.4 F.B. Culley Unit 3 Intelligent Sootblowing Deployment

An ISB system will not be investigated for this unit because F.B. Culley Unit 3 already has ISB installed.

3.8 IMPROVED O&M PRACTICES

The purpose of this project would be to improve O&M practices as they pertain to three particular areas of focus: heat rate improvement training, on-site appraisals for identifying additional heat rate improvements, and improved condenser cleaning strategies.

3.8.1 Heat Rate Improvement Training

Black & Veatch conducts heat rate awareness training, which covers the fundamentals of determining unit performance, how to use these metrics, and the operating conditions and decisions that impact unit efficiency and heat rate. The course includes numerous real-life case studies identified through years of monitoring and diagnostic work. This on-site course is typically 2.5 days and is primarily geared toward operators and engineers.

Total Installed Capital Cost	$15,000/class (could cover multiple units and plants)
Heat Rate (efficiency) Improvement:	Unknown, although improved O&M practices at peer coal fired EGUs have claimed to result in net plant heat rate improvements of 0.1 to 0.5 percent in the first year of implementation

3.8.2 On-Site Heat Rate Appraisals

On-site heat rate appraisals, mentioned as a BSER in the EPA ACE proposal, is left open to interpretation; indeed, the EPA was not able to provide suitable guidance for estimated ranges of capital cost or HRI. On-site heat rate appraisals are often conducted via a detailed assessment of controllable losses, especially those that can be reduced or eliminated by low-impact operations changes and equipment repairs and upgrades. This assessment utilizes a combination of a review and analysis of historical operations data, interviews with plant O&M personnel, review of past test and capability reports, a detailed study of the current fuel sources and fuel-related impacts upon the plant, discussions with plant management to understand the plant generation goals and objectives, and a reliability and maintenance history analysis.

Real-world examples of heat rate improvement projects resulting from on-site heat rate appraisals and audits include the following:

- Diagnosis of a cracked feedwater heater partition plate via analysis of online performance data, which resulted in a $12,000 monthly heat rate savings and 0.4 MW capacity improvement.
- Discovery of a failed reheat stop valve by analyzing reheat pressure swings over time, resulting in a $65,000 monthly heat rate improvement and 4 MW capacity improvement.
- An audit of terminal temperature difference (TTD) and drain cooler approach (DCA) temperature trends across a feedwater heater train at one power plant found that the highest-pressure feedwater heater emergency drain valve was leaking, with 50 percent of its flow returning to the condenser, rather than cascading to the next feedwater heater. This failure resulted in a heat rate loss of 53 Btu/kWh (about 0.5 percent and a net capacity loss of 2.5 MW.
- Testing of mill dirty air flows and coal flow balances at one power plant found that by rebalancing the flows on four mills to bring the coal and air flow deviation to within ± 10% (compared to the ± 30 percent it formerly operated at), coal unburned carbon heat losses decreased by 0.5 percent, which directly translated to an HRI of 0.5 percent. Moreover, burner-zone slagging was nearly eliminated by this change, resulting in significantly less use of sootblowing steam in the furnace wall blowers, which resulted in an additional long-term heat rate benefit of 0.1 percent (and a corresponding improvement in furnace wall tube life).
- Long-term analysis of subtle deviations in feedwater heater extraction lines revealed an internal line had failed, resulting in not only a $15,000 heat rate loss, but the potential for an unplanned outage because of debris in the heater.
- An analysis of 19 different truck coals supplied to a power plant found that not only were 7 of the coals unprofitable to burn, burning the worst coal resulted in a heat rate loss of more than 2 percent Moreover, this coal was responsible, in whole or in part, for the majority of the plant de-rates because of high-temperature sodium-based fouling, which cost the unit an additional 1.2 percent in heat rate on an annual basis because of the increased number of starts and stops from fouling-related outages.
- A long-term analysis of plant continuous emissions monitoring system (CEMS) data and motor amperage data found that a malfunctioning VFD controller in the coal handling system was responsible for incorrect blending of two different coals to meet the plant SO_2 limit, resulting in not only excess use of low-sulfur coal, but a loss of heat rate equating 0.6 percent on an annual basis.

Heat rate assessment is an ever-moving target, so while there is substantial benefit from a focused heat rate auditing and improvement program, long-term use of some type of performance and O&M monitoring system will provide the best overall heat rate improvement.

3.8.3 Improved Condenser Cleanliness Strategies

3.8.3.1 A.B. Brown Unit 1 Improved Condenser Cleaning Strategies

Condenser performance problems can be caused by any combination of many factors: tube sheet fouling, tube fouling, high number of plugged tubes, circulating water flow issues, waterbox priming, air in-leakage, and poor steam cycle isolation to condenser. Generally, plant data can provide clear evidence of condenser performance problems, but the causes may be difficult to discern.

To determine condenser performance, an energy balance was calculated between the boiler and turbine cycle. Gross generation data allowed the calculation of a gross turbine cycle heat rate and condenser heat duty. The condenser design data and industry standard condenser performance calculations were used to determine the actual operating condenser performance and calculate the expected back pressure. This allowed a comparison between actual and expected condenser back pressure. The turbine OEM back pressure correction curve was employed to calculate a heat rate impact for the difference between actual and expected back pressure. For every hour of operation in the remaining data set, the heat rate impact in $/hour was calculated with an assumed fuel cost of $2.50/MBtu, actual generation, and assumed boiler efficiency.

Condenser performance was reviewed over 1.3 years of operating data. The timing covered two summers and one winter. Condenser performance was calculated across load and across seasons. The working data set began with 8,500 hours of data. Nearly 8,000 hours of data (93 percent) were considered good quality and used for analysis. The range of unit load for the data set spanned 120 MW to 270 MW gross load. Low load operation (less than 175 MW gross) comprised 56 percent of the generation while high loads (less than 240 MW gross) accounted for 31 percent operating data.

From summer 2017 to summer 2018, the hourly average heat rate impact for condenser back pressure showed a significant change across the 2018 spring outage. Condenser performance during 2017 showed very poor performance at low loads. The expected back pressure across load for A.B. Brown Unit 1 is shown by the red trace on Figure 3-10. Actual unit back pressure is shown by the blue trace on this figure. Actual back pressure never falls below 3.3 in. HgA when the unit drops load. This yielded a high heat rate impact on average of 84 Btu/kWh, with an associated fuel cost of $37.00/h.

Figure 3-10 shows a “floor” in actual back pressure (blue) around 3.5 in. HgA in 2017. As unit load goes down, the back pressure should follow the red trend.

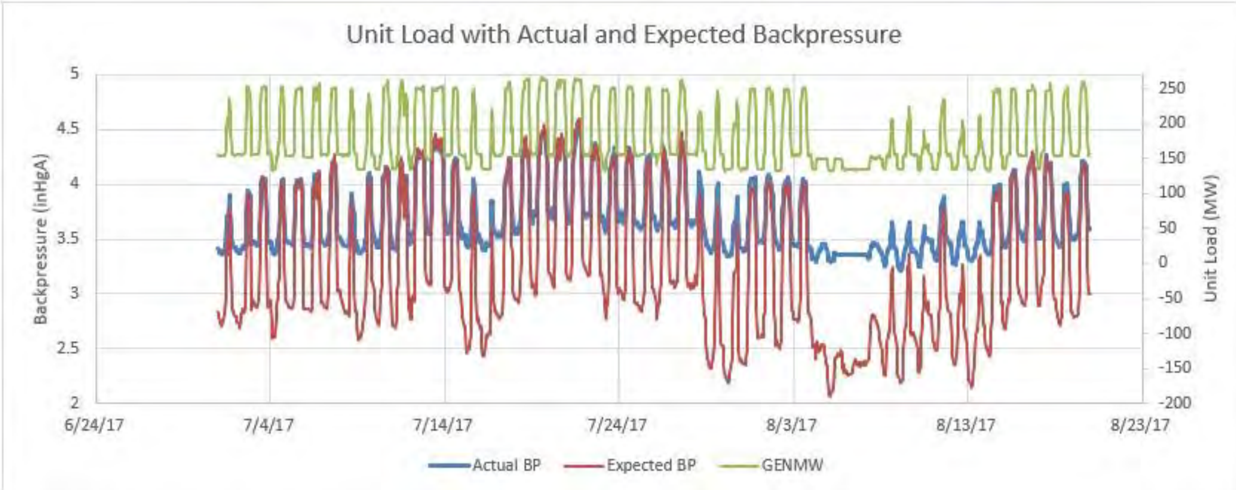


Figure 3-10 Summer 2017 Backpressure vs Time (the actual is shown in red and blue is expected performance.)

Figure 3-11 provides the perspective of actual and expected backpressure versus circulating water flow at low load. Back pressure deviations at low load for any unit can be significant.

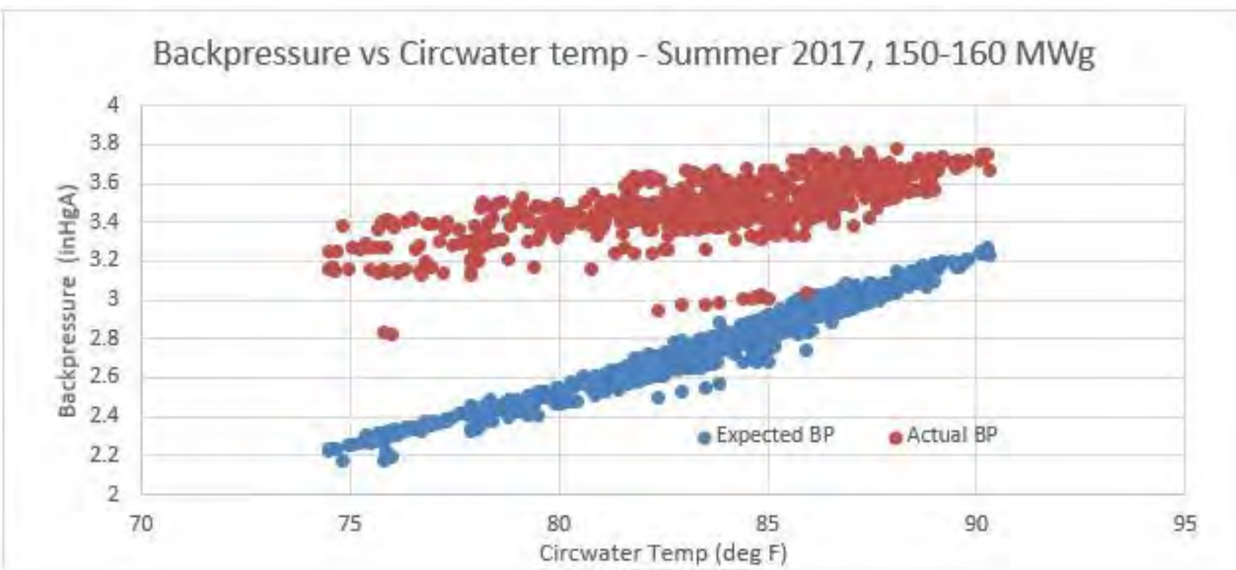


Figure 3-11 Poor Condenser Performance at Low Load 2017

When normal operation resumed in May of 2018, condenser performance looked good across load. The average heat rate impact from May to September of 2018 was estimated at 14 Btu/kWh, with a fuel-based heat rate cost of $5.7/h.

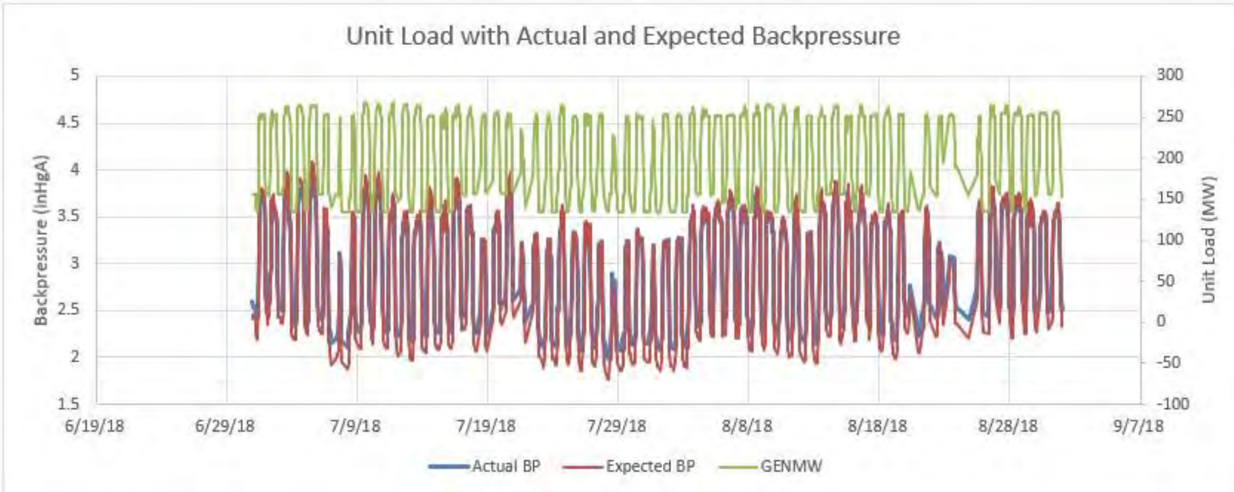


Figure 3-12 2018 Post Outage Actual and Expected Backpressure Over Time

On Figure 3-13 and 3-14, this actual back pressure is much closer to expected values in 2018. The remaining heat rate impact after the outage is likely to be due to the remaining gap in condenser performance at low load.

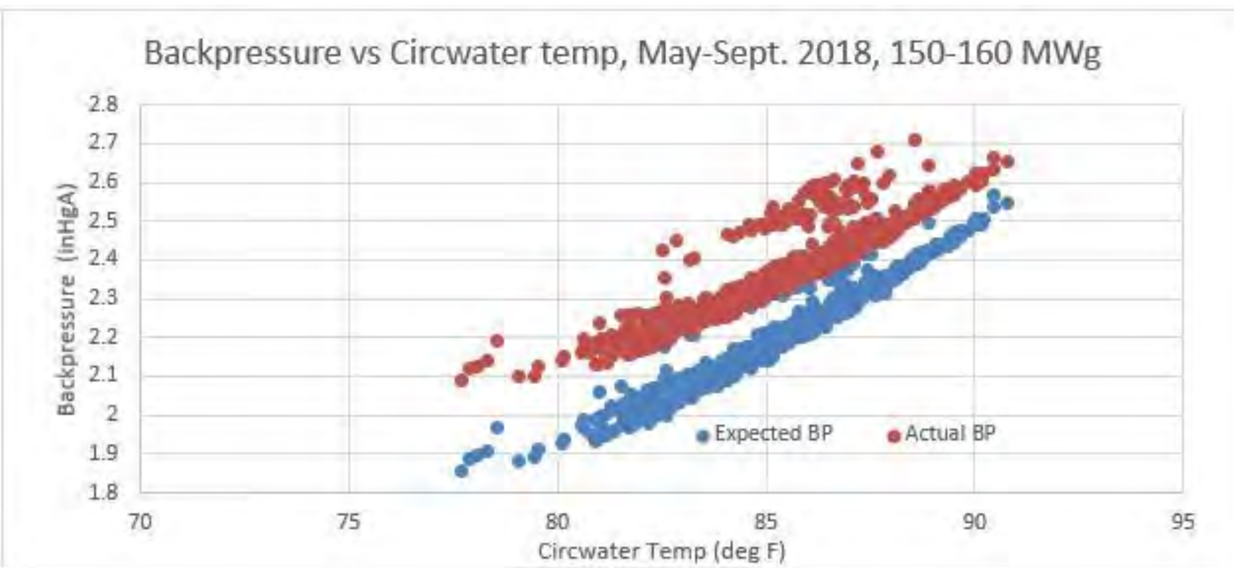


Figure 3-13 2018 Post Outage Performance at Low Load vs Circulating Water Outlet Temperature

Another noted change in condenser operation looking at both summers was calculated circulating water flow rate. Through the summer of 2017, average circulating water flow estimates were typically more than 25 percent below the design circulating water flow rate of 124,000 gpm. After the 2018 spring outage, estimated circulating water flow at full unit load was consistently 145,000 gpm, which is well above design. The estimated flow is sensitive to field measured circulating water temperatures and may need closer inspection.

The combination of these changes suggests significant air in-leakage or air removal improvements were made on the steam side, and water condenser cleaning yielded higher circulating water flows. According to plant personnel, they have repaired steam seal piping internal to the condenser neck. This issue has been appearing more regularly, and F.B. Culley 3 has had to perform similar repairs twice in the last two years. Across the span of the 15 months of operating data at full load, condenser performance was generally good, with cleanliness values at or above 70 percent as shown on Figure 3-14. However, because of low load performance problems, a fuel-based cost for 2017 operation is estimated to be $230,000 on an annual basis. Following the spring 2018 outage, the small deviation from expected condenser performance yields an estimated annual fuel cost of $35,000 on an annual basis. On the basis of the outage improvements seen in 2018, regularly scheduled maintenance and trending of performance should be sufficient to maintain good condenser performance.

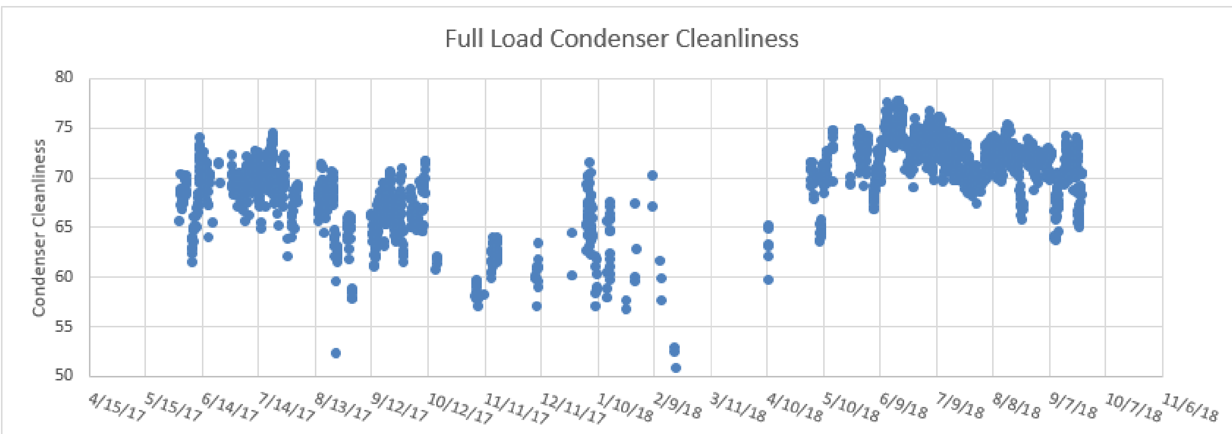


Figure 3-14 Full Load Cleanliness Results Over Time

3.8.3.2 A.B. Brown Unit 2 Improved Condenser Cleaning Strategies

Condenser performance was reviewed over 1.3 years of operating data. The timing covered two summers and one winter. Condenser performance was calculated across load and across seasons. In the process of reducing bad or suspicious data, 46 percent of the total data was removed. Nearly 6,000 hours of operating data ranging from 148 MW gross to full load was used for analysis.

Calculated results showed good performance for the condenser across load. It is suspected that measured back pressure readings may be biased low by approximately 0.2 to 0.3 in. HgA as actual back pressure consistently trended lower than expected and TTD at full load is unrealistically low (too good) at 3.5 to 5° F. The relationship between actual and expected back pressure versus circulating water temperature at constant load can be seen on Figure 3-15. As a result, condenser cleanliness values at full load consistently run greater than 90 percent and more than 100 percent at lower loads. Calculated circulating water flow rate is stable with estimated flows between

110,000 and 120,000 gpm. This is slightly below the design value of 124,000 gpm. Temperature rise across the condenser at full load runs 22° F versus design values of 20° F.

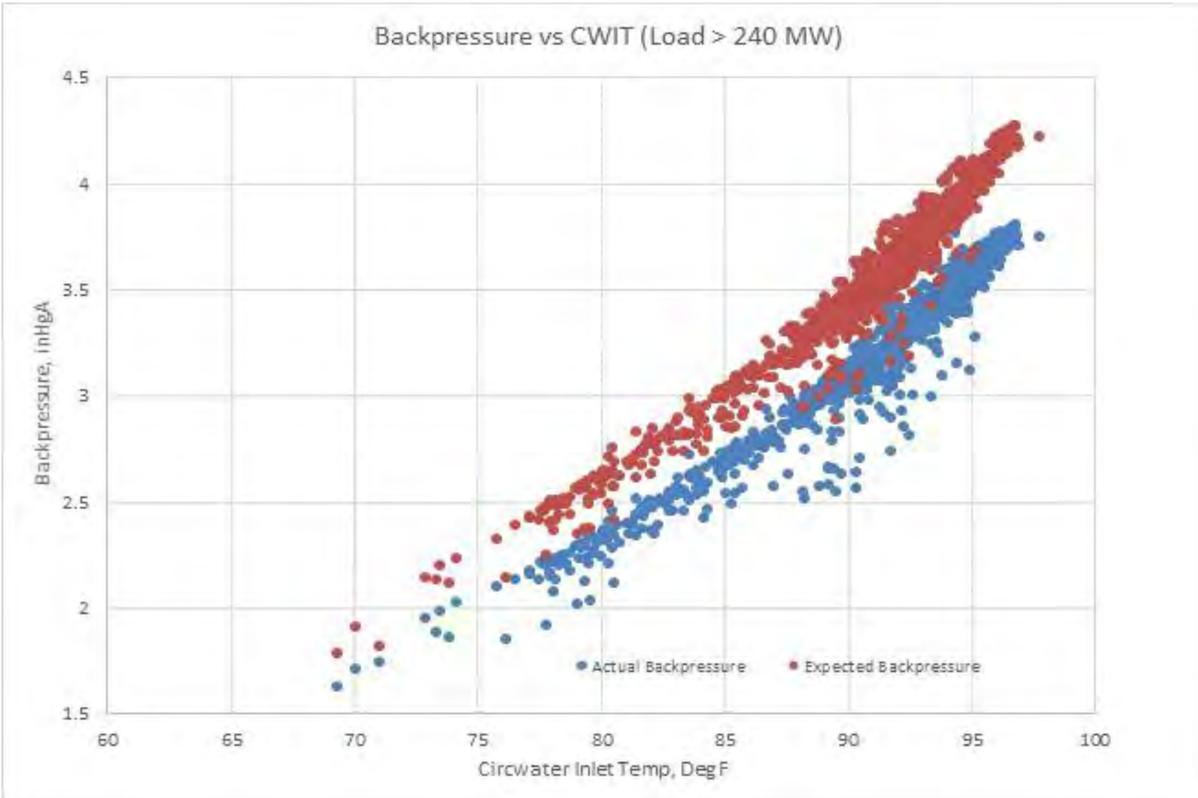


Figure 3-15 Condenser Back Pressure Versus Circulating Water Temperature at High Load

Generally, back pressure trended well across load during summer of 2017 and 2018. Separate trends of condenser performance behavior for summer 2017 and summer 2018 are provided on Figure 3-16 and Figure 3-17.

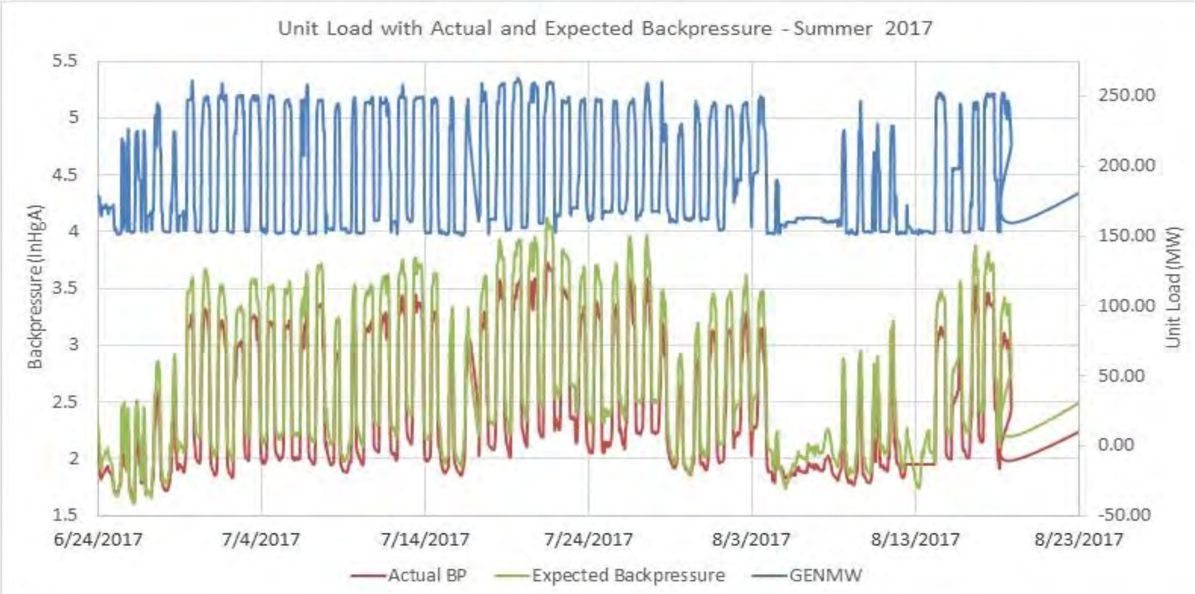


Figure 3-16 Condenser Performance Summer 2017 Across Load

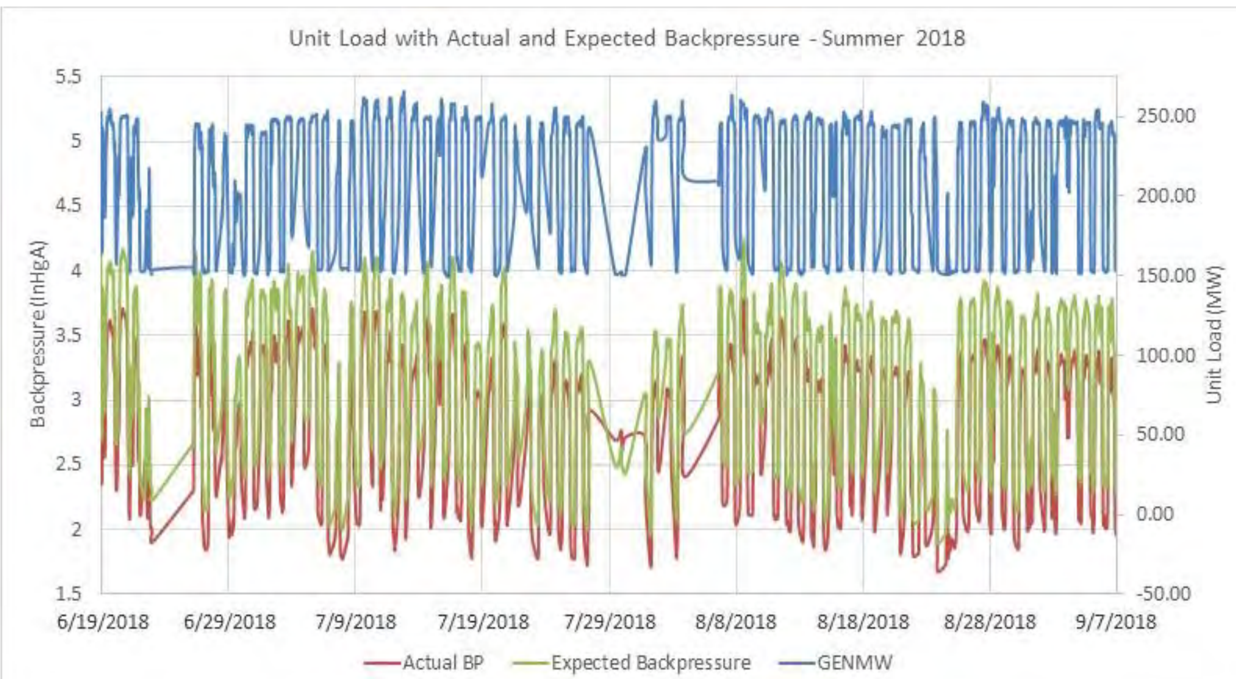


Figure 3-17 Condenser Performance Summer 2018 Across Load

Because the actual back pressure trends better than expected, no heat rate penalty is associated with normal unit operation for the data reviewed. Regularly scheduled maintenance and tracking of performance to highlight changes should be enough to maintain good condenser performance. For improved fidelity and confidence in performance metrics, the measured back pressure indication should be checked for accuracy and proper installation. The addition of more circulating water temperature measurements leaving the condenser would also improve accuracy of results by better capturing temperature stratification in the return piping.

3.8.3.3 F.B. Culley Unit 2 Improved Condenser Cleaning Strategies

For this study, 2 years of plant data were reviewed. Condenser performance was calculated across load and across seasons. Significant data reduction was necessary to eliminate offline or suspect data. This yielded more than 4,800 hours of operating data to characterize operation. In this data set, nearly 60 percent of the operating data were part load operation below 70 MW gross. Just over 30 percent of the data represented loads greater than 90 MW gross.

The hourly average heat rate impact of high condenser back pressure for Unit 2 is $42/h. Assuming the unit operates for 70 percent of a calendar year, this equates to a fuel cost of $257,000 per year. The average cleanliness value for Unit 2 is 28 percent. The highest achieved cleanliness values were in the low 50 percent range. The most significant observation with this analysis is shown on Figure 3-18 and is typical for the unit operation. Back pressure should have a strong load dependency. The Unit 2 back pressure data does not follow the expected pattern. The most likely cause of this behavior is significant air in-leakage or inadequate air removal system performance or limited capacity. Two additional factors are that Unit 2 relies upon steam jet air ejectors for air removal, and there is a suspected large air in-leakage around the turbine that has been present for years and has never been successfully resolved.

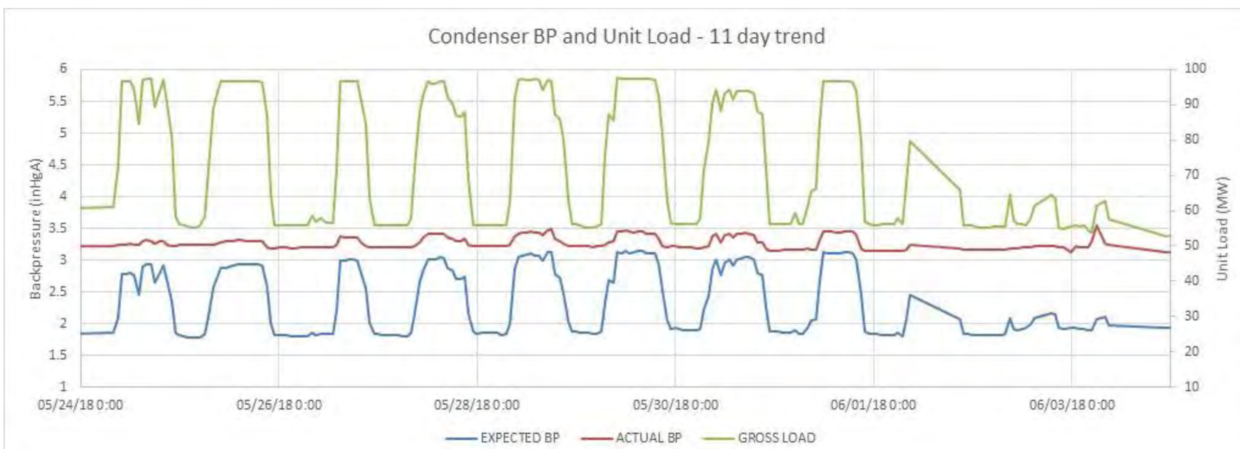


Figure 3-18 Condenser Back Pressure Versus Time (11 Day Trend)

The expected back pressure is calculated assuming no condenser tubes are plugged and cleanliness of 70 percent. Circulating water flow rate is calculated based on actual heat duty and circulating water temperature rise. Looking at full load operations across all season, there is a notable gap between actual and expected back pressure. This is shown on Figure 3-19, which illustrates back pressure versus circulating water temperature and versus time in Figure 3-20. The primary driver is expected to be the same issue of steam side air binding inhibiting lower backpressure at low circulating water temperatures.

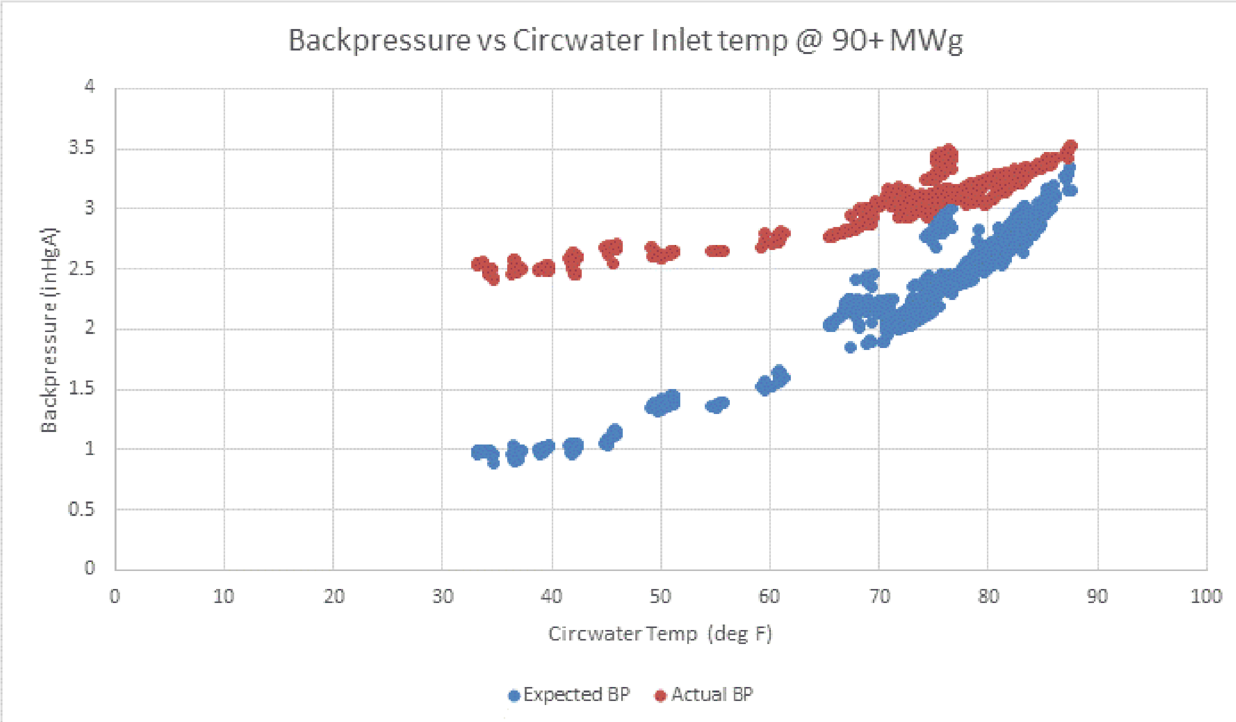


Figure 3-19 Condenser Back Pressure Versus Circulating Water Temperature

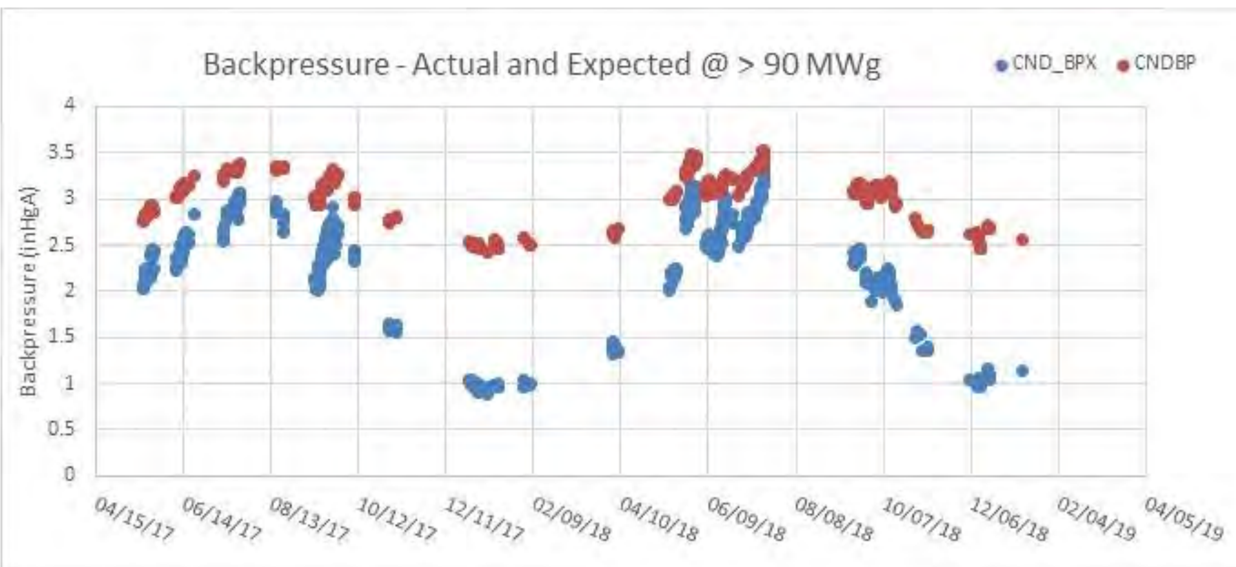


Figure 3-20 Back Pressure Versus Time (2-year trends)

3.8.3.4 F.B. Culley Unit 3 Improved Condenser Cleaning Strategies

The review of operating data for Unit 3 included 1.8 years of operational data. Data reduction to eliminate offline or suspect data eliminated 20 percent of the data, yielding more than 12,700 hours of data. The load used for analysis ranged from 135 MW gross up to 289 MW gross.

The hourly average heat rate impact of high condenser back pressure across all loads was 42 Btu/kWh and $24.8/h. Based on the data set for this analysis, the unit was in operation 90 percent of the time. Assuming this level of availability on an annual basis, the fuel cost associated with poor condenser performance is conservatively estimated at $196,000 per year. Load derates caused by high back pressure limits are probable for this unit, but highly variable, depending on the turbine design and manufacturer recommendation. Given the emphasis on efficiency opportunity in this report, an estimate for potential load impacts is not considered in this evaluation.

The highest sustained cleanliness value was slightly above 60 percent, with significant decay in performance lasting 9 of the 22 months, as seen on Figure 3-21.

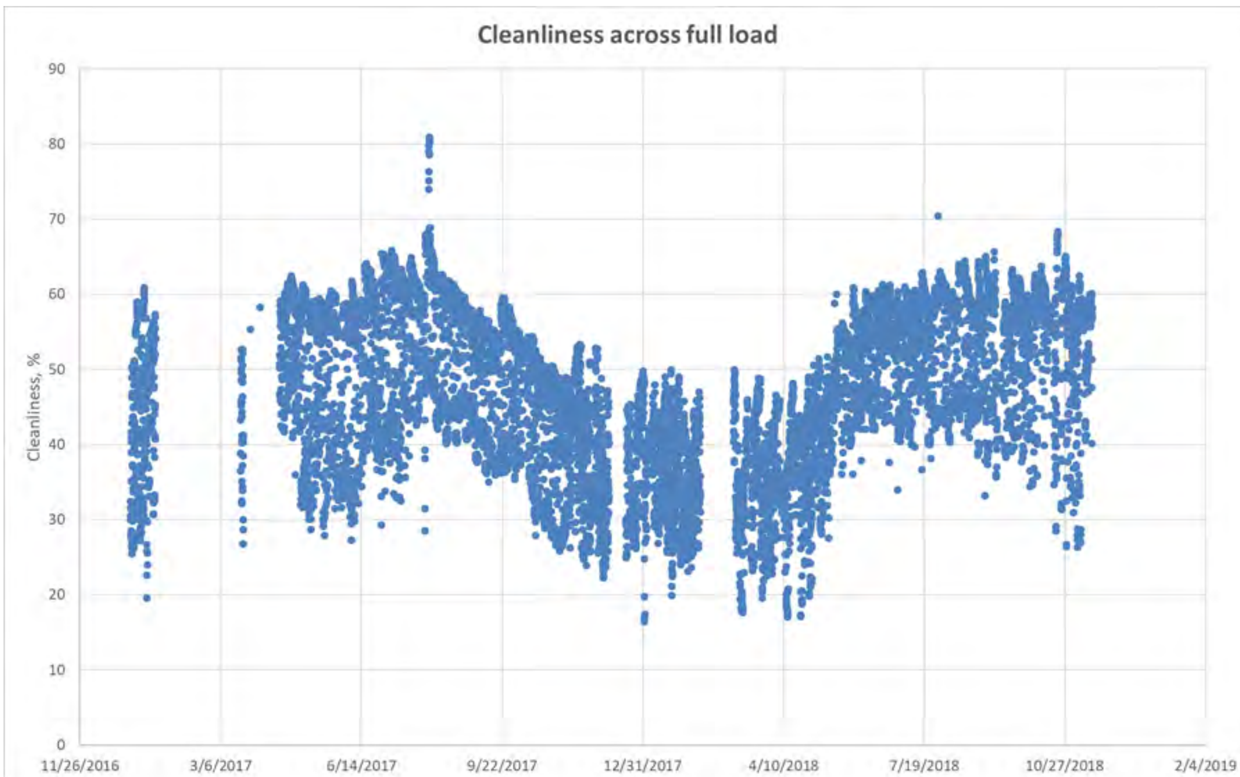


Figure 3-21 Condenser Cleanliness Across Time and Load

On closer look at the operating data, the repeated trend of increasing back pressure suggests significant tube sheet and or tube fouling issues on Figure 3-22.

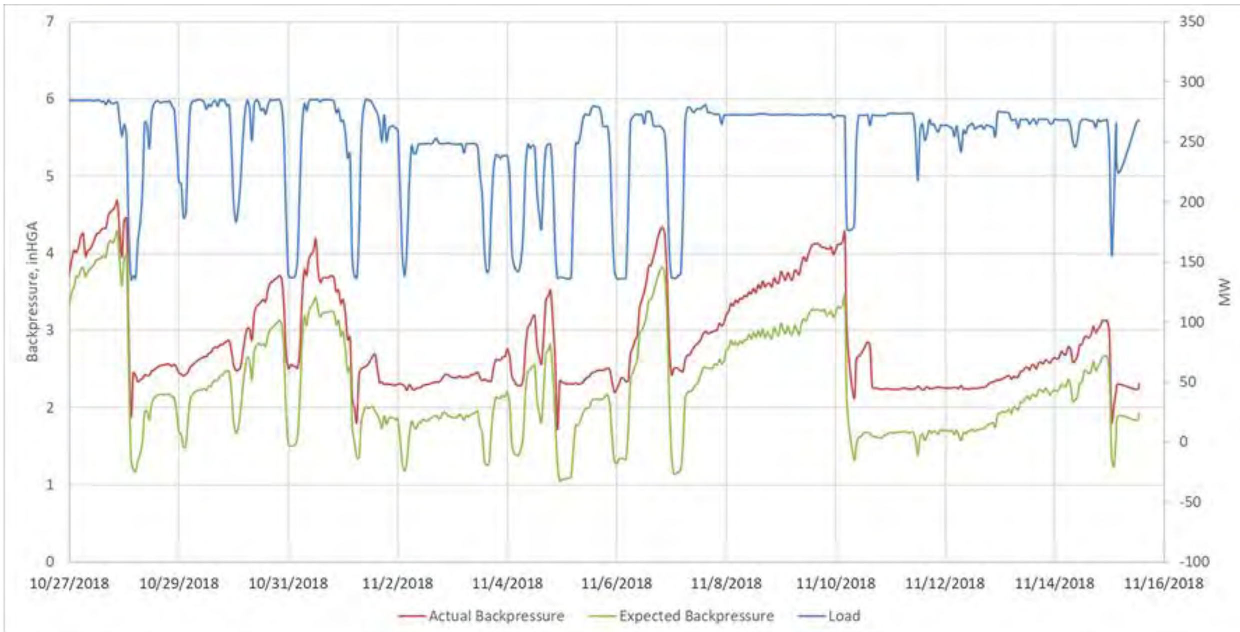


Figure 3-22 Condenser Performance – 11 Day Trend

On Figure 3-23 and 3-24, a trend of back pressure versus circulating water inlet temperature at high load shows a mixture of good performance and very poor performance, especially at lower river temperatures.

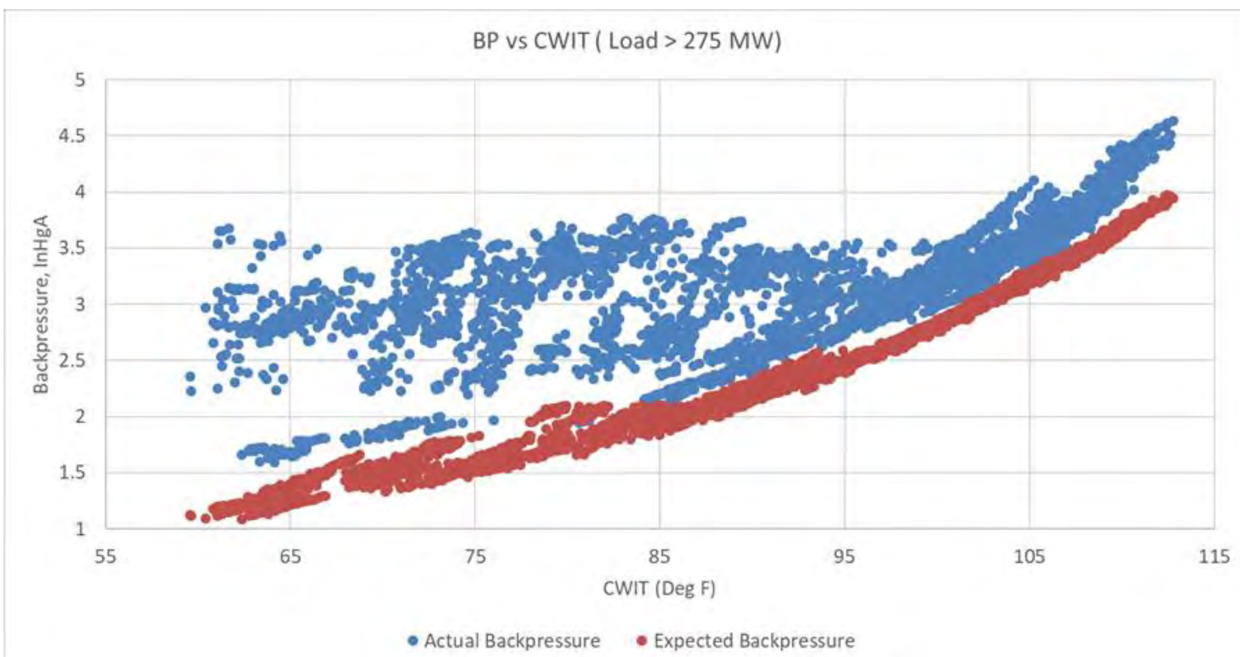


Figure 3-23 Condenser Back Pressure Versus Circulating Water Inlet Temperature

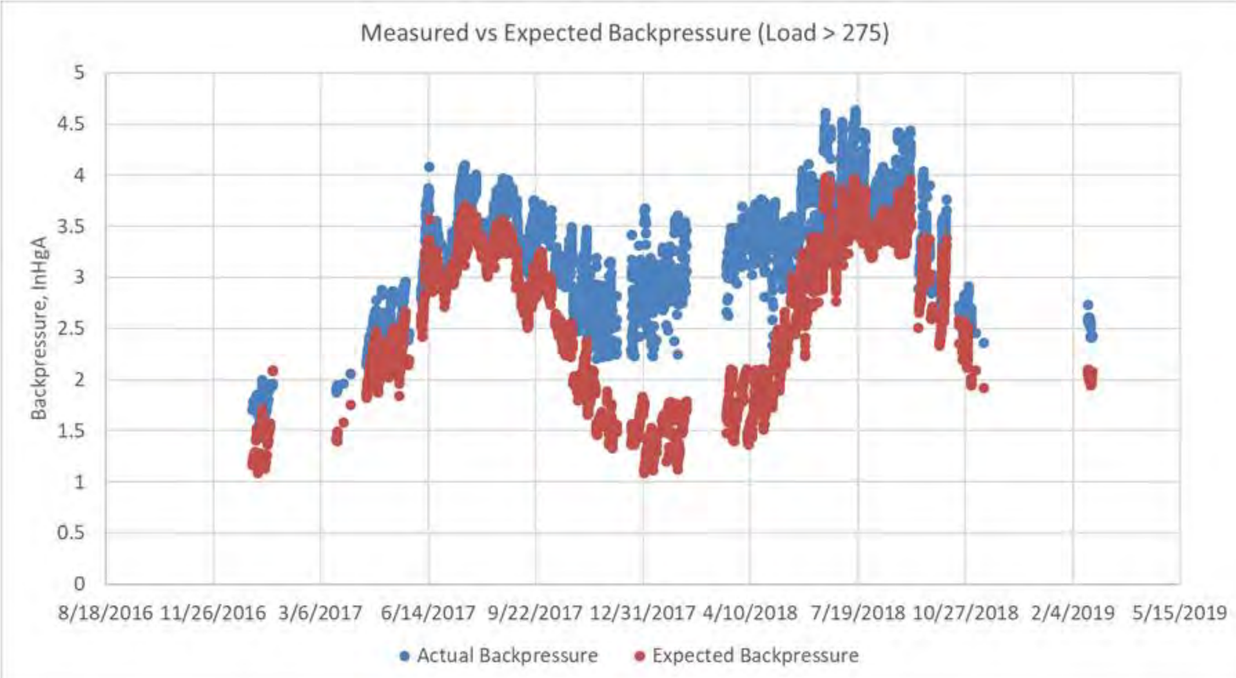


Figure 3-24 Condenser Back Pressure Versus Time at High Load

Condenser performance problems are unique to each unit and can be caused by a combination of factors. Considering the high availability, load capacity, and extent of condenser performance issues, this unit could be a candidate for added focus for improvement. If fouling the condenser is the primary concern felt by O&M personnel, payback on capital expenditure to rectify the situation may be too long, given this fuel cost. Adding backwash capability is likely to be cost prohibitive because of proximity of major piping work that would be required close to the turbine foundation. The addition of a debris filtering system would be beneficial and would be required before possible consideration of a ball cleaning system. The combined cost of these two capital improvements would likely be cost prohibitive.

4.0 Performance and CO_2 Production Estimates

High-level plant performance estimates were used to estimate the average annual CO_2 reduction. These performance benefits are summarized in Appendix B, Table B-1, Table B-2, Table B-3, and Table B-4, for A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3, respectively. It should be noted that some projects will have overlapping performance impacts and benefits, so that the overall net benefit for a series of projects considered together will likely differ from the sum of the individual project benefits listed in each table.

The annual CO_2 production estimates shown in Tables 4-1 through 4-4 were based on the following plant performance basis. Net capacity, capacity factor, and the average annual net plant heat rate were provided by average annual values from the most recent full year data (2017) provided by SNL and Ventyx Velocity data.

Table 4-1 Basis for A.B. Brown Unit 1 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
265/248	43.7	11,575	11,427,186	205.2	1,172,428

Table 4-2 Basis for A.B. Brown Unit 2 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
265/248	45.7	11,007	11,554,139	205.2	1,185,450

Table 4-3 Basis for F.B. Culley Unit 2 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
104/90	22.2	12,639	2,395,298	205.0	245.523

Table 4-4 Basis for F.B. Culley Unit 3 CO_2 Reduction Estimates

GROSS/NET CAPACITY (MW)	NET CAPACITY FACTOR (%)	AVERAGE ANNUAL NET PLANT HEAT RATE (BTU/KWH)	FUEL HEAT INPUT (MBTU/Y)	LB CO_2/ MBTU (HHV)	ANNUAL CO_2 (TONS/Y)
287/270	70.5	10,552	20,885,900	205.1	2,141,818

Where:

Fuel Heat Input [MBtu/y] =

Net Capacity [MW] * 1,000 kW/MW * Capacity Factor [%] * 8,760 h/y * NPHR [Btu/kWh, HHV]/ (1,000,000 Btu/MBtu)

Annual CO_2 Production [tons/y] =

Fuel Heat Input [MBtu/y] * CO_2 Production Rate [CO_2 emissions, lbm/MBtu of Fuel Burned]/ (2,000 lbm/ ton)

5.0 Capital Cost Estimates

High-level capital cost estimates were developed for each alternative and are detailed with each HRI project in Section 3.0. These estimates are summarized in Appendix B, Tables B-1, B-2, B-3, and B-4 and are based on the information available and should be considered preliminary for comparative purposes. The estimates are on an overnight basis (exclusive of escalation). The estimates represent the total capital requirement for each project, assuming a turnkey EPC project execution strategy. Pricing was based on similar project pricing or Black & Veatch's internal database. Black & Veatch has not developed preliminary equipment sizing or layouts to determine the feasibility of adding the proposed equipment or performing the modifications that will be required to support their installation. More detailed evaluations will be required to verify, refine, and confirm the viability of any of the proposed projects that require equipment modification or additional area.

6.1 Project Risk Considerations

Factors that influence the ability to maintain power plant efficiency and corresponding CO_2 emissions reductions on an annual basis are discussed in this section.

6.2 EFFICIENCY DIFFERENCES DUE TO OPERATING PROFILE

Efficiency is significantly affected when plants operate under off-design conditions, particularly part-load operation or with frequent starts. The future operating characteristics of A.B. Brown Unit 1, A.B. Brown Unit 2, F.B. Culley Unit 2, and F.B. Culley Unit 3 can have a significant impact on the ability to achieve the expected efficiency gains and associated reduced CO_2 emissions.

6.2.1 Operating Load and Load Factor

Plants that operate with a low average output will have lower efficiency than their full-load design efficiency. Load or capacity factor describes the plant output over a period of time relative to the potential maximum; it depends on both running time at a given load and the operating load. Therefore, annual variation in both operating load and load factor can alter the CO_2 emissions as well as the benefit of capital projects intended to reduce plant emissions. Variation in the unit load factor can significantly impact the annual CO_2 emissions for a given generation rate.

Capital projects that may offer benefit in reducing outage duration or frequency may also see some benefit mitigated. For example, a plant may be able to extend the time between major overhauls and shorten the time required for a major overhaul of the steam turbine because of improved design. However, this could increase the hours the plant may run in a year and could increase the annual CO_2 emissions. Plant generation may be limited to avoid exceeding annual CO_2 emissions rates, negating some of the potential benefit of the upgrade.

6.2.2 Transient Operation

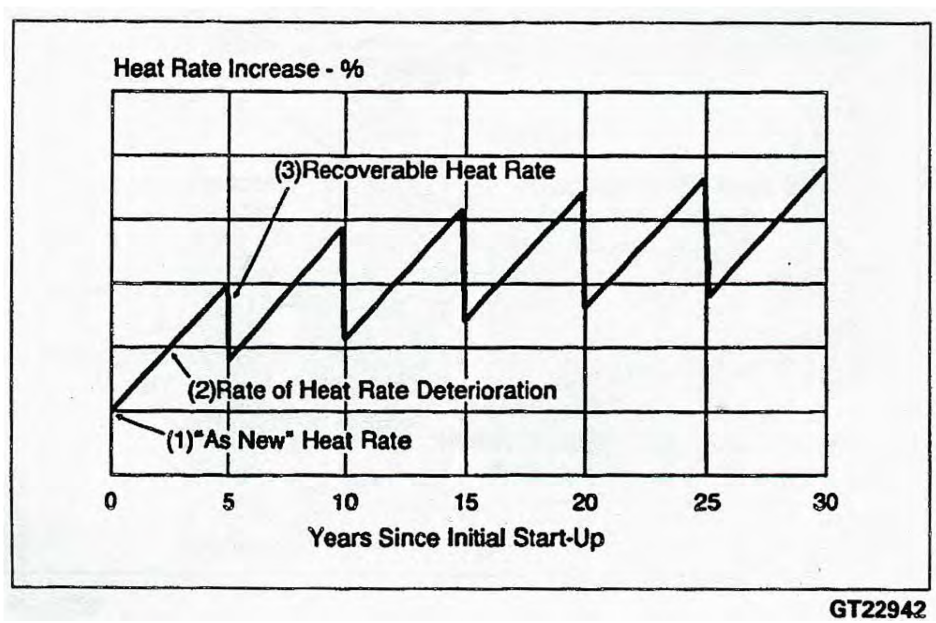
The greater the number of transients from steady state operating conditions that the plant experiences, the greater the impact to annual efficiency. During each of these transients, the plant will not be operating at peak performance. The influence of increasing renewable energy can affect the frequency of transient operation. Operation in frequency response mode, where steam flow and boiler firing fluctuate to regulate system frequency, can lead to more transients. Other situations may require frequent load changes, notably in response to power system constraints or power market pricing.

6.2.3 Plant Starts

Frequent shutdowns incur significant off-load energy losses, particularly during subsequent plant startup. Power plants operating in volatile or competitive markets, or operating as marginal providers of power, may be required to shut down frequently. This can also lead to deterioration in equipment condition, which will further affect annual plant efficiency and increase CO_2 emissions.

6.3 DETERIORATION

Figure 6-1 illustrates the characteristic performance deterioration that the steam turbine can be expected to experience between major overhauls. In addition, the ability of the steam turbine to economically recover from any deterioration in performance during a regularly scheduled maintenance overhaul is also illustrated. Any steam turbine retrofit is expected to experience a similar pattern of increasing deterioration, where increasingly, a portion of this deterioration is not viably recovered, even following a major overhaul. Turbine suppliers recognize the importance of sustained efficiency and work to incorporate features that result in superior sustained efficiency. The degree to which deterioration can be minimized by new designs is in large part dependent on the current design and feasible proven options. The ability of the steam turbine to sustain efficiency is a significant factor in achieving year after year CO_2 reduction.



Source: Steam Turbine Sustained Efficiency, GER-3750C

Figure 6-1 Steam Turbine Generator Heat Rate Change Over Time

Other plant equipment is also expected to see performance deterioration over the operating life after capital projects are implemented. The degree of deterioration and the rate at which it occurs is difficult to predict and presents a risk to the longer-term ability of the plants to sustain their efficiency gains.

6.4 PLANT MAINTENANCE

As well as ensuring plant availability, a key requirement of plant maintenance is to maintain peak operating efficiency. Improved maintenance and component replacement and upgrading can reduce energy losses.

Any poorly performing auxiliary equipment or individual components that affect performance will also contribute to the overall deterioration of plant performance over time, compounding the effects of deterioration in major components, such as the steam turbine. While not an intended outcome, plant upgrades can also result in increased maintenance if the expected improvements cannot be not achieved without increased or more complicated plant maintenance. Tables B-1, B-2, B-3, and B-4 (Appendix B) include an order-of-magnitude rating of comparative operating and maintenance cost impact associated with each of the given projects.

6.5 FUEL QUALITY IMPACTS

Variation in fuel quality can have a significant impact on the boiler efficiency. Reduced boiler efficiency will increase the required fuel heat input for a given generation which will increase CO_2 emissions. Variation in fuel composition can also have an effect on the pounds of CO_2 emission/MBtu of fuel burned.

6.6 AMBIENT CONDITIONS

Variation in ambient conditions can affect the condenser operating pressure and the resulting steam turbine output. In particular, higher wet bulb temperatures can have a significant impact on plant heat rate. Variation in annual average turbine back pressure because of wet bulb will affect the expected benefits of several of the heat rejection and steam turbine capital improvement projects.

Appendix A. Abbreviations and Acronyms

°F	Degrees Fahrenheit
ACE	Affordable Clean Energy (Plan)
ADSP	Advanced Design Steam Path
AH	Air Heater
AQCS	Air Quality Control System
BSER	Best System of Emission Reduction
Btu	British Thermal Unit
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPP	Clean Power Plan
DCA	Drain Cooler Approach
DCS	Distributed Control System
EGU	Electric Generating Unit
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
FD	Forced Draft
Ft	Feet
GE	General Electric
GHG	Greenhouse Gas
gpm	Gallons per minute
h	Hour
HHV	Higher Heating Value
hp	Horsepower
HP	High Pressure
HRI	Heat Rate Improvement
ID	Induced Draft
IGBT	Insulated-Gate Bipolar Transistor
in. HgA	Inches of Mercury – Absolute
IP	Intermediate Pressure
IRP	Integrated Resource Plan
ISB	Intelligent Sootblowing
kW	Kilowatt
kWh	Kilowatt hour
lbm	Pound
LP	Low Pressure
MBtu	Million British Thermal Units

MW	Megawatt
NO_x	Nitrogen Oxide
NP	Normal Pressure
NPHR	Net Plant Heat Rate
NSR	New Source Review
OEM	Original Equipment Manufacturer
PA	Primary Air
PJFF	Pulse Jet Fabric Filter
rpm	Revolutions per Minute
SLR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
STG	Steam Turbine Generator
TTD	Terminal Temperature Difference
VFD	Variable Frequency Drive
VWO	Valve Wide Open
y	Year

Appendix B. Capital Cost and Performance Estimates

Table B-1 A.B. Brown Unit 1 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	HP/IP Upgrades or Full Steam Path Upgrades	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Economizer	Redesign or Replacement	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	57.88	57,136	5,862	145.0	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	350	0.10	11.6	11,427	1,172	298.5	N/A
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	2,100	N/A	N/A	N/A	N/A	N/A	Low
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.43	50.3	49,701	5,099	392.2	Low/Med
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	2,900	2.39	276.50	272,973	28,007	103.5	Low
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.23	26.6	26,283	2,697	185.4	Low
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.43	49.77	49,137	5,041	99.2	N/A

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500.0	0.60	69.5	68,563	7,035	71.1	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Heat rate improvement training.	15	0.30	34.7	34,282	3,517	4.3	Low
Improved O&M Practices	On-site heat rate appraisals.	Variable	Variable	N/A	N/A	N/A	N/A	Low
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	0.15	17.4	17,141	1,759	N/A	Low

Table B-2 A.B. Brown Unit 2 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	HP/IP Upgrades or Full Steam Path Upgrades	Not Recommended	N/A	N/A	N/A	N/A	N/A	No change
Economizer	Redesign or Replacement	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	850	0.50	55.0	57,771	5,927	143.4	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	350	0.10	11.0	11,554	1,185	295.2	Low
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	Not Recommended	N/A	N/A	N/A	N/A	N/A	Low
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	2,100	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.26	28.6	30,015	3,080	649.4	N/A
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	2,900	1.33	146.3	153,608	15,760	184.0	Low
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.23	25.3	26,575	2,727	183.4	Low/Med
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.43	47.33	49,683	5,097	98.1	Low

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500	0.60	66.0	69,325	7,113	70.3	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	Not Recommended	N/A	N/A	N/A	N/A	N/A	Low
Improved O&M Practices	Heat rate improvement training.	15	0.30	33.0	34,662	3,556	4.2	Low
Improved O&M Practices	On-site heat rate appraisals.	Variable	Variable	N/A	N/A	N/A	N/A	Low
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	N/A	N/A	N/A	N/A	N/A	Low

Table B-3 F.B. Culley Unit 2 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	Full steam path upgrades.	10,400	1.4	176.9	33,534	3.44	3,025,611	No change
Economizer	Redesign or Replacement	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	476	0.50	63.2	11,976	1.23	387,744	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	600	0.60	75.8	14,372	1.47	407,294	N/A
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	900	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.48	60.9	11,549	1.18	1,689,525	N/A
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.26	32.9	6,228	0.64	783,257	Low/Med
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.47	59.40	11,258	1.15	433,291	Low

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500	0.62	78.4	14,851	1.52	328,463	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	350	0.10	12.64	2,395	0.25	1,425,528	Low
Improved O&M Practices	Heat rate improvement training.	15	0.30	37.9	7,186	0.74	20,365	Low
Improved O&M Practices	On-site heat rate appraisals.	Variable	Variable	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	0.42	53.1	10,060	1.03	N/A	Low

Table B-4 F.B. Culley Unit 3 Preliminary EPC Capital Cost Estimate (in 2019 Dollars) and First Year Performance Benefits

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Steam Turbine	HP/IP upgrades	19,900	1.5	158.3	313,289	32,127	619.4	No change
Economizer	Major redesign with additional tube passes.	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Air Heater/Duct Leakage	Air Heater Basket, Seal, and Sector Plate Replacement	750	0.50	52.8	104,430	10,709	70.0	Low
Air Heater/Duct Leakage	Air Heater (Steam Coil) System Repairs	350	0.10	10.6	20,886	2,142	163	Low
Variable Frequency Drive (VFD) Upgrades	Boiler Feed Pumps	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Circulating Water Pumps	2,100	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Cooling Tower Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Variable Frequency Drive (VFD) Upgrades	Forced Draft Fans	2,000	0.51	54.3	107,412	11,015	181.6	N/A
Variable Frequency Drive (VFD) Upgrades	Induced Draft Fans	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.25% reduction in excess O_2)	500	0.25	26.4	52,215	5,355	93.4	Low/Med
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.50% reduction in excess O_2)	500	0.46	48.54	96,075	9,852	50.7	Low

Component	Project Description	Est Capital Cost ($000)	Heat Rate Reduction (%)	Heat Rate Reduction (Btu/kWh)	Total Annual First Year Fuel Reduction (MBtu/y)	First Year Annual CO_2 Reduction (Tons/y)	Capital Cost/Annual CO_2 Reduction - First Year ($/(Ton/y))	Average Annual O&M Cost Impact**
Neural Network	Neural network deployment for combustion control and boiler excess air reduction. (0.75% reduction in excess O_2)	500	0.62	65.4	129,493	13,279	37.7	Low
Intelligent Soot Blowing (ISB)	Synchronized controlled sootblowing system designed to alleviate excessive use of steam, air or water that have a negative effect on heat rate.	Not Recommended	N/A	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Heat rate improvement training.	15	0.30	31.7	62,658	6,425	2.3	Low
Improved O&M Practices	On-site Heat Rate Appraisals	Variable	Variable	N/A	N/A	N/A	N/A	N/A
Improved O&M Practices	Improved Condenser Cleaning Strategies	N/A	0.44	46.4	91,898	9,424	#VALUE!	Low

Table B-5 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report – 5 year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	39.9	29.00
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	43.93310101	59.71
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	420.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	9.764152778	22.49
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	271.9	68.23
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	40.22590404	37.08
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-11.8	19.84
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-56.17667929	14.22
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-75.0	0.85
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	189.3	-75.26
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	297.9	-50.94
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	420.2	-39.15
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	40.8	29.00

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	44.15010234	59.71
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	420.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	582	41.22
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	402.0	170.59
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	40.54523538	2.84
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-11.2	19.84
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-55.09938596	14.22
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-74.5	0.85
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	239.3250631	-100.34
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	282.9	-47.39
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	340.2219394	-27.96
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	66.9	16.24
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	180	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	88.0	17.06
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	373.6878337	68.23

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	85.3	32.81
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	73.38804211	18.15
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	64.9	13.76
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	64.33711872	59.71
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-14.0	0.85
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	3358.478728	226.31
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-57.3	25.59
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	28.38202472	59.71
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	420.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	211.424224	74.17
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-3.7	34.12
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-90.57891699	18.54

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (5-year useful life)	Cost per ton of CO2 ($) (5-year useful Life)
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-156.8	13.76
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-121.4613034	0.85
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	10.8	70.12
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	40.4	92.79
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	73.7	117.78

Table B-6 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –10 year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	-45.1	14.50
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	8.9	29.85
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	210.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	-280.2	11.24
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	71.9	34.12
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	-9.8	18.54
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-61.8	9.92
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-106.2	7.11
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-76.5	0.43
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	114.3	-37.63
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	190.4	-25.47
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	280.2	-19.58

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	-44.2	14.50
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	9.2	29.85
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	210.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	292.0	20.61
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	202.0	85.29
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	-9.5	1.42
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-61.2	9.92
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-105.1	7.11
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-76.0	0.43
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	139.3	-50.17
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	182.9	-23.69
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	240.2	-13.98

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	19.3	8.12
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	90.0	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	28.0	8.53
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	173.7	34.12
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	35.3	16.40
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	23.4	9.07
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	14.9	6.88
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	29.3	29.85
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-15.5	0.43
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	1,368.5	113.16
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-132.3	12.79
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	-6.6	29.85

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (10-year useful life)	Cost per ton of CO2 ($) (10-year useful Life)
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	210.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	11.4	37.08
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-53.7	17.06
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-140.6	9.27
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-206.8	6.88
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-123.0	0.43
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	-64.2	35.06
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	-67.1	46.40
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	-66.3	58.89

Table B-7 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –15 year)

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	-73.4	9.67
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	-2.7	19.90
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	-376.9	7.50
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	5.3	22.74
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	-26.4	12.36
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-78.5	6.61
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-122.8	4.74
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-77.0	0.28
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	89.3	-25.09
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	154.6	-16.98
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	233.6	-13.05

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	-72.6	9.67
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	-2.5	19.90
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	195.3	13.74
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	135.3	56.86
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	-26.1	0.95
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-77.9	6.61
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-121.8	4.74
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-76.5	0.28
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	106.0	-33.45
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	149.6	-15.80
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	206.9	-9.32

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	3.4	5.41
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	60.0	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	8.0	5.69
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	107.0	22.74
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	18.6	10.94
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	6.7	6.05
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	-1.8	4.59
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	17.7	19.90
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-16.0	0.28
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	705.1	75.44
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-157.3	8.53
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	-18.3	19.90

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (15-year useful life)	Cost per ton of CO2 ($) (15-year useful Life)
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	-55.2	24.72
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-70.3	11.37
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-157.2	6.18
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-223.4	4.59
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-123.5	0.28
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	-89.2	23.37
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	-102.9	30.93
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	-113	39.26

Table B-8 Preliminary Fuel and O&M Cost Impacts Expansion, Including Useful Plant Life for all Units (Report –20 year)

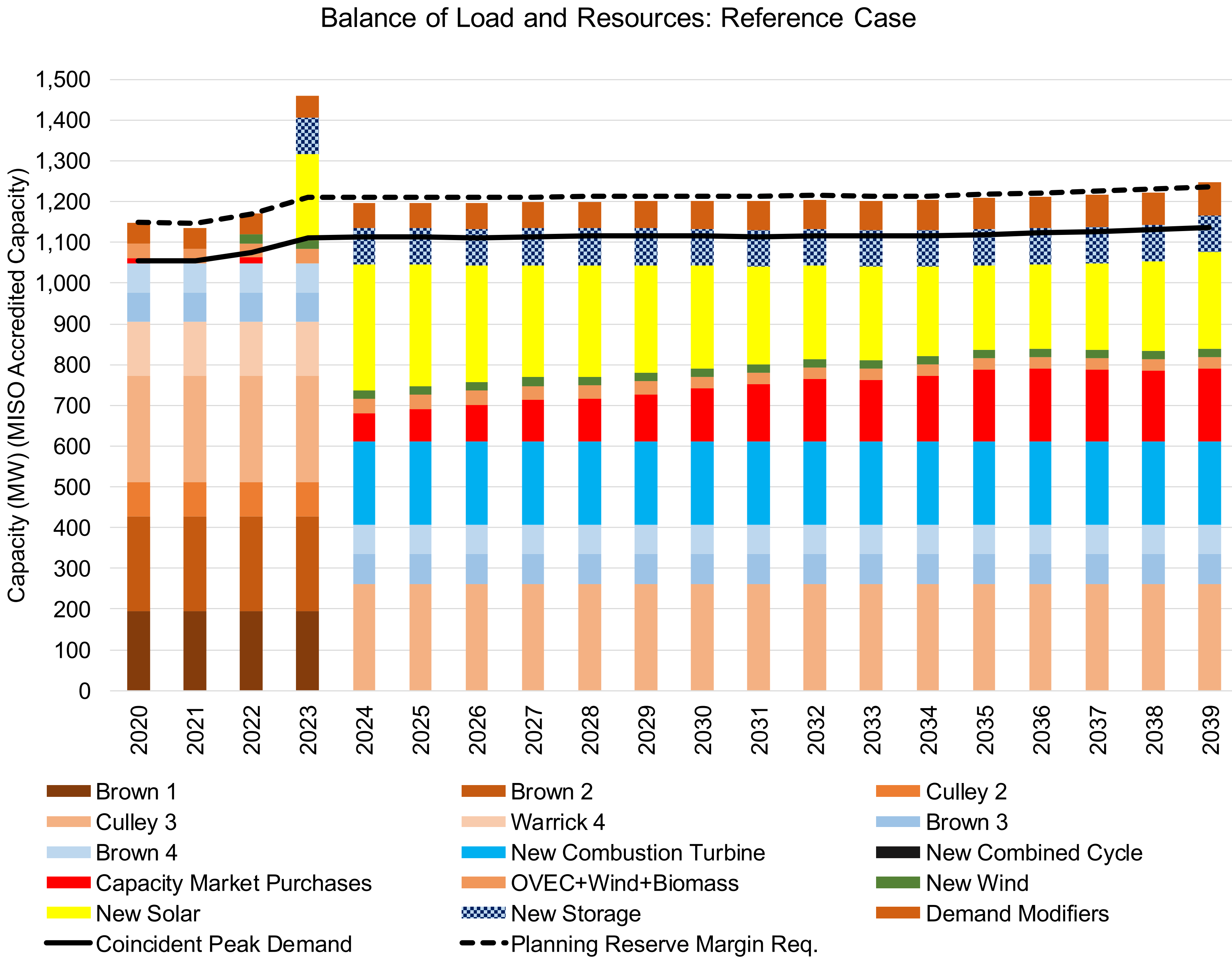
Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
ABB1	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	58	58,716	130.1	0	0	130.1	6.5	8.5	-73.4	9.67
ABB1	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11.6	11,768	26.1	0	0	26.1	13.4	15.4	-2.7	19.90
ABB1	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB1	Induced Draft Fans	2021	2,900	2.2	254.65	258,330	572.2	-2	0	570.2	5.1	7.1	-376.9	7.50
ABB1	Forced Draft Fans	2021	2,000	0.5	58	58,711	130.1	-2	0	128.1	15.6	17.6	5.3	22.74
ABB1	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.23	26.6	26,984	59.8	0	0	59.8	8.4	10.4	-26.4	12.36
ABB1	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	50	50,489	111.8	0	0	111.8	4.5	6.5	-78.5	6.61
ABB1	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	69.5	70,504	156.2	0	0	156.2	3.2	5.2	-122.8	4.74
ABB1	Heat Rate Improvement Training.	2021	15	0.3	35	35,201	78.0	0	0	78.0	0.2	2.2	-77.0	0.28
ABB1	On-Site Heat Rate Appraisals.	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB1	Improved Condenser Cleaner Strategies	2021	N/A	0.2	17	17,651	39.1	0	0	39.1	N/A	N/A	N/A	N/A
ABB1	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-17,753	-39.3	0	N/A	-39.3	-19.1	-17.1	76.8	-18.81
ABB1	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-37,433	-82.9	0	N/A	-82.9	-13.0	-11.0	136.7	-12.73
ABB1	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-63,302	-140.2	0	N/A	-140.2	-10.0	-8.0	210.2	-9.79
ABB2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	850	0.5	55	58,348	129.2	0	0	129.2	6.6	8.6	-72.6	9.67

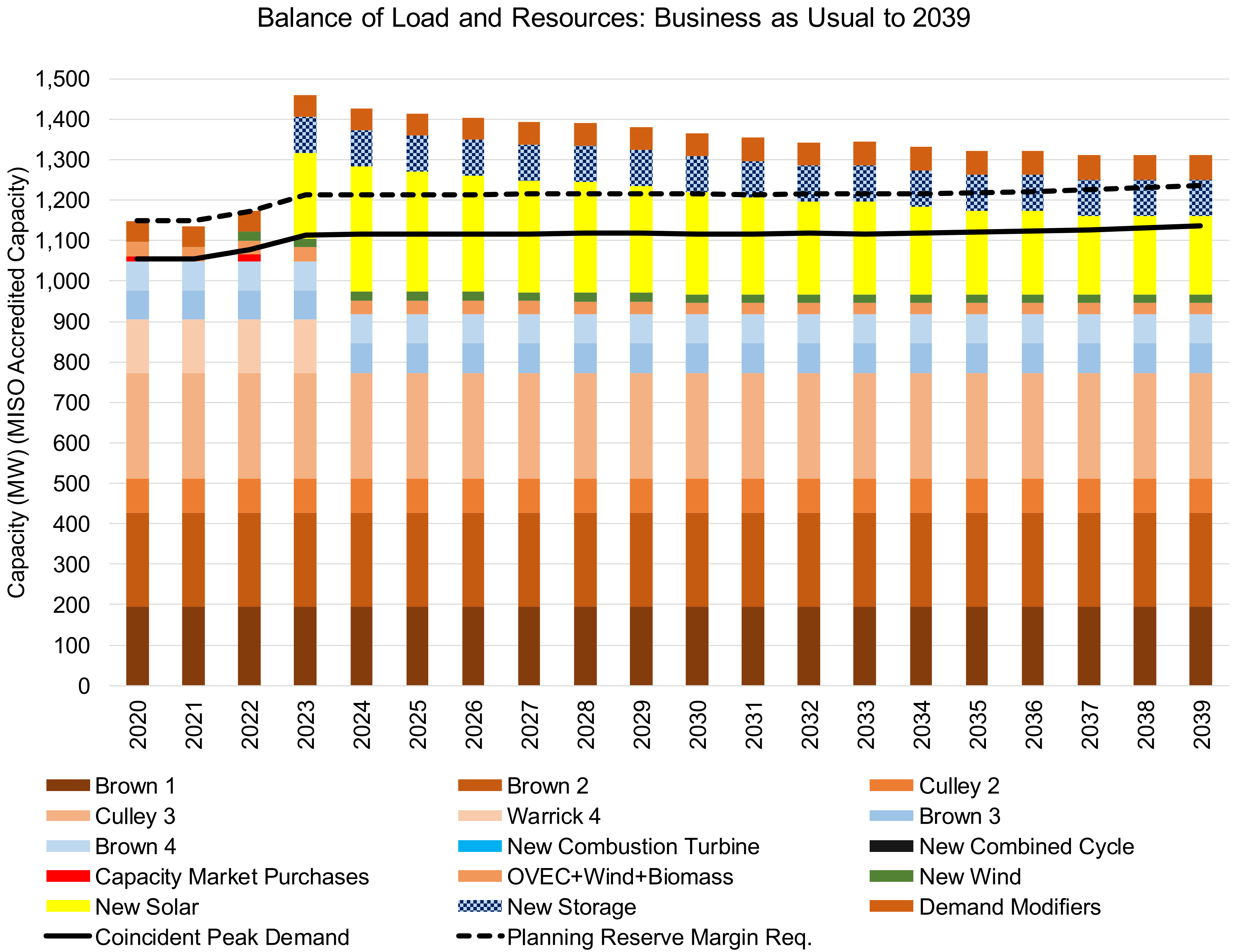
Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
ABB2	Air Heater (Steam Coil) System Repairs	2021	350	0.1	11	11,670	25.8	0	0	25.8	13.5	15.5	-2.5	19.90
ABB2	Circulating Water Pumps	2021	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
ABB2	Induced Draft Fans	2021	2,900	1.2	132.084	140,125	310.4	0	0	-2.0	-1,450.0	-1448.0	195.3	13.74
ABB2	Forced Draft Fans	2021	2,000	0.2	22	23,354	51.7	0	0	-2.0	-1,000.0	-998.0	135.3	56.86
ABB2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	3	25.3	26,840	59.5	0	0	59.5	8.4	10.4	-26.1	0.95
ABB2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.4	47	50,211	111.2	0	0	111.2	4.5	6.5	-77.9	6.61
ABB2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	66	70,018	155.1	0	0	155.1	3.2	5.2	-121.8	4.74
ABB2	Heat Rate Improvement Training	2021	15	0.3	33	35,009	77.5	0	0	77.5	0.2	2.2	-76.5	0.28
ABB2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Improved Condenser Cleaner Strategies	2021	N/A	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
ABB2	Economizer (1 Tube Pass)	2021	750	-0.17	-17.5	-18,565	-41.1	0	N/A	-41.1	-18.2	-16.2	106.0	-33.45
ABB2	Economizer (2 Tube Pass)	2021	1,075	-0.4	-37	-39,146	-86.7	0	N/A	-86.7	-12.4	-10.4	149.6	-15.80
ABB2	Economizer (3 Tube Pass)	2021	1,400	-0.61	-62.4	-66,199	-146.6	0	N/A	-146.6	-9.5	-7.5	206.9	-9.32
FBC2	Air Heater Basket, Seal, and Sector Plate Replacement	2021	476	0.5	63	12,782	28.3	0	0	28.3	16.8	18.8	3.4	5.41
FBC2	Circulating Water Pumps	2021	900	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	60.0	N/A
FBC2	Boiler Feed Pump	2021	600	0.6	76	15,337	34.0	-2	0	32.0	18.8	20.8	8.0	5.69
FBC2	Forced Draft Fans	2021	2,000	0.5	63.195	12,781	28.3	-2	0	26.3	76.0	78.0	107.0	22.74

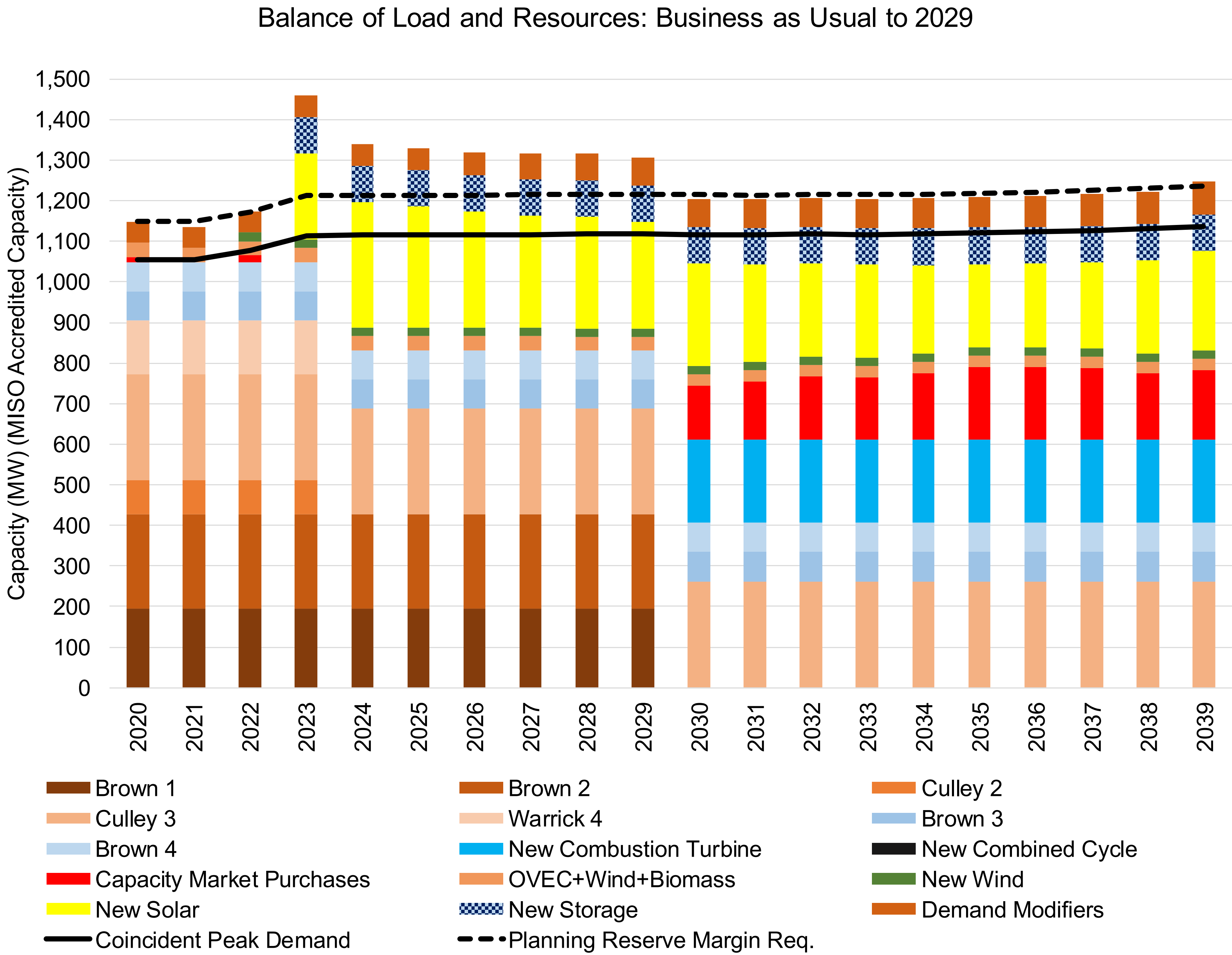
Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
FBC2	Neural Network with 0.25% Reduction in Excess O_2	2021	500	0.3	33	6,654	14.7	0	0	14.7	33.9	35.9	18.6	10.94
FBC2	Neural Network with 0.50% Reduction in Excess O_2	2021	500	0.47	59.4	12,014	26.6	0	0	26.6	18.8	20.8	6.7	6.05
FBC2	Neural Network with 0.75% Reduction in Excess O_2	2021	500	0.6	78	15,856	35.1	0	0	35.1	14.2	16.2	-1.8	4.59
FBC2	Synchronized Controlled Sootblowing System	2021	350	0.1	12.64	2,556	5.7	0	0	5.7	61.8	63.8	17.7	19.90
FBC2	Heat Rate Improvement Training	2021	15	0.3	38	7,665	17.0	0	0	17.0	0.9	2.9	-16.0	0.28
FBC2	On-Site Heat Rate Appraisals	2021	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC2	Improved Condenser Cleaner Strategies	2021	N/A	0.4	53	10,740	23.8	0	0	23.8	N/A	N/A	N/A	N/A
FBC3	HP/IP Upgrades	2022	19,900	1.5	158.3	280,580	621.5	0	0	621.5	32.0	35.0	705.1	75.44
FBC3	Air Heater Basket, Seal, and Sector Plate Replacement	2022	750	0.5	53	93,586	207.3	0	0	207.3	3.6	6.6	-157.3	8.53
FBC3	Air Heater (Steam Coil) System Repairs	2022	350	0.1	10.6	18,788	41.6	0	0	41.6	8.4	11.4	-18.3	19.90
FBC3	Circulating Water Pumps	2022	2,100	N/A	N/A	N/A	N/A	0	0	0.0	N/A	N/A	140.0	N/A
FBC3	Forced Draft Fans	2022	2,000	0.46	48.5392	86,034	190.6	-2	0	188.6	10.6	13.6	-55.2	24.72
FBC3	Neural Network with 0.25% Reduction in Excess O_2	2022	500	0.3	26	46,793	103.7	0	0	103.7	4.8	7.8	-70.3	11.37
FBC3	Neural Network with 0.50% Reduction in Excess O_2	2022	500	0.46	48.54	86,035	190.6	0	0	190.6	2.6	5.6	-157.2	6.18

Unit	Project Description	In-Service Year	Project Cost ($000's)	Heat Rate Improvement (%)	Heat Rate Improvement (Btu/kWh)	MMBtu Savings	Coal Savings per year ($000's)	Variable O&M Savings per year ($000's)	Natural Gas Savings Per Year ($000's)	Total Savings per year ($000's)	Payback Period (Yrs. from project in-service)	Total Period	Cost per year ($000's) (20-year useful life)	Cost per ton of CO2 ($) (20-year useful Life)
FBC3	Neural Network with 0.75% Reduction in Excess O_2	2022	500	0.6	65	115,919	256.8	0	0	256.8	1.9	4.9	-223.4	4.59
FBC3	Heat Rate Improvement Training	2022	15	0.3	31.7	56,187	124.5	0	0	124.5	0.1	3.1	-123.5	0.28
FBC3	On-Site Heat Rate Appraisals	2022	Variable	Variable	N/A	N/A	N/A	0	0	0.0	N/A	N/A	N/A	N/A
FBC3	Improved Condenser Cleaner Strategies	2022	N/A	0.44	46.4	82,242	182.2	0	0	182.2	N/A	N/A	N/A	N/A
FBC3	Economizer (1 Tube Pass)	2022	750	-0.1	-14	-25,169	-55.8	0	195.0	139.2	5.4	8.4	-101.7	17.53
FBC3	Economizer (2 Tube Pass)	2022	1,075	-0.28	-29.1	-51,578	-114.3	0	288.8	174.6	6.2	9.2	-120.8	23.20
FBC3	Economizer (3 Tube Pass)	2022	1,400	-0.4	-45	-79,583	-176.3	0	382.6	206.3	6.8	9.8	-136.3	29.44

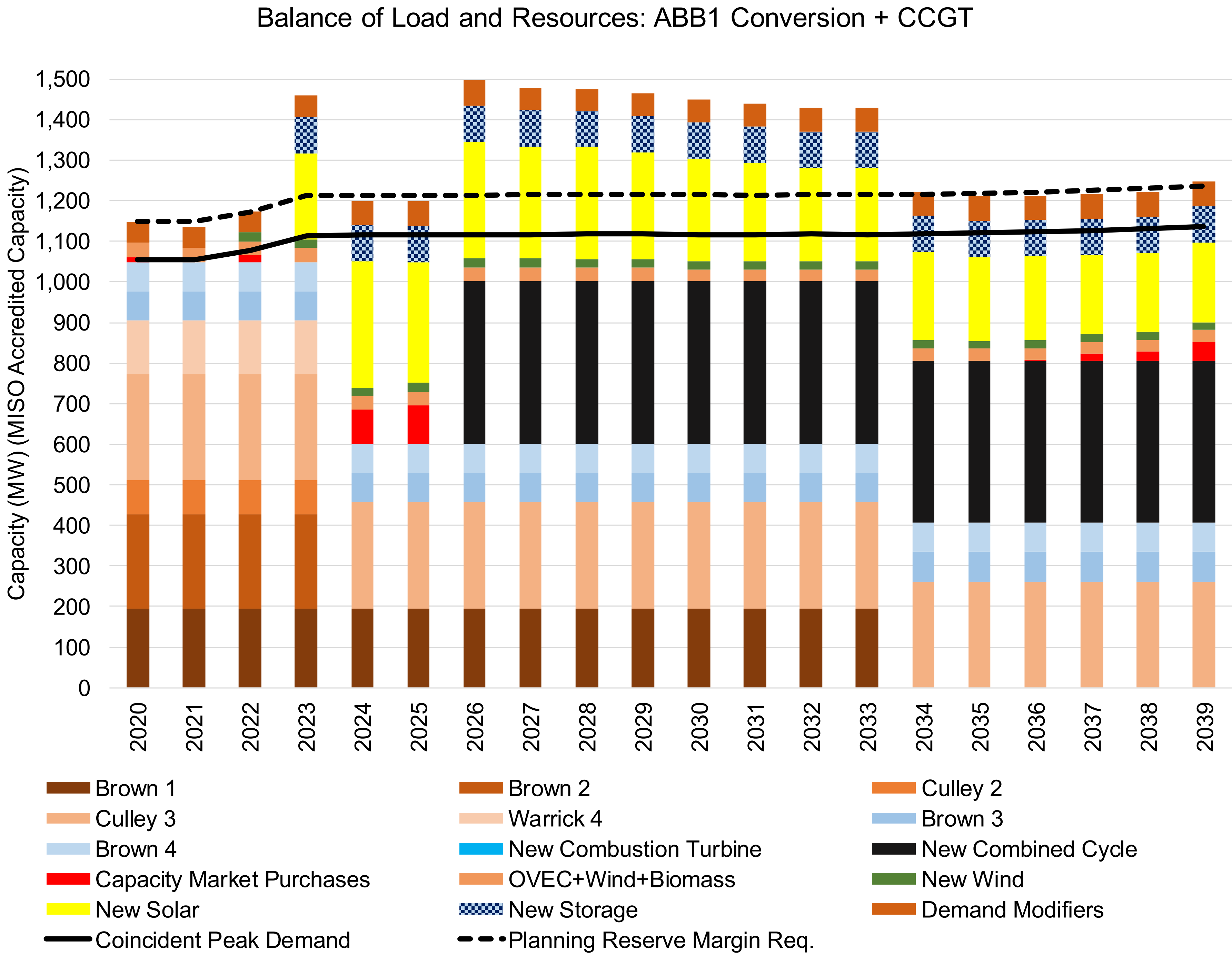
Attachment 8.1 Balance of Load and Resources

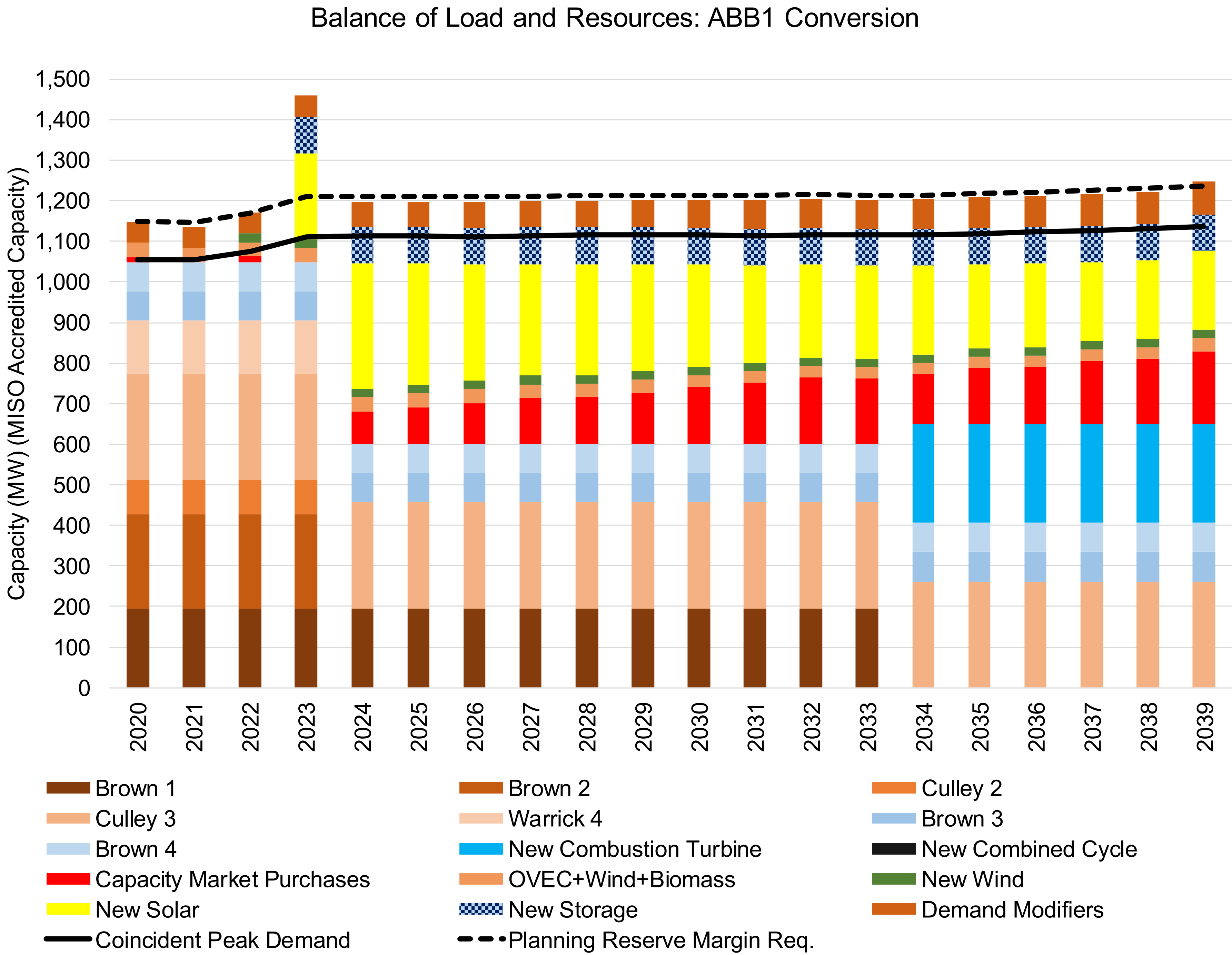

Balance of Load and Resources: Reference Case
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: Business as Usual to 2039
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

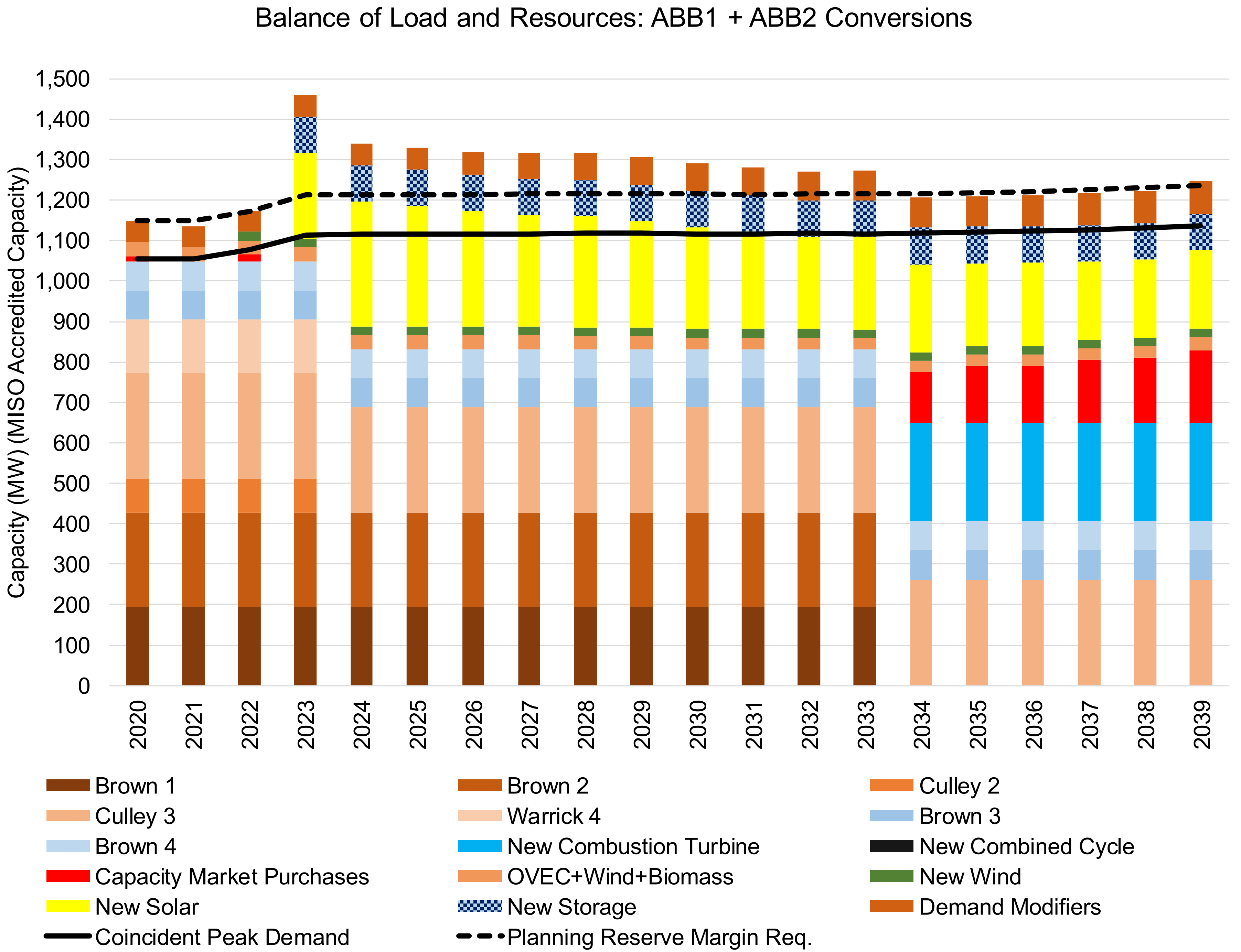


Balance of Load and Resources: Business as Usual to 2029
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

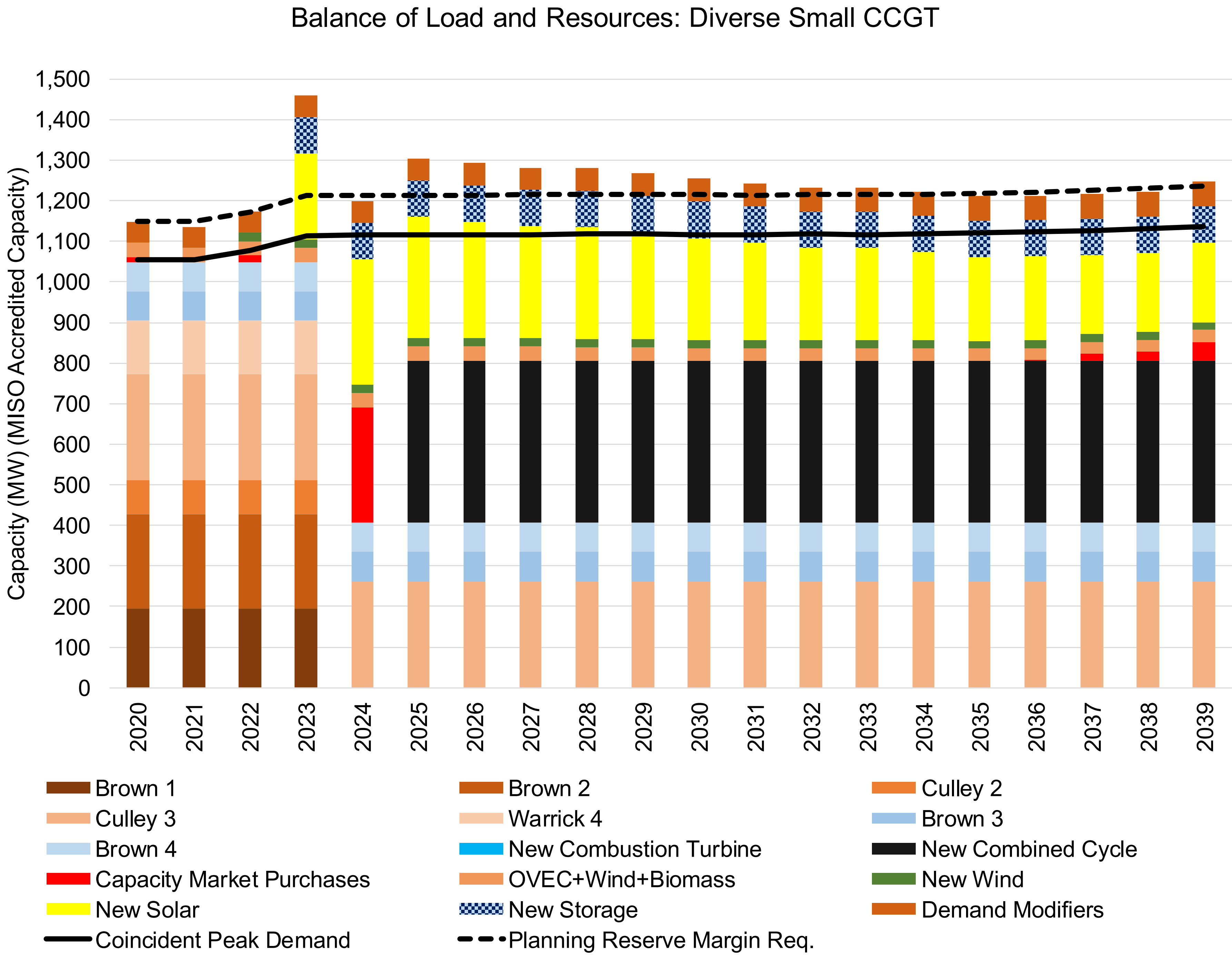

Balance of Load and Resources: ABB1 Conversion + CCGT
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

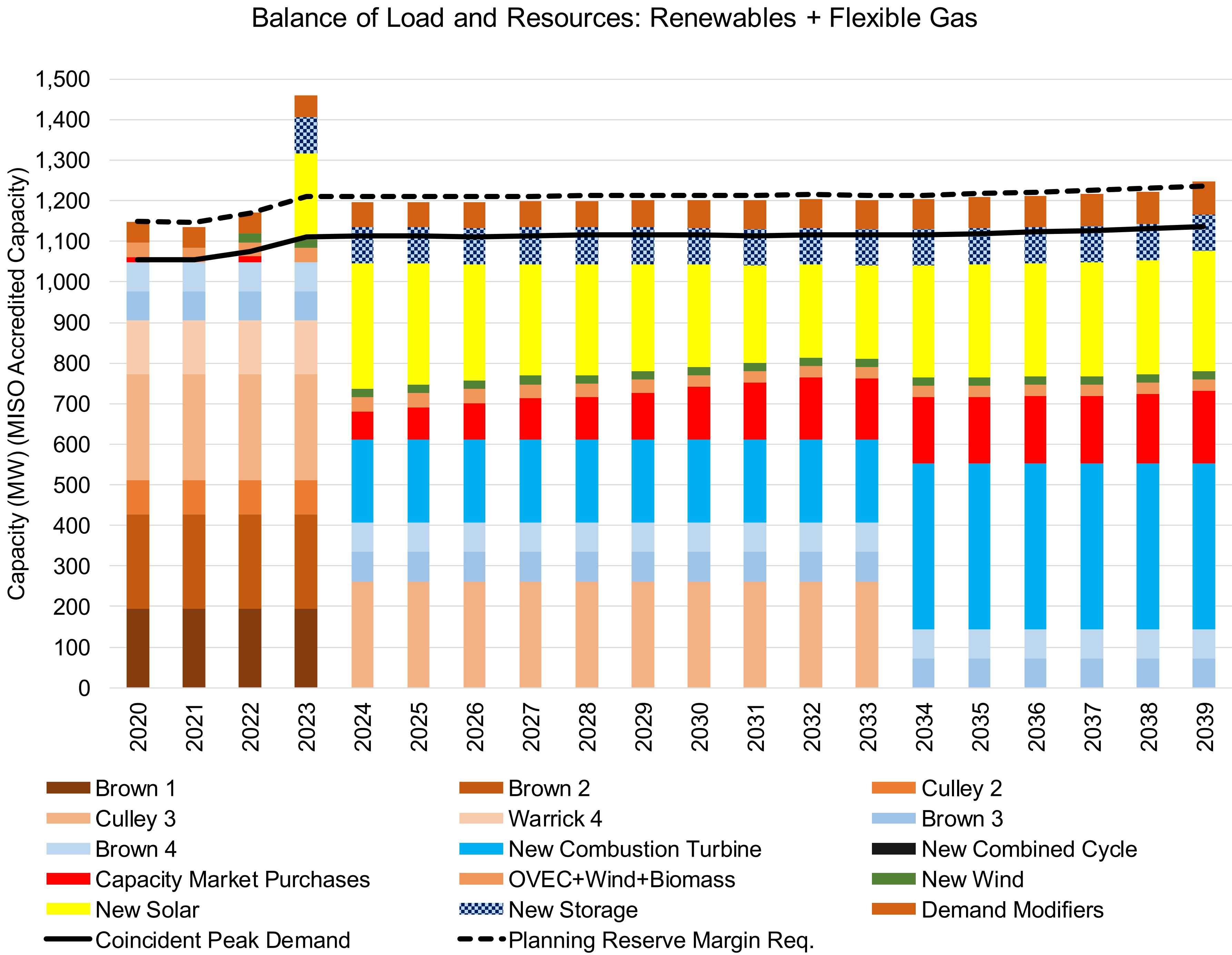


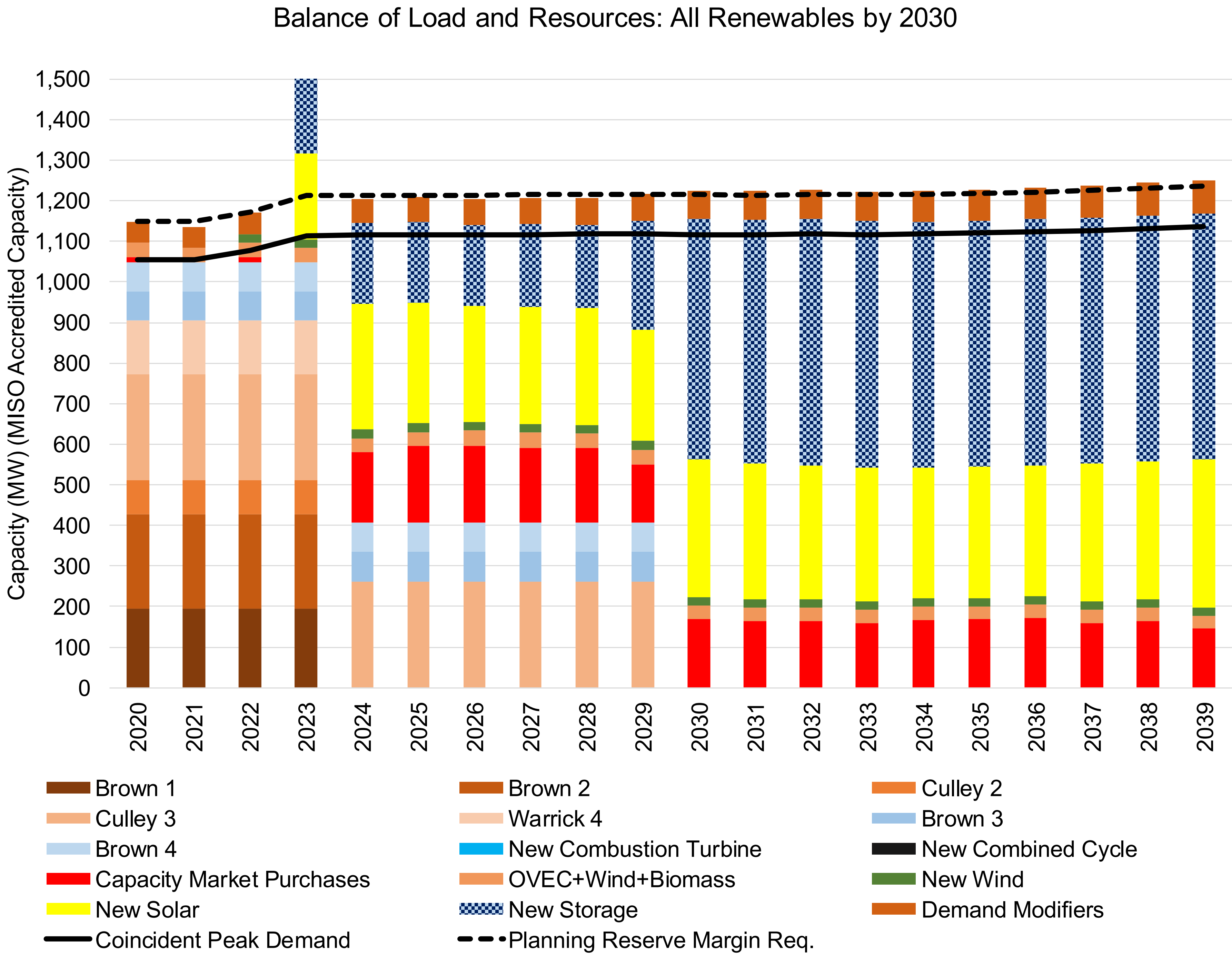
Balance of Load and Resources: ABB1 Conversion
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.

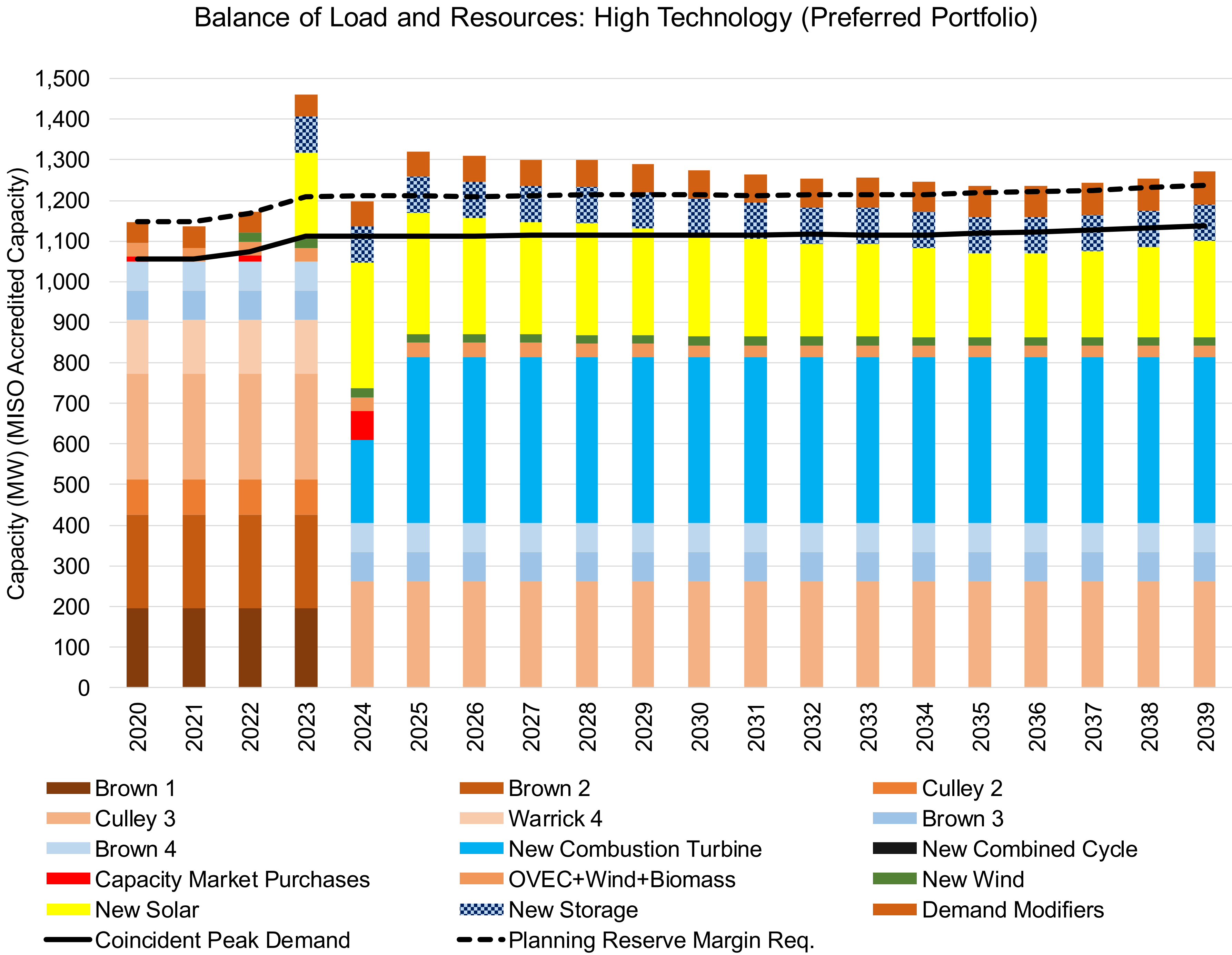


Balance of Load and Resources: ABB1 + ABB2 Conversions
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: Diverse Small CCGT
Capacity (MW) (MISO Accredited Capacity)
0
100
200
300
400
500
600
700
800
900
1,000
1,100
1,200
1,300
1,400
1,500
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: Renewables + Flexible Gas
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: All Renewables by 2030
Capacity (MW) (MISO Accredited Capacity)
0
100
200
300
400
500
600
700
800
900
1,000
1,100
1,200
1,300
1,400
1,500
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.


Balance of Load and Resources: High Technology (Preferred Portfolio)
Capacity (MW) (MISO Accredited Capacity)
1,500
1,400
1,300
1,200
1,100
1,000
900
800
700
600
500
400
300
200
100
0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
Brown 1
Brown 2
Culley 2
Culley 3
Warrick 4
Brown 3
Brown 4
New Combustion Turbine
New Combined Cycle
Capacity Market Purchases
OVEC+Wind+Biomass
New Wind
New Solar
New Storage
Demand Modifiers
Coincident Peak Demand
Planning Reserve Margin Req.