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COURT CLERK'S OFFICE - OKC
CORPORATION COMMISSION
OF OKLAHOMA

BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER OF THE COMMISSION	)	
AUTHORIZING APPLICANT TO MODIFY ITS	)	CAUSE NO. PUD 201700496
RATES, CHARGES, AND TARIFFS FOR RETAIL	)	
ELECTRIC SERVICE IN OKLAHOMA	)	

Direct Testimony

of

Phillip L. Webster

Associate Vice President for Black & Veatch Corporation

on behalf of

Oklahoma Gas and Electric Company

January 16, 2018

Q. **Would you please state your name, your employer and business address?**

A. My name is Phillip Webster. I am employed by Black & Veatch Corporation ("Black & Veatch") and my business address is 11401 Lamar Avenue, Overland Park, KS 66211.

Q. **Please describe the Black & Veatch Corporation.**

A. Founded in 1915, Black & Veatch is a leading global engineering, consulting and construction company. Black & Veatch is employee-owned and has more than 100 offices worldwide. Black & Veatch specializes in the following major markets: Power, Water, Oil & Gas, Telecommunications, Mining, Governments, Smart Cities and Data Centers. Black & Veatch service offerings include: conceptual and preliminary engineering, procurement, engineering design and construction, management consulting asset management, environmental consulting and security design.

Q. What is your position and role at Black & Veatch?

A. I hold the position of Associate Vice President. I am a project manager and senior consultant in the Operations and Maintenance ("O&M") Business Line within the Power Generation Services group. As a consultant in the O&M Business, I provide consulting services to existing power generators to help those clients improve their reliability while managing their O&M costs. In this role, I lead projects to conduct condition assessments of various different types of conventional power generating plants. The O&M Business team also supports the development of O&M programs at new power generating facilities, creates and delivers plant systems operations training services and O&M cost estimates to internal Black & Veatch projects supporting our electric utility clients with Integrated Resource Plans ("IRP"). I have also participated in numerous due diligence projects when Black & Veatch clients were investigating the acquisition of new and/or existing power generating assets.

I have actively participated in and/or led numerous condition assessments of coal, oil and gas fired generating units in the U.S., Canada, Mexico, Thailand and China. I have also led a large multiple year effort to improve outage management practices at a number of coal-fired steam generating units in South Africa. Attached as Direct Exhibit PLW-1, is my curriculum vita.

Q. **Would you please summarize your professional and educational background?**

A. I have been employed by Black & Veatch in essentially the same role for the past nineteen (19) years. Prior to joining Black & Veatch I was employed by an operating electric utility known as Kansas City Power & Light Company ("KCP&L"). I began my career at KCP&L in the system planning area. In that role, I supported long-range planning for the utility including the development of IRPs. I also served as a performance testing engineer at KCP&L where I directly supported the maintenance groups at all of the utility's fossil generating stations.

I received a Bachelor of Science degree in Engineering Management with an emphasis in Mechanical Engineering from the Missouri University of Science and Technology and I also received a Master of Business Administration degree from the University of Missouri in Kansas City. I am a registered Professional Engineer, licensed in the State of Missouri.

Q. **Have you previously testified before the Oklahoma Corporation Commission ("Commission")?**

A. No, I ask that the Commission accept my credentials.

Q. **What is the purpose of your Direct Testimony in this proceeding?**

A. I am appearing on behalf of Oklahoma Gas and Electric Company ("OG&E" or the "Company"). The purpose of my testimony is to present the conclusions from a Black & Veatch study prepared for OG&E regarding the Company's decision to retire its old, 1950's vintage, steam units at the Mustang Generating Station, specifically Units 1, 2, 3 and 4.

Q. **Did Black & Veatch prepare a study which details its evaluation and conclusions related to OG&E's Mustang plant?**

A. Yes. Black & Veatch's study is entitled Evaluation Report: Mustang Power Plant Retirement Consideration dated September 20, 2016 and is presented as Direct Exhibit PLW-2.

Q. **Was this Exhibit prepared by you or under your supervision and direction?**

A. Yes, it was.

Q. **What was the objective and scope of the Black & Veatch evaluation?**

A. Black & Veatch was asked by OG&E to conduct an independent review and offer an expert opinion regarding the Company's 2014 decision to retire units 1 through 4 at the Mustang Generating Station. The scope of services included a review of reports and statistics made available by OG&E with a particular emphasis on review of an earlier report prepared by Burns & McDonnell, dated January 2012. The scope of our assignment was limited to consider only the Mustang steam units using data available at the time the decision was made by OG&E to retire the units.

Q. **What was the approximate timeframe in which the Black & Veatch work was undertaken?**

A. The work was initiated in May of 2016 and the final report was completed and provided to OG&E in September of 2016.

Q. **What was Black & Veatch's final conclusion from its review of OG&E's decision to retire Mustang Units 1 through 4?**

A. Given the advanced age of the Mustang units, Black & Veatch concluded that their continued operation, with the associated operating costs, maintenance requirements, capital investment and likely degrading reliability was clearly not the optimal path. Therefore, Black & Veatch concluded that retirement of the units, on the OG&E timeline, was a prudent decision.

Q. **How did Black & Veatch conduct its review of OG&E's decision to retire the Mustang units?**

A. First**,** Black & Veatch assessed the condition of the Mustang units, how they have been used and how they performed the required role or roles in the OG&E fleet. Black & Veatch also evaluated certain projects that would be required to be undertaken in order to keep the Mustang units safe, reliable and compliant with the applicable air emissions permits. Then, Black & Veatch sought to understand whether or not the role(s) and resulting operation of the units was likely to change in the future, when compared to the historical operation, and how that change in operation could impact the ability of the units to perform their intended function in the OG&E portfolio of resources.

Q. **What information did Black & Veatch review in the process of evaluating the condition of OG&E's Mustang plant?**

A. Understanding the condition of a power generating asset, such as the Mustang plant, begins with documentation of the design and configuration of the equipment at the plant. First, Black & Veatch reviewed the report prepared by Burns and McDonnell, dated January 2012. This report discussed multiple different power generating units owned and operated by OG&E, though our assessment was limited to the Mustang steam units only. The report contained a description of the original design of each unit and their commercial operation dates, configuration of major plant systems and other details, such as design steam flow rates and steam conditions, the Original Equipment Manufacturer ("OEM") and other facts that assisted the Black & Veatch team become familiar with the equipment at each of the units at the Mustang plant.

Q. **Were there other data sources used by Black & Veatch and if so what were they?**

A. Yes. Black & Veatch also reviewed recent performance data for the units, which included both performance and financial details. The performance data was comprised of historical starts, capacity factors and annual outage data in the Generator Availability Data System ("GADS") format. The GADS data provided individual data from 2004 through 2013 for each of the four units showing Equivalent Forced Outage Rate ("EFOR"), Equivalent Availability Factor ("EAF") and Net Capacity Factor ("NCF") data. The financial data included non-fuel O&M expenses and capital spending history for the units.

Q. **Was there any other information used by Black & Veatch to assess the condition of the Mustang units?**

A. Yes. We also reviewed pertinent documents from the Mustang filings in the Oklahoma and Arkansas jurisdictions[1]. This information provided Black & Veatch with a good understanding of OG&E's views on the condition of the Mustang units and their historical utilization levels.

Q. **What was the overall conclusion of the 2012 Burns & McDonnell report with regard to the Mustang units?**

A. The Burns & McDonnell report identified certain capital projects that would be necessary in order for OG&E to maintain reliability of the Mustang units though 65 years of operation.

Q. **What was Black & Veatch's conclusion regarding the Burns & McDonnell report and recommendations**?

A. The Burns & McDonnell report appeared to be a very comprehensive assessment of OG&E's Mustang units. Burns & McDonnell recommended OG&E undertake approximately $94 million in capital projects on the Mustang units. Those projects are detailed in Tables 2-1, 2-2, 2-3, and 2-5 of the attached Black & Veatch report. Black & Veatch considers the projects as commensurate with the age of both the plant itself and the relevant equipment. In Black & Veatch's experience, these types of projects are common to older power plants and are necessary to maintain an acceptable level of

[1] *In the Matter of the Application of Oklahoma Gas and Electric Company for Authorization of a Plan to Comply with the Federal Clean Air Act and Cost Recovery; and for Approval of the Mustang Modernization and Cost Recovery*, Cause No. PUD 201400229; *and In the Matter of the Application of Oklahoma Gas and Electric Company for Authority to Construct a Natural Gas Fired Combustion Turbine Generation Facility in the State of Oklahoma,* Docket No 16-014-U.

equipment reliability and also prevent catastrophic failure of plant's critical components. While Black & Veatch agrees that these capital projects would have been necessary to continue to operate the units, it also believes additional projects would have been necessary for Mustang Units 3 and 4. Those projects are identified in Tables 2-4 and 2-6 of the attached Black & Veatch report, and the project costs were estimated to be approximately another $15 million.

Q. **In the opinion of Black & Veatch, what would be the result of OG&E continuing to operate its Mustang units beyond the recommended retirement dates without making the capital investments recommended?**

A. Many of these types of projects are intended to prevent the failure of the respective plant components while in service. Many of the systems recommended for replacement in the Burns and McDonnell report, if not replaced, could result in a catastrophic failure leaving the unit incapable of operation and likely requiring an extended lead time to procure the necessary replacement. Of particular concern would be the transformers and boiler systems.

Transformer failures can be expensive to replace but are a significant safety concern because the failure will often result in a fire. Failure of high energy steam systems could result in a major release of high energy steam with the potential to cause equipment damage as well as risk to the lives of workers caught in the area.

Q. **Would implementation of all of the recommendations presented in the Burns & McDonnell study guarantee the continued reliability of the Mustang units?**

A. No. There are no guarantees of continued unit availability, especially given the advanced age of the units, and their component parts. In fact, even the most prudent operators periodically experience forced outages on units of this vintage. A perfect example of this is the turbine vibration problems with Mustang Unit 2 and, conversely, the reduced reliability experienced in 2015. If OG&E had undertaken the $16 million in capital projects identified by Burns & McDonnell, it still would have been faced with the same turbine vibration issues that caused OG&E to retire the unit two years early.

Q. **Can you summarize how the Mustang units were being operated?**

A. Yes, based on a review of OG&E's IRP, the Mustang units were primarily serving as peaking units, used infrequently and characterized by a high number of starts per operating hour yet very low capacity factors.

Q. **Could a change in the operation of OG&E's Mustang units, from a baseload type operation, create any concerns relative to the age and condition of this facility?**

A. Yes. OG&E's Mustang units were designed for baseload operation, meaning that the units were meant to run at high capacity factors, starting infrequently as an energy resource as well as a capacity resource. Using the Mustang units as peaking assets includes expectations for cycling of the units.

Q. **Why is cycling these units a concern from an operational perspective?**

A. Many of the failure mechanisms of the plant's components identified either by Burns & McDonnell or Black & Veatch are exacerbated or, at least, accelerated by cycling of the units. Cycling operation would involve at least one and likely both of the following modes of plant operation.

1. Frequent on/off cycles of the entire plant
2. Frequent ramping of the unit up and down in order to match the demands of the utility's electric system

These modes of operation result in additional thermal cycles of the equipment (as compared to baseload operation). These thermal cycles are known in the power industry to be problematic for boiler components (*i.e.*, superheater, reheater, and economizer) and for the steam turbines in particular. There are three particular failure mechanisms which are exacerbated by plant load changes (ramping up and down) and cycling (on and off). These are:

1. Thermal expansion
2. Corrosion
3. Thermal fatigue

Q. **Would you please elaborate on how those failure mechanisms could damage the plant's components?**

A. Yes. With respect to thermal expansion, all of the metal components in the plant expand as the plant is started, going from ambient temperature to in some cases well in excess of 2,000 Degrees Fahrenheit, and to a lesser extent when the load changes on the unit. This differential expansion results in the movement of the heated components relative to the cooler structures and associated equipment which is not exposed to the same level of heat. This is particularly problematic for the support structures for the high temperature components in the boiler. Thermal expansion also contributes to superheater and reheater cracking at the tube-to-header connections. Additionally, temperature differentials particularly in the high pressure steam turbine incurred during start up can lead to cracks in the turbine rotor.

Corrosion often causes plant challenges with respect to the maintenance of water chemistry, especially with respect to dissolved oxygen in the feedwater as the result of leaks in the condenser or other piping that operates at less than atmospheric pressure. This failure mechanism will eventually lead to waterwall cracks and subsequent tube leaks.

Thermal fatigue is the breakdown of the metallurgy after many cycles of heating and cooling. This is known to accelerate the potential for cracking of thick-walled components. Examples of thermal fatigue cracking have been observed in other plants as ligament cracking between tube stubs of superheater and reheat headers, but also in turbine valves and casings.

Q. **Would operating the Mustang plant as a peaking resource change the value of the generating units with respect to the capital investments recommended for the plant's continued operation?**

A. Yes. Peaking units require extra emphasis on reliability because of the relatively short time periods during which they are required to operate. A forced outage, especially one that results in an extended repair time, due to long lead times for the replacement materials, or even worse, collateral damage, is extremely problematic because the need for the units is for comparatively short time periods. So most any compromise of reliability becomes problematic and therefore costly to replace.

Q. **After considering the condition and expected operation of the Mustang units, what else did Black & Veatch review?**

A. Black & Veatch then reviewed whether there were any alternatives to continued investment and operation of the Mustang units; alternatives that would be more cost effective.

Q. **Please describe the financial evaluation process Black & Veatch utilized to evaluate alternative generation sources.**

A. To provide a financial comparison of potential options available for the Mustang units, Black & Veatch calculated the before tax levelized cost of electricity ("LCOE") for selected options specified by OG&E in its 2014 IRP. The LCOE method calculates a comparative energy price in $/MWh for each generation option and includes fuel costs, operations and maintenance ("O&M") costs, carbon costs and capital costs.

Q. **What were the data sources used in Black & Veatch's LCOE analysis?**

A. Black & Veatch started from the information provided by OG&E so as to replicate the decision process it used in the retirement decision. However, Black & Veatch reviewed each and every assumption to ensure that we were not utilizing data that was inconsistent with what we knew to be the case in the power industry. The specific input assumptions were documented in Appendix B to the Report (Direct Exhibit PLW-2). These assumptions included details of the plant design such as the net capacity of each of the Mustang units as well as the potential replacement units, performance information such as the heat rate for the existing and proposed units and O&M costs and expected capacity factors.

The LCOE model used by Black & Veatch also required input data for fuel costs, expected escalations rates, in this case the consumer price index ("CPI") and an estimate of OG&E's weighted average cost of capital ("WACC"). Black & Veatch utilized prefiled written testimony provided by OG&E to document what OG&E would have known at the time of the analysis that preceded the retirement decision. In our opinion, none of these values were inconsistent with industry knowledge at the time.

Q. **Did Black & Veatch perform an independent assessment of the input data used in OG&E's IRP?**

A. Yes. Black & Veatch reviewed the input data that were documented in OG&E's IRP. However, in conducting an independent analysis, Black & Veatch did not rely on the conclusions of the IRP analysis. Black & Veatch did review all of the input data to the LCOE analysis to determine if they were reasonable and consistent with our understanding of the OG&E system at the time of the Mustang retirement decision process.

Q. **What options were considered in Black & Veatch's LCOE analysis?**

A. Our LCOE analysis compared the following three options for the Mustang units:

- Option 1: Mustang Units 2 through 4 continue to operate until 2017. After 2017, Mustang Unit 2 shuts down, Mustang Unit 3 continues to operate until 2020, and Mustang Unit 4 continues to operate until 2024. In this option, the Mustang Combustion Turbines ("CTs") are not constructed.
- Option 2: Mustang Units 2 through 4 continue to operate until 2017. All three units are then shut down and replaced by the Mustang CT in 2018, which operates until 2044 in accordance with the IRP (a 27 year life).
- Option 3: This is a combination of Options 1 and 2. In this option, Mustang Units 2, 3 and 4 operate until 2017, 2020, and 2024, respectively (according to Option 1). The Mustang CT then commences operation in 2025 and operates for 27 years until 2051. Inclusion of this option allows the value of deferring the capital to construct the Mustang CT to be considered.

Q. **Was the LCOE analysis conducted by Black & Veatch meant to be an exhaustive review and evaluation of the optimum alternative available to OG&E for its Mustang units?**

A. No. Our LCOE analysis was not intended to be an exhaustive analysis identifying the optimum alternative available to OG&E for its Mustang units. Instead, it was offered as part of our Report only to review OG&E's decision to retire the Mustang units. The LCOE analysis was intended to demonstrate that lower cost options existed. Therefore, the continued operation of the Mustang units was not the least cost option available to OG&E.

Q. **Was the replacement of the existing Mustang units with combustion turbines ("CTs") more cost effective than continuing to invest in and operate the old Mustang units until 65 years?**

A. Yes. The LCOE analysis confirms that retirement of the existing Mustang units and construction of CTs at the Mustang site was a lower cost alternative to the continued investment in and operation of the old Mustang units. Therefore, the decision to retire the units (Option 2 noted above), and thereby avoid the capital investment in the Mustang units was a prudent decision.

Q. **Did Black & Veatch look at any other issues as part of its review of the Mustang retirement decision?**

A. Yes. Black & Veatch looked at the environmental risks associated with continuing to operate the old Mustang units. Black & Veatch concluded that, under a worst case scenario, additional capital investment for pollution control equipment would be necessary for the old Mustang Units. This capital investment would be over and above the identified capital projects identified by Burns and McDonnell and Black & Veatch in Tables 2-1 through 2-6 of our report. Black & Veatch concluded that it was likely that no capital projects would be required on the existing Mustang units for compliance with environmental emission requirements. This statement assumes the plant does not complete any physical changes that could be considered by the EPA to be modifications under air permit regulations. Black & Veatch notes that the various projects recommended in the report when evaluated against the PSD /NA NSA permitting metrics of "modification" may render the boilers subject to the installation of additional air quality control systems ("AQCS") or upgrading of existing systems to satisfy Best Available Control Technology ("BACT") or Lowest Achievable Emission Rate ("LAER") requirements.

Q. **In its report, did Black & Veatch also address the benefits of Mustang generation on the OG&E transmission system?**

A. While not included in our scope of service, our report does recognize, from a basic understanding of electric transmission system operations, voltage control and transmission congestion, that there is value in having dispatchable power generation, with voltage and reactive power capability, relatively close to a utility's load center. We also recognize that having CTs at the Mustang site potentially increases the strategic value of the Mustang site by having quick starting and more dynamic resources capable of managing voltage from that location.

Q. **Please summarize the overall conclusions of the Black & Veatch report.**

A. Black & Veatch concluded that the continued operation of the Mustang units, with the associated operating costs, maintenance requirements, capital investment and likely degrading reliability was clearly not the optimal path. Therefore, Black & Veatch concludes that retirement of the units, on the OG&E timeline, was a prudent decision.

Q. **Does that conclude your direct testimony?**

A. Yes.

Phillip L. Webster, MBA, P.E.

Phillip L. Webster is a Project Manager with more than 29 years' industry experience in support of power generation assets. This experience includes leading the Black & Veatch Operations & Maintenance Consulting Services business line and assignments in plant operations, maintenance and engineering. As manager of O&M Services he leads a team of O&M professionals who provide services including: life assessments, reliability improvement, training programs, operations improvements, and outage management. Additional operations services include performance testing, asset evaluation, operator training, and development / review of operating procedures.

Prior to joining Black & Veatch, Webster was employed by a utility generating company as O&M consultant to the development company, performance testing engineer, fuels analyst, and in corporate planning.

In addition to his project experience, Webster serves on the planning committee for the Electric Power Expo, is a board member with the Plant Management Institute and has authored and presented numerous papers at conferences and in industry publications.

PROJECT EXPERIENCE

PowerSouth; Plant Assessments; Alabama, United States; 2017-In-Progress

Project Manager - Black & Veatch. PowerSouth requested Black & Veatch provide an independent assessment of selected assets tied to certain loans with the RUS. These included generating plants and transmission assets, as well as communications equipment. Black & Veatch provided a review of the equipment condition, historical utilization, performance, O&M expenditures, additional capital investment, and maintenance practices.

Index Energy; Ajax Plant Condition Assessment; Ajax, Ontario, Canada; 2017-2017

Project Manager - Black & Veatch. Black & Veatch assisted this waste wood fueled plant with an assessment of the plant conditions and maintenance practices. The scope of service included specific recommendations for modifications designed to increase the reliability and capability of the plant.

ASSOCIATE VICE PRESIDENT

Expertise:
Consulting Engineering Services; Remaining Life Assessment Operations and Maintenance; Outage Management; Reliability;

Education

Master of Business Administration, Business Administration, Quantitative Analysis, University of Missouri at Kansas City, 1985, United States

Bachelor of Science, Engineering Management, Mechanical Engineering, University of Missouri at Rolla, 1980, United States

Professional Registration

License, Professional Engineer, Mechanical, E-21298, Missouri, United States, 1985

Total Years of Experience

32.8

Black & Veatch Years of Experience

18.8

Professional Associations

Electric Power Conference Planning Committee - Plant O&M Track Chair

Language Capabilities

English

Office Location

Overland Park, Kansas, USA: United States

TransAlta; Auxiliary Power Assessment; Alberta, Canada; 2016-2017

Project Manager - Black & Veatch. TransAlta requested assistance from Black & Veatch to review their equipment and operating practices relative to the use of auxiliary power at their coal fired plants in Alberta. This effort reviewed the historical auxiliary power use for multiple different generating units that included assets used in a load following mode as well as more traditional Baseload units. The focus was on changes in operating practice as opposed to modifications requiring significant capital investment. The deliverables are to focus on either confirmation that the current operation is prudent and comprehensive or recommendations for operating practice modifications intended to reduce the auxiliary power use.

Associated Electric Cooperatives; CMMS Project; Missouri, United States; 2015-2017

Project Manager - Black & Veatch. As an integrated element of a maintenance improvement strategy, AECI requested Black & Veatch assist in the re-population of the assets in their computerized maintenance management system (CMMS). Scope included walkdown and revision of P&IDs and electrical one-line drawings. Equipment in the field was documented along with pertinent details for upload into the CMMS via an asset structure defined in the scope of service. This effort was initiated on one coal unit and subsequently continued for an additional five generating units.

DTE; St. Clair Peaker Overhaul Support; St. Clair, Michigan, United States; 2016-2016

O&M Specialist - Black & Veatch. After an in-service failure of a Pratt & Whitney FT8 gas turbine, Black & Veatch supported DTE in solicitation and comparison of competitive bids for the overhaul of their damaged gas turbine.

El Paso Electric; Newman Plant Productivity Assessment; El Paso, Texas, United States; 2016-2016

Project Manager - Black & Veatch. After experiencing a number of equipment failures, El Paso requested a review of the Newman Plant operations and maintenance processes. The study objectives focused on an evaluation of the effectiveness of the plant O&M programs and staffing levels. This included benchmarking of the plant roles and headcount to industry averages and comparison of actual O&M practices versus company procedures.

Hoosier Energy; Merom Cycling Impacts Assessment; Merom, Indiana, United States; 2016-2016

Project Manager - Black & Veatch. Facing the likelihood of modified operations for their two PC generating units, Hoosier requested Black & Veatch review the assumptions, impacts, and cost estimates for recommendations to mitigate cycling impacts to their units. The study also investigated modification to reduce start times and increase load ramping capabilities. This study included not only capital projects but also changes in operating procedures.

Kansas City Power & Light; Sibley Outage Support; Sibley, Missouri, United States; 2016-2016

Project Manager - Black & Veatch. In order to ensure the major capital projects were completed without compromising the schedule of a maintenance outage, KCP&L utilized the outage planning capabilities of Black & Veatch to develop an integrated schedule and then track progress through the outage execution.

Kansas City Power & Light; Iatan Outage Support; Iatan, Missouri, United States; 2016-2016

Project Manager - Black & Veatch. In an effort to improve outage execution practice, KCP&L retained Black & Veatch to advise and consult with the Iatan station planner in his efforts to develop an integrated plan for a significant outage at the Iatan coal fired generation station.

PacifiCorp; Integrated Resource Plan Support; Washington, United States; 2016-2016

O&M Specialist - Black & Veatch. In support of the company Integrated Resource Plan (IRP), Black & Veatch prepared input data defining the expected reliability, performance, capital cost, and long-term O&M costs for various different technologies and configurations under consideration by PacifiCorp.

Rio Tinto; Boron Plant Assessment; Boron, California, United States; 2016-2016

Project Manager - Black & Veatch. Black & Veatch assisted the plant in the review of the plant power and steam generation equipment condition and provided recommendations for maintenance inspections to help ensure the continued reliable operation of the Westinghouse W251 gas turbine and heat recovery boiler.

Sonoco Products; Hartsville Boiler and Steam System Condition Assessment; Hartsville, South Carolina, United States; 2016-2016

Project Manager - Black & Veatch. Before implementing a number of process modifications, Sonoco requested assistance with the assessment of the plant steam system. The scope of services included review of the design and current condition via outage and condition assessment data provided by the plant, supplemented with interviews and visual inspection. Deliverables included maintenance and inspection recommendations.

Tri-State Generation & Transmission; Escalante Variable O&M Analysis; Escalante, Colorado, United States; 2016-2016

Project Manager - Black & Veatch. Tri-State provided Black & Veatch with a very detailed historical record of operations and maintenance cost history and requested an evaluation to refine their delineation of O&M costs as either fixed or variable. Deliverables included recommendations based on the FERC chart of accounts including a breakdown of selected accounts across both categories that could be used for projected spending.

Beowulf Energy; L'Energia Spares Assessment; Boston, Massachusetts, United States; 2015-2015

Project Manager - Black & Veatch. Black & Veatch assisted with the sales process for a combined cycle plant with recommendations for optimization of the spares inventory at this combined cycle plant. The plant consisted of a Rolls-Royce Trent 60 combustion turbine and an ABB VAX steam turbine.

Eskom; Outage Management Support Services; Mpumalanga, South Africa; 2011-2015

Project Manager - Black & Veatch. Outage process improvement for a coal fleet of more than 30 GW. Work included establishing process standards, readiness reviews, contract reviews, planning and scheduling standards, and execution support services.

Confidential Client; Texas Assets Due Diligence; Texas, United States; 2014-2014

O&M Specialist - Black & Veatch. In support of the client's bid to acquire multiple different generating assets in ERCOT, Black & Veatch provided assessments of each of the plants. This scope included site visits, review of historical maintenance practices, operations, reliability, major maintenance, condition reports, O&M expenditures, and capital. The scope also included providing the client projections of future O&M, as well as capital requirements to continue operation in the ERCOT market.

KCP&L; Northeast Black Start Analysis; United States; 2010-2011

Project Manager - Black & Veatch. Investigated the capabilities of the black start combustion turbine assets relative to system operations requirements in the event of a black start event in order to establish capability requirements and minimum acceptable fuel inventory. Included an analysis of transmission system reactive power requirements for normal and reliability events.

TransAlta Utilities; Keephills Outage Planning & Support; Alberta, Canada; 2009-2011

Project Manager - Black & Veatch. TransAlta requested assistance in the development of a detailed outage scope, schedule and budget for the planned outages for major overhauls and modifications to Keephills Units 1-2. Outage scope includes modifications to both HP steam turbines, blade replacements in the LP turbines, DCS replacement, various BOP maintenance and routine boiler maintenance activities. Black & Veatch provided outage managers (one each plant), area leads for the boiler, turbine and BOP as well as scheduling resources. Deliverables include work packages, detailed cost estimate and resource loaded schedule. Outage support in 2012 included project scheduling and 2nd shift outage manager.

Glow Energy; Glow 2 Life Assessment; Rayong, Thailand; 2010-2010

Project Manager - Black & Veatch. The project involved the evaluation of the remaining life of two blocks of 3x1 combined cycle cogeneration facilities that provide power, steam and water to local industrial clients as well as selling power to the Thai Utility (EGAT). The project also evaluated various different potential replacement configurations designed to reduce emissions and provide additional steam as well as power generation capability.

HECO; Minimum Fuel Inventory Analysis; United States; 2009-2009

O&M Consultant - Black & Veatch. Black & Veatch investigated the fuel delivery and inventory systems of the company in order to establish the minimum inventory levels required to support reliable operation of the generating fleet based on system demand, distributed storage capability and transportation systems.

Prairie State Generating Company; Owner's Engineer Information Technology (IT) Infrastructure Implementation; Global; 2009-2009

Project Manager - Black & Veatch. Served as the Owner's representative and consultant during the installation and commissioning of the IT applications for a new two unit coal plant and mining operation. Emphasis was on work management, performance, and fuels management.

Meiya Power Corporation; Power Generating Asset Performance Benchmarking; Global; 2009-2009

Project Manager - Black & Veatch. The project involved comparing thermal and reliability performance of the client's generating assets to comparable units in the US and China. Technologies included coal-steam as well as gas fired combined cycle.

Confidential Client; Wind Generating Asset Portfolio Analysis; Global; 2009-2009

O&M Specialist - Black & Veatch. Provided assistance in the form of review of wind farm O&M practices, procedures, and budgets for a client bidding on the acquisition of a large portfolio of wind assets.

Cemex; Tamuin CFB; Mexico; 2006-2009

O&M Specialist - Black & Veatch. . Provided the O&M review during the acquisition due diligence as the asset ownership transitioned. This role was expanded to serve as the consultant to the owner through the ownership transition and initial budget year's operation. In this role, Mr. Webster provided consultation regarding the appropriateness of the staffing levels, reviewed the O&M budgets and provided an opinion regarding the O&M and reliability programs instituted by the new owner-operator.

AES Corporation; Power Industry Fundamentals Training; United States; 2006-2009

Project Manager and Instructor - Black & Veatch. In response to a Request for Proposal (RFP), Black & Veatch developed and delivered a 5 day course on the fundamentals of the electric power industry for non-technical staff.

Various Clients; Due Diligence Assessments - Various Projects and Assignments; Global; 1998-2009

O&M Consultant - Black & Veatch. Provided O&M process, cost, and staffing effectiveness assessments for various projects throughout the United States, Mexico, and Canada. Provided analysis of O&M programs and the impact on unit costs, availability, and performance. Developed estimates of O&M expenses and long-term capital requirements and identified opportunities for reliability and / or O&M cost improvements. To date, these efforts have included well in excess of 100 existing facilities as well as proposed projects and retrofit / repowering facilities. Generation technologies included the following:

- Gas fired steam generating facilities.
- Simple and combined cycle gas turbine facilities, including gas, oil, and diesel fuel units.
- Solid fuel fired facilities, ranging from less than 60 to greater than 800 MW net capacity. These included baseload and seasonal operations; pulverized coal, stoker boilers, and circulating fluidized bed (CFB) units; bituminous, subbituminous, lignite, biomass, and petroleum coke (petcoke) fueled facilities.
- Biofuel and integrated gasification combined cycle (IGCC) facilities utilizing various fuels and in combination with steam host facilities.

TransAlta Utilities; CO2 Efficiency Projects; United States; 2008-2008

Project Manager - Black & Veatch. Led an effort to identify and characterize potential CO2 reduction projects for Keephills Unit 2.

Siemens Corporation; Power Industry Fundamentals Training; United States; 2008-2008

Project Manager and Instructor - Black & Veatch. Developed and delivered a 3 day course on the fundamentals of the electric power industry for Siemens' service center staff; focused on equipment and systems other than Siemens' products.

Oglethorpe Power Corporation (OPC); Benchmarking Assessment; United States; 2008-2008

Project Manager - Black & Veatch. Led an effort to review OPC's benchmarking practices and provide recommendations for improvements. These efforts addressed OPC's self-operated units, as well as the assets operated by others on behalf of OPC, including coal, nuclear, and hydro plants.

Electric Power Research Institute; Capital Projects for Energy Efficiency; United States; 2008-2008

Project Manager - Black & Veatch. Led a team of engineers and was the primary author of a report outlining the potential costs and benefits associated with a comprehensive list of capital projects designed to deliver energy efficiency improvements.

Kansas City Power & Light (KCP&L); Fleet CO2 Emissions Reduction Program; Missouri, United States; 2007-2007

Project Manager - Black & Veatch. In response to an agreement between KCP&L and the Sierra Club, provided KCP&L with an evaluation of projects necessary to achieve targeted levels of CO2 reductions from within the existing coal based generating fleet. Issues investigated included all types of efficiency improvements, as well as alternative fuels, fuel beneficiation, and blending.

Northern Indiana Public Service Company (NIPSCO); Maintenance Assessment; United States; 2007-2007

O&M Consultant - Black & Veatch. Led an effort to evaluate NIPSCO's maintenance practices, including outage planning and scope and spending in support of rate case materials submitted by attorneys to NIPSCO for a fuel adjustment rate case.

Alliant Energy; Ancillary Services Strategy Development; United States; 2007-2007

O&M Consultant - Black & Veatch. Led the effort to estimate the impact on unit operations, long-term maintenance cost, and market strategy for utilizing the Alliant fleet in the MISO ancillary services market.

Nevada Power Corporation; Clark and Sunrise Assessments; Nevada, United States; 2006-2006

Project Manager - Black & Veatch. Prepared an assessment of the impact of long-term operation of the two combined cycle facilities under a modified operating regime with a modified emphasis baseload operation to cycling.

KCP&L; Montrose and La Cygne Long-Term Alternatives Assessments; Missouri, United States; 2006-2006

Project Manager - Black & Veatch. Prepared an assessment of alternatives required at each of the coal fired generating stations to satisfy expected reductions in emissions. Alternatives included replacement scrubbers, new steam generators, or use of biofuels.

MidAmerican Energy; System Description and Operator Training; Iowa, United States; 2004-2004

Project Manager - Black & Veatch. Led a team that created system descriptions and operator training manuals for each of three generating units. Managed a project creating and presenting an operator training course.

OPC; Staffing Assessment; Georgia, United States; 2003-2003

Project Manager - Black & Veatch. Reviewed the staffing structure and resources for the peaking generating facilities operated by the cooperative utility as well as the need for a central engineering staff and a roving maintenance capability.

JEA; Performance Testing - Northside Unit 2 CFB Fuel Flexibility Test; Florida, United States; 2003-2003

Engineering Manager - Black & Veatch. Managed the development of the test protocol and the selection of various subcontractors for the US Department of Energy (DOE) fuel flexibility tests. Northside is a DOE sponsored CFB boiler. The tests were required to demonstrate the capability of the CFB boiler to utilize various blends of coal and petcoke. The test protocol was submitted to and accepted by the DOE. Subcontractors included flue gas sampling services (stack and flue gas desulfurization [FGD]), material (sample) analysis, and instrument calibration.

Key West Utilities; O&M Assessment; Florida, United States; 2002-2002

O&M Consultant - Black & Veatch. Reviewed the staffing, availability, and O&M expense for the peaking generating facilities operated by the municipal utility.

KCP&L; Performance Testing - Hawthorn Unit 9 Acceptance Testing; Missouri, United States; 2001-2001

Project Manager - Black & Veatch. Managed the execution of the heat recovery steam generator (HRSG) acceptance tests. Provided steam turbine and gas turbine test analysis to develop net plant performance.

AES Thames; Performance Testing - Acceptance Testing; Connecticut, United States; 1999-2000

Project Manager - Black & Veatch. Managed the execution of the steam turbine upgrade and air heater replacement acceptance tests. Provided extensive unit performance testing and analysis.

Coal Fuel Budget; Missouri, United States; 1997-1998

Fuels Analyst - KCP&L. Developed the coal procurement budget for a fleet of 7 generating units totaling over 3000 MW.

Generation Planning; Missouri, United States; 1985-1998

Generation Planning Engineer - KCP&L. Developed operating plans for the generating fleet as well as long-range expansion plans, integrated resource plans, and rate case support and analysis.

Performance Engineering; Missouri, United States; 1991-1997

Performance Engineer - KCP&L. Responsible for thermal performance and capability testing for the fossil fleet of generating units including PC coal, cyclone coal, oil fired gas turbines, and gas fired gas turbines.

Performance Testing; Missouri, United States; 1985-1988

Performance Testing Engineer - KCP&L. Performed the performance and condition assessment testing for the KCP&L generating fleet, including more than 3,000 MW of coal fired steam units and 370 MW of oil fired gas turbines.

O&M Consulting; Missouri, United States; 1985-1988

O&M Consultant - KCP&L. Served as the O&M consultant to the development company in the efforts to develop and operate various generating plants in Asia and Latin America.

PRESENTATIONS & PUBLICATIONS

Webster, Phillip L. “Plant Closures - Drivers and Implications.” Plant Management Institute, Electric Power Expo; New Orleans, Louisiana. March 2014.

Webster, Phillip L., Stephen Nelson, and Steve Maloney. “Outage Management 101.” Power Engineering International; PowerGen Africa. January 2012.

Webster, Phillip L. “An Introduction to Generating Unit Dispatch and ISO Operations.” Black & Veatch Technology Conference; Overland Park, Kansas. February 2009.

Webster, Phillip L. “Understanding Commercial Availability.” Transforming PGAM Conference, Electric Utility Consulting Inc. (EUCI); Chicago, Illinois. August 2004.

Webster, Phillip L. and Robert Shepard. “How to Increase Plant Efficiency Through Positive O&M.” Electric Light and Power. January 2003.

Webster, Phillip L. and G. Scott Stallard, Black & Veatch. "An Overview of Energy Asset Management." 2002 PGAM Conference, EUCI, Black & Veatch; Atlanta, Georgia. September 2002.

Webster, Phillip L. "Outage Management & Planning." Black & Veatch Florida Asset Management Forum; Orlando, Florida. April 2002.

Webster, Phillip L. "Redefining Performance and Optimization." Black & Veatch Florida Asset Management Forum; Orlando, Florida. April 2002.

Webster, Phillip L. "Comprehensive Asset Management Strategy." Power Generation Asset Management (PGAM) Conference, EUCI; Atlanta, Georgia. March 2000.

Webster, Phillip L., Black & Veatch, and Jason Kramm, Power Costs Inc. "Asset Management at the Portfolio and Plant Level." PGAM Conference, EUCI, Power Costs Inc.; Atlanta, Georgia. March 2000.

Webster, Phillip L. "Linking Generation to Trading." Electric Utility Consulting Inc. (EUCI) Conference; Denver, Colorado. December 1999.

Webster, Phillip L. "Development of an Automated Operator Rounds Data Acquisition Program." Association of Rural Electric Generating Cooperatives (AREGC) Conference; Biloxi, Mississippi. June 1999.

Webster, Phillip L. "What is Heat Rate?" 1993 Coal User's Conference; St. Louis, Missouri. February 1993.

Direct Exhibit PLW-2

EVALUATION REPORT: MUSTANG POWER PLANT RETIREMENT CONSIDERATION

BLACK & VEATCH PROJECT NO. 192633

PREPARED FOR

OGE Energy Corp.

Oklahoma Gas & Electric

20 SEPTEMBER 2016

BLACK & VEATCH
Building a world of difference.

Reviewed by:

Signature

September 20, 2016
Date

Mike Grady
Printed Name

Professional Engineer:

Signature

September 21, 2016
Date

DUSTIN J. ROGGE
Printed Name

22982
License No.

Approved by:

Signature

September 20, 2016
Date

Phillip Webster
Printed Name

LICENSED PROFESSIONAL ENGINEER
DUSTIN J.
ROGGE
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OKLAHOMA

21 SEP 2016

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Executive Summary

Black & Veatch was contracted to provide a third-party evaluation of the decision by Oklahoma Gas & Electric (OG&E) to retire the gas steam units at the Mustang generating plant. The evaluation was to review recent plant life assessments/studies and potential impacts of environmental regulatory requirements on OG&E's Mustang Power Plant. This report provides an independent view of OG&E's decision to retire the original gas fired steam turbine units at Mustang.

Black & Veatch concludes that the original capital improvement projects recommended in an earlier 2012 Burns & McDonnell study were technically sound and could have been implemented if the goal was to operate the plant to the retirement dates specified in the Burns & McDonnell study. Black & Veatch identified a few additional projects that should have been considered given the age of the units and equipment. Failure to perform these projects may lead to premature equipment failure, reduction in plant reliability/availability, or early plant retirement due to catastrophic failure. Overall, Black & Veatch believes that avoiding these projects and instead retiring the existing units was a prudent decision.

The Black & Veatch environmental review concludes that the majority of current and anticipated legislation is not expected to have a material impact on the Mustang units. There is, however, a small possibility that nitrogen oxide (NO_x) reduction techniques such as selective catalytic reduction (SCR) or combustion optimization may have needed to be installed on the existing units dependent on the state and federal regulator's interpretation and application of the Cross-State Air Pollution Rule (CSAPR).

The Black & Veatch financial review concludes that there is a significant difference in the levelized cost of electricity (LCOE) between the following options:

- Option 1: Mustang units are retired in accordance with the originally recommended retirement dates from the 2012 Burns & McDonnell report and not replaced.
- Option 2: Mustang units are retired in accordance with the 2014 Integrated Resource Plan (IRP) and replaced thereafter with combustion turbines in 2018/2019.
- Option 3: Mustang units are retired in accordance with the originally recommended retirement dates from the 2012 Burns & McDonnell report and replaced thereafter with combustion turbines in 2025.

The options considered in this analysis were selected to show potential alternatives. It was not meant to be an exhaustive analysis of options nor does it purport to represent an optimized approach. The intent was merely to demonstrate that retiring the existing units and replacing them with CTS was a more cost effective option than performing the projects identified by Burns & McDonnell (B&M) on the existing units. The analysis supports the assertion that the retirement of the units was a prudent decision.

Since a lower LCOE option was identified, Black & Veatch concluded that the Mustang retirement decision was a prudent financial decision given the information available at the time. Subsequently, the additional expenditures identified, along with changes in fuel prices, serve to further reinforce the prudency of that decision.

1.0 Introduction

The Mustang Power Plant, located in Canadian County, Oklahoma, is comprised of four natural gas fired boilers with steam turbines, supplemented by two dual-fuel simple cycle combustion turbines. For the purposes of this report, only the gas fired steam turbine plants, numbered one to four, are considered. A summary of the plant configuration is shown in Table 1-1.

Table 1-1 Mustang Plant Configuration

UNIT (TECHNOLOGY)	NAMEPLATE OUTPUT (MW)	AVERAGE WINTER / SUMMER OUTPUT (MW)	FIRST YEAR OF OPERATION
1 (Gas Fired Steam)	82	50	1950
2 (Gas Fired Steam)	63	50	1951
3 (Gas Fired Steam)	133	121	1955
4 (Gas Fired Steam)	253	242	1959
5A (Combustion Turbine)	41	34	1971
5B (Combustion Turbine)	41	33	1971
Sources: US Energy Information Administration, Annual Electric Generator Report, 2014;OG&E IRP, 2014			

In 2011, Oklahoma Gas & Electric (OG&E) retained the services of Burns & McDonnell to perform a third-party condition assessment of the Mustang Power Plant and recommend maintenance activities necessary to ensure reliable operation until expected retirement. The first step of the study was to determine projected retirement dates of Mustang Units 1 through 4. Burns & McDonnell performed an industrywide review of the histories of power plants of similar size and design and, together with an assessment of technical obsolescence of the plant, Burns & McDonnell proposed retirement dates of 2015, 2017, 2020, and 2024 for Mustang Units 1 through 4, respectively. This information, along with changes in market conditions, was used to develop the 2012 and 2014 Integrated Resource Plans (IRPs) produced by OG&E. The 2012 IRP reiterated the retirement dates listed in the 2012 Burns & McDonnell report. However, the 2014 IRP revised the proposed retirement dates listed in the 2012 IRP such that Unit 1 would retire in 2015 and the remaining units would retire in 2017. In addition, the 2014 IRP recommended replacing the capacity of the Mustang Units 1 through 4 by constructing simple cycle combustion turbines in the 2018-2019 time frame. Table 1-2 summarizes the outcomes of the 2012 Burns & McDonnell report, the 2012 IRP, and the 2014 IRP. It also highlights the differences between their recommended retirement dates. (Negative difference denotes a reduction in operating life.)

Table 1-2 Recommended Retirement Dates Summary

UNIT	2012 B&M REPORT RECOMMENDED RETIREMENT DATE (AGE [YEARS])	2012 IRP RECOMMENDED RETIREMENT DATE (AGE [YEARS])	2014 IRP RECOMMENDED RETIREMENT DATE (AGE [YEARS])	DIFFERENCE BETWEEN 2012 REPORTS AND 2014 IRP
1	2015 (65)	2015 (65)	2015 (65)	0
2	2017 (66)	2017 (66)	2017 (66)	0
3	2020 (65)	2020 (65)	2017 (62)	-3
4	2024 (65)	2024 (65)	2017 (58)	-7

In 2015, Unit 2 was experiencing reduced reliability because of ongoing steam turbine vibration issues during the startup sequence. Therefore, based on Unit 2 utilization concerns, the projected costs to troubleshoot and correct the vibration problem, and the projected costs to implement capital improvement projects to address life extension (discussed further in Section 2.0), OG&E decided to retire Unit 2 two years early. In addition, Unit 1 was retired in accordance with the recommendations from both the 2012 and 2014 IRPs. As a result, both Units 1 and 2 were retired in December 2015.

Through a desktop study of supplied information, this report will address the following questions:

- Does Black & Veatch agree with the capital projects originally recommended in the 2012 Burns & McDonnell report to ensure plant reliability until the proposed retirement dates?
- What are the environmental considerations and impacts of operating the units to the retirement dates proposed in the 2012 Burns & McDonnell report and 2012 IRP?
- What is the cost differential between extending the life of the units versus reasonable alternatives such as installing new combustion turbines, in accordance with the 2014 IRP?
- Given the large investments required to ensure the Mustang units were reliable and available, would it have been prudent to make the investments required to keep the units reliable when compared to other reasonable alternatives?

2.0 Technical Evaluation

The 2012 Burns & McDonnell report identified a number of capital investments that would be required to maintain reliability of the units through to the specified retirement dates. Each unit is discussed in further detail in the following sections, along with further recommendations that Black & Veatch thinks would be prudent to consider, given the age of the plant and the anticipated operating regime.

2.1 UNIT 1

Table 2-1 shows the recommended capital projects for Unit 1, as stated in the 2012 Burns & McDonnell report.

Table 2-1 Mustang Unit 1 Recommended Capital Projects (2012 Consultant's Report)

DATE	PROJECT	COST (2012$)
2012	HP Feedwater Heater Replacement	$3,273,000
2012	DCS Upgrade	$4,000,000
2013	Superheater Replacement	$1,559,000
2013	Auxiliary Transformer Replacement	$1,095,000
2014	Generator Rewind	$3,707,000
2015	Economizer Replacement	$2,004,000
2016	Reserve Auxiliary Transformer Replacement(1)	$1,192,000
	TOTAL UNIT 1	**$16,830,000**

(1) The reserve auxiliary transformer is common between Units 1, 2, and 3, but will only be attributed to Unit 1 for this study.

Without performing a detailed plant life assessment, Black & Veatch considers the proposed projects as commensurate with the age of both the plant itself and the relevant equipment. In Black & Veatch's experience, these types of projects are common to older power plants and are necessary to maintain an acceptable level of equipment reliability and also prevent catastrophic failure of plant critical components. Given the short time between the expected retirement date (2015) and the date of the consultant's analysis (2012) there may have been an opportunity to implement mitigation measures to reduce the impact of a failure of one of the above systems without spending the full amount of the capital investments noted in Table 2-1. An example would be to identify a source for a spare auxiliary transformer that could be purchased and installed (on short notice) but not actually purchasing or installing a new auxiliary transformer.

From the supplied information, it appears that none of the recommended projects were implemented between 2012 and the retirement of Unit 1 in 2015. In light of the low net capacity factors expected during this period (driven by the market pricing), avoiding the capital expenditures noted in Table 2-1 would appear to have been a prudent decision. Recovery of those costs in that short time frame with so little expected utilization would never have allowed for recovery of the costs. The alternative, even in light of a potential failure would have been to purchase energy in the Southwest Power Pool (SPP) at market prices. Actual capacity factors experienced in this time period were 3 percent, 2 percent, and 5 percent for the 2012 to 2014 periods, respectively.

2.2 UNIT 2

Table 2-2 shows the recommended capital projects for Unit 2, as stated in the 2012 Burns & McDonnell report.

Table 2-2 Mustang Unit 2 Recommended Capital Projects (2012 Consultant's Report)

DATE	PROJECT	COST (2012$)
2012	Distributed Control System (DCS) Upgrade	$4,000,000
2014	Superheater Replacement	$1,559,000
2014	Auxiliary Transformer Replacement	$1,095,000
2015	Generator Rewind	$3,707,000
2016	Economizer Replacement	$2,004,000
2018	High-Pressure (HP) Feedwater Heater Replacement	$3,273,000
	TOTAL UNIT 2	**$15,638,000**

In line with the recommendations for Unit 1, Black & Veatch considers the proposed projects as commensurate with the age of both the plant itself and the relevant equipment. In Black & Veatch's experience, these types of projects are common to older power plants and are necessary to maintain an acceptable level of equipment reliability while also reducing the risk of catastrophic failure of plant critical components.

In addition, it appears that none of the recommended projects were implemented between 2012 and the retirement of Unit 2 in 2015. In light of the low net capacity factors expected during this period (driven by the market pricing), avoiding the capital expenditures noted in Table 2-2 would appear to have been a prudent decision. Recovery of those costs in that short time frame with so little expected utilization would never have allowed for recovery of the costs. The alternative, even in light of a potential failure, would have been to purchase energy in the SPP at market prices. Actual capacity factors experienced in this time period were 3 percent, 2 percent, and 5 percent for the 2012 to 2014 periods, respectively.

Black & Veatch concurs with the data presented that inspection of the Unit 2 steam turbine bearings and possibly the removal of the steam turbine shell would be necessary to establish the root cause of the vibration issue. Determining and correcting the root cause may include replacement and/or refurbishment of the bearings, rotor blades, diaphragms, or rotor repairs. All of which would incur significant expenditures, and lead times for component replacement would likely lead to an extended unplanned outage. The decision to retire the unit and avoid the expenditures appears to be a prudent decision.

2.3 UNIT 3

Table 2-3 shows the recommended capital projects for Unit 3, as stated in the 2012 Burns & McDonnell report.

Table 2-3 Mustang Unit 3 Recommended Capital Projects (2012 Consultant's Report)

DATE	PROJECT	COST (2012$)
2015	Auxiliary Transformer Replacement	$1,095,000
2016	Reserve Transformer Replacement	$1,192,000
2017	Superheater Replacement	$2,685,000
2018	Reheater Replacement	$3,113,000
2019	DCS Replacement	$8,000,000
2019	Economizer Replacement	$1,328,000
2020	HP Feedwater Heater Replacement	$3,273,000
	TOTAL UNIT 3	**$20,686,000**

Without performing a detailed plant life assessment, Black & Veatch considers the proposed projects as commensurate with the age of both the plant itself and the relevant equipment. In Black & Veatch's experience, these types of projects are common to older power plants and are necessary to maintain an acceptable level of equipment reliability while also reducing the risk of catastrophic failure of plant critical components.

In addition, Black & Veatch also considers the following additional capital projects shown in Table 2-4 to be prudent to improve plant reliability. Based on Black & Veatch's experience, these additional projects are also likely to be areas of concern within an aging plant, especially with the forecasted cycling operating regime. Without having access to detailed life assessment information, a date of implementation cannot be provided. Cost estimates are Association for the Advancement of Cost Engineering International (AACEI) Class 4 estimates with a range of ±30 percent.

Table 2-4 Mustang Unit 3 Additional Capital Projects (Black & Veatch Recommendations)

DATE	PROJECT	COST (2016$)
NA	Condenser Tube Replacement	$2,000,000
NA	Large Fan and Motor Replacements	$750,000
NA	High Energy Piping – Partial Replacement	$1,500,000
NA	Low-Pressure (LP) Turbine Inspection and Repairs	$1,500,000
NA	Boiler Steam Drum Replacement	$2,000,000
	TOTAL UNIT 3	**$7,750,000**

From the information supplied, it appears that neither the auxiliary nor the reserve transformers were replaced or planned for replacement in 2015 and 2016, as recommended in the 2012 Burns & McDonnell report. Catastrophic transformer failures will often result in collateral damage to nearby equipment and are a significant safety concern. In addition, the lead time to procure large power transformer replacements can be very long (6 to 24 months). Failure to implement any of the recommended capital improvement projects (especially the transformer replacements) will expose the plant to significant risk and will likely result in reduced unit reliability and availability.

Continuing to operate Mustang Unit 3 would have required OG&E to absorb the capital investment noted previously while also expending the operations and routine maintenance costs for units that were expected to run at low capacity factors. These factors, and knowledge that lower cost options were likely to be available, make the decision to retire the unit and avoid the expenditures appear to be a prudent decision.

2.4 UNIT 4

Table 2-5 shows the recommended capital projects for Unit 4, as stated in the 2102 Burns & McDonnell report.

Table 2-5 Mustang Unit 4 Recommended Capital Projects (2012 Consultant's Report)

DATE	PROJECT	COST (2012$)
2016	Auxiliary Transformer Replacement	$1,156,000
2017	Generator Step-Up Transformer Replacement	$5,291,000
2018	Reserve Transformer Replacement	$1,192,000
2018	DCS Replacement	$8,000,000
2019	Generator Rewind	$4,990,000
2020	Superheater Replacement	$4,965,000
2021	Reheater Replacement	$4,506,000
2022	Economizer Replacement	$2,457,000
2023	HP Feedwater Heater Replacement	$6,545,000
	TOTAL UNIT 4	**$39,102,000.00**

Without performing a detailed plant life assessment, Black & Veatch considers the proposed projects as commensurate with the age of both the plant itself and the relevant equipment. In Black & Veatch's experience, these types of projects are common to older power plants and are necessary to maintain an acceptable level of equipment reliability while also reducing the risk of catastrophic failure of plant critical components.

In addition, Black & Veatch considers the following additional capital projects shown in Table 2-6 to be prudent to improve plant reliability. Based on Black & Veatch's experience, these additional projects are also likely to be areas of concern within an aging plant, especially with the forecasted cycling operating regime. Without having access to detailed life assessment information, a date of implementation cannot be provided. Cost estimates are AACEI Class 4 estimates with a range of ±30 percent.

Table 2-6 Mustang Unit 4 Additional Capital Projects (Black & Veatch Recommendations)

DATE	PROJECT	COST (2016$)
NA	Condenser Tube Replacement	$2,000,000
NA	Large Fan and Motor Replacements	$750,000
NA	High Energy Piping – Partial Replacement	$1,500,000
NA	HP Turbine Inspection and Repairs	$1,500,000
NA	Boiler Steam Drum Replacement	$2,000,000
	TOTAL UNIT 3	**$7,750,000**

From the information supplied it appears that the auxiliary transformer was not planned for replacement in 2016, as recommended in the 2012 Burns & McDonnell report. Catastrophic transformer failures will often result in collateral damage to nearby equipment and are a significant safety concern. In addition, the lead time to procure large power transformer replacements can be very long (6 to 24 months). Failure to implement any of the recommended capital improvement projects (especially the transformer replacements) will expose the plant to significant risk and will likely result in reduced unit reliability and availability.

Continuing to operate Mustang Unit 4 would have required OG&E to absorb the capital investment noted previously while also expending the operations and routine maintenance costs for units that were expected to run at low capacity factors. These factors, and knowledge that lower cost options were likely to be available, make the decision to retire the unit and avoid the expenditures appear to be a prudent decision.

2.5 OPERATING REGIME

As a result of joining the SPP in 2014, it was determined that the Mustang units were likely to continue their recent trend of operating as “cycling” units. A “peaking” cycling regime results in low plant utilization but high numbers of startups and shutdowns to meet periods of unusually high load demands. Heat up and cooldown cycles combined with significant periods of time with little or no recirculation of water in the steam drums and boiler feed and condensate systems will result in higher wear of rotating machinery, high cycle fatigue in the boilers, and corrosion throughout the plant. As a result, piping and operating equipment is more prone to failures. In addition to the on/off cycling described previously, the operation of the units would also be expected to require additional ramping of the units both up and down to sustain the grid operations. Ramping operation is known to increase the damage mechanisms associated with thermal cycles on the turbine and steam system.

The power industry widely acknowledges that cycling of this type of unit goes against the original baseload design philosophy of older power plants such as Mustang Units 1 through 4. A 2001 report by the Electric Power Research Institute (EPRI) noted the following:

> ***"The severity of cyclic operation affects boiler, turbine, electrical, and auxiliary components. The effect is largely design dependent, and older plants (which were originally designed for baseload usage) are less tolerant of cyclic operation."***

The report further identified specific fatigue related failure mechanisms associated with cycling operation and identified increases in the costs to operate a facility that is utilized in such a manner. Black & Veatch concurs with these findings and the consequences of a cycling operating regime are considered in the findings of this report.

2.6 TRANSMISSION NETWORK

Black & Veatch recognizes that the Mustang site also offers strategic value to OG&E's transmission systems operation. This is because of its close proximity to the major demand center(s) and its ability to provide dynamic reactive support to manage voltage. This value could potentially be increased if the existing gas fired steam turbine units were to be replaced with combustion turbines.

Evaluation and quantification of this value is not part of this report; however, they do support the decision to continue to generate electricity at the Mustang site, especially when compared to using other sites.

2.7 TECHNICAL SUMMARY

Black & Veatch has determined the methodology employed in the original 2012 Burns & McDonnell condition assessment to be sound and consistent with prudent engineering practice and industry standards relative to life estimation for depreciation and rate making processes. The additional capital improvement projects identified by Black & Veatch are used solely to highlight that the original 2012 report was not overly cautious or pessimistic about the remaining life of the units and capital costs could increase, or reduce, significantly based on the findings of additional inspections. As such the costs associated with the additional projects identified by Black & Veatch are not considered in Section 4.0 of this report.

3.0 Environmental Impact Analysis

The following review was performed to evaluate the potential for current, pending, and reasonably foreseeable air regulations to impact operations at the existing Mustang Power Plant. Such regulations may result in additional costs associated with environmental compliance to keep the generating units operating.

3.1 MERCURY AND AIR TOXICS STANDARDS

The United States Environmental Protection Agency (EPA) mercury and air toxics standards (MATS) rule regulating mercury, acid gases, and emissions of other toxic air pollutants from coal and oil fired power plants became effective on April 16, 2012, and is codified under 40 Code of Federal Regulations (CFR) 63 Subpart UUUUU. The MATS regulate emissions from new, reconstructed, and existing electric utility steam generating units, which the rule defines as "[…] a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale […]" While the MATS have been responsible for numerous boiler add-on control installations and retirements across the United States, they do not regulate emissions from natural gas fired boilers (assuming natural gas accounts for 90.0 percent or more of the average annual heat input during any 3 consecutive calendar years or 85.0 percent or more of the annual heat input in 1 calendar year). As such MATS are not considered further in this analysis.

3.2 ACID RAIN PROGRAM

The Acid Rain Program (ARP) is a rule aimed at achieving major emissions reductions of sulfur dioxide (SO_2) and nitrogen oxide (NO_x), the primary precursors of acid rain. The rule achieved NO_x reduction by imposing emissions limits on applicable boilers that were in operation at the time the rule was implemented. Reduction of SO_2, on the other hand, is achieved via a cap-and-trade program. Regulated emissions units are required to surrender allowances for each ton of SO_2 emitted annually. In general, SO_2 allowances required for a facility to surrender may be allocated by the EPA, obtained by purchasing allowances on the open market, or transferred from owner-held accounts. The boilers are currently subject to the ARP and no major regulatory changes are expected for this program.

3.3 CROSS-STATE AIR POLLUTION RULE

After a lengthy legal process, on January 1, 2015, the Cross-State Air Pollution Rule (CSAPR) replaced the Clean Air Interstate Rule as the EPA's cap and trade program aimed at curbing cross-state transport of NO_x and SO_2 emissions in the eastern United States. Ultimately, the purpose of the rule is to reduce the number of $PM_{2.5}$ and ozone nonattainment areas caused by cross-state air pollution from the power sector. Under CSAPR, affected units are those that serve a generator greater than 25 MWe and produce electricity for sale. For regulated units in Oklahoma, CSAPR requires that allowances are surrendered for ozone season (May through September) emissions of NO_x.

For each affected unit, a given state allocates allowances for each regulated pollutant and compliance period (e.g., ozone season NO_x allowances). Any surplus allowances can be banked and held for future compliance and/or sold on the open market. Should a facility's emissions be in excess of its annual allocation, the deficit is required to be covered by banked allowances and/or allowances purchased on the open market.

The boilers are currently subject to the CSAPR and must surrender allowances in an amount equal to their emissions of NO_x during the ozone season. It is generally only practical to consider additional NO_x control if emissions are in excess of the units' allocations and if the costs to purchase additional allocations to cover their compliance obligations would exceed the cost of installation of additional controls (e.g., low NO_x burners, overfire air, combustion optimization, SCR). The boilers are currently allocated a sum total of 457 tons of ozone season NO_x allowances. While NO_x emissions from the boiler during the ozone season have been higher than this value within the past 5 years, the current allocation is more than sufficient to cover operations typical of the past 2 years indicating additional controls would not be warranted. Should operation return to more of a baseload service, it may be prudent to evaluate the cost of compliance for emissions above the allocated amount. Ozone season NO_x allowances were recently trading at $245 per ton. That is, for each ozone season ton of NO_x emitted above the allowance of 457 tons, OG&E could potentially have to secure an allowance on the open market at this price if it does not have other accounts from which it could transfer allowances.

3.4 FEDERAL CARBON DIOXIDE REGULATIONS

3.4.1 Background and Boilers Applicability Given Operation as Utility Boilers

On June 25, 2013, the president of the United States released an administrative order regarding power sector carbon pollution standards. The president's administrative order called for the EPA to create regulations on carbon dioxide (CO_2) emissions from both new and existing power plants. In response to the president's directive, on August 3, 2015, the EPA finalized both New Source Performance Standards (NSPS) Subpart TTTT to regulate CO_2 emissions from new, modified, and reconstructed power plants and the Clean Power Plan (CPP) to regulate CO_2 emissions from existing power plants. Given that NSPS Subpart TTTT is applicable to power plants that were constructed, modified, or reconstructed after January 8, 2014, NSPS Subpart TTTT would not be applicable to the boilers. Therefore, they would be regulated as existing electric generating units (EGUs) and would thus be subject to the CPP.

As finalized, the CPP seeks to reduce CO_2 emissions by approximately 32 percent from 2005 industry levels by 2030. In the final rule, the EPA has set emissions performance rates, phased in over the period from 2022 to 2030, for two subcategories of affected fossil fuel fired EGUs: fossil fuel fired electric utility steam generating units (SGUs) and stationary combustion turbines that meet the definition of either a natural gas combined cycle (NGCC) or combined heat and power (CHP) combustion turbine. In setting these performance standards, the EPA identified three specific measures, or "building blocks," that represent the Best System of Emissions Reduction (BSER):

1. Improving heat rate at affected coal fired steam EGUs.
2. Replacing generation from higher-emitting affected SGUs with increased generation from lower-emitting existing NGCC units.
3. Replacing generation from affected fossil fuel fired EGUs with new zero-emitting renewable energy generating capacity.

Specifically for SGUs, the EPA has developed the emissions performance rates (in pounds CO_2 per megawatt-hour [lb CO_2/MWh]) listed in Table 3-1 by considering the BSER building blocks.

Table 3-1 EPA Target Emissions Performance Rates

YEAR[1]	FOSSIL FUEL STEAM GENERATION (LB CO_2/MWH-NET)
2022 to 2024	1,671
2025 to 2027	1,500
2028 to 2029	1,380
2022 to 2029 Interim Period	1,534
2030 Final Standard	1,305
[1]Three year intervals in the interim period (2022 to 2029) reflect the gradual implementation of the BSER or the phased "glide-path" to compliance.	

Each state will determine whether to apply these rates directly to each affected EGU or take an alternative approach and meet either an equivalent statewide rate-based goal or statewide mass-based goal. To develop statewide rate-based goals or statewide mass-based goals, the EPA applied the rates listed in Table 2-1 to each state's particular mix of fossil fuel fired EGUs. This allowed the agency to generate each state's carbon intensity goal. Specifically, Oklahoma's generation mix as of 2012 consisted of 56 percent from fossil fuel fired SGUs and 44 percent from NGCC. Applying this generation mix to the target emissions performance rates yields the emissions performance rates and equivalent mass-based standards specific to Oklahoma (Table 3-2).

Table 3-2 Oklahoma CPP Emissions Performance Rates

YEAR	GENERATION MIX RATE (lb CO_2/MWh-net)	GENERATION MIX TONS – ANNUAL AVERAGE (SHORT TONS CO_2)(1)
2022 to 2024	1,319	47,577,611
2025 to 2027	1,197	43,665,021
2028 to 2029	1,116	41,577,379
2022 to 2029 Interim Period	1,223	44,610,332
2030 Final Standard	1,068	40,488,199

(1)Oklahoma mass-based goals calculated based on 2012 MWh produced by affected sources in Oklahoma.

3.4.2 CPP Compliance Plan Approaches

The EPA has ultimately left the specifics of achieving the target performance rates (i.e., CPP compliance) up to individual states. However, the agency has proposed two separate cap and trade-based approaches: one rate-based and one mass-based. For each approach, the EPA has developed a model rule, which a state can adopt in its entirety, with assurance of EPA approval, and a federal implementation plan (FIP), which will be implemented by the EPA in states that do not propose a state implementation plan (SIP) that meets the EPA's criteria. Additionally, the EPA has granted states the flexibility of devising their own, unique compliance plan under a "state measures approach." A state measures plan would achieve CPP compliance by relying upon state-enforceable measures on nonaffected entities in conjunction with federally enforceable emissions standards on affected EGUs. According to the final CPP, a state measures plan must employ the mass-based approach.

The rate-based model rule proposes to apply the incremental CO_2 emissions performance rates, depending on the type of EGU, to each individual affected unit (as an alternative the state may choose a blended rate based on the state's mix of generation assets in 2012 to apply evenly across all affected EGUs; for Oklahoma, this blended rate is listed in Table 2-2). Should an affected EGU operate in excess of the prescribed standard, emissions reduction credits, which represent a megawatt-hour (MWh) of generation produced with no CO_2 emissions, must be applied to reconcile the difference between the unit's emissions rate and the prescribed standard. Under the rate-based approach, emissions reduction credits are designed to serve as the market instrument that will hold value and can be bought/sold on the open market and/or banked for future resale or use.

The mass-based model rule entails a more traditional cap and trade program based on state-specific carbon budgets. Under the mass-based FIP, each state's budget of CO_2 allowances would be allocated to regulated EGUs based on their historical output data. However, the EPA has given states the flexibility of allocating allowances via alternative methods in their SIPs, including periodic allowance auctions. Additionally, set-aside allowance pools could be created to provide incentives for various beneficial practices and/or projects such as renewable energy and demand-side energy efficiency initiatives. Under the mass-based approach, CO_2 emissions allowances, each representing one ton of CO_2 emissions, would serve as the cap and trade market instrument.

The CPP required each state to submit a final SIP by September 6, 2016. However, if a state needed additional time to submit a final plan, that state could request an extension by the September 6, 2016, deadline. Should an extension be granted, a state would have until September 6, 2018, to submit its final plan. This timeline has been suspended by the Supreme Court stay, which is summarized in the following section.

3.4.3 Legal Uncertainties

On February 9, 2016, the United States Supreme Court issued an order to stay (suspend) the CPP until legal challenges to the rule can be settled in federal court(s). The one certain outcome of the stay is that states are no longer obligated to submit initial SIPs by the September 9, 2016, deadline. However, responses to this reprieve have varied among individual states. Several states have halted work toward developing an SIP, while others have decided to continue planning or at least consider whether continued planning is prudent.

Regional grid operators are reacting to the stay in a similar manner, with some organizations continuing an assessment of their options under the rule, while others have halted preparation. Meanwhile, utilities arguably benefit the least from the stay because the uncertainty of the future of the regulation makes it difficult for asset owners to make long-term plans.

Given the uncertainty that the Supreme Court's ruling has created, along with the impending (2016) presidential election, the speed and timing of the litigation has become an issue. The current schedule would have the case reviewed before the entire 11 judge US Court of Appeals, District of Columbia Circuit, beginning in late September. Regardless of the circuit court ruling, it is almost certain that the decision will be appealed to the Supreme Court, with a final decision not likely until well into the next president's administration.

Meanwhile, the stay will remain in effect. The next president will have significant influence over the level of support given to defend the rule in any appeal to the Supreme Court. Ultimately, it may be 2018 before the results of litigation become final. It is unknown what elements, if any, of the CPP will survive the legal reviews, or what the EPA may be directed to address and revise on remand from the court(s). It is similarly unknown whether and to what extent the September 2018 deadline for states to submit a final SIP will be extended to account for the suspension during litigation or whether it will remain as set forth in the CPP.

3.4.4 Implications for the Boilers

Black & Veatch notes that because of the latitude provided to states to formulate their respective implementation plans and the uncertainty surrounding the rule from ongoing legal issues, it is difficult to assess specific CPP compliance requirements or strategies for the boilers. However, comparing emissions from the boilers as reported to the EPA and made public via the Clean Air Markets Division (CAMD) website, it would appear that using the maximum emissions rate reported in the past 5 years, Boilers 1 and 2 would demonstrate compliance with the rate-based standards presented in Table 3-1 up through 2029 and Boilers 3 and 4 would demonstrate compliance with even the final standard indicating that the CPP is not likely a costly environmental driver for these natural gas fired units. If Oklahoma adopted state-wide blended rates as presented in Table 3-2, compliance would look quite different. Boilers 1 and 2 would need additional reduction credits in all compliance periods while Boilers 3 and 4 would no longer meet the final 2030 standard without additional reduction credits to offset emissions. The CAMD data are shown in Table 3-3.

Table 3-3 Historical Boilers CO_2 Emissions Rates (lb CO_2/MWh)

YEAR	UNIT 1	UNIT 2	UNIT 3	UNIT 4
2011	1,492	1,452	1,182	1,165
2012	1,538	1,462	1,186	1,168
2013	1,538	1,522	1,206	1,182
2014	1,515	1,490	1,201	1,056
2015	1,533	1,460	1,267	1,215

3.5 OZONE STANDARD

National Ambient Air Quality Standards (NAAQS) are established by the EPA and are designed to protect public health and public welfare by regulating ambient air quality. States and regional authorities are primarily responsible for ensuring attainment and maintenance of NAAQS.

On October 1, 2015, the EPA finalized a revised air quality standard for ground-level ozone that strengthened (lowered) the NAAQS to 70 parts per billion (ppb) to reflect scientific evidence on ozone's effect on public health and welfare. The new standard is based on the 3 year average of the annual fourth-highest daily maximum 8 hour average.

Once a new standard is finalized, areas of the country that exceed the standard are designated as nonattainment areas within 2 years. States with nonattainment areas are required to prepare and submit SIPs within 3 years of the area designation to outline how pollutant concentrations and emissions from contributing sources will be reduced to achieve compliance with the NAAQS. Areas not meeting the standards will have until 2020 through late 2037 to come into compliance, depending on the severity of the area's air quality. To achieve the necessary emissions reductions, states will seek commitments or impose requirements on selected sources to reduce emissions that lead to ground level ozone formation (e.g., NO_x and/or volatile organic compounds [VOCs]). Because of this, coal fired facilities operating in the designated nonattainment areas could be compelled to install NO_x air quality control equipment to meet such requirements. These are typically known as Reasonably Available Control Technology (RACT) rules. According to information provided by the EPA for the years 2012 to 2014, the ozone concentration within Canadian County is just above the newly finalized 2015 standard with 71 ppb. It is important to note that states may use updated monitor data (e.g., 2013-2015 or perhaps even 2014-2016) to make the final designations and as such it is possible that air quality in the county may have improved over a more recent time period. Regardless, the potential exists that Oklahoma may have to develop a SIP that could include NO_x reduction measures upon existing emissions sources.

Control techniques for reducing NO_x emissions from existing fossil fuel fired utility boilers can be grouped into two fundamentally different methods: combustion controls and post-combustion controls. Combustion controls reduce NO_x formation during the combustion process and include methods such as operational modifications, low NO_x burners, overfire air, and others. While gas fired boilers may not be the state's immediate target for such RACT control options, it is not out of the realm of possibility that any significant emission source of NO_x could be impacted. RACT controls are generally not costly (add-on controls such as SCR) but may include the lesser NO_x options such as dry low NO_x burners or combustion optimization projects.

3.6 SULFUR DIOXIDE STANDARD

On June 2, 2010, the EPA finalized a 1 hour SO_2 NAAQS of 75 ppb (based on the 99th percentile value average over 3 consecutive years). Following the finalization of the 2010 standard, the EPA developed a white paper that identified possible methodologies for determining how NAAQS compliance could be determined, given the limited coverage of the SO_2 ambient monitoring network. Following the issuance of the white paper, the EPA developed an implementation strategy that included both monitoring (where applicable) and air dispersion modeling methodologies for identifying areas not in compliance with the NAAQS.

The EPA has already made compliance determinations for those areas where an adequate ambient monitoring network exists. For those areas that do not currently have an adequate monitoring network, the EPA has required that states identify each source with SO_2 emissions of greater than 2,000 tons per year (tpy). For each of these sources, states are then required to indicate whether they will characterize the air quality surrounding the source(s) (i.e., whether the NAAQS is being met or not) using ambient monitoring or air dispersion modeling. For the areas that states propose to use modeling, a complete modeling analysis is required to be submitted to the EPA by January 13, 2017.

Being natural gas fired sources, emissions of SO_2 from the boilers at the Mustang facility are significantly less than 2,000 tpy and as such are not likely to be a target of this rule.

3.7 REGIONAL HAZE RULE

The Regional Haze Program requires states to demonstrate "reasonable progress" in regulating air emissions impacting visibility in 156 designated Class I areas (national parks and wilderness areas) to eventually return visibility to natural conditions in 2064. The original rule issued in 1999 was revised in 2005 to provide guidelines for states to use in developing SIPs to determine which sources of visibility impairing pollution (SO_2, NO_X, and PM) will need to install Best Available Retrofit Technology (BART). Only power plants constructed between 1962 and 1977 are subject to SIP imposed reductions under this initial BART rule. The Mustang boilers each pre-date 1962 and as such were not impacted by the BART provisions of the rule.

However, the BART control strategies only cover the initial implementation period extending to the year 2018. The Regional Haze Program requires a reassessment and revision of those strategies, as appropriate, to occur every 10 years thereafter. If states are not on their glide paths to 2064 natural visibility conditions during the 10 year reassessment periods, they may evaluate the need for reductions from non-BART sources (e.g., boilers constructed outside of the above dates, or even combustion turbine facilities). A Federal Register notice from January 5, 2016, indicates that Oklahoma is not meeting its reasonable progress goals at the Wichita Mountains National Wildlife Refuge Class I area. However, modeling shows that even if Oklahoma eliminated all emissions from Oklahoma sources, it would still not be sufficient to show compliance with the 2064 glide path. Rather, the modeling implicated Texas-based sources impacting the Class I area. As such, it would seem that this regulation would not warrant additional reductions from Oklahoma sources (and particularly natural gas fired sources such as the boilers at Mustang) during this upcoming 10 year control period.

3.8 NEW SOURCE REVIEW

Finally, a discussion of the potential applicability of air regulations would not be complete without discussing air permitting regulations. Unlike the previously discussed regulations which can impact a source's operations regardless of it triggering the action of applicability, air permitting regulations apply only when a facility desires to make modifications. These modifications can be changes to existing emissions equipment or the addition of new emissions sources to the facility. A modification to existing equipment is a physical change or change in the method of operation that significantly increases the emissions of any regulated pollutant. This is an important concept for these boilers since many of the improvements discussed herein and in prior studies conducted for the plant would be considered physical changes and thus must be evaluated to determine if they constitute modifications under air permitting regulations because, if they are, then the project would need to undergo major source permitting that can result in additional emissions controls as a result of the air construction permit application process (explained in detail below).

The air construction permit application process entails New Source Review (NSR), which begins with an analysis to determine the applicability of major source permitting requirements under the provisions of Prevention of Significant Deterioration (PSD) for those pollutants for which a project's location is in attainment of the NAAQS or unclassifiable, or nonattainment NSR (NA NSR) for those pollutants for which the project's location is not in attainment of the NAAQS for one or more pollutants. PSD permitting, if applicable to a project, entails several significant and potentially costly requirements including air dispersion modeling and the application of Best Available Control Technology (BACT) (i.e., the most stringent, yet technologically and financially feasible, control technology) to emissions sources included in the project that emit an applicable pollutant. NA NSR carries several additional requirements that are more onerous and potentially more costly than PSD permitting, including the requirement to purchase emissions offsets, possibly at a ratio of greater than 1:1, for a project's emissions of applicable pollutants. NA NSR also requires Lowest Achievable Emission Rate (LAER) technology, which stipulates the most effective, technologically feasible control technology, regardless of cost.

To understand which permitting programs discussed above may be applicable to a given improvement project, assuming the project meets the definition of a modification, the air quality designation of the project location must be considered. Canadian County, Oklahoma, is currently classified as "in attainment" or "unclassifiable" for all applicable pollutants. Therefore, the PSD permitting program would apply to any projects found to be modifications causing a significant emissions increase. However, the county has recently monitored emissions of ozone in excess of the NAAQS and could be on the brink of being classified as nonattainment for ozone. Any improvement projects that cause a significant emissions increase of NO_x or VOC post nonattainment designation would trigger NA NSR review and its provisions as discussed above.

Black & Veatch notes that the various improvement projects evaluated herein when evaluated against the PSD/NA NSR permitting metric of "modification" may render the boilers subject to the installation of additional air quality control systems (AQCSs) or upgrading of existing systems to satisfy BACT or LAER requirements.

As a parting note, the NSR program offers a potential benefit to the Mustang facility. Should OG&E wish to install new, more efficient generation at the facility (e.g., combustion turbine technology), the emissions from the existing boilers can be utilized under an element of the NSR program known as "netting." Netting provides an avenue for using existing source emissions to offset increases in new source emissions in an effort to demonstrate that the new generation will not cause a significant net emissions increase at the facility thereby negating the need for NSR for the new generation. For this to occur, the existing generation must have a "baseline" of historical emissions sufficient to offset the potential emissions increase from the new generation. NSR regulations allow for a 5 year look back period for EGUs to establish an emission unit's baseline emissions. The more an emission unit operated during the look back period the higher the available baseline of that unit for offsetting emissions from new generation.

A review of the CAMD data indicates that the boiler operations have been steadily declining in recent years. As such, their emissions have been declining thereby shrinking the units' baseline emissions available for netting of any new generation projects. When this is the case, baselines are shrinking and new generation is under consideration, it is prudent to move quickly on the permitting and installation of new generation while adequate baseline is still available for netting against the new units' emissions increases.

3.9 ENVIRONMENTAL SUMMARY

It is difficult to speculate on future environmental legislation and the subsequent impact it may have on the Mustang Power Plant. A worst-case scenario would result in the need for an SCR requirement, from one or more programs, yet most likely would be some kind of precombustion solution for NO_x and other pollutants. The best-case scenario (with respect to environmental legislation requirements) would require no changes at all, leaving the retirement decision as a technical and financial decision.

Table 3-4 gives a summary for best case, worst case, and most likely, with each legislative impact. No financial values have been apportioned to the impacts, and they are not considered in Section 4.0 of this report.

Table 3-4 Environmental Summary

LEGISLATION	BEST CASE IMPACT	WORST CASE IMPACT	MOST LIKELY IMPACT
MATS	None	None	None
ACID RAIN	None	None	None
CSAPR	None	Purchase NO_x allowances from open market	None
CPP	None	Additional reduction credits required	None
OZONE	None	SCR required	Combustion optimization required
SO_2	None	None	None
REGIONAL HAZE	None	None	None
NEW SOURCE REVIEW	None	Modifications trigger NSR + insufficient netting	None

4.0 Financial Evaluation

4.1 BEFORE TAX LEVELIZED COST OF ELECTRICITY

To provide a comparison of potential options available for the Mustang Power Plant, Black & Veatch calculated the before tax levelized cost of electricity (LCOE) for selected options described below. The LCOE method calculates a comparative energy price in $/MWh for each generation option and includes fuel costs, operations and maintenance (O&M) costs, carbon costs, and capital costs. This section summarizes the assumptions and findings of this analysis.

4.2 LEVELIZED COST OF ELECTRICITY ANALYSIS OPTIONS AND ASSUMPTIONS

Based on information provided by the client, the LCOE analysis compared the following three options for Mustang:

- Option 1: Mustang Units 2 through 4 continue to operate until 2017. After 2017, Mustang Unit 2 shuts down, Mustang Unit 3 continues to operate until 2020, and Mustang Unit 4 continues to operate until 2024. In this option, the Mustang Combustion Turbine Plant (Mustang CT) is not constructed.
- Option 2: Mustang Units 2 through 4 continue to operate until 2017. All three units are then shut down and replaced by the Mustang CT in 2018, which operates until 2044 in accordance with the IRP (a 27 year life).
- Option 3: This is a combination of Options 1 and 2. In this option, Mustang Units 2 through 4 operate until 2017, 2020, and 2024, respectively (according to Option 1). The Mustang CT then commences operation in 2025 and operates for 27 years until 2051. Inclusion of this option allows the value of deferring the capital to construct the Mustang CT to be considered.

This analysis is not intended to be an exhaustive analysis identifying the optimum alternative available to OG&E. It is offered only to review the decision to retire the Mustang units and avoid excessive expenditures in very old generating stations and/or units. The LCOE analysis was intended to demonstrate that lower cost options existed; therefore, the continued operation of the Mustang units was not the least cost option available. The options described above do not include an exhaustive analysis of the various alternatives suggested by the intervenors in the rates case (or cases). Such an analysis is beyond the scope of this investigation as it requires (at a minimum) details on the alternative generation sources, their production costs, availability, market options, system demands, and transmission constraints.

The options are summarized in Table 4-1.

Table 4-1 Mustang Options for Financial Review

ASSUMPTION	OPTION 1 UNIT 3 AND 4 LIFE EXTENSION	OPTION 2 COMBUSTION TURBINE CONSTRUCTION	OPTION 3 UNIT 3 AND 4 LIFE EXTENSION + 2025 COMBUSTION TURBINE
Unit 3 Shutdown	2020	2017	2020
Unit 4 Shutdown	2024	2017	2024
Combustion Turbine Start	NA	2018	2025
Combustion Turbine Shutdown	NA	2044	2051

The start year for the analysis is 2014 to align with OG&E's previous IRP. The majority of the key assumptions for the analysis were extracted from supporting documents to the IRP. The key assumptions for the analysis are summarized in Appendix B.

There are a number of additional costs that are not considered in the financial analysis, since the simple analysis performed provides a sufficient conclusion regarding the cost differences between the highlighted options and Black & Veatch does not have access to all the data required to estimate the costs. Addition of these costs to the analysis would only serve to increase the difference in cost between Options 2 and 3.

The additional costs are as follows:

- Capital costs to install emissions control technologies that may be required as a result of failing to achieve emissions netting baseline requirements prior to construction of new combustion turbines (refer to Section 3.8). This is pertinent to Option 3, whereby the 5 year baseline generation, and therefore emissions, will not be adequate to offset the new generation and emissions.
- O&M cost increases because of the cycling operating regime (refer to Section 2.5).
- Additional costs to secure generating capacity as a result of staggered retirement of Mustang gas fired steam turbine units. This additional capacity is to enable OG&E to meet capacity margin requirements.

4.3 ANALYSIS FINDINGS

The findings of the LCOE analysis are summarized in Table 4-2 and on Figure 4-1.

Table 4-2 LCOE Comparison

LCOE COMPONENT	OPTION 1 UNIT 3 AND 4 LIFE EXTENSION ($/MW)	OPTION 2 COMBUSTION TURBINE CONSTRUCTION ($/MW)	OPTION 3 UNIT 3 AND 4 LIFE EXTENSION + 2025 COMBUSTION TURBINE ($/MW)
Capital	119	97	130
O&M	149	29	59
Fuel	57	57	70
Carbon	4	9	14
Total LCOE	329	192	273

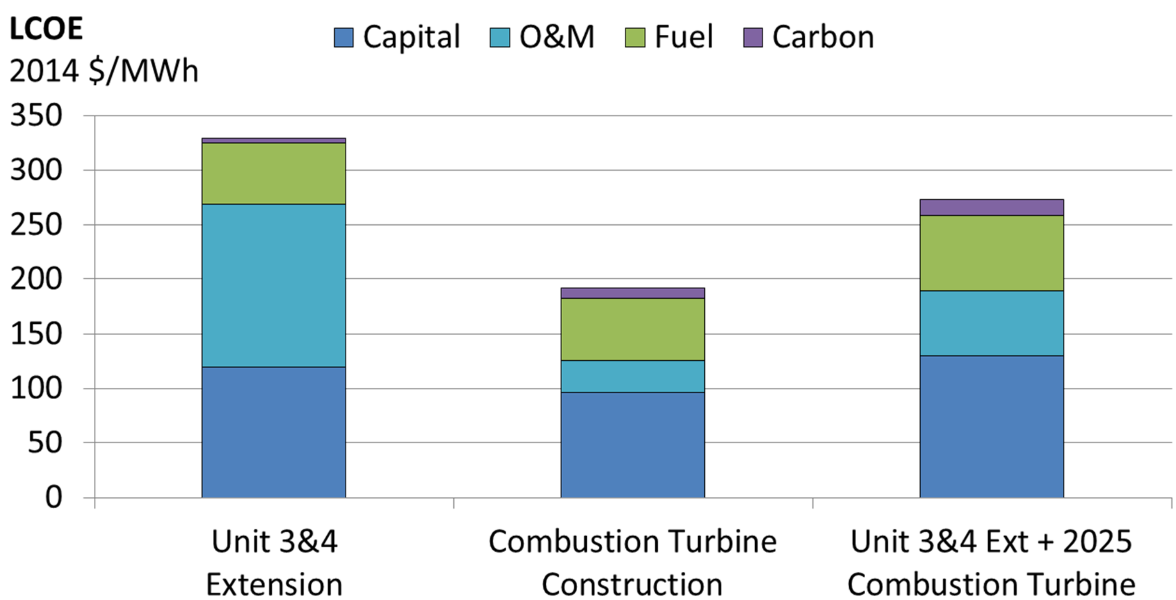

Figure 4-1 LCOE Comparison Chart

Based on Table 4-2 and Figure 4-1, it can be concluded that Option 1, extending the life of Units 3 and 4 to 2020 and 2024, respectively, has the highest LCOE. This is because the significant capital investment required to extend the unit's lives ($25.4 million for Unit 3 and $39.1 million for Unit 4) and the relatively short time period for OG&E to recoup capital and return from customers. The low annual output from the Units 2 through 4 also increases the LCOE as the annual fixed operating costs are spread over less generation.

The Option 2 initial capital investment is higher than Option 1 mostly due to $407 million (in 2014$) for the engineering design, procurement, and construction of the replacement Mustang combustion turbines. However, there is a longer time period for OG&E to recoup capital and return from customers. The Mustang CT is also more efficient, lowering its dispatch cost and increasing its annual generation. Increased annual generation lowers the O&M cost on a $/MWh basis. This results in the lowest LCOE of the three options.

In the case of Option 3, continued operation of Units 2 through 4 until 2017, 2020, and 2024, respectively, and postponing the construction of the replacement combustion turbines until 2025 had a lower LCOE than Option 1 but was not as low as Option 2. However, this case does not consider the potential for the capital and operating costs of the replacement units being higher than expected because of additional air emissions compliance equipment requirements that likely would be required as the “netting” benefits would be compromised or would no longer apply. In the cases of Options 1 and 3, OG&E will be making the capital expenditures recommended by Burns & McDonnell. But in the case of Option 3, the new combustion turbines would provide added revenue through 2051. While in the case of Option 1, there are is no plant revenue after 2024. Meanwhile, the Option 2 LCOE is less than Option 3 because there is less capital investment to extend the life of Units 2 through 4 and the new combustion turbines are expected to have higher capacity factors because of a more efficient design.

5.0 Conclusion

Fossil fuel fired generating stations built in the mid-20th Century, such as Mustang Units 1 through 4, were traditionally designed and built with a nominal design and economic life of around 30 years. More than 30 to 40 years ago, the common design method to avoid failure mechanisms was to overdesign with high safety factors to ensure component reliability. Since this time, failure mechanisms have been researched and are better understood, and original equipment manufacturers have approved lower design margins. This allowed plant owners and operators to operate beyond the original nominal life expectancy.

With a longer life expectancy for the original plant equipment, there are inherent economical and strategic advantages in making the capital investments to implement plant modifications and upgrades to improve efficiency and/or reduce emissions. Therefore, the plants have been able to remain economically competitive for longer than originally planned. As a result, there are many plants worldwide that were originally designed for a 30 year life still in operation at the 50 year point and beyond. However, there comes a point where design safety margin cannot be further reduced and efficiency improvement modifications simply do not improve heat rate and emissions of these older plants to compete with modern high efficiency power plant designs. In short, the costs of life extension and efficiency improvements escalate exponentially with plant age. Eventually, the costs exceed the benefits and continued plant operation is no longer a prudent financial option.

By analyzing the technological, environmental, and financial aspects of the decision to retire Mustang, Black & Veatch has considered a wide degree of factors that have an impact on any such decision. The significant difference in the LCOE between the three options clearly demonstrated that lower cost options were now (in 2014) available to OG&E. In evaluating the prudence of this decision, Black & Veatch did not consider alternatives to the replacement of the existing Mustang generating units other than the installation of new combustion turbines at the Mustang location. Whether or not replacement with new combustion turbines is the optimum solution is the subject of a more rigorous analysis. The continued operation of the Mustang units, with the associated operating costs, maintenance requirements, capital requirements, and likely degrading reliability was clearly not optimal. Therefore, it is the opinion of Black & Veatch that retirement of the units was a prudent decision by OG&E management.

Appendix A. References

U.S. Energy Information Administration (EIA), (2014), Annual Electric Generator Report, Available at: https://www.eia.gov/electricity/data/eia860/.

EPRI, (2001), "Damage to Power Plants Due to Cycling," Available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000000001001507.

Appendix B. Assumptions

ASSUMPTION	UNIT	VALUE	NOTES
After tax nominal WACC	% pa	8.323	From *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Federal and state income tax	% pa	40	
CPI annual increase	% pa	1.7	Average increase to CPI (all items less energy and food) from 2008 to 2015, *http://www.bls.gov/cpi/cpid1605.pdf.*
Mustang Unit 1 net capacity	MW	50	From *2014 IRP – Oklahoma Report.pdf.*
Mustang Unit 2 net capacity	MW	50	From *2014 IRP – Oklahoma Report.pdf.*
Mustang Unit 3 net capacity	MW	121	From *2014 IRP – Oklahoma Report.pdf.*
Mustang Unit 4 net capacity	MW	242	From *2014 IRP – Oklahoma Report.pdf.*
Mustang Unit 1 net heat rate	MBtu/MWh	12.3	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 2 net heat rate	MBtu/MWh	12.3	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 3 net heat rate	MBtu/MWh	10.9	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 4 net heat rate	MBtu/MWh	10.6	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang annual capacity factors			From *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 1 CO_2 factor	ton/MWh	0.732	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 2 CO_2 factor	ton/MWh	0.732	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 3 CO_2 factor	ton/MWh	0.645	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 4 CO_2 factor	ton/MWh	0.633	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 3 capital investment			From *Confidential – BM Report.pdf.*
Mustang Unit 4 capital investment			From *Confidential – BM Report.pdf.*
Mustang Units 1 through 4 VO&M	2014 $/MWh	2.50	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*

ASSUMPTION	UNIT	VALUE	NOTES
Mustang Unit 1 through 4 FO&M	2014 $ pa		Calculated from *MT OM 2010 to 2016.xlsx*.
Mustang combustion turbine net capacity	MW	406	From *DEQ permit review.pdf.*
Mustang combustion turbine net heat rate	MBtu/MWh	8.9	From *2014 IRP – Oklahoma Report.pdf.*
Mustang combustion turbine CO_2 factor	ton/MWh	0.542	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx*.
Mustang combustion turbine capital cost	2014 $/kW	1,002	From *2014 IRP – Oklahoma Report.pdf.*
Mustang combustion turbine FO&M	2014 $/kW	26.59	From *2014 IRP – Oklahoma Report.pdf.*
Mustang combustion turbine VO&M	2014 $/MWh	1.81	From *2014 IRP – Oklahoma Report.pdf.*
Natural gas prices			Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx*.
Carbon prices			Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx*.
After tax nominal WACC	% pa	8.323	From *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Federal and state income tax	% pa	40	
CPI annual increase	% pa	1.7	Average increase to CPI (all items less energy and food) from 2008 to 2015, *http://www.bls.gov/cpi/cpid1605.pdf*.
Mustang Unit 1 net capacity	MW	50	From *2014 IRP – Oklahoma Report.pdf.*
Mustang Unit 2 net capacity	MW	50	From *2014 IRP – Oklahoma Report.pdf.*
Mustang Unit 3 net capacity	MW	121	From *2014 IRP – Oklahoma Report.pdf.*
Mustang Unit 4 net capacity	MW	242	From *2014 IRP – Oklahoma Report.pdf.*
Mustang Unit 1 net heat rate	MBtu/MWh	12.3	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx*.

ASSUMPTION	UNIT	VALUE	NOTES
Mustang Unit 2 net heat rate	MBtu/MWh	12.3	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 3 net heat rate	MBtu/MWh	10.9	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 4 net heat rate	MBtu/MWh	10.6	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang annual capacity factors			From *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 1 CO_2 factor	ton/MWh	0.732	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 2 CO_2 factor	ton/MWh	0.732	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 3 CO_2 factor	ton/MWh	0.645	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 4 CO_2 factor	ton/MWh	0.633	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Unit 3 capital investment			From *Confidential – BM Report.pdf.*
Mustang Unit 4 capital investment			From *Confidential – BM Report.pdf.*
Mustang Units 1 through 4 VO&M	2014 $/MWh	2.50	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang Units 1 through 4 FO&M	2014 $ pa		Calculated from *MT OM 2010 to 2016.xlsx.*
Mustang combustion turbine net capacity	MW	406	From *DEQ permit review.pdf.*
Mustang combustion turbine net heat rate	MBtu/MWh	8.9	From *2014 IRP – Oklahoma Report.pdf.*
Mustang combustion turbine CO_2 factor	ton/MWh	0.542	Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Mustang combustion turbine capital cost	2014 $/kW	1,002	From *2014 IRP – Oklahoma Report.pdf.*
Mustang combustion turbine FO&M	2014 $/kW	26.59	From *2014 IRP – Oklahoma Report.pdf.*

ASSUMPTION	UNIT	VALUE	NOTES
Mustang combustion turbine VO&M	2014 $/MWh	1.81	From *2014 IRP – Oklahoma Report.pdf.*
Natural gas prices			Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
Carbon prices			Calculated from data in *Copy of OIEC 1-11_Att01_2014_IRP_ProdCost_ScrubConvert_Base_CT_spread.xlsx.*
CPI = consumer price index FO&M = fixed operations and maintenance pa = per annum VO&M = variable operations and maintenance WACC = weighted average cost of capital			