PSD AIR CONSTRUCTION PERMIT APPLICATION

ADDENDUM – GREENHOUSE GAS BACT ANALYSIS

Riverton Facility

Unit 12 Conversion to Combined Cycle

Project

B&V PROJECT NO. 176883

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PREPARED FOR

Empire District Electric Company

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Acronym List

BACT	Best Available Control Technology
BHP	Break horsepower
Btu	British Thermal Unit
CAA	Clean Air Act Amendments of 1990
CCCT	Combined cycle combustion turbine
CCS	Carbon capture and storage
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
ECBMR	Enhanced Coal Bed Methane Recovery
Empire District	Empire District Electric Company
EOR	Enhanced Oil Recovery
GHG	Greenhouse Gas
GWP	Global Warming Potential
HRSG	Heat recovery steam generator
IGCC	Integrated Gasification Combined Cycle
KDHE	Kansas Department of Health and Environment
kW	Kilowatt
kWh	Kilowatt-hour
LDAR	Leak Detection and Repair
LSFO	Low Sulfur Fuel Oil
MEA	Monoethanolamine
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt-hour
NSPS	New Source Performance Standard
PSD	Prevention of Significant Deterioration
RBLC	RACT/BACT/LAER Clearinghouse

1.0 Introduction

On January 25, 2013, Empire District Electric Company (Empire District) submitted the Riverton Unit 12 Conversion to Combined Cycle Project Prevention of Significant Deterioration (PSD) Air Permit Application to the Kansas Department of Health and Environment (KDHE). That application document indicated the conversion of Unit 12 from simple cycle to combined cycle operation would trigger PSD permitting for $PM/PM_{10}/PM_{2.5}$ and Greenhouse Gases (GHGs). Accordingly, these pollutants are subject to full PSD review including the requirements to address Best Available Control Technology (BACT), impacts upon ambient air quality, as well as impacts upon area growth, soils, vegetation, and visibility. As such, Empire District is submitting this Addendum to the PSD Air Permit Application to address BACT for GHGs. Additional addendums will address the remaining PSD elements mentioned above.

As discussed in the PSD Air Permit Application document, the Project consists of the following GHG emission sources:

- Conversion of the existing Unit 12 natural gas-fired simple cycle combustion turbine to combine cycle operation with natural gas-fired duct burners in the Heat Recovery Steam Generator (HRSG)
- New natural gas-fired auxiliary boiler
- New emergency diesel generator
- Two new circuit breakers

GHG emissions calculations for each of the above listed sources can be found in Appendix A.

2.0 Greenhouse Gas BACT Basis

The Clean Air Act Amendments of 1990 (CAA) established revised conditions for the approval of pre-construction permit applications under the PSD program. One of these requirements is that BACT be installed to control all pollutants regulated under the Act that are emitted in significant amounts from new major sources or major modifications. BACT need not necessarily result in an emissions control device. Rather, BACT is an emission limitation made on a case-by-case basis accounting for several project-specific factors. However, in no case is BACT allowed to be less stringent than the emissions limits established by an applicable New Source Performance Standard (NSPS).

EPA announced its final "PSD Tailoring" rule on May 13, 2010 which established GHG emission thresholds for triggering major source PSD permitting requirements including an evaluation of BACT. The emission thresholds, 100,000 for new sources and 75,000 for increases from modifications of existing sources measured in tons per year (tpy) of carbon dioxide equivalent (CO_{2e}) – took effect in 2011.

As required under the NSR/PSD regulations, the BACT analysis presented herein employed the EPA-preferred "top-down," five-step analysis process to determine the appropriate emission control technologies and/or emissions limitations for the Project:

- Step 1--Identify All Control Technologies
- Step 2--Eliminate Technically Infeasible Options
- Step 3--Rank Remaining Control Technologies by Control Effectiveness
- Step 4--Evaluate Most Effective Controls
- Step 5--Select BACT

The following sections present the GHG BACT analysis conducted for the Unit 12 converted combined cycle combustion turbine (CCCT), as well as the new auxiliary boiler, emergency diesel generator, and circuit breakers. This GHG BACT analysis utilizes information from various reference and research documents developed by or for various government entities including the USEPA, the Department of Energy's National Energy Technology Laboratory, and the Interagency Task Force on CCS to name a few. It also relies upon information provided in a recent (August 2012) Statement of Basis developed by USEPA Region 6 for a natural gas-fired CCCT in Texas where Region 6 remains the permitting authority for GHGs. Information from these and other sources of data are referenced throughout this application as footnote entries.

3.0 Combined Cycle Combustion Turbine

3.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

The first step in a top-down analysis is to identify all available control options for the emission unit in question. Identifying all the potential available control options consists of those air pollution control technologies or techniques with a practical potential for application to the emission unit and the regulated pollutant under evaluation. The potential available control technologies and techniques may include lower emitting processes and practices, as well as post-combustion controls. Lower emitting practices can include fuel cleaning, treatment, or innovative fuel combustion techniques such as pre-combustion or oxy-combustion controls.

Available CO_2 control techniques include carbon capture and storage (CCS) and inherently lower emitting process and practices via energy efficient designs. The inherently lower emitting processes and practices can be evaluated for the proposed Project (including the combustion turbine and HRSG), as well as on a plant-wide basis. While this analysis will evaluate such processes and practices for the existing combustion turbine and the new HRSG, it will not focus on plant-wide aspects which the USEPA states in its March 2011 guidance was intended for new facilities which have more opportunity to consider such efficiency improvements during development than does an existing generating facility which should focus only upon the emitting unit(s) being modified.[1]

3.1.1 Carbon Capture and Storage

As for CCS, the USEPA, in the same March 2011 guidance document, classifies CCS as an "add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)." The USEPA believes that it is a technology that warrants initial consideration and should not necessarily be eliminated in Step 1, but rather should be evaluated based on technical feasibility and costs. If CCS is to be eliminated during subsequent BACT steps, then it should be done so on record of evaluation.[2] This GHG BACT will serve as that record of evaluation.

CCS involves separating and capturing CO_2 from an emission unit's flue gas, pressurizing the captured CO_2 and finally transporting the compressed CO_2 for injection into an available geologic storage structure. There are generally three primary technologies for CO_2 capture: pre-combustion, post-combustion, and oxy-combustion.[3, 4]

- <u>Pre-combustion Capture</u> – Typically used in Integrated Gasification Combined Cycle (IGCC) power plants and other industrial facilities, pre-combustion capture

[1] USEPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA-457/B-11-001 (March 2011), 30.
[2] USEPA, 32-33.
[3] DOE/NETL, *Advanced Carbon Dioxide Capture R&D Program Accomplishments* (April 2012), 2-5.
[4] Intergovernmental Panel on Climate Change, *Carbon Dioxide Capture and Storage* (2005), 25.

processes the primary fuel in a reactor with steam and air or oxygen to produce a mixture consisting mainly of CO and hydrogen called a synthesis gas. It then requires the CO be shifted to CO_2 before being separated from the hydrogen leaving a pure hydrogen stream to be used as the fuel.

- Post-combustion Capture –Primarily being developed for conventional coal-fired power plants (but there is no reason it would not be adaptable to CCCT plants), post-combustion capture refers to removal of CO_2 in the flue gas just prior to discharge to the atmosphere. Several post-combustion processes are in various stages of development including absorption, adsorption, and gas separation membrane technologies. The most widely used of these technologies (and the only one that is commercially available) is absorption which uses amine or monoethanolamine (MEA)-based solvents[5] to chemically separate CO_2 from other flue gases.
- Oxy-combustion Capture - Primarily being developed for pulverized coal-fired power plants, oxy-combustion capture uses oxygen instead of air (upstream separation required) for combustion of the fuel to produce an exhaust stream that is mainly water and CO_2. Additional purification of the CO_2 stream may be required to meet pipeline and storage requirements.

Once captured, CO_2 must be pressurized for injection into a pipeline or other shipping container in order to be transported for ultimate sequestration such as injection into an available geologic storage structure. The following provides a list of transportation and storage options in various stages of research or development[6]:

- Transportation
  - Pipeline
  - Shipping
- Underground Geological Storage
  - Oil/gas fields (either abandoned fields or for enhanced oil recovery (EOR) in active fields)
  - Saline formations
  - Unminable coal seams (with potential for enhanced coal bed methane recovery (ECBMR))
  - Other geologic media including basalts, oil or gas-rich shale, salt caverns, and abandoned mines (all offer small niche options for storage)
- Oceanic Storage
- Mineral Carbonation
- Industrial Uses of CO_2

[5] USEPA Region 6, *Statement of Basis – Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Calpine Corporation, Deer Park Energy Center (DPEC), LLC* (August 2012), 8.
[6] Intergovernmental Panel on Climate Change, 215-220, 279, 321.

While there are various methods of transport and storage, any discussion providing further details of these options is rather inconsequential unless and until the remaining steps of this GHG BACT analysis prove CO_2 capture is warranted (i.e., the technology is available, cost-effective, and has no significant energy or other environmental impacts that would otherwise preclude its use). Such factors for the capture component of CCS are further evaluated in Step 4 of the GHG BACT. The USEPA applies this same approach in its March 2011 GHG guidance document wherein the agency recognizes that it is not necessary to provide a detailed evaluation of every step of the CCS process if one part of the process warrants eliminating the control technology (e.g., if transportation of CO_2 is cost-prohibitive there is no need to continue the analysis and provide cost information for CO_2 capture).[7]

3.1.2 Inherently Lower Emitting Process and Practices

As mentioned previously, the USEPA through various guidance documents indicates that inherently lower-polluting processes are appropriate for consideration as available control alternatives. In doing so, however, the agency has recognized that a Step 1 list of options need not necessarily include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant.[8] Given the USEPA's stance on not allowing inherently lower emitting processes and practices to redefine the source and the fact that the Project consists of converting an existing simple cycle combustion turbine to combined cycle (i.e., not installing a new emissions source, but rather modifying an existing one), the inherently lower emitting processes and practices will be limited to those process and practices that can be undertaken on the modified combustion turbine and new HRSG.

According to the USEPA, inherently lower emitting processes and practices include methods, techniques, and systems designed to increase energy efficiency and can be classified into two categories: 1) technologies or processes that maximize the energy efficiency of the individual emissions unit and 2) those that maximize the energy efficiency across the entire facility. As discussed previously, and per USEPA guidance, energy efficiency improvements shall be limited to the modified and proposed new emissions sources and will not reach out plant-wide as is more appropriate for the construction of new facility.[9]

The Project by its shear nature is designed to increase the efficiency of Unit 12 by converting it from simple cycle to combined cycle thereby capturing waste heat and converting it to useful energy that would otherwise be lost out of the stack. Generally speaking energy efficiency can increase from 30 percent for simple cycle turbines to 50 percent for combined cycle operation. While the conversion will make Unit 12 much more efficient, there are other design processes and operating practices that can further improve and assist to maintain the unit's energy efficiency. Based on Black & Veatch's knowledge of power plant design and operation, as well as other GHG

[7] USEPA, 42.
[8] USEPA, 24.
[9] USEPA, 29-30.

permits and permit applications for similar natural gas-fired CCCTs[10, 11], the following inherently lower emitting processes and practices are presented as available GHG control technologies/energy efficiency measures:

- Periodic Maintenance and Tuning – Follow manufacturer recommendations regarding inspection and maintenance activities to maintain/restore optimal efficiency.
- Reduce Heat Losses – Install insulation on both the steam turbine and HRSG components to minimize heat loss thereby increasing energy efficiency via heat recovery. In addition, the HRSG stack will have a damper and insulation below the damper to minimize heat loss during shutdowns thereby reducing startup times.
- Instrumentation and Controls – Employ the use of the latest computer-based control systems (including upgrade of present combustion turbine control system) to monitor and optimize fuel and air flows which optimizes combustion operations thereby producing the maximum amount of power for the least amount of fuel burned while maintaining emissions performance over a range of load and ambient temperature conditions.
- Steam Cycle Efficiency –Employ a reheat steam cycle with high steam temperatures to increase the amount of power generated from the recovered waste heat.
- Heat Exchanger Design – Select a design which optimizes waste heat transfer from the combustion turbine exhaust gas while minimizing corrosion at the outlet of the HRSG.
- Minimize Fouling of Heat Exchanger Surfaces – Employ inlet air filtering, proper feed water chemistry, and tube surface cleaning practices to minimize fouling of the heat exchange surfaces and maintain the maximum waste heat exchange between the combustion turbine exhaust gas and the HRSG thereby maintaining/restoring optimal efficiency.
- Reduce Steam Losses – Follow an inspection routine that checks for and repairs steam leaks from valve, flanges, and piping to maintain/restore optimal efficiency.
- Use of "Clean Fuels" – Natural gas has the lowest carbon content of any fossil fuel and will be utilized in both the combustion turbine and HRSG. While the USEPA does include the use of "clean fuels" in the definition of BACT, and other fuels (such as hydrogen and bio-fuels) do exist that would produce little to no net CO_2 emissions, the agency has stated that the initial list of control options for a BACT analysis does not need to include "clean fuel" options that would fundamentally redefine the source including those that would require a permit applicant to switch to a primary fuel type (i.e., coal, natural gas, or biomass) other than the type of fuel

[10] USEPA Region 6,, 10-13.
[11] NRG Texas Power LLC, *Application for PSD Air Quality Permit Greenhouse Gas Emissions Unit 5, S.R. Bertron Generating Station, Laporte, Harris County, Texas* (November 26, 2012), 6-3, 6-4.

that an applicant proposes to use for its primary combustion process.[12] Unit 12 is currently designed and permitted to burn natural gas (the lowest carbon content fossil fuel available) and will continue to do so after the conversion to combined cycle.

3.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The second step of the top-down analysis is to identify the technical feasibility of the control options identified in Step 1, which are evaluated with respect to source-specific factors. A control option that is determined to be technically infeasible is eliminated. "Technically infeasible" is defined as a clearly documented case of a control option that has technical difficulties that would preclude the successful use of the control option because of physical, chemical, and engineering principles. After completion of this step, technically infeasible options are then eliminated from the BACT review process.

Conversely in Step 2, the control option may be identified as technically feasible. A "technically feasible" control option is defined as a control technology that has been installed and operated successfully at a similar type of source of comparable size under review (demonstrated). If the control option cannot be demonstrated, the analysis gets more involved. When determining if a control option has not been demonstrated, two key concepts need to be analyzed. The first concept, "availability," is defined as technology that can be obtained through commercial channels or is otherwise available within the common sense meaning of the term. A technology that is being offered commercially by vendors or is in licensing and commercial demonstration is deemed an available technology. Technologies that are in development (concept stage/research and patenting) and testing stages (bench-scale/laboratory testing/pilot scale testing) are classified as not available. The second concept, "applicability," is defined as an available control option that can reasonably be installed and operated on the source type under consideration. In summary, the commercially available technology is applicable if it has been previously installed and operated at a similar type of source of comparable size, or a source with similar gas stream characteristics.

3.2.1 Carbon Capture and Storage

While many of the CO_2 capture technologies discussed previously are at various stages of bench or pilot scale deployments, and none to-date have been applied to full-scale natural gas-fired power generation, the USEPA has indicated that CCS should be evaluated beyond technical feasibility. As such, this analysis will continue under the assumption that post-combustion capture using absorption technology such as amine/MEA is technically feasible while other capture technologies including pre-combustion and oxy-combustion are not. These other technologies are infeasible because they have not to-date been applied at the appropriate scale (e.g., post-combustion adsorption or gas separation membrane technologies); or because they would fundamentally redefine the source (e.g., pre-combustion and oxy-combustion) by either requiring

[12] USEPA, 27.

new combustion units capable of combusting low CO_2 fuels (such as hydrogen) of which the existing unit is not capable. This is commensurate with other recent GHG BACT determinations made by the USEPA for similar natural gas fired generation technologies.[13] The non-commercial availability of these technologies is further evidenced by DOE/NETL research as recent as 2011 which confirms that commercial CO_2 capture technology for large-scale power plants is not yet available and indicates that it may take until 2020 to become so. [14]

CO_2 transportation via pipeline and shipping is considered technically feasible as these are the primary transportation methodologies utilized for compressed CO_2 today for many industrial applications (pipelines more so than shipping). In fact, a pipeline is currently under construction in southeast Kansas which will transport CO_2 from a fertilizer plant in Coffeyville, KS to Burbank, OK for EOR[15] making it the nearest CO_2 pipeline to Riverton according to the National Energy Technology Laboratory.[16]

CO_2 storage is also considered technically feasible since such practices with respect to EOR have been used for decades (although of concern today is the *permanent* sequestration of the CO_2 once it has done the EOR). Other potential storage options such as gas/oil fields and saline formations are currently being evaluated across the United States including Kansas. However, these are still in the research and development stage[17] and are not yet commercially available. All other storage options listed in Section 3.1.1 are still in the research and development phase with small scale bench and pilot scale deployment and as such are considered infeasible. Regardless of whether various storage options are feasible or not, including the distance a pipeline must traverse to find a suitable storage solution, CO_2 capture must still first prove economical before any more detailed consideration of storage options is warranted. A discussion of such economic consideration for CO_2 capture is provided in Section 3.4.

3.2.2 Inherently Lower Emitting Process and Practices

With the exception of the use of low carbon content fuels other than natural gas, all of the energy efficiency improvements discussed in Section 3.1.2 are commonly utilized in CCCT facilities across the country and are thus considered feasible.

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[13] USEPA Region 6, 13.
[14] DOE/NETL, *Carbon Sequestration Program: Technology Program Plan* (February 2011), 10.
[15] Walton, Rod. "Chaparral Energy to pipe CO2 to help extract Osage County oil," Tulsa World, December 26, 2012, http://www.tulsaworld.com/business/article.aspx?subjectid=49&articleid=20121226_49_A16_CUTLIN234763.
[16] NETL. "Carbon Storage." http://www.netl.doe.gov/technologies/carbon_seq/FAQs/carboncapture3.html (Accessed March 7, 2013).
[17] Graff, Trevor. "Kansas Geological Survey begins testing for CO2 underground," The University Daily Kansan, September 12, 2012, http://kansan.com/news/2012/09/12/kansas-geological-survey-begins-testing-for-co2-storage-in-underground-saline-reservoirs/?print=26693005342.

3.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

The third step of the top-down analysis is to rank all the remaining control alternatives not eliminated in Step 2, based on control effectiveness for the pollutant under review. If the BACT analysis proposes the top control alternative, there would be no need to provide cost and other detailed information in regard to other control options that would provide less control. Otherwise, the analysis should proceed to Step 4.

The following list ranks the remaining control technologies not eliminated in Step 2 (listed in order of greatest control to least control):

- Carbon Capture and Storage – Post-combustion capture using absorption techniques such as amine/MEA are generally capable of 85 to 90 percent CO_2 reduction.
- Conversion to Combined Cycle Operation – Inherent in the project design Unit 12 will experience an efficiency improvement by implementing waste heat recovery via installation of an HRSG for combined cycle operation. Increases in thermal efficiency from around 30 percent for simple cycle operation to 50 percent for combined cycle operation are typical; resulting in approximately 40 percent reduction in GHG emissions.
- Inherently Lower Emitting Process and Practices – While not readily quantifiable, the measures listed in Section 3.1.2 will provide additional efficiency improvements to the converted CCCT.

3.4 STEP 4 – EVALUATE MOST EFFECTIVE CONTROLS

Once the control effectiveness is established in Step 3 for all the feasible control technologies identified in Step 2, additional evaluations of each technology are performed to make a BACT determination in Step 4. The impacts of the technology implementation on the viability of the control technology at the source are evaluated. The evaluation process of these impacts is also known as an "Impact Analysis." The following impact analyses may be performed:

- Energy evaluation of alternatives
- Environmental evaluation of alternatives
- Economic evaluation of alternatives

The first impact analysis addresses the energy evaluation of alternatives. The energy impact of each evaluated control technology is the energy penalty or benefit resulting from the operation of the control technology at the source. Direct energy impacts include such items as the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance of the control technology in the flue gas flow path. The costs of these energy impacts are defined either in additional fuel costs or the cost of lost generation, which impacts the cost-effectiveness of the control technology.

The second impact analysis addresses the environmental evaluation of alternatives. Non-air quality environmental impacts are evaluated to determine the cost to mitigate the environmental impacts caused by the operation of a control technology. Examples of non-air

quality environmental impacts include polluted water discharge and solids or waste generation. The procedure for conducting this analysis should be based on a consideration of site-specific circumstances.

The third and final impact analysis addresses the economic evaluation of alternatives. This analysis is performed to indicate the cost to purchase and operate the control technology. Information should be obtained from established sources that can be referenced. The estimated cost of control is represented as an annualized cost ($/year) and, with the estimated quantity of pollutant removed (tons/year), the cost-effectiveness ($/tons) of the control technology is determined. The cost-effectiveness describes the potential to achieve the required emissions reduction in the most economical way. The cost-effectiveness compares the potential technologies on an economical basis.

3.4.1 Carbon Capture and Storage

The addition of CCS to a power generation facility will have negative energy and environmental impacts upon the plant and its surroundings. Auxiliary power is required to operate the CO_2 capture technologies thereby decreasing the net electrical output of the plant and reducing net plant efficiency; auxiliary power is also required for CO_2 compression. Studies estimate that use of CCS at a power generating facility could decrease power generating capacity by as much as one third and net plant efficiency by 7 to 10 percent depending on the type of facility.[18] Additionally, to meet the facility's power output requirements, additional/larger combustion sources would need to be installed at the plant or replacement power sourced from the grid ultimately resulting in additional GHG emissions (as well as traditional criteria pollutants) per MW of generation. As for negative environmental impacts, the addition of amine or MEA post-combustion CCS would require significant additional water usage and land resources [19], as well as amine emissions from the stack and a solid/sludge waste from the cleanup of the amine solution.

The biggest detractor to installation of a CCS system, however, is the cost. The majority of the cost associated with CCS is due to the post-combustion capture and compression system. Costs for post-combustion CO_2 capture, transport, and storage are shown in Table 3-1. As illustrated in Table 3-1, the cost of CO_2 capture is approximately $95 per ton of CO_2 removed (without transportation and storage which are small comparatively) which is not cost effective. In fact, this equates to an annualized cost of approximately $88 million for installation and operation of CCS. Research done by the government's Interagency Task Force indicates that adding carbon capture to a 550 MW reference natural gas fired CCCT would increase capital cost by $340 million.[20] Scaling this data to the appropriate size for Unit 12 would indicate an increase in capital cost of approximately $211 million which would more than double currently estimated capital cost of the Project without CO_2 capture. The research further indicates the unit could experience as much as a

[18] DOE/NETL, *Advanced...*, 6.
[19] DOE/USEPA (Co-task Force Leaders), *Report of the Interagency Task Force Carbon Capture and Storage* (August 2010), 35.
[20] DOE/USEPA, 33.

57 percent increase in cost of electricity ($/MWh) by adding CCS.[21] Therefore, based on the evaluation of negative energy, environmental, and economic impacts assessed here, CCS shall not be considered BACT for the Project

Table 3-1 Estimated Costs for Post-combustion CCS

CCS COMPONENT	COST OF CONTROL ($/TON CO_2 REMOVED)[1]	CO_2 REMOVED PER YEAR (TONS)[2]	TOTAL ANNUALIZED COST ($)
Capture and Compression	$95	919593	$87,361,335
Transport[3]	$0.91/100 km	919,593 at 80 km	$669,464
Storage	$0.51	919,593	$468,992
Total CCS Costs	$96.24	919,593	$88,499,791
Project Modification Cost	Total Capital Cost	Capital Recovery Factor	Annualized Capital Cost
Cost Comparison without CCS	$140,000,000	0.1099	$15,386,000

Notes:
1. Cost values are from DOE/USEPA (Co-task Force Leaders), *Report of the Interagency Task Force Carbon Capture and Storage* (August 2010), 34, 37, 44. Where ranges of values were given, the lowest bound was conservatively used. Capture and compression cost data includes all costs over the generating system's lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital. All cost data was converted from $/tonne to $/ton.
2. Project-specific CO_2 emission information is derived from calculations presented in Appendix A for the CCCT (combustion turbine plus HRSG) assuming a 90 percent control for post-combustion capture.
3. Pipeline length was selected based on distance (as the crow flies) from Riverton, KS to Coffeyville, KS, the site of the nearest pipeline (currently under construction) assuming the pipeline could accommodate additional CO_2 which it may not thereby requiring an even longer pipeline for this Project.

3.4.2 Inherently Lower Emitting Process and Practices

The remaining control technologies (heat recovery and good combustion practices including energy efficiency improvements), however, have no appreciable negative energy or environmental impacts and are considered cost effective for implementation. Therefore, they will not be eliminated here and will continue on to Step 5.

3.5 STEP 5 – SELECT BACT

The highest ranked control technology that is not eliminated in Step 4 is proposed as the BACT for the pollutant and emission unit under review. In addition to the conversion of Unit 12 from simple cycle to a more efficient combined cycle operation (a more than 30 percent

[21] Ibid.

improvement in heat rate), the following good combustion practices to promote energy efficiency are proposed as GHG BACT:

- Follow manufacturer recommendations regarding inspection and maintenance activities to maintain efficiency.
- Install insulation on both the steam turbine and HRSG components to minimize heat loss. In addition, the HRSG stack shall have a damper and insulation below the damper to minimize heat loss.
- Employ the use of the latest computer-based control systems (including upgrade of present combustion turbine control system) to monitor and optimize fuel and air flows.
- Select a steam turbine and HRSG design that maximizes efficiency while meeting Empire District's needs.
- Clean heat exchanger surfaces as needed.

3.5.1 Proposed CCCT BACT Emission Limit

BACT for the converted CCCT is good combustion practices including selected energy efficiency measures which are proposed to be made enforceable with an annual ton per year BACT limit. The USEPA in its GHG guidance has recommended that because the environmental concern with GHG emissions is their cumulative impact upon the environment, emission limitations should focus on longer-term averages (e.g., 12-month or 365-day rolling average) rather than short-term averages.[22] As such, Empire District proposes an annual CO_2 emission limit of 1,021,770 tons per year on a 12-month rolling average basis. The limit is proposed as CO_2 which accounts for 99.9 percent of total CO_{2e} emissions.

3.5.2 Proposed Compliance Monitoring

Empire District proposes to continue its current CO_2 monitoring methodology by determining the CO_2 mass emissions using an oxygen (O_2) concentration monitor in accordance with 40 CFR Part 75. Appropriate formulas and F and Fc (carbon-based) fuel factors found in 40 CFR Part 75 are used in combination with the oxygen monitor data (which meets the quality assurance requirements listed in 40 CFR Part 75) to determine the mass-based CO_2 emissions. This method is consistent with the CO_2 reporting requirements of 40 CFR 98, Subpart D – *GHG Mandatory Reporting Rule for Electricity Generation*.

[22] USEPA, 46.

4.0 Auxiliary Boiler

The 18.6 MMBtu/hr auxiliary boiler will be fired exclusively on natural gas. Given the small size of this unit, the fact that it is already proposed to burn natural gas (the lowest carbon-content fossil fuel available), and the only true identified GHG control measures are CCS and good combustion practices to promote energy efficiency, there is no reason to believe that the outcome for GHG BACT for the auxiliary boiler will have a different result than that for the combustion turbine. Specifically, CCS has been ruled out as BACT based on cost and other negative impacts, leaving only general design and operational practices remaining to maximize and maintain energy efficiency thereby minimizing GHGs to the most practicable extent possible. Therefore, the full 5-step top-down BACT approach is not presented again here as Empire District proposes to select the top control technologies presented below available to small natural gas-fired boilers such as the one proposed herein.

Selection of BACT and Compliance

Empire District proposes the following good combustion practices as BACT for the auxiliary boiler:

- Boiler Design – Employ an efficient boiler design that meets Empire's needs using efficient burners and proper insulation materials in the boiler components to minimize heat losses thereby increasing efficiency.
- Periodic Boiler Tune-ups – Follow manufacturer recommendations regarding inspection and maintenance activities including cleaning burners and convection tubes as needed to maintain efficiency.
- Air and Fuel Flow Adjustments – Manually adjust flows to maximize combustion (automated controls were assumed to not be warranted given the small size of the boiler and the fact that the magnitude of CO_{2e} emissions from the boiler is less than 1 percent of the CO_{2e} emissions from the CCCT).

Empire District proposes to limit the CO_2 emissions from the auxiliary boiler on an annual basis to 9,512 tpy (annual averaging period) with compliance demonstrated by recording fuel usage and using emission factors presented in Appendix A of this BACT analysis to determine resulting emissions. Detailed GHG emission calculations for the auxiliary boiler are provided in Attachment A.

5.0 Emergency Diesel Generator

The exact capacity of the emergency diesel generator has not yet been determined, but for permitting purposes, Empire District has assumed the capacity to be 1,102 break horsepower (BHP) or 750 kW electrical output. Because of its small size, infrequent operation, and status as emergency equipment, GHG emissions from this unit will be insignificant at an estimated 59 tpy. Also, there are no pre-combustion or post-combustion controls for reducing GHGs from internal combustion engines indicating the full 5-step BACT evaluation for the engine is not warranted.

Selection of BACT and Compliance

Empire District proposes the only GHG control available as BACT for sources such as this which is to select the most efficient engine available that meets the plant's emergency needs. Empire District also proposes to limit annual operations to no more than 100 hours per year for maintenance and readiness testing.

6.0 SF_6 Insulated Circuit Breakers

The Project will require the installation of two new SF_6-insulated circuit breakers. SF_6, or sulfur hexafluoride, is a potent GHG with a Global Warming Potential (GWP) of 23,900. Even so, estimated emission loses of SF_6 from circuit breakers is extremely low at only 6.9 tpy of CO_{2e} (only 0.0006 percent of the total Project CO_{2e} emissions).

6.1 STEP 1--IDENTIFY ALL CONTROL TECHNOLOGIES

- Use of dielectric oil or compressed air circuit breakers which contain no SF_6 or other GHG pollutants.
- Use of modern SF_6 circuit breakers designed to be totally enclosed systems with density alarms that sound when 10 percent of the SF_6 has escaped.

6.2 STEP 2--ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Circuit breakers with insulating gases other than SF_6 are not yet commercially available[23] and certainly any use of less effective insulation material to control just 6.9 tpy of CO_{2e} would not be warranted if available. As such non-SF_6 circuit breakers will be eliminated.

6.3 STEP 3--RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

The only remaining feasible control is to use a modern, totally enclosed SF_6 circuit breakers with leak detection alarms.

6.4 STEP 4--EVALUATE MOST EFFECTIVE CONTROLS

With only one control option there is no need for this evaluation step.

6.5 STEP 5--SELECT BACT

Empire District proposes to use modern, totally enclosed SF_6 circuit breakers with density (leak detection) alarms having a threshold of 10 percent.

[23] Christophorous, L.G., J.K. Olthoff, and D.S. Green, Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6: NIST Technical Note 1425 (November 1997).

7.0 Suggested Permit Conditions

BACT Emission Limitations

- BACT for the CCCT is good combustion practices and selected energy efficiency measures. The emissions of CO_2 shall not exceed 1,021,770 tpy on a 12-month rolling average basis.[24]
- BACT for the auxiliary boiler is good combustion practices. The emissions of CO_2 shall not exceed 9,512 tpy on a 12-month rolling average basis.
- BACT for the emergency diesel generator shall be the selection of the most efficient engine that meets the facility's emergency needs.
- BACT for SF_6 circuit breakers shall be installation of modern, totally enclosed SF_6 circuit breakers with density (leak detection) alarms and a guaranteed loss rate of 0.5 percent by weight or less per year.

Monitoring Requirements

- The owner or operator shall monitor CO_2 mass emissions from the CCCT using an oxygen (O_2) concentration monitor in accordance with CO_2 calculation provisions provided in 40 CFR Part 75.
- The owner or operator shall monitor CO_2 mass emissions from the auxiliary boiler by recording fuel usage and using emission factors presented in air permit application to determine resulting emissions.
- The owner or operator shall implement a density (leak detection) alarm system on the SF_6 circuit breakers with a threshold of 10 percent. In the event of an alarm, the owner or operator will investigate the event and take any necessary corrective action to address any problems.

[24] The limit is proposed as CO_2 which accounts for 99.9 percent of total CO_{2e} emissions.

Appendix A. GHG Emission Calculations

Empire Riverton Power Station

Greenhouse Gas Emissions Estimate

Summary of GHG Mass and CO_2e Emissions

Table A-1

Emission Source	GHG Mass Emissios [1] (tpy)	GHG CO_2e [2] (tpy)
CTG and Duct Burner	1,021,791.3	1,022,755.9
Auxiliary Boiler	9,512.3	9,521.5
Emergency Generator	59.3	59.5
SF_6 Insulated Circuit Breakers	0.00029	6.9
Total Estimated Emissions (tpy):	**1,031,363**	**1,032,344**

Notes [ ]

1. The GHG Mass Emissions are based on the sum of estimated emissions of GHGs from each emission source.
2. The GHG CO_2e emission are based on the sum of GHG CO_2e emissions using Global Warming Potential Factors for each GHG.

Empire Riverton Power Station
Greenhouse Gas Emissions Estimate
Combustion Turbine and Duct Burner
Table A-2

Pollutant	Emission Source	Annual Heat Input [1] (MMBtu/hr)	Emission Factor [2, 3] (lb/MMBtu)	Hours of Operation [4] (Hrs/Yr)	Mass Emissions [5] (tpy)	Global Warming Potential [6]	CO_2e (tpy)
CO_2	CTG	1679.2	118.86	8760	874,181.9	1	874,181.9
	Duct Burner	283.5	118.86	8760	147,588.5	1	147,588.5
CH_4	CTG	1679.2	0.002205	8760	16.21	21	340.5
	Duct Burner	283.5	0.002205	8760	2.74	21	57.5
N_2O	CTG	1679.2	0.0002205	8760	1.62	310	502.7
	Duct Burner	283.5	0.0002205	8760	0.27	310	84.9
				Total Estimated Emissions (tpy):	**1,021,791.3**	--	**1,022,755.9**

Notes [ ]

1. Annual heat input for the CTG and Duct Burner is based on performance data at 100 percent load and ambient temperature of 59°F firing natural gas.
2. Emission factor for CO_2 was calculated from constants for natural gas in Section 2.3 of 40 CFR Part 75, Subpart G as follows:
CO_2 (lb/MMBtu) = 1040 scf/MMBtu x 1 lb-mol/385 scf x 44 lb CO_2/lb-mol = 118.86
3. Emission factors for CH_4 and N_2O were calculated using specified values from Table C-2 of 40 CFR Part 98, Subpart C as follows:
CH_4 (lb/MMBtu) = 0.001 kg CH_4/MMBtu x 2.20462 lb/kg = 0.002205
N_2O (lb/MMBtu) = 0.0001 kg N_2O/MMBtu x 2.20462 lb/kg = 0.0002205
4. This estimate assumes the CT and Duct Burner will operate 8,760 hours per year.
5. The mass emissions for CO_2, CH_4, and N_2O are calculated using the annual heat input, emission factor, and hours of operation as follows:
CO_2 for CTG (tpy) = 1,679.2 MMBtu/hr x 118.86 lb/MMBtu x 8,760 hrs/yr x 1 ton/2000 lb = 874,181.9
CH_4 for Duct Burner (tpy) = 283.5 MMBtu/hr x 0.002205 lb/MMBtu x 8,760 hrs/yr x 1 ton/2000 lb = 2.74
N_2O for CTG (tpy) = 1,679.2 MMBtu/hr x 0.0002205 lb/MMBtu x 8,760 hrs/yr x 1 ton/2000 lb = 1.62
6. The Global Warming Potential factors for CO_2, CH_4, and N_2O are from Table A-1 of 40 CFR Part 98, Subpart A.

Empire Riverton Power Station
Greenhouse Gas Emissions Estimate
Auxiliary Boiler
Table A-3

Pollutant	Emission Source	Annual Heat Input [1] (MMBtu/hr)	Emission Factor [2, 3] (lb/MMBtu)	Hours of Operation [4] (Hrs/Yr)	Mass Emissions [5] (tpy)	Global Warming Potential [6]	CO_2e (tpy)
CO_2	Auxiliary Boiler	18.58	116.89	8760	9,512.2	1	9,512.2
CH_4	Auxiliary Boiler	18.58	0.002205	8760	0.18	21	3.8
N_2O	Auxiliary Boiler	18.58	0.0002205	8760	0.0179	310	5.56
				Total Estimated Emissions (tpy):	**9,512.3**	--	**9,521.5**

Notes [ ]

1. The Auxiliary Boiler annual heat input is based on specifications for the conceptual design.
2. Emission factor for CO_2 was calculated using default CO_2 emissions factors for natural gas fuel from Table C-1 of 40 CFR Part 98, Subpart C as follows:
CO_2 (lb/MMBtu) = 53.02 kg CO_2/MMBtu x 2.20462 lb/kg = 116.89
3. Emission factors for CH_4 and N_2O were calculated using specified values for natural gas fuel from Table C-2 of 40 CFR Part 98, Subpart C as follows:
CH_4 (lb/MMBtu) = 0.001 kg CH_4/MMBtu x 2.20462 lb/kg = 0.002205
N_2O (lb/MMBtu) = 0.0001 kg N_2O/MMBtu x 2.20462 lb/kg = 0.0002205
4. This estimate assumes the auxiliary boiler will operate 8,760 hours per year.
5. The mass emissions for CO_2, CH_4, and N_2O are calculated using the annual heat input, emission factor, and hours of operation as follows:
CO_2 for Aux. Boiler (tpy) = 18.58 MMBtu/hr x 116.89 lb/MMBtu x 8,760 hrs/yr x 1 ton/2000 lb = 9,512.2
CH_4 for Aux. Boiler (tpy) = 18.58 MMBtu/hr x 0.002205 lb/MMBtu x 8,760 hrs/yr x 1 ton/2000 lb = 0.18
N_2O for Aux. Boiler (tpy) = 18.58 MMBtu/hr x 0.0002205 lb/MMBtu x 8,760 hrs/yr x 1 ton/2000 lb = 0.0179
6. The Global Warming Potential factors for CO_2, CH_4, and N_2O are from Table A-1 of 40 CFR Part 98, Subpart A.

Empire Riverton Power Station
Greenhouse Gas Emissions Estimate
Emergency Generator
Table A-4

Pollutant	Emission Source	Annual Heat Input [1] (MMBtu/hr)	Emission Factor [2, 3] (lb/MMBtu)	Hours of Operation [4] (Hrs/Yr)	Mass Emissions [5] (tpy)	Global Warming Potential [6]	CO_2e (tpy)
CO_2	Emergency Generator	7.27	163.05	100	59.3	1	59.3
CH_4	Emergency Generator	7.27	0.006614	100	0.0024	21	0.1
N_2O	Emergency Generator	7.27	0.001323	100	0.0005	310	0.15
				Total Estimated Emissions (tpy):	**59.3**	--	**59.5**

Notes [ ]

1. The annual heat input for the emergency generator is based on fuel consumption data at full standby for a Cummins Inc. Model QST30-G5 NRT 60 Hz Diesel Generator Set and the default high heat value for distillate fuel oil No. 2 displayed in Table C-1 of 40 CFR 98, Subpart C. The heat input is calculatedas follows:
Heat Input (MMBtu/hr) = 52.7 gallons/hour x 0.138 MMBtu/gallon = 7.27
2. Emission factor for CO_2 was calculated using default CO_2 emissions factors from Table C-1 of 40 CFR Part 98, Subpart C as follows:
CO_2 (lb/MMBtu) = 73.96 kg CO_2/MMBtu x 2.20462 lb/kg = 163.05
3. Emission factors for CH_4 and N_2O were calculated using specified values from Table C-2 of 40 CFR Part 98, Subpart C as follows:
CH_4 (lb/MMBtu) = 0.003 kg CH_4/MMBtu x 2.20462 lb/kg = 0.006614
N_2O (lb/MMBtu) = 0.0006 kg N_2O/MMBtu x 2.20462 lb/kg = 0.001323
4. This estimate assumes the auxiliary boiler will operate 100 hours per year.
5. The mass emissions for CO_2, CH_4, and N_2O are calculated using the annual heat input, emission factor, and hours of operation as follows:
CO_2 for Emerg. Gen. (tpy) = 7.27 MMBtu/hr x 163.05 lb/MMBtu x 100 hrs/yr x 1 ton/2000 lb = 59.3
CH_4 for Emerg. Gen. (tpy) = 7.27 MMBtu/hr x 0.006614 lb/MMBtu x 100 hrs/yr x 1 ton/2000 lb = 0.0024
N_20 for Emerg. Gen. (tpy) = 7.27 MMBtu/hr x 0.001323 lb/MMBtu x 100 hrs/yr x 1 ton/2000 lb = 0.0005
6. The Global Warming Potential factors for CO_2, CH_4, and N_2O are from Table A-1 of 40 CFR Part 98, Subpart A.

Empire Riverton Power Station
Greenhouse Gas Emissions Estimate
Electrical Equipment Insulated with SF_6
Table A-5

Pollutant	Emission Source	Count (Breakers)	Mass of SF_6 per Breaker (lb/Breaker)	Annual SF_6 Leak Rate (% by weight)	Mass Emissions [1] (tpy)	Global Warming Potential [2]	CO_2e (tpy)
SF_6	Electrical Breakers	2	58	0.5	0.00029	23,900	6.9
				Total Estimated Emissions (tpy):	**0.00029**	--	**6.9**

Notes [ ]

1. The annual mass emissions of SF_6 from electrical breakers is calculated using the number of breakers, mass of SF_6 per breaker, and annual leak rate as follows:

SF_6 for Electrical Breakers (tpy) = 2 breakers x 58 lb/breaker/year x 0.5% x 1 ton/2,000 lbs = 0.00029

3. The Global Warming Potential factors for SF_6 is from Table A-1 of 40 CFR Part 98, Subpart A.