UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 7
11201 Renner Boulevard
Lenexa, Kansas 66219

NOV 19 2015

Mr. James Hodina
Linn County Public Health Air Quality Division
501 13th Street NW
Cedar Rapids, Iowa 52405

RE: Archer Daniels Midland Company (ADM) Corn Processing – Project 15-214 Prevention of Significant Deterioration (PSD) Permit Comments

Dear Mr. Hodina:

On October 15, 2015, the United States Environmental Protection Agency (EPA) Region 7 received notification of Linn County Public Health Air Quality Division's/Iowa Department of Natural Resources' (IDNR) intent to issue a Prevention of Significant Deterioration (PSD) construction permit to ADM to install a General Electric (GE) Frame 6 combustion turbine generator system at the company's Cedar Rapids cogeneration facility located at 1350 Waconia Ave SW, Cedar Rapids, Iowa. We have completed our review of the draft permit and our comments are enclosed.

We provide the comments to help ensure the project meets the Federal Clean Air Act (CAA) requirements, that the permit will provide necessary information so that the basis for the decision is transparent and readily accessible to the public, and that the record provides adequate support for the permit decision. We appreciate the opportunity to provide what we hope you will find to be constructive comments. Please contact Joseph Schulingkamp at (913) 551-7795 if you have any questions or comments regarding this letter.

Sincerely,

Mark A. Smith, Chief
Air Permitting and Compliance Branch
Air and Waste Management Division

Enclosure

cc: Sarah Piziali
Iowa Department of Natural Resources

EPA Comments on Archer Daniels Midland (ADM) Prevention of Significant Deterioration (PSD) Project 15-214 (Generator #7)

Project Background

ADM owns and operates a corn wet mill, a corn dry mill, and a cogeneration facility in Cedar Rapids, Iowa. At this facility, ADM plans to install a natural gas-fired GE Frame 6 combined-cycle combustion turbine (CCCT) generator system equipped with a heat recovery steam generator (HRSG). The combustion turbine is rated at 38.5 megawatts (MW) of electricity (not including any electricity derived from steam production) and the exhaust from the turbine will be used to produce 210,408 pounds of steam per hour (lbs/hr) through the HRSG; the turbine has a rated firing capacity of 472 million British thermal Units per hour (MMBtu/hr).

Emissions from the turbine will be controlled by the turbine's combustion management system and an add-on catalytic control to reduce Nitrogen Oxides (NO_x), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). In addition, the post combustion controls include a Selective Catalytic Reduction (SCR) system using Ammonia (NH_3) injection to control NO_x emissions and a separate oxidation catalyst system to control CO. After controls, the project's potential emissions increase causes this project to be subject to PSD preconstruction review for PM_{10}, $PM_{2.5}$, and greenhouse gases (GHGs).

Comments

Comment #1: Applicability to New Source Performance Standards, Subpart TTTT

As stated above this turbine is rated at 472 MMBtu/hr, 38.5 MW, and is only allowed to burn natural gas. According to 40 CFR 60.5509 a steam generating unit is subject to this subpart if the unit: (1) Has a base load rating greater than 250 MMBtu/hr of fossil fuel;[1] and (2) Serves a generator or generators capable of selling greater than 25 MW of electricity to a utility power distribution system (hereafter "the grid"). In addition, the proposed unit does not fall under any of the exclusions contained in §60.5509(b).

It is unclear from the available information in the permit, engineering evaluation, or the permit application whether or not the proposed unit is able, or the facility intends, to sell electricity to the grid. Upon review of other construction permits at the facility, there appears to be several emission units that have conditions requiring ADM to "record the net actual electrical output to any power distribution system for sale annually."[2] However, no conditions exist for the units which limit the sale of electricity

[1] As defined in §60.5580, the term "fossil fuel" includes natural gas.

[2] Condition 14.I for Cogen Units #1, 2, and 3, Permit #s 86-A-090P1, 86-A-91P1, and 90-A-083-P1, respectively, all issued December 2011; and Condition 14.J for Cogen Boiler #5, Permit # 98-A-507P-S2 issued August 2006.

to the grid. Additionally, data supplied to the U.S. Energy Information Administration (EIA) shows a range of annual net electrical generation between 602,407 and 991,080 MWh for data supplied from 2001 to 2014, with 941,472 MWh generated in 2014.[3] This EIA data, in combination with the permit conditions at other units, leads EPA to believe that the ADM facility produces more electricity than required and therefore ADM sells this additional electricity to the grid.

Assuming that the proposed unit will, or will be able to, sell electricity to the grid, and no additional permit conditions are added to the draft permit which limit the operating conditions or sale of electricity, this proposed unit may be subject to the requirements of 40 CFR 60, Subpart TTTT – *Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units*.

Comment #2: Applicability to the Transport Rule (TR)

According to 40 CFR 97, subsections 404(a)(1), 504(a)(1), and 604(a)(1), a unit is subject to the respective subpart if the unit is a fossil fuel-fired combustion turbine serving, at any time on or after January 1, 2005, a generator with a nameplate capacity of more than 25 MWe (megawatt, electrical) producing electricity for sale. As previously stated in Comment #1, the proposed unit is rated at 38.5 MW and it is unclear as to whether the unit will, or has the ability to, sell electricity to the grid. In addition, the proposed unit does not fall under any of the exceptions under §97.404(b), 504(b), or 604(b).

Assuming this unit will, or will have the ability to, sell electricity to the grid, and assuming no additional permit conditions are added that limit the operating conditions or sale of electricity, this unit may be subject to the requirements of 40 CFR 97, Subparts AAAAA – *TR NO_x Annual Trading Program*, BBBBB – *TR NO_x Ozone Season Trading Program*, and CCCCC – *TR SO_2 Group 1 Trading Program*.

Comment #3: Assumptions for GHG BACT analysis for fugitive emissions

Upon review of the facility's PSD permit application, EPA questions the assumptions ADM made with regards to the GHG best available control technology (BACT) analysis for fugitive emissions from the combustion turbine's natural gas supply system piping. According to ADM the project will involve installation of 27 connectors, 10 valves (under gas service), and one pressure relief valve, all of which have the potential to leak resulting in fugitive emissions of GHGs in the form of methane (CH_4). ADM correctly states that a leak detection and repair (LDAR) program is a feasible means of reducing fugitive CH_4 emissions from leaking components, but EPA questions ADM's assumptions when determining the costs of implementing a LDAR program on the proposed new unit.

[3] Source: EIA electricity data browser (retrieved November 6, 2015) http://www.eia.gov/electricity/data/browser/#/plant/10864?freq=A&ctype=linechart&ltype=pin&pin=&maptype=0&linechart=ELEC.PLANT.GEN.10864-ALL-ALL.A&columnchart=ELEC.PLANT.GEN.10864-ALL-ALL.A

In determining the costs of implementing a LDAR program, ADM uses background information created by EPA for proposed standards in the synthetic organic chemical manufacturing industry.[4] The assumptions used in this document for implementing a LDAR program were based on chemical manufacturing facilities that contained hundreds of valves, pumps, and connectors and in some cases were based on facilities implementing a new LDAR program after having never implemented a leak detection program.

After reviewing other construction permits issued to the ADM facility, we found there to be several emission units that are subject to 40 CFR 60, Subpart VV – *Standards of Performance for Equipment Leaks of Volatile Organic Compounds in the Synthetic Organic Chemical Manufacturing Industry* as well as 40 CFR 63, Subpart FFFF – *National Emission Standards for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing*.[5] Both the NSPS Subpart VV and NESHAP Subpart FFFF require a LDAR program to be implemented to limit emissions from equipment leaks. Therefore ADM already implements a LDAR program onsite at other process units.

In their BACT analysis for GHG fugitive emissions, ADM assumes that they would implement a new LDAR program instead of expanding their current LDAR program. By assuming a new LDAR program, ADM considers the costs of the following items that would already be accounted for in their current LDAR program (all in 1992 dollars): Capital costs of new monitoring equipment ($1,495); annual cost of maintaining the monitoring equipment ($4,280); annual miscellaneous charges for the monitoring equipment ($260); annual labor charges for LDAR monitoring ($12,940); and annual labor charges for administrative support ($8,124). In addition, the $7,369 that ADM estimated for annual labor charges for subsequent repairs was not adjusted to compensate for the difference in the number of components from the model unit and the proposed turbine. (Assuming the natural gas components have the same leak frequency, repair frequency, and labor cost as the model unit the total annual labor cost for repairs should be $135.) After making these corrections to ADM's cost analysis and adjusting for inflation to 2013 dollars (as ADM did), the total cost per ton of CO_2e (carbon dioxide equivalent) becomes $35 per ton, not $1,207 per ton as ADM calculated.

Although EPA is not commenting on the economic reasonableness of $35/ton of CO_2e removed, the fact that the facility is already subject to, and currently implementing, a LDAR program in other parts of the facility should make it easier to extend the program (rather than implement a new program) to cover the relatively small number of additional valves and connectors associated with this new project.

[4] ADM relied on information published in *Hazardous Air Pollutant Emissions from Process Units in the Synthetic Organic Chemical Manufacturing Industry-Background Information for Proposed Standards - Volume 1C: Model Emission Sources.* Emission Standards Division, U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and standards, Research Triangle Park, North Carolina 27711, November 1992; EPA-453/D-92-016c.

[5] See for example Condition 13 of Permit # 07-A-571-P1, Alcohol Rail Loadout #2 issued December 2012.

Comment #4: SCR operation at "steady state operations"

Condition 14.B reads, "The Selective Catalytic Reduction (CE 545A) shall be operated at all time during steady state operation." IDNR should clarify what is meant by "steady state operation" somewhere in the permit in order to limit the possibility of future confusion as to whether steady state operations were or were not achieved, and thus, whether the use of the SCR was required. Additionally, the emission limits set forth in condition 10c for NO_x, VOC, and CO have lb/hr limits that, "appl[y] during steady state operating conditions."

Comment #5: Recommendation to revise condition for SCR during startup conditions

Condition 14.D(d) reads as follows:

> *"During startup, the Turbine Generator and HRSG emissions shall comply with emission limits in Condition 10, and the SCR system, including ammonia injection, shall be operated in a manner to minimize emissions, as technologically feasible, and not later than when the load reaches 60% of the generator net output."*

EPA suggests dividing the condition into two separate sentences so as to avoid the assumption that the "limits in Condition 10" (all numerical pollution limits) do not apply when operation of the SCR and ammonia injection system is not technologically feasible. By dividing the condition into two distinct sentences IDNR will eliminate the possibility of confusion in the future. For example, the condition could be modified to the following, while still retaining what EPA believes is the intent of the condition (to operate the SCR when technologically feasible, but no later than 60% of net output):

> *"During startup, the Turbine Generator and HRSG emissions shall comply with emission limits in Condition 10. SCR system, including ammonia injection, shall be operated during startup in a manner to minimize emissions, as technologically feasible, and not later than when the load reaches 60% of the generator net output."*