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Cc:	Robinson, Jeffrey
Subject:	Occidental Ingleside Ethylene Plant
Date:	Tuesday, July 16, 2013 5:17:00 PM
Attachments:	Occidental_Ingleside_Ethylene Plant Completeness Comments_071613.docx

Mark,

As we've discussed, I have attached for your review the latest copy of EPA's Completeness Comments. If you have any questions, please call me.

Thank you,

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ENCLOSURE

EPA Completeness Comments
Occidental Chemical Corporation
Application for Greenhouse Gas Prevention of Significant Deterioration Permit
Ingleside Chemical Plant – Ethylene Plant

1. Please supplement the process flow diagram by providing the following information; and if Occidental finds it beneficial or necessary, it is suggested that additional pages be created and provided to EPA to represent the process to avoid overcrowding and confusion.

   A. On page 2 of the permit application, it states that recycle ethane from the Ethylene Fractionator is combined with ethane feed and superheated with water before being sent to the cracking furnaces. Please show this combining of streams on the process flow diagram.
   B. The permit application indicates the use of selective catalytic reduction (SCR) technology for NO_x control. Please indicate this add-on pollution device on all five of the cracking furnaces.
   C. The permit application states that to reduce coke formation in the cracking furnace tubes, a sulfide material is added continuously to the ethane feed. This sulfide chemical is stored in a pressurized tank. Please show this chemical addition in combination with the ethane feed.
   D. The permit application states that the effluent from the cracking furnaces is used to produce high pressure stream in transfer line exchangers (TLEs) before being quenched in the Quench Tower. Please show this heat recovery and list the units that benefit from this high pressure steam production. Can Occidental estimate the amount of reduction of GHG emissions anticipated using this heat recovery instead creating high pressure using a steam combustion turbine?
   E. It is stated in the permit application that the condensed gasoline and dilution steam, along with quench water, are separated in the bottom section of the Quench Tower and the non-condensable gas exits the top of the quench column. It is also stated that the Quench Tower overhead vapor is sent to the first stage of the steam driven-charge gas compressor. Is the "non-condensable gas that exits the top of the Quench Column" the same stream that is referred to as the "Quench Tower overhead vapor"? Are these two different streams? Please explain and if appropriate, revise the process flow diagram to properly show these streams and where the streams are directed.
   F. The permit application states that the charge gas from the dryer feed chiller system overhead is dried in a molecular sieve drying system before entering the De-Ethanizer. Please update the process flow diagram to show the molecular sieve system.
   G. The permit application states that the De-Ethanizer overhead product is chilled and sent to the De-Methanizer. Please supplement the process flow diagram to show the heat exchanger used to chill the overhead product from the De-Ethanizer.
   H. The permit application states that the De-Methanizer bottoms are fed to the Ethylene Fractionator. Is the Ethylene Fractionator represented on the process flow diagram as the C2 Splitter? Are the names used interchangeably? If so, please include Ethylene Fractionator as an alternate name for the C2 Splitter on the process flow diagram. If the Ethylene Fractionator is a different unit, please include on the process flow diagram.
   I. On page 3 of the permit application, a summary of the storage tanks that are proposed for this project is provided. Please include a depiction of these storage tanks on the process flow diagram. Also, include the Wastewater Storage Tank and Steam Stripper.
   J. On page 9 of the permit application, it is stated that fugitive emissions were estimated for six areas of the proposed facilities: CR Furnace Area Fugitives (EPN: CR-13), CR Charge Gas

Area Fugitives (EPN: CR-14), CR Recovery Area Fugitives (EPN: CR-15), CR C3+ Area Fugitives (EPN:CR-16), CR Waste Treatment and C5 Area Fugitives (EPN: CR-17) and CR LPG Storage Area Fugitives (EPN: CR-18). However, since the last two areas do not contain GHG pollutants, they are not included in this GHG application. The current process flow diagram shows all six emission units. Please supplement the process flow diagram to indicate that the emission units EPN: CR-17 and EPN: CR-18 are non-GHG sources.

K. On page 10 of the permit application, it states that the existing cogeneration units are not being modified and their increased fuel firing will not exceed previously authorized levels. However, as affected sources the cogenerations units will enter the scope of the project to supply the new demand for steam and power for the proposed facilities. Please supplement the process flow diagram to show these affected (existing non-modified emission points where emissions will increase) units along with the appropriate EPNs and identify this units as affected.

2. On page 3 of the permit application, it is stated that low pressure discharges of vent gases from the process equipment and storage vessels are collected in dedicated headers and transferred to a thermal oxidizer for disposal. Two thermal oxidizers are designed to destroy and remove organic materials from the collected vent gases with an efficiency of 99.9%. The thermal oxidizer will also be equipped with heat recovery boilers for increased energy efficiency. In Appendix D on page 6 of 18 of the BACT analysis, an estimate of GHG emissions reductions by about 18,200 tons per year as a result of installing waste heat recovery on thermal oxidizers is provided. Please provide supplemental data and calculations that support this statement. Please include the percent energy increase or gain attributed to the addition of heat recovery boilers. Please supplement the process flow diagram to include a representation of the heat recovery from the thermal oxidizers. It is also stated that steam generation from these units is intended to reduce the demand for steam from the existing cogeneration units. If possible, please provide the anticipated reduction in steam demand from the existing cogeneration units. Also include an estimate of the difference in GHG emissions that will be produced by the thermal oxidizer and not produced by the cogeneration units.

   Also stated on page 6 of 18 of the permit application, the capture, compression and sequestration of the carbon dioxide in the thermal oxidizer flue gas would reduce the GHG emissions from the thermal oxidizers by up to 111,700 tons per year, but would require an additional 159 MMBtu per hour of thermal energy to strip the carbon dioxide from the capture solvent. This would require new natural gas fired steam boilers that would create additional GHG emissions. It is estimated that the increased GHG emissions from the new steam generators would be 100,300 tons per year. Please provide calculation and documentation to support these conclusions.

3. Aforementioned in Comment 2, the permit application indicates that low pressure discharges of vent gases from process equipment and storage vessels are collected in a dedicated header and transferred to two thermal oxidizers for disposal. A backup enclosed, low pressure flare system is proposed to provide backup emission control in the unlikely event of thermal oxidizer failure. Is this low pressure flare system a ground or elevated flare? An additional flare system provides a means to collect and burn hydrocarbon process streams that have relieved or been drained to the flare headers. This emergency relief collection and transfer system discharges to a high pressure ground flare. Was a flare gas recovery system considered for the proposed project? Please supplement the BACT analysis to support its elimination. It is suggested that to facilitate the understanding of the control scheme of the two flares, a separate process flow diagram that depicts the flare header along with the vent streams that are directed to the flare header. Please

include the storage tanks discussed on page 3 of the permit application and previously mentioned in Comment 1 (I), if appropriate. Please specify which streams are continuous/routine and intermittent. Also, please ensure that the flare emission data and calculations include the storage tank emissions, if appropriate.

4. On page 5 of the permit application, it is stated that the project proposes the installation of five identical ethylene cracking furnaces expected to fire natural gas and hydrogen-rich fuel gas at a maximum rate of 275 MMBtu/hr. Is this proposed as BACT for the furnaces? What efficiency was used to calculate this heat rate? Were other furnace designs evaluated for this project? If so, please provide comparison data and a basis for the elimination. Please provide supplemental information on the thermal efficiency - best and worst case- for the five furnaces. What will be Occidental's preferred method of monitoring and recordkeeping for the determination of fuel quality? In Appendix D on page 1 of 18 of the BACT analysis, it is stated that waste heat recovery from the furnace flue gas and furnace process effluent gases, thereby offsetting GHG emissions from other process heating sources. Please provide supplemental information that explains how heat recovery is utilized and benefits the operation of the production units and by how much is the offset of GHG emissions from other processes. On page 3 of 18 of the BACT analysis, it is indicated that stack gas temperature will be maintained at less than 400° F. Please provide a technical basis and rationale to support the proposed stack temperature limit. Provide any supporting data and calculations to substantiate operating and design improvements to the proposed technologies compared to the past operation and design, e.g., past energy consumed per ton of product and what will be the difference compared to the new construction, comparative benchmark studies to similar operations. Please include any technical data that supports your conclusions, as well as the associated decrease in GHG per pound of product. If possible, provide a list of process streams that are preheated and/or steam production.

5. In the previous comment, the furnaces will be fired by natural gas and hydrogen-rich fuel gas. Please update the process flow diagram to indicate these streams to the furnaces. The permit application also states on page 5, that this fuel gas is a combination of hydrogen, methane, ethane, and heavier hydrocarbons. Is this the same fuel gas that is discussed on page 2 as being a hydrogen-rich vapor from the De-Methanizer that is processed and the extracted hydrogen is used in the hydrogenation reactors and the balance is used as fuel gas? If so, please supplement the process flow diagram by showing the process that extracts the hydrogen from the De-Methanizer vapor stream and then this product hydrogen stream being fed to the hydrogenation reactors. Also, please update the process flow diagram to show the fuel gas directed to the furnaces. The process flow diagram indicates fuel gas directed to the low and high pressure flares and the thermal oxidizer. Is this the same fuel gas that is used for the furnaces? On page 5 of the permit application, it states that natural gas is supplied to the low and high pressure flares and the thermal oxidizers. Please supplement the process flow diagram to show natural gas directed to these emission control devices and update process description to indicate that the "process generated" fuel gas is used by the emission control devices as well.

6. On page 6 of the permit application, it is stated that due to high furnace tube temperatures during normal operations, coke deposits build up on the furnace tube walls. In order to maintain efficient furnace operation, this coke must be removed periodically using a steam decoking process. The steam decoking process is started by cutting the ethane feed to an operating furnace while leaving steam flowing through the furnace tubes, and maintaining fire box heat input at a reduced rated. The furnace discharge continues to feed forward to the quench tower until the ethane is purged from the furnace tubes. Once the furnace tubes are cleared of ethane, the

furnace discharge is diverted from the quench tower to the furnace fire box. In Appendix D on page 5 of 18 the BACT analysis states that the use of a proper furnace coil design for ethane together with the use of anti-coking agents in the furnace feed to maximize the furnace run time between decokes is commonly practiced and considered BACT for this application.

A. A total of 36 decoking events are expected per year. What is the anticipated decoking schedule for the five furnaces? How many decoking events does this represent per furnace? Please provide the anticipated run time of the furnaces – best and worst case. Will there be simultaneous decoking events with the five furnaces? How do 36 decoke events compare to similar sources? What percentage of coke reduction in the tubes due to the sulfide addition will occur in lbs coke/lbs of product processed? Please include technical data that supports your conclusions, as well as the potential associated decrease in GHG per pound of product anticipated due to the sulfide addition.
B. Typically, during the oxidation and spalling of coke removal, ethylene furnaces employ the use of a decoking drum to allow the disengaging of coke fines in the effluent during these decoking events. Will Occidental use a decoking drum to decoke the five ethylene furnaces? If so, please indicate this additional equipment and piping connections to the furnaces on the process flow diagram.

7. On page 8 of the permit application, it is stated that the Hydrogenation Reactors will be used to convert olefinic C3 and C4 compounds. How many Hydrogenation Reactors are proposed for this project? Only one emission point (EPN: CR-12-MSS) has been identified on the process flow diagram and the emissions summary table. If there is more than one Hydrogenation Reactor, do they all vent through a common stack? The permit application also states that periodic regeneration of these reactors is required to remove coke and residual hydrocarbon deposits from the catalyst. This regeneration process is started by shutting off the process flow to the reactor and routing the reactor discharge to the Quench Tower. Steam is used to sweep hydrocarbons form the reactor into the quench column for recovery of these materials. After the steam sweep is completed, the reactor discharge is routed to an atmospheric vent. High pressure steam and air are used to burn the remaining coke and residual hydrocarbons from the reactor catalyst.

A. What is the regeneration schedule for the reactors? How often is this done? Is a decoking drum utilized to allow coke fines to disengage from the Hydrogenation Reactor effluent during the regeneration process? If so, please indicate this equipment on the process flow diagram. Is it possible to recover thermal energy from this reactor effluent during regeneration?
B. In Appendix D on page 16 of 18 of the BACT analysis, it is stated that a proper reactor design with good operating practices will minimize coke formation and is considered BACT for this application. The reactor will be loaded with hydrogenation catalyst per catalyst supplier recommendations. Reactor temperatures, pressures and hydrogen concentrations will be maintained within recommended levels. Being mindful of EPA's PSD and Title V Permitting Guidance for GHG dated March, 2011 on page 17, which states if the permitting authority determines that technical or economic limitations on the application of a measurement methodology would make a numerical emissions standard infeasible for one or more pollutants, it may establish design, equipment, work practices or operational standards to satisfy the BACT requirement. Please provide supplemental data to the BACT analysis that details the work practices and operational standards that Occidental proposes to put into place for the Hydrogenation Reactor catalyst regeneration. Please provide supplemental data

that details Occidental's proposed monitoring methodology for the maintenance and operational standards to be used to minimize coke formation?

8. In Appendix D beginning on page 2 of 18 of the BACT analysis, it states that the use of waste heat recovery can reduce the GHG production from both the furnace and the cogeneration unit by reducing the furnace firing rate and steam demand for the ethylene unit. It is estimated that GHG emissions from the cracking furnaces will be reduced by 43,000 tons per year GHG emissions from the cogeneration facility will be reduced by about 316,000 tons per year as a result of installing waste heat recovery on the cracking furnaces. Also, it is estimated that the GHG emissions from the cracking furnaces is reduced by about 260 tons per year using the hydrogen rich vent gas from the ethylene recovery section. Please provide calculation and documentation to support these conclusions since EPA may rely upon this data in making its BACT determination.

   Also stated on page 2 of 18 of the BACT analysis, the capture, compression and sequestration of the carbon dioxide in the cracking furnace fuel gas would reduce the GHG emissions from the cracking furnaces by up to 312,000 tons per year, but would require an additional 445 MMBtu per hour of thermal energy to strip the carbon dioxide from the capture solvent. This would require new natural gas fired steam boilers that would create additional GHG emissions. It is estimated that the increased GHG emissions from the new steam generators would be 280,000 tons per year. Please provide calculation and documentation to support these conclusions.

9. Please provide the details to the good operating and maintenance practices which includes visual monitoring of flame patterns and periodic cleaning of burner and feed nuzzles to assure complete combustion and efficiency. Please provide details concerning the preventive maintenance on burners, frequency and recordkeeping. How often will burners be inspected? How will this be ensured? What recordkeeping requirements are you proposing? What will alert on-site personnel to problems? What will be the frequency, recordkeeping and action taken to resolve irregular flame patterns? What is the proposed compliance monitoring methodology for the maintenance and operating practices?

10. In Appendix D beginning on page 1 of 18, cost estimates were provided throughout the BACT analysis for the Carbon Capture and Storage (CCS) for the proposed combustion units (i.e., furnaces, thermal oxidizer, low and high pressure flares). Please supplement the application with your calculations to support these cost estimates. Please provide site-specific facility data to evaluate and eliminate CCS from consideration. This material should contain detailed information on the quantity and concentration of CO_2 that is in the waste stream and the equipment for capture, storage and transportation. Please include cost of construction, operation and maintenance, cost per pound of CO_2 removed by the technologies evaluated and include the feasibility and cost analysis for storage or transportation for these options. Please discuss in detail any site specific safety or environmental impacts associated with such a removal system.