The Dow Chemical Company
2301 N. Brazosport Blvd.
Freeport, Texas 77541
USA

July 9, 2013

Certified Mail 7012 1010 0003 4047 3562

Return Receipt Requested

EPA Region 6 Main Office
Air Permits Section, 6PD-R
1445 Ross Ave., Suite 1200
Dallas, TX 75202-2733
Attn: Brad Toups

Re: Response to June 20, 2013 Completeness Determination Letter
Dow Chemical – Texas Operations
Light Hydrocarbon 9 GHG Permit Application

Dear Mr. Toups,

Enclosed please find the response to the Application Completeness Determination letter pertaining to the Light Hydrocarbon 9 GHG permit application. The letter is dated June 20, 2013 with a requested response date of July 10, 2013. The USEPA items/questions from the request are included in the attached enclosure – with Dow's response in italicized font.

Should you have any further questions concerning this permit application, or the information provided in this response, please contact me at (979) 238-5832 or via e-mail at clsteves@dow.com.

Respectfully,

Cheryl Steves

Cheryl Steves
Environmental Manager
The Dow Chemical Company

Enclosure/cls

cc: Cindy Rodriguez
Mary Schwartz

1. Upstream/Downstream effects and other PSD triggers. You indicate in section 1.5 of the November 28, 2012 application (App) that "No modifications are necessary to these units [existing cogeneration units] as they are currently sized to provide adequate energy to meet current and future site needs."

   Please show by calculation what if any effect on emissions increases will occur as the cogeneration units are effectively "debottlenecked" by the addition of this new process. Include the emissions from these units in the plantwide PSD analysis of emissions increases and decreases, as applicable, recognizing that an emission unit whose emissions increase over the baseline due to a project may not trigger a best available control technology (BACT) review for unmodified sources which experience an emissions increase. In your analysis of the contemporaneous period sitewide increases and decreases, have any of the listed values already been utilized in PSD subject projects at the site? If so, please remove the increases and decreases from your list for those changes that have been relied upon in previous PSD analyses and revise your analysis.

   Energy is provided to the Oyster Creek site from a 3rd party facility. Current site demands exceed the capacity therefore power is imported from the grid. The increased increment needed for Light Hydrocarbon 9 will be sourced from existing tie-lines. None of the increases or decreases shown in the sitewide contemporaneous netting analysis have been relied upon for any other PSD permitting for greenhouse gas emissions.

2. Since the project proposes the construction of an entirely new process at the existing site, will Dow utilize any electrical components containing sulfur hexafluoride (SF6)? If so, please include those units, and provide the supporting analysis, including emissions limitations, BACT, work practice standards, monitoring, testing, and recordkeeping as required to support the authorization of those sources as well.

   The projects will not utilize any electrical components that contain SF_6. The project will install Air Insulated Circuit Breakers, Vacuum Circuit Breakers and Oil Filled Power Transformers.

3. Decoking process. App page 7. What are the parameters that will be monitored to trigger decoking? How will these parameters be monitored and used to assure maximum energy efficiency and in process control?

   The furnace operation will include on-line monitoring of coil inlet pressures and routine monitoring of tube-metal temperatures with pyrometers to monitor coil coking. These parameters are utilized to determine when to decoke each furnace. These parameters will trigger a furnace decoke before any significant decrease in thermal efficiency occurs.

4. Caustic wash. App page 8. You indicate that the caustic wash is to remove CO2 and sulfur compounds, but I do not see any of the process streams that contain sulfur compounds. Also, from which emission point are the CO2 emissions, if any? Please clarify.

   Dimethyl Disulfide (DMDS) is added to the furnace feed in ppm levels where it is converted to H_2S which then passivates the nickel in the furnace coils to reduce coke formation. The CO_2 is either *present in the ethane feedstock and/or produced in the furnace coils (conversion of small amounts of hydrocarbon plus steam into CO and CO_2). Both the H_2S and CO_2 are then removed from the process gas stream in the caustic tower. The sulfur leaves the process as Na_2S (sodium sulfide) in the spent caustic stream and is oxidized to sodium sulfate (Na_2SO_4) in subsequent treatment steps. The CO_2 leaves the process as sodium carbonate and sodium bicarbonate in the spent caustic stream and requires no further treatment. The sulfur species and CO_2 never leave the process as airborne emissions.*

5. Dryers. App page .8. What is the heat source for the dryers?

   The heat source for dryer regeneration is high pressure steam. This steam is included in the net steam balances and emissions represented in the permit.

6. Cracking Furnaces. App page 13.

   Does the differential firing rate of the three furnaces (EPN OC2H126, 127, and 128) and emissions compared to furnaces 121-125 (App page A-S) warrant a different GHG efficiency value for these two groups of furnaces? Why or why not? How will Dow tune the furnace firing variations between fuels to assure that the target GHG efficiency value is reached for each furnace and each operating scenario? Which parameters will Dow monitor and how will Dow utilize various process parameters to minimize the number of decoking cycles, startups and shutdowns, and other operating scenarios that reduce furnace efficiency or cause offspec product to be routed to the flare?

   The one group of furnaces (H-121 to H-125) will be operated on light feedstock all of the time. The other group of furnaces (H-126 to H-128) will be operated on either light feedstock or heavier feedstock or some combination thereof depending on economic factors. While the firing rate on the heavier feedstock will be slightly higher than the light feedstock, the furnace efficiency remains virtually unchanged (anticipate less than 0.25% difference on overall thermal efficiency). This would not warrant a separate GHG efficiency value. The furnace operation will have on-line control of process temperatures and excess air in the flue gas to control the furnace operation over the range of offgas to natural gas fuel blends that the furnaces will see.

   Dow will have on-line control of furnace feed rates, dilution steam flow, process temperatures, firing rates, excess air, and dimethyl-disulfide addition (see Item 4 above) to optimize furnace operation, which includes production, run-length (coking rates), and thermal efficiency. Decoke operation does not cause any off-spec material that needs to be routed to flare. The timing and frequency of planned startups and shutdowns is maximized to lessen the business impact of a production interruption. Timing is generally on the order of several years.

7. Flares. App section 3.2. You indicate that Dow will use the emissions methods referenced in 40 CFR §98.243(d) to calculate emissions from the flare's pilot fuel and fuel from the process streams routed to the flare. Will you actually use 40 CFR §98.253(b)(I)-(3) which the previous reference cites?

   Yes – emissions of GHG from the flare will be calculated in accordance with 40 CFR §98.253(b)(1) – (3) as referenced by 40 CF4 §98.243(d).

Also, what are the expected emissions from de-inventorying any furnace off-spec cracked materials or any other downstream material when the process is taken off-line or when starting up again after a planned or unplanned outage? Where are those emissions accounted for? What is the expected time duration of such an event, and how many such events are planned, given that any given furnace is expected to go 50 days between de-coking cycles? Do these events warrant their own efficiency values or BACT limitations? Why or why not?

Emissions associated with start-ups and shutdowns will be accounted for in MSS emissions. Flaring associated with start-ups is typically no more than 24 hours. There may be unplanned start-up and shutdown events that occur in between the planned turnarounds due to plant upsets or mechanical issues. Upset emissions are not included in the permit calculations as upsets cannot be permitted. MSS emissions are still being finalized, and will be incorporated into the emission calculations soon. Updates to the permit emissions will be submitted at that time.

There are no flare emissions associated with routine decoke operations. The flaring of furnace effluent would be related with planned or unplanned outages of the separations section of the plant and not furnace decokes. Emissions from startup, shutdown, and maintenance (MSS) activities are not representative of normal operations, they are of relatively short duration, and do not occur frequently. These emission sources should not be held to the same efficiency standards during periods of MSS as the process is not operating in an optimal, steady-state.

8. Equipment leak fugitive emissions. Will the 28 VHP LDAR program include proper calibration for quantifying methane emission leaks in addition to non methane volatile organic carbon compounds? Will you be using correlation equations to estimate emissions based on the instrumental readings obtained in your LDAR program? How will you determine, document, and quality assure the determined emissions from this source?

   All LDAR monitoring follows the calibration requirements specified in Method 21 to assure the instrument is able to respond to the chemical being measured. Since the primary reference gas mixture for Method 21 calibration uses methane in air balance, measurement of equipment in methane service would provide the most accurate measurement of any VOC measured. Additionally, the instrument is calibrated per Method 21 to assure capability of measurement of any non – methane VOC that meets the Method 21 requirement of having a response factor of <10. The use of correlation equations is consistent with our normal process. The instrument monitoring data (results) are logged at the time a component is monitored using a hand-held data logger and downloaded to the LDAR database daily. Annual emissions will be calculated based upon the monitoring information and correlation analysis for the fugitive components as monitored during the calendar year. The data is quality assured during an annual review process that includes a review by plant staff.

9. Overall process efficiency. App section 4.1.4.3. Since maximizing the use of thermal energy released in the furnace is important to minimization of GHG emissions and overall process efficiency, do you plan to monitor stack exit temperature as well as temperatures of the flue gas after each stage of heat transfer? With exit temperatures of 271^{o} F for 5 furnaces and 308^{o} F for three (App page A-

5), will flue gas condensation in the stack pose maintenance problems that would result in increased down time?

The furnaces include on-line monitoring of flue gas temperatures between each stage of heat recovery. These temperatures are used to monitor the performance of each heat recovery zone and for trouble-shooting purposes if the overall furnace efficiency is less than design.

The stack temperatures used in the design of the heaters do take into account acid gas condensation temperatures. Condensation will not occur at the normal operating temperatures so no degradation of performance is expected due to acid gas corrosion.

10. Applicability. App page 1. Is the site an existing major source for a regulated NSR pollutant that is not GHGs? While your application cites an approximate 745 tpy increase in CO, your applicability discussion only refers to the test for "Step 2" modifications. Please specify whether and how your basis of applicability falls under 40 CFR 52.21(b)(49)(iv).

    The Freeport site is an existing major stationary source for non-GHG NSR pollutants. Additionally, the site has a PTE exceeding 75,000 tons/year CO_2e and 100/250 tons/year of GHGs on a mass basis. The planned facility is considered to be a modification of a major source, and will have GHG emissions increases exceeding the 75,000 ton CO_2e trigger. PSD review is required for the GHG pollutant category because the project will result in an emissions increase of GHGs for the site in excess of the thresholds described in 40 CFR 52.21(b)(49)(iv)(b).