Comments on Working Draft PSD GHG Permit & Statement of Basis

Received from Region 6 EPA July 2, 2013
DCP Midstream, LP
Jefferson County NGL Fractionation Plant

INTRODUCTION

DCP Midstream, LP ("DCP") submitted a Greenhouse Gas ("GHG") Prevention of Significant Deterioration ("PSD") permit application to construct the Jefferson County NGL Fractionation Plant to the United States Environmental Protection Agency ("USEPA") Region 6 on July 9, 2102. DCP received a letter from the USEPA Region 6 on November 14, 2012 determining that the GHG PSD permit application is incomplete and requesting additional information. DCP submitted a response to the incomplete letter and a revised GHG PSD permit application on March 1, 2013 for the construction of a two natural gas liquids (NGL) fractionation train facility.

On July 2, 2013, DCP received from the EPA a draft GHG PSD permit and Statement of Basis (SOB). This document has been prepared for submitting DCP's comments on these two (2) documents. Each document is identified in the heading. Beneath each heading is the section to which the comments pertain and the comments are either enumerated or the Special Permit Condition identified. Detail of the location in the document has been provided to allow the location in the document to which the comment pertains.

Since DCP has identified several inconsistencies, DCP would also propose to be allowed to review the final drafts of each of the documents. To facilitate the communication of DCP's comments, DCP has also included each of the documents with DCP's comments indicated using the "Track Changes" functionality. This is included only with the electronic submittal of DCP's comments and is meant only for convenience.

GHG Statement of Basis (SOB)

I. Executive Summary

The SOB identifies the deisobutanizer (DIB) as a unit. DCP respectfully suggests that the deisobutanizer is a column in the train and does not operate independently. In addition, the DIB column separate isobutane and normal butane from the mixed butane stream. Please revise the description from a DIB *"unit"* to a DIB *"column"* and revise isobut<u>ene</u> to isobut<u>ane</u>.

II. Applicant

1. The Applicant is identified as:

   DCP Midstream, LP
   662 S. Shelby
   Carthage, TX 75633

   DCP respectfully requests that the *"Applicant"* address be revised to the following in order to designate the corporate headquarters rather than a field office:

   DCP Midstream, LP
   370 17th Street, Suite 2500
   Denver, CO 80202

2. Facility Physical Address is identified as Hillebrandt Road with a comment that the facility will be located on Hillebrandt Road approximately 3.2 miles North of Steinhagen Road (Humble Camp Road) Intersection, or 2.8 miles West and Sourth of the intersection of Hillebrandt Road and W Port Arthur Rd (TX-93 Spur). DCP concurs that at this time, an actual street address is not available. The site designated for construction is as described in the comment by Ms. Wilson.

3. Contact is identified as Lynn C. Ward, Senior Environmental, Enterprise Products Operating LLC (281) 381-5437. The contact information is incorrect. Lynn C. Ward recently changed her name to Lynn C. Holt. Lynn C. Holt is employed by the Applicant, DCP Midstream, LP and the phone number is (903) 694-4114. DCP requests the correction of the contact name, company, and telephone number.

III. Permitting Authority

DCP has no comments on this section.

IV. Facility Location

DCP has no comments on this section.

V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

In the first paragraph of this section, DCP requests that EPA replace *"DCP calculates CO_2e emissions of xxx tpy"* with *"DCP calculates CO_2e emissions of 210,693 tpy"* to match the estimated CO_2e emissions in Table 1.

VI. Project Description

1. Isobutene is identified as one of the products in the first sentence. Please revise isobutene to isobutane.

2. The Project Description states *"designed with a nominal capacity of 75,000 barrels per day (bpd) per plant"*. DCP agrees the design is for a nominal capacity of 75,000 bpd however the design can accommodate higher throughputs dependent on the composition of the NGL entering the facility and as explained in the GHG PSD permit application. DCP would like the EPA to include an understanding of higher throughputs dependent on composition of the feedstock. DCP proposes including the following as the next to last sentence in the first paragraph: *"The facility throughput may exceed 75,000 bpd and is dependent on the inlet NGL composition without exceeding the CO_2e emissions estimated in the GHG PSD permit application."*

3. The Project Description describes the flare as an *"emergency"* flare. The flare is not limited to emergency operation. As described in the GHG PSD permit application, the flare will also receive streams from routine activities as well as maintenance, startup, and shutdown activities. Please remove the term *"emergency"* from the description as it implies a limitation to the flare activation only during emergency events.

4. In the seventh sentence of the Process Description, please insert the word "*emergency*" in front of the firewater pump engine. The firewater pump engine is designated for emergency use only and is thus applicable to the unit.

5. The second paragraph of the Project Description defines a minimum temperature in the combustion chamber for the TO. DCP has proposed a minimum temperature based on an initial compliance test. DCP proposes the sentence be revised as follows and also include a second sentence to specific performance testing to determine the minimum temperature: The TO will be designed to combust low-VOC concentration gas and will have a fuel rating of 5 MMBtu/hr which will keep the temperature in the combustion chamber at or above the temperature required to maintain a 99.9% destruction efficiency. The combustion chamber temperature required to maintain a 99.9% destruction efficiency will be based on performance testing as outlined in the permit.

6. The third paragraph of the Project Description states that natural gas is used to regenerate the sieve beds. This is not the case. Rather, dehydrated NGL is vaporized to regenerate the sieve beds. DCP proposes to revise this paragraph as follows:

> *From the Amine Unit, the NGL will be routed through a Molecular Sieve dehydration unit, where the water content of the NGL will be reduced. A regeneration heater will vaporize a small slip stream of the NGL downstream of the mole sieve dehydrators to a gas which is routed back through the mole sieve beds to regenerate the beds. The wet gas will then be condensed to wet NGL and routed back into the system inlet. There are two sieve beds in the molecular sieve design, and one bed will be regenerated at a time. The Molecular Sieve unit will not have vents to the atmosphere. The only GHG emissions from the Molecular Sieve will be fugitive piping equipment leaks. From the Molecular Sieve dehydration unit, the NGL will be fed to a series of trayed columns (deethanizer, depropanizer, debutanizer, and deisobutanizer) for separation into constituent product gases. No GHG emissions will be generated from the product columns, because the processes will be closed system and most, if not all,* CO_2 *is removed at the Amine Unit. Additionally, very little, if any, methane is contained in the NGL that will enter the plant.*

<u>VII. General Format of the BACT Analysis</u>

DCP has no comments on this section.

VIII. Applicable Emission Units and BACT Discussion

1. DCP respectfully requests that the fifth bullet point for the Firewater Pump Engine be revised to Emergency Firewater Pump Engine. This source has been designated as emergency use with emission estimates based on 100 hours/year of operation for readiness testing.

IX. Plant-wide GHG Controls

DCP has no comments on this section.

X. Hot Oil Heaters (EPNs: HOH1 and HOH2)

1. In Step 3, second sentence of the paragraph, the SOB discusses hydrogen as a primary fuel and CO2 emissions from a cracking furnace. DCP did not include an evaluation of hydrogen as a primary fuel and believes these references are left over fragments from another applicant. DCP does agree that hydrogen is not produced from the process however it was not considered an alternative technology in the BACT analysis. DCP respectfully requests removal of the references to hydrogen as a fuel and the cracker furnace.

2. Under the BACT Limits and Compliance, the thermal efficiency for the hot oil heaters is to be calculated for each operating hour. Section III.A.1.r and A.1.s of the GHG PSD Draft Permit, the frequency is identified as monthly. DCP requests that the SOB and GHG PSD Draft Permit be revised to be consistent and suggests that the thermal efficiency be calculated hourly, reduced to a monthly average, and maintain a minimum overall thermal efficiency of 85% on a 12-month rolling average basis.

XI. Regeneration Heaters (HTR1 and HTR2)

1. Under the BACT practices proposed for the regeneration heaters, last sentence of the first bullet, DCP notes the inclusion of a demonstration of thermal efficiency on a 12-month rolling average basis. The regeneration heaters operate cyclically and the parameters required to make this demonstration are not recorded at a frequency to allow a calculation

of the thermal efficiency on a 12-month rolling average basis nor has DCP proposed this monitoring. Further this monitoring would not be conclusive due to the significant time periods of stand-by in the operation. DCP requests removing the language *"on a 12-month rolling average basis"* and has proposed an annual demonstration based on the collection of the parameters semiannually during portable analyzer stack testing which has been specified in the draft GHG PSD Permit as condition III.A.2.l.

2. Under the BACT Limits and Compliance, the regeneration heaters are to be continuously monitored for exhaust temperature, fuel temperature, ambient temperature, and excess oxygen with thermal efficiency calculated for each operating hour using the monitored parameters. DCP respectfully contends that *"continuous"* monitoring was not proposed for exhaust temperature, fuel temperature, ambient temperature, and excess oxygen in order to calculate an hourly efficiency. DCP proposed a semiannual monitoring of the stack oxygen and EPA has included the semiannual monitoring in Special Permit Condition III.A.2.l. In addition, the operation of the regeneration heaters is intermittent and not continuous which would also impair *"continuous"* monitoring. DCP respectfully proposes to monitor each of the four parameters semiannually, calculate the thermal efficiency on a semiannual basis, and calculate a rolling annual average thermal efficiency using the two most recent semiannual tests.

<u>XII. Thermal Oxidizers (EPNs: TO1 and TO2)</u>

1. DCP notes that in Step 5, Selection of BACT, second set of bullet points, second bullet states the minimum temperature shall never be less than 1,500 °F during normal operation. DCP respectfully proposed in the GHG PSD permit application that the minimum temperature would be determined by an initial performance test and requests the removal of the default minimum temperature designation. As an alternative, DCP proposes a specification of 1,500 °F <u>until completion of the initial performance test</u> to determine the minimum temperature required to maintain a 99.9% DRE.

2. DCP requests that the annual performance test in the second and third bullets be revised to every three (3) years consistent with the GHG PSD Permit Section V.N of the Initial Performance Testing Requirements (pg. 17).

3. The last paragraph of this section states: *"The annual emission limit includes MSS emissions."* However, no MSS emissions are proposed to be directed to the thermal oxidizers; therefore, DCP requests that this sentence be removed.

XIII. Analyzer Sample Purge Gas/Trace Erase System (EPNs: TE1 and TE2)

1. The Trace Erase System controls the plant analyzers purge gas stream. Please revise the first sentence in Step 5 to say *"analyzer"* Trace Erase system instead of the Trace Erase System Analyzers.

2. Second paragraph, last bullet states *"Limit waste gas volume sent to the analyzers to 5,520 scf per year..."* The TE system is not an analyzer. Please revise this sentence to say *"sent to each of the TE systems"*. In addition, the bullet suggests the total volume to both TE systems is limited to 5,520 scf per year. The emission calculations were based on a 5,520 scf sent to **each** TE. Please revise to remove the word *"combined"* so as to eliminate confusion.

XIV. Flare (EPN: FLR1)

1. The table following the first paragraph of this section identifies only nine maintenance activities that may be routed to the flare on an annual basis. However, the MSS emissions estimates for the flare in the GHG PSD permit application include a larger number of MSS activities. DCP requests that this table be removed and the last sentence of the paragraph be changed to the following:

   "The maintenance activities that may be routed to the flare, along with the material flared, and frequency, are identified in Attachment B of the revised GHG PSD permit application submitted on February 27, 2013."

2. Step 5, Selection of BACT, second bullet point, *"Proper Operation of the Flare"*, states in the last sentence that the flow rate and gas composition analyzer shall "continuously *record*" the molecular weight and mass flow rate of the flare gas. DCP suggests that "continuously record" is not an accurate description and proposes that *"continuous sampling"* is more appropriate. For an inline technology, the sample is drawn from a continuous sample stream and analyzed. The analyzer requires a specific duration to perform the analysis before a record is created. Therefore, while the analyzer continuously samples, it does not have the capability for continuously recording. Please revise the sentence to say *"The flow rate and gas composition analyzer shall continuously sample and record the molecular weight and mass flow rate of the flare gas consistent with the stream analyzer frequency."*

3. Step 5, Selection of BACT, second paragraph, third bullet point; please correct misspelling of *"or."*

4. In the last section of Step 5, DCP notes that the equation identified for calculating CO_2 emissions specifically references 40 CFR 98 Subpart Y while the preceding sentence specifies Subpart C. DCP contends these references should be the same and reference Subpart W.

<u>XV. Firewater Pump Engine (EPN: ENG1) and Emergency Generator Engine (EPN: ENG2)</u>

1. First paragraph, first sentence, describes the firewater pump engine as a "booster" pump engine. The firewater pump engine is not a *"booster"* pump engine. It is the only firewater pump engine. Please remove *"booster"* from the description of the firewater pump engine.

2. Continuing in paragraph one, the firewater pump is referred to as a *"booster"* pump in the 5^{th}, 6^{th}, and 7^{th} sentences. Please remove the word *"booster"* from all references.

3. The firewater pump engine drives the firewater pump in the event of an emergency for the discharge of firewater. DCP requests the description of the firewater pump engine

include the term *"emergency"* since the unit will operate only during emergency with the exception of maintenance and readiness testing.

4. The emergency firewater pump and engine will comprise a new firewater system. The entire system will be new and not "added". DCP respectfully requests that the 5th sentence be revised to say *"The emergency firewater pump engine will supply power to a firewater pump and will comprise a new firewater system."*

5. Emission estimation methods assume that Tier 3 calculation method in 40 CFR 98.33 that requires fuel sampling will be used to determine CO2, CH4, and N2O emissions from the emergency firewater pump and emergency generator engines. However, fuel sampling of diesel fuel is not normally conducted for diesel fuel used in emergency engines. In addition, 40 CFR 98.33(b)(1)(i) provides that the Tier 1 calculation method is allowed for any fuel listed in Table C-1 that is combusted in a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less. The maximum rates heat input capacity of each engine is less than 250 MMBtu/hr; therefore, DCP requests that the calculation methodology be revised to the Tier 1 calculation methodology. DCP proposes to change the calculation methodology to the following:

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)

Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be obtained from company records.

HHV = Default high heat value of Distillate Fuel Oil No. 2 from Table C-1 to Subpart C of Part 98.

EF = Default CO2 emission factor for Distilalte Fuel Oil No. 2 from Table C-1 to Subpart C of Part 98.

1.102311 = Conversion of metric tons to short tons.

XVI. Process Fugitives (EPNs: FUG1 and FUG2)

DCP does not have any comments on this section.

XVII. Threatened and Endangered Species

DCP does not have any comments on this section.

XVIII. National Historic Preservation Act (NHPA)

DCP does not have any comments on this section.

XIX. Environmental Justice (EJ)

DCP does not have any comments on this section.

XX. Conclusion and Proposed Action

DCP does not have any comments on this section.

Appendix – Annual Facility Emission Limits, Table 1.

1. Facility Emission Limits, contains a typographical error for FLR1. The TPY CO_2e is listed as 9,437 tpy. DCP contends the total should be 9,447 tpy. Please revise Table 1 of the Appendix as indicated.

2. BACT Requirement for TO1 and TO2 includes the reference to 1,500 ^oF. DCP proposes the language be revised to temperature *"based on performance testing"*. The reference would be *permit condition III.A.3.b and condition V.N.*

GHG PSD DRAFT PERMIT

<u>Permit Cover Letter</u>

DCP respectfully requests that the "Permittee" address be revised to the following:

DCP Midstream, LP

370 17th Street, Suite 2500

Denver, CO 80202

Facility Location is identified as Hildebrand Road with a notation requesting a street address for the property. The road is Hillebrandt Road. Please correct the road name. In addition, at this time and since the facility is not constructed, an actual street address is not available. The site designated for construction is located approximately 3.2 miles North of Steinhagen Road (Humble Camp Road) Intersection, or 2.8 miles West and South of the intersection of Hillebrandt Road and W Port Arthur Rd (TX-93 Spur) as described in the SOB.

First paragraph, last sentence states "The Permit applies to the addition of a two new natural gas liquids (NGL) fractionation trains each with a deisobutanizer (DIB) unit located in Beaumont, Texas." DCP requests this description be revised, replacing the word "addition" with "construction" since the proposed project is for new construction and to include identification of purity products ethane, propane, normal butane, isobutane, and natural gasoline. DCP respectfully suggests the following: *"The Permit applies to the construction of two new natural gas liquids (NGL) fractionation trains to separate a NGL feed into separate ethane, propane, butane, isobutane, and natural gasoline fractions. Each train will include a deisobutanizer (DIB) column to separate isobutane and normal butane from a mixed butane stream. The facility will be located in Beaumont, Texas."* DCP believes the expanded purity product identification is more appropriate for the fractionation process and consistent with the SOB discussion above.

Second paragraph begins with a similar sentence to the above, referring only to the deisobutanizer *"unit"*. DCP also requests replacing *"unit"* with *"column"* since the DIB is a single column and part of each train and does not operate independently of the train.

Project Description

First sentence in the Project Description identifies the deisobutanizer (DIB) unit only as the project and suggests that the two NGL fractionation trains are an *"addition"* to an existing facility. The project is the construction of a *"new"* facility called the Jefferson County NGL Fractionation Plant which will fractionate NGL into purity products ethane, propane, normal butane, isobutane, and natural gasoline. DCP respectfully requests the first sentence be revised as articulated above in *italics*. DCP would also like to clarify that the debutanizer column separates isobutane and normal butane. Please revise isobut<u>ene</u> to isobut<u>ane</u>.

The fourth sentence of the Project Description states "designed with a nominal capacity of 75,000 barrels per day (bpd) per plant". DCP agrees the design is for a nominal capacity of 75,000 bpd however the design can accommodate higher throughputs dependent on the composition of the NGL entering the facility. DCP proposes adding the following sentence to the paragraph, immediately after the sentence ending with "flare": *"The facility throughput may exceed 75,000 bpd and is dependent on the inlet NGL composition without exceeding the CO_2e emissions estimated in the GHG PSD permit application."*

Fourth sentence of the Project Description describes the flare as an "emergency" flare. DCP respectfully contends the flare is not limited to emergency operation. As described in the GHG PSD permit application, the flare will also receive streams from routine sources, maintenance, startup, and shutdown activities. Please remove the term *"emergency"* from the description in the sentence.

Equipment List

The Equipment List includes ENG1 and ENG2. ENG1 is described as a Firewater Pump Engine. The Firewater Pump Engine is an emergency engine only similar to the Emergency Generator Engine. DCP requests the description for the Firewater Pump Engine be revised to Emergency Firewater Pump Engine to clarify the service.

II. Annual Emission Limits

Table 1 provides the annual emission limits for GHGs for each source and the total sitewide GHG emissions for informational purposes. DCP notes that the GHG PSD application total for TPY CO_2e is 9,447.29 tpy. Please revise the highlighted cell to reflect 9,447 tpy as reflected in the Flare detail (pg 146 of 310 of the PDF application).

FLR1	FLR1	Flare	CO_2	7,215	9,437	Use of Good Combustion Practices. See permit condition III.A.5.
			CH_4	1		
			N_2O	7.1		

DCP also notes that the total sitewide estimated GHG emissions do not reflect the total of emissions for each GHG pollutant as represented in the draft permit table and the GHG PSD permit application. Please revise the total sitewide estimated GHG emissions to reflect the following: 207,677 tpy-CO_2, 6.45 tpy-CH_4, 7.46 tpy-N_2O, and 210,693 tpy-CO_2e.

In addition to the above emission estimate corrections, DCP also believes that footnotes 5 and 6 should be corrected as follows:

> Footnote 5 - Fugitive process emissions from EPNs FUG1 and FUG2 are estimated to be 0.17 TPY of CO_2,0.96 TPY of CH_4, and 297 TPY CO_2e each. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
>
> Footnote 6 - The total emissions for CO_2, CH_4, and CO_2e include the PTE for process fugitive emissions of CO_2, CH_4, and CO_2e. These totals are given for informational purposes only and do not constitute emission limits.

Table 1 also includes BACT Requirements. DCP will later discuss the Minimum firebox temperature of 1,500 ^oF for TO1 and TO2. DCP respectfully contends that the BACT Requirement for TO1 and TO2 should be revised to *"Minimum firebox temperature based on performance testing. See permit condition III.A.3.b and V.N."* Please refer to the Thermal Oxidizer Special Permit Condition section of this document for further discussion of this request below.

III. Special Permit Conditions

Hot Oil Heaters (EPNs: HOH1 and HOH2)

Special Permit Condition III.A.1.h requires performing cleaning of the burner tips at a minimum frequency of annually. The Statement of Basis (SOB) states clean heater burner tips and convection tubes at a minimum of every 5 years. DCP requested "as needed" in the GHG PSD application. The hot oil heaters produce all the process heat requirements. Cleaning the burner tips of the hot oil heaters would require a shutdown of each train, every year, for the express purpose of cleaning the burner tips. DCP contends that a train shutdown requires the mobilization of significant resources, both financial and energy, as well as significantly impacting the operation of upstream facilities that deliver NGL product. While coordination with these outside operated entities will minimize the startup and shutdown emissions, these emissions are beyond the control of DCP and a disruption will ultimately result in emissions which otherwise are not required. DCP believes it is prudent to manage a train outage based on operational conditions and needs and suggests a "not to exceed" language. In addition, the heaters will combust only pipeline quality natural gas which does not result in significant soot formation as with other gaseous or liquid fuels; therefore, DCP believes cleaning of the burner tips every 5 years will maintain proper performance. DCP proposes the following language which is consistent with the SOB:

> *"Permittee shall clean the burner tips of each hot oil heater during an annual shutdown if occurring. If a planned outage is not performed, cleaning may be delayed until the next planned outage, not exceed 5 years from the previous cleaning."*

Special Permit Condition III.A.1.q requires a rolling 12 month average and a one-hour maximum firing rate calculated daily to demonstrate compliance with the firing rates in II.A.1.p. The fuel consumption is required to be measured and recorded every 15 minutes in Special Permit Condition III.A.1.f and monthly CO_2, CH_4, N_2O, and CO_2e emissions calculated as described in Special Permit Conditions III.A.1b, III.A.1.c, and III.A.1.d. DCP's understanding of Special Permit Condition III.A.1.q suggests that both the rolling 12 month average and the one-hour maximum firing rate are required to be calculated daily. DCP suggests that it is not the intent to calculate the 12 month average daily and requests a slight revision as follows: *"A rolling 12* *month average firing rate shall be calculated monthly and the one-hour maximum firing rate shall be calculated daily to demonstrate compliance with the firing rates in III.A.1.p."*

Regeneration Heaters (EPNs: HTR1 and HTR2)

Special Permit Condition III.A.2.u (as currently identified in the draft permit) requires a 12-month rolling average, calculated monthly, for the thermal efficiency. Per Special Permit Condition III.A.2.o, the equation used to determine thermal efficiency requires exhaust temperature, input fuel temperature, and stack oxygen. However, due to the cyclic operation these parameters are not continuously monitored. Therefore, it is not valid to perform a monthly thermal efficiency calculation for these heaters. Given the fact that the stack oxygen content will be measured semiannually per Special Permit Condition III.A.2.l, DCP proposes to perform a thermal efficiency calculation semiannually and average the two most recent calculations to determine an annual thermal efficiency. DCP respectfully requests the condition be revised to state: *"The Permittee shall maintain a minimum overall thermal efficiency of 80% based on an annual rolling average, calculated semiannually using data from the two most recent semiannual stack tests".*

Special Permit Condition III.A.2.o (as currently identified in the draft permit) requires continuously monitoring the exhaust temperature, input fuel temperature, and stack oxygen and a calculation of the thermal efficiency for the **hot oil heaters** *(sic)* monthly. As described previously in the comments on Special Permit Condition III.A.2.u, the operation of the regeneration heaters is cyclical; therefore, continuous monitoring is not appropriate. The instrumentation associated with the regeneration heaters is not capable of continuously monitoring the exhaust temperature, input fuel temperature, and stack oxygen. In addition, the Draft Permit includes Special Permit Condition III.A.2.l, which requires semiannual monitoring of the stack oxygen content. The semiannual stack oxygen monitoring requirement is also referenced in the SOB. DCP respectfully requests the condition be revised to state: *"The regeneration heaters (HTR1 and HTR2) will be monitored for exhaust temperature, input fuel temperature, and stack oxygen during the semiannual stack test. Thermal efficiency for the regeneration heaters will be calculated semiannually from these parameters using equation G-1 from the American Petroleum Institute (API) methods 560 (4th ed.) Annex G."*

Please note: The alphabetic identifiers for Special Permit Conditions III.A.2.u through III.A.2.p are not in consecutive order. DCP respectfully requests that Permit Special Conditions III.A.2.u through III.A.2.p be relabeled as Permit Special Conditions III.A.2.o through III.A.2.q.

Thermal Oxidizers (EPNs: TO1 and TO2)

Special Permit Condition III.A.3.h requires the combustion temperature to be maintained at a minimum of 1,500 °F at all times and installation of a temperature recording device to continuously monitor the firebox temperature and recorded the temperature on an hourly basis. DCP notes that the temperature requirement is inconsistent in the Draft GHG PSD permit and in the SOB. DCP also commented on the temperature requirements in the SOB above. DCP believes that the minimum temperature to meet the DRE of 99.9% should be established by performance testing in order to reduce combustion CO_2 emissions by avoiding use of additional natural gas to maintain a higher temperature than may actually be required to achieve the desired DRE. Therefore DCP has proposed that a minimum temperature will be determined by an initial performance test and requests the removal of the minimum temperature designation. DCP would be agreeable to specification of 1,500 °F until completion of the initial performance test to determine the minimum temperature required to maintain a 99.9% DRE and suggests the following revision: *"The Permittee shall maintain the combustion temperature at a minimum of 1,500 °F until the initial performance testing occurs at which time the minimum temperature will be revised consistent with the minimum required to maintain a 99.9% DRE at all times when processing waste gases in the thermal oxidizer."*

Analyzer/Trace Erase System (EPNs: TE1 and TE2)

Special Permit Condition III.A.4.a uses the term "Trace Erase System Analyzer". The proposed Trace Erase (TE) system is not an analyzer. The TE system controls the vent stream from the process analyzers. Please revise the description to say *"one analyzer Trace Erase System"*.

Special Permit Condition III.A.4.c also uses the term "Trace Erase System Analyzer". Please revise to *"...waste gas emissions sent to the analyzer Trace Erase System ..."*. Additionally, the condition states *"the permittee shall not exceed 5,520 scf/yr of waste gas emissions...for both* *unitscombined."* DCP respectfully contends that emissions were estimated based on a 5,520 scf/yr flow rate for each TE system. Please revise the condition to state *"for each TE unit"* in place of *"for both units combined"*.

Flare (EPN: FLR1)

Special Permit Condition III.A.5.a requires the composition analyzer to continuously record the molecular weight and mass flow rate of the flare gas. DCP contends that the description of the analyzer operation is inaccurate. The analyzer continuously samples the flare gas and generates a record consistent with the stream analyzer frequency. DCP understands that the intent of the condition is to continuously sample and generate a record. DCP therefore respectfully suggests the condition be revised to state: *"Permittee shall install, operate, and maintain a flow rate and composition analyzer to monitor the waste gas combusted by the flare. The flow rate and composition analyzer shall continuously sample the flare gas stream and record the molecular weight and mass flow rate of the flare gas consistent with the stream analyzer frequency."*

Firewater Pump Engine (EPN: ENG1) and Emergency Generator Engine (EPN: ENG2)

DCP suggests that the Firewater Pump Engine is an emergency unit and requests that this designation be included by insertion of "Emergency" prior to Firewater Pump Engine throughout the Special Permit Conditions for the Firewater Pump Engine.

Permit Special Condition III.A.6.g states that compliance with annual emission limits shall be demonstrated on a 12-month total, rolling monthly, calculated in accordance with 40 CFR part 98 Subpart C 98.33(a)(3)(ii). The calculation methodology referenced in this condition requires fuel sampling to determine CO2, CH4, and N2O emissions. However, fuel sampling of diesel fuel is not normally conducted for diesel fuel used in emergency engines. In addition, 40 CFR 98.33(b)(1)(i) provides that the Tier 1 calculation method is allowed for any fuel listed in Table C-1 that is combusted in a unit with a maximum rated heat input capacity of 250 MMBtu/hr or less. The maximum rates heat input capacity of each engine is less than 250 MMBtu/hr; therefore, DCP requests that the calculation methodology be revised to the Tier 1 calculation methodology. DCP requests to change the condition language to the following: *"Compliance* *with the Annual Emission Limit shall be demonstrated on a 12-month total, rolling monthly, calculated in accordance with 40 CFR Part 98 Subpart C §98.33(a)(1)(i)."*

V. Initial Performance Testing Requirements

Special Permit Condition V.B references Special Permit Condition III.A.2.u. However, Special Permit Condition III.A.2.u is out of order alphabetically and should be changed to Special Permit Condition III.A.2.o.

Special Permit Condition V.G requires flare compliance determinations to be made following the requirements in 40 CFR Part 65 sections 65.147(b)(3)(i) through 65.147(b)(3)(iv). However, the monitoring requirements for the flare in Permit Special Condition III.A.5.e are based on 40 CFR 60.18, which are very similar, if not the same, to the requirements in 40 CFR 65.147. Therefore, DCP requests that the condition be revised to read as follows: *"Flare compliance determinations shall be made following the requirements in 40 CFR Part 60 sections 60.18(f)(1) through 60.18(f)(4)."*

Special Permit Condition V.H requires a minimum combustion chamber temperature of 1,500 °F for TO1 and TO2. DCP has previously commented on the minimum temperature requirement in the Thermal Oxidizer section above. DCP requests this condition be revised consistent with the above discussion, that 1,500 °F is the minimum temperature required until the establishment of a minimum temperature during the performance testing.

Special Permit Condition V.I states that the "thermal oxidizer shall be operated at or above the combustion chamber set-point temperature used to demonstrate compliance, and at all times greater than 1,300 °F." DCP requests that Special Permit Condition V.I be revised to: state: *"...the thermal oxidizers shall be operated at or above the combustion chamber set-point temperature establish by the initial performance test until re-established in subsequent performance testing."*

Special Permit Condition V.J identifies EPA Test Methods to be used for specific sampling and traverse points. Please revise this sentence to state include a reference to *Appendix A* of EPA 40 CFR 60, Test Methods which will aid in the future identification of the referenced methods.

Permit Special Conditions V.L through V.N at the end of Section V are not in correct alphabetical order with the previous conditions in Section V. The last three Special Permit Conditions in Section V should be relabeled M through O.