From:	Ward, Lynn C
To:	Wilson, Aimee
Cc:	Stuart Doss; Brad Herrin (bherrin@spiritenv.com)
Subject:	RE: Questions on DCP Jefferson County - CCS
Date:	Wednesday, June 05, 2013 4:41:26 PM

Dear Aimee,

As requested, DCP is providing additional cost information related to the determination that CCS is economically unreasonable. DCP has previously provided an annualized cost estimate to implement CCS at the proposed facility of $25,047,449 per year, as represented in the revised GHG PSD permit application submitted on February 27, 2013. The total capital cost of the Jefferson County NGL Fractionation plant is estimated to be $500,000,000. Based on a 7% interest rate, and a 20 year equipment life, the annualized capital cost is estimated to be $47,196,465 per year. The cost of CCS would result in an approximate 53% increase in the annual cost of the project.

In addition to the significant increase in the cost of the project, CCS would also result in negative environmental and energy impacts due to additional equipment to compress, cool, purify, dry, and recompress the purified CO_2 to pipeline pressure. Recovering CO_2 from the amine unit vents would require additional compression and a drying component, either glycol or mole sieve towers with a fired heater to purify or regenerate the glycol or mole sieve. The dried stream would then have to be compressed for introduction into a CO_2 pipeline. Recovery of CO_2 from the combustion device exhausts would require additional compression of approximately 11,000 brake horsepower ("BHP") to compress the exhaust gases to the required inlet pressure for purification in an additional amine treater. The amine treater would require an additional hot oil heater [approximate heat duty of 177 million British thermal units per hour ("MMBtu/hr") and additional controls (possibly combustion) for the contaminants removed from the CO_2 stream. Following purification in the amine treater, the CO_2 would be cooled and heated, then recompressed to the required CO_2 pipeline pressure. Approximately 1,500 BHP of compression would be required to recompress the CO_2 to pipeline pressure.

The additional compression and heaters required to implement CCS at the facility would result in an increase of CO_2 emissions, as well as nitrogen oxides ("NO_X"), carbon monoxide ("CO"), volatile organic compounds ("VOC"), particulate matter ("PM"), and sulfur dioxide ("SO_2"). The additional heater and compression equipment required to capture, purify, and compress the fired heater exhaust gases alone would result in a CO_2 emissions increase of approximately 140,000 tons per year ("tpy"). The additional heater and compression required to recover CO_2 from the fractionation plant process unit amine vents would result in an emissions increase of CO_2 in addition to the 140,000 tpy. As shown on Table 5.3.1-1 in the GHG PSD permit application submitted on February 27, 2013, the total expected reduction in CO_2 emissions from the implementation of CCS is estimated to be 171,861 tpy. Therefore, the implementation of CCS would result in at most a 19% CO_2 emission reduction compared to the CO_2 emissions from the facility without CCS. This small CO_2 reduction would further increase the cost per ton of CO_2 reduced from $145.74 per ton (page 5-9 of GHG PSD permit application) to $786.15 per ton. In addition, it is very likely that the total CO_2 emissions increase from CCS implementation would equal or exceed the total CO_2 emissions captured from the fractionation plant, when the CO_2 emissions from the equipment to recover CO_2 from the fractionation plant amine unit vents are added to the total. Compression needs potentially could be served using electric motors; however, based on conversations with the local electric power provider, the additional electricity required may not be available. Generation of additional electricity by the local power provider would result in an increase of CO_2, NO_X, CO, VOC, PM, and SO_2 emissions at the local power plant. If gas-fired engines/turbines are required instead of electric motors, the compression would result in an increase of CO_2, NO_X, CO, VOC, PM, and SO_2 emissions at the site, as stated previously. The resulting increase of criteria pollutants at the site would cause the total project emissions of one or more of these pollutants to exceed their significant emissions level, requiring PSD review for one or more criteria pollutants. Implementation of CCS at the proposed facility would result is negative environmental and energy impacts for the following reasons.

- The additional CO_2 emissions resulting from implementation of CCS would represent either a relatively small reduction or more likely an increase of CO_2 emissions, as compared to the CO_2 emissions from the proposed facility without CCS. Whether or not there is a small reduction or an increase in CO_2 emissions, the energy used (natural gas and electricity) to power the CCS equipment would result in a negative energy impact on other facilities using energy in the surrounding area without significant benefit to the environment.

- The electrical energy required to power the additional CCS equipment would require the local utility to generate additional power.

- Installation of additional heaters and gas-fired compression would result in emissions of one or more criteria pollutants exceeding the PSD significant emissions level.

- The proposed plant is located in Jefferson County, which is part of the former Beaumont-Port Arthur ozone nonattainment area. This area is currently in maintenance for compliance with the National Ambient Air Quality Standard ("NAAQS") for ozone; therefore, additional increases of NO_X and VOC could have a negative impact on the area maintaining compliance with the ozone NAAQS.

DCP has prepared the above utilizing generally accepted engineering principles and estimates of BHP and heat rate required to achieve capture and compression of CO_2 emissions from the associated processes. Emissions are rough estimates for purposes of providing the information requested and are not the result of a detailed engineering analysis which would be required to actually construct the equipment.

Please contact me if you require any additional information or you have further questions.

Sincerely,

Lynn Holt
Senior Environmental Specialist
DPC Midstream, LP
Arklatex / Gulf Coast Assets

(o) 903-694-4114
(c) 903-754-0945

From: Wilson, Aimee [mailto:Wilson.Aimee@epa.gov]
Sent: Thursday, May 23, 2013 1:11 PM
To: Ward, Lynn C
Cc: Stuart Doss
Subject: RE: Questions on DCP Jefferson County

I'm sorry, not the hot oil heaters, I meant the regeneration heaters.

On CCS- we are going to need more information to be able to support eliminating CCS as a control option. We either need more data on costs, or try to bolster the argument that there are environmental and energy impacts that eliminate CCS. You may need to discuss this with my boss, Jeff Robinson.

From: Ward, Lynn C [mailto:LCWard@dcpmidstream.com]
Sent: Thursday, May 23, 2013 12:53 PM
To: Wilson, Aimee
Cc: Stuart Doss
Subject: FW: Questions on DCP Jefferson County

Sorry, I got distracted apparently, see below for DCP's response to the hot oil heater question.

I would like to talk further about the estimates for NOx and VOC and why they are needed. To generate estimates that have any basis, DCP would have to undertake engineering design work that is currently beyond the scope of the project. I would prefer to have a discussion about this so I can understand the need. Is this point going to hold up the project draft permit/statement of basis, etc?

Thanks,
Lynn

From: Wilson, Aimee [mailto:Wilson.Aimee@epa.gov]
Sent: Thursday, May 23, 2013 11:54 AM
To: Ward, Lynn C
Cc: Brad Herrin; Stuart Doss
Subject: RE: Questions on DCP Jefferson County

Lynn,

What about my question on the hot oil heaters having an output based limit or a minimum thermal efficiency?

DCP proposes an efficiency based BACT limit of 85% for each hot oil heater. Please see page 5-24 of the revised application submitted on 2-27-2013.

Also, I think we will need an estimate of the NOx and VOC emission increases if CCS were implemented.

Thanks,
Aimee

From: Ward, Lynn C [mailto:LCWard@dcpmidstream.com]
Sent: Thursday, May 23, 2013 11:32 AM
To: Wilson, Aimee
Cc: Brad Herrin (bherrin@spiritenv.com); Stuart Doss
Subject: RE: Questions on DCP Jefferson County

Dear Aimee,

I greatly appreciate your patience with DCP on responding to your 5/17 email. For my part, I had received all the information I needed yesterday morning but didn't realize that I had. I have added DCP's comments to your original email below in blue text. Thanks again for your patience.

Sincerely,

Lynn Holt
Senior Environmental Specialist
DPC Midstream, LP
Arklatex / Gulf Coast Assets

(o) 903-694-4114
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From: Wilson, Aimee [mailto:Wilson.Aimee@epa.gov]
Sent: Friday, May 17, 2013 10:57 AM
To: Ward, Lynn C
Cc: Brad Herrin (bherrin@spiritenv.com); Stuart Doss
Subject: Questions on DCP Jefferson County

Lynn,

The draft permit and statement of basis have gone through internal review and I have some questions from the reviewers.

CCS – Can you give an estimate of what the NOx and VOC increases would be if CCS were implemented? The equipment for a CCS system has not undergone complete design and engineering, because the cost of CCS was determined to be economically unreasonable. Therefore, the NO_X and VOC emissions that would be associated with CCS implementation cannot be estimated at this time.

In a previous response on the hot oil heater use, you had replied. "The hot oil is used in three of the four column reboilers, a heat exchanger for the caustic/hydrocarbon separator in natural gasoline treating, the process waste water flash drum heating coil, and for an occasional use water heater associated with the natural gasoline treaters." Can you clarify if each of the sources utilized the ehat by a reboiler, heat exchanger, or column. Maybe a short description of each. Also, my boss is not happy with only having a limitation on hours of firing at maximum firing. Can you propose either an output based limit (lb CO_2/MMBtu or lb CO_2/bbl processed) or a minimum thermal efficiency to meet?

The hot oil is used to heat process fluid in each of the pieces of equipment for each process train, as described below:

1. Deethanizer Bottom Reboiler, Depropanizer Bottom Reboiler, Debutanizer Reboiler, and Amine Regenerator Reboiler – These reboilers are all shell and tube heat exchangers. Hot oil is routed through the tubes in the heat exchanger to heat process fluid from the respective process column in the shell side of the heat exchanger. In addition to heat from the hot oil, the Deethanizer Bottom Reboiler heat exchanger uses heat from the Depropanizer Heat Pump Compressor discharge stream in a second set of tubes to reduce the amount of heat required from the hot oil system.
2. Caustic/Hydrocarbon Separator Heater – Hot oil is routed through a heating tube bundle in the Caustic/Hydrocarbon Separator vessel to heat the spent caustic solution to aid in the separation of any dissolved or entrained hydrocarbons.
3. Natural Gasoline Treating Water Heater – This is a shell and tube heat exchanger. Hot oil is routed through the tubes in the heat exchanger to heat water which is occasionally used in the natural gasoline treater vessels.
4. Process Waste Water Flash Drum Heating Coil – Hot oil is routed through a heating coil in the Process Waste Water Flash Drum to heat the process waste water to aid in the separation and vaporization of any hydrocarbons that may be dissolved or entrained in the waste water prior to sending it to the waste water storage tank.

Engines – Will the emergency generator engines meet off-road GHG standards? Will they meet 60.4205(b) for emergency generator engines < 30L or 60.4205(d) for greater than 30L after 2012? Wanted to verify.

1. The site will include only one emergency generator engine, which is intended to remain

permanently on the site. This is a fixed generator installation, not a portable generator.

2. DCP understands that the only GHG emission standards that have been promulgated by the USEPA that specifically address engines, rather than motor vehicles only, are found in 40 CFR Part 1036. Specifically, this regulation addresses "heavy-duty" engines which are defined in 40 CFR 1036.801 as "…any engine which the engine manufacturer could reasonably expect to be used for motive power in a heavy-duty vehicle…". A heavy-duty vehicle is defined as "…any motor vehicle above 8,500 pounds GVWR or that has a vehicle curb weight above 6,000 pounds or that has a basic vehicle frontal area greater than 45 square feet." Because the emergency generator engine is part of packaged equipment meant to be used for emergency generation rather than for motive power, no GHG standards are currently applicable to the engine.
3. The emergency generator engine will meet the applicable emission standards in 40 CFR 60 Subpart IIII for emergency engines less than 30 liters per cylinder, per 40 CFR 60.4205(b).

Thanks,
Aimee