10 Desta Drive, Suite 500W
Midland, Texas 79705
Direct: 432-620-5460
Fax: 432-620-4162

March 3, 2020

Kerwin C. Singleton
Planning Section Chief
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505

**Re: NMED Jan. 7, 2020 Request for Additional Information on the Four-Factor Analysis Report
Regional Haze Program
DCP Operating Company, LP – Eunice Gas Plant**

Mr. Singleton,

DCP Operating Company, LP (DCP) is in receipt of the New Mexico Environment Department's (NMED's) January 7, 2020, "*Request for Additional Information for Four-Factor Analyses under the Regional Haze Program*" ("Request for Additional Information" or supplemental information request), which requests various and specific supplemental information, technical discussions, analyses, and data, including possible supplemental "Four-Factor Analyses," for multiple sources with respect to DCP's Eunice natural gas processing plant in Lea County, New Mexico. In the time afforded, and given the objections below, this letter provides DCP's responses to the January 2020 Request for Additional Information (in **blue** font, below).

NMED's January 7, 2020, Request for Additional Information, including potential Four-Factor Analyses, does not state a timeline by when the operator is to provide responsive information, and only states qualitatively to submit responses "as soon as possible." DCP notes that NMED's initial request for Four-Factor Analyses dated July 18, 2019, afforded approximately three and a half months to fulfill NMED's request for responses and analyses, requested by November 1, 2019. Given the level of information expected in NMED's initial request, DCP believes three and a half months was impracticably short, but DCP fulfilled the request to the best of the company's ability. With respect to the January 2020 Request for Additional Information, DCP received a phone call from NMED on February 10, 2020, expecting a response to the supplemental information request and possible Four-Factor Analyses by February 14, 2020, five weeks from NMED's letter of January 7, 2020. February 14, 2020, is unrealistic and unreasonable for the responses requested by NMED. DCP will provide what information it reasonably can by March 3, 2020, and will otherwise provide follow-on requested information when it is reasonable to do so given what is being requested by the agency.

As this is an administrative proceeding with an administrative record, for the record DCP must note any objections it has to the NMED request. DCP states the following objections for the record in relation to NMED's request for Regional Haze-related information and analyses, and preserves its rights related thereto notwithstanding DCP's providing information requested by NMED.

- DCP has limited resources available to respond to NMED's initial, and now supplemental information request; DCP does not have resources available to be dedicated full time to responding to NMED requests analyses, technical discussions, and responding to requests for information. DCP has expended resources, where practicable, to have third party support with respect to the company's responses to NMED's requests for assessments and information, but that support is not always practicable or available, and there are limitations on DCP's use of such third party support. DCP is providing the responses herein, to the agency's supplemental request for information, to the best of the company's ability, in the time afforded, given the limitations of its resources.

- NMED's amount of time afforded to respond to the agency's Request for Additional Information, potentially including Four-Factor Analyses, is impracticably short, unrealistic and unreasonable for a number of the requested items, and affects DCP's ability to respond to the various requests.

- DCP objects to NMED's Request for Additional Information to the extent the requests are for assessments, discussion, information, data that are not presently available and in the possession of the source, in this case DCP. It is within NMED's authority to request information presently available and in the possession of a source operator, but it is beyond the agency's authority to require a source to create or generate information or data that does not presently exist or is not in the possession of the source, or to require a source to expend monies/resources to create or generate such information or data.

- DCP objects to vague, ambiguous or undefined terms in the Request for Additional Information, and objects to the extent the request require DCP to engage in speculation in order to attempt to respond to an agency's stated question or request.

- DCP objects NMED's requests for assessments or analyses that directly or indirectly result in or would relate to "redefining the source," being a properly-authorized, operating, and permitted emissions source. The federal Regional Haze regulation contemplates emissions control technologies that might be cost-effectively retrofitted on a source; redefining a properly-authorized, permitted and operating source is not a retrofit control technology, and is beyond the authority of the Regional Haze rule to consider as a Reasonable Progress measure.

- DCP objects to the fact that NMED has not provided, as part of this administrative process, the cost-effectiveness threshold for control technologies for the Regional Haze Reasonable Progress rulemaking.

- DCP objects to the agency's fundamental threshold for requesting 4-Factor Analyses from sources in the State, *i.e.*, Q/d of 5, as this is unreasonably stringent and requiring resource expenditures for assessments of sources that would not effectively contribute to visibility improvement in Class I areas. The State of Colorado applied a Q/d of 20 as its screening criteria, which assumed an estimated associated deciview improvement of 0.3; a Q/d of 5 would provide, presumably, one-quarter of the assumed visibility improvement, so requiring screening of sources at that level that would provide potentially, *e.g.*, 0.07 deciview improvement.

Preserving the objections noted, above, DCP responds to the agency's January 7, 2020, Request for Additional Information as follows (NMED Jan. 7, 2020, requests re-stated in black font, and DCP responses provided in blue font).

Please provide the following information for the units that were evaluated in four-factor analysis for potential nitrogen oxides (NO_X) controls.

1. General

It appears that the cost analysis calculations submitted with the Eunice Gas Plant submittal apply to the Linam Ranch Gas Plant and not to the Eunice Gas Plant. So that the record is complete, please update the four-factor analysis with the Eunice Gas Plant cost calculations. Also, provide the electronic files of these calculations.

The correct cost calculation spreadsheet for Eunice Gas Plant was submitted by Trinity Consultants in November 2019.

Please note that changes may need to be made to the calculations based on information requested in this letter.

2. Sour Gas Amine Treating Unit Amine-01

a. Please provide the 2007 geologic formation review that resulted in not recommending a deep injection well in the Devonian formation.

As noted in the November 2019 Four Factor Analysis report, the referenced document is considered to be DCP proprietary material. DCP expended considerable resources to receive this evaluation report. DCP will provide this January 26, 2007, evaluation report to NMED in response to NMED's request for information, as proprietary and Confidential Business Information (CBI), under separate CBI transmittal.

b. Provide the scope, time, and cost of completing geologic analysis and injection well/geologic reservoir feasibility study for acid gas injection (AGI) well near the Eunice Gas Plant.

DCP objects to this request as it pre-supposes re-definition of the facility process equipment, in this case properly authorized, permitted, and operating facility amine treatment system with its associated sulfur recovery unit (SRU) process system for recovering elemental sulfur from acid gas – re-defining a source is not a retrofit control technology, and is beyond the authority of the Regional Haze rule to consider as a Reasonable Progress measure. DCP further objects to the extent this request would require the source operator to create or generate information that presently does not exist, having to expend resources to do so; such a request is beyond the agency's legal authority. Accordingly, it is not required that DCP discuss this topic.

Without waiving objections, the above-referenced January 2007 geologic evaluation report reflects that an AGI is technically infeasible. Further, the cost of completing a geologic analysis and geologic reservoir feasibility study, in the area of and immediately surrounding the Eunice nat. gas processing plant, is roughly in the range of $30,000 for the geologic feasibility assessment alone, with substantial additional costs necessary for conducting related steps for such a process (permitting-level preparation; outward steps to secure authorization) all of which serve to increase certainty in relation to the targeted geologic reservoir. If the agency believes more certainty is needed for the cost, time and scope to conduct a geologic analysis and geologic reservoir feasibility study in the area of and immediately surrounding the Eunice nat. gas processing plant, please advise and the company will inquire of a relevant vendor to provide such. If the area scope is materially expanded beyond the immediate area of the Eunice nat. gas processing plant, *e.g.*, if an identified geologic reservoir would require piping some material distance to dispose of acid gas, then the cost to conduct a geologic analysis and geologic reservoir feasibility study would increase substantially.

c. The analysis states that installing an AGI system would completely replace the sulfur recovery unit (SRU)-Thermal Oxidizer (TO) amine unit control. Please state why an AGI and could not be used in conjunction with an SRU-TO to reducing flaring.

   DCP re-states the prior objection that this request pre-supposes re-definition of the facility process equipment, and thus redefining a source which is beyond the authority of the Regional Haze rule. DCP also objects to the extent this request requires speculation. Without waiving objections, the above-referenced January 2007 geologic evaluation report reflects that an AGI was deemed technically infeasible.

d. If found to be technically feasible, complete a four-factor analysis for AGI system controls. The analysis should assume a redundant compressor system.

   Refer to above response to Question 2(b).

e. Consider and discuss options for additional amine unit controls, such as adding additional catalyst beds to the Claus SRU or replacing the Claus SRU with a LO-CAT sulfur recovery technology. If technically feasible, include a four-factor analysis.

   Adding additional catalyst beds to the existing SRU would require further study of technical feasibility by sulfur experts, which cannot be completed within time frame given for this additional information response.

   Replacing the existing SRU with a LO-CAT sulfur recovery technology is deemed technically infeasible as LO-CAT sulfur recovery technology is not suitable for natural gas processing plants with greater than 20 TPD sulfur production.

3. Flares

Please provide the following information for the flares at the DCP Eunice Gas Plant, unit numbers 111, 112A, 113, and 114A. All flares at the DCP Eunice Gas Plant are permitted for the control of vented gases during routine or predictable start up, shut down, and/or maintenance (SSM).

a. Provide a description of each flare, the design and type, and its purpose.

   Please see *Attachment A – Eunice Flare Summary*, which was kindly provided by Ms. Cember Hardison of NMED.

b. List and describe the reasons that trigger each type of flaring event.

   Please reference steady-state emission from the flares as shown in the *Attachment B – Flare Emission Calculation*.

   Other flaring events include permit authorized planned SSM flaring events and unplanned flaring events. Planned SSM emission flaring events are triggered by routine maintenance. Allowable emission limit as included in the facility's air permit represent maximum amount of emission that can occur during all planned maintenance activities and startup/shutdown events that is anticipated pre and post-maintenance. However, these planned maintenance events do not occur at the same frequency, i.e. quarterly, annual, biennial, every five year and etc, therefore, actual emission that occur at the facility differs each year as represented in DCP's process and SSM flaring four factor analysis report submitted on December 16, 2019.

Unplanned flaring events are triggered through various unforeseeable reasons such as equipment malfunction, power loss, and etc. Excess emission resulting from these event are reported to NMED pursuant to NMAC 20.2.7.110. DCP operates emission equipment in a manner consistent with good air pollutant control practices for minimizing emission.

c. Provide a discussion on how the entire facility and/or source specific operations can be improved to reduce the frequency of SSM flaring events. If it is not possible to make any improvements to the facility or its processes to reduce SSM flaring events, then please explain why.

   Eunice's current process and operation is optimized to reduce SSM flaring event to minimum frequency.

d. Discuss potential alternative control options or operational changes that could reduce nitrogen oxides (NO_X) and/or sulfur dioxide (SO_2) flaring emissions; including:
   i. infrastructure that allows re-routing or recirculating the gas within the facility or outside of the facility until an SSM event is over;

      Eunice's current infrastructure supports nat. gas re-routing, nat. gas recycle, and off-loading when feasible under certain circumstances, each of which serve to reduce flaring emissions. Eunice has the ability, when necessary, to close the nat. gas inlet to the facility, which significantly limits or prevents flaring at the facility. Eunice also coordinates with the producers, either prior to a planned event, or when feasible during an unplanned event, to temporarily re-route nat. gas to other facilities if practicable or to shut in nat. gas for a finite period, to reduce the volume of nat. gas potentially subjected to flaring at the facility. Under certain circumstances DCP can, and does, utilize producer temporary off-load capabilities, or DCP capability to temporarily re-route gas when practicable and feasible, to minimize the volume of nat. gas potentially subjected to flaring at the facility. DCP believes that these capabilities and measures, taken together, serve to prevent flaring at the Eunice facility or to mitigate the duration of a flaring event or the volume of material subjected to flaring. DCP is not aware of another technically feasible option to appreciably further reduce flaring events or volumes at the facility.

   ii. sulfur absorbent technology used to remove sulfur from pipelines and other auxiliary equipment to reduce inlet or plant flaring SO_2 emissions;

      The Eunice nat. gas processing plant receives, and is designed to receive, high hydrogen sulfide ("H2S") concentration natural gas, referred to as "sour" nat. gas. Given the high H2S concentration received by the Eunice plant, an amine treatment system is the most effective and the only technology that is technically feasible to remove sulfur and treat the sour gas stream of this volume and concentration.

      Other sulfur absorbent technology, such as pipeline additive injection, commonly referred to as hydrogen sulfide scavenger, is utilized only non-sour gas systems, meaning on what are known as "sweet" gas streams, in order to treat very small amounts of hydrogen sulfide that might exist in a sweet gas stream to meet a certain specification, and are not suitable or effective for treating the sour gas stream processed at Eunice; they would not meaningfully reduce the concentration of H2S that would recognizably affect the amount of sulfur received by the Eunice Plant.

iii. Gas Capture Plans with facilities located downstream and upstream similar to those required for producers to better synchronize upstream and downstream services with the DCP Eunice Gas Plant;

DCP objects to the use of an ambiguous or undefined term with respect to a midstream nat. gas processing plant facility, and to the extent this question requires speculation. A Gas Capture Plan is a New Mexico Oil Conservation Division ("NMOCD") requirement for producer entities, for the producer's production development, to ensure communication between the producer entity and gatherer in order to improve communication and planning future nat. gas takeaway capacity, in order to mitigate the potential for a producer entity having to flare what would be stranded gas at its well production facility if there weren't nat. gas takeaway. DCP as a midstream entity does confer with producers about the producer's Gas Capture Plans. The concept, however, has no applicability to a midstream nat. gas processing plant as such a facility, for example the Eunice plant, is by definition designed to receive and process the producer's nat. gas; DCP's Eunice gas plant does not flare nat. gas due to lacking capacity, for example, so the concept is not applicable to a midstream gas processing plant.

iv. use of remote capture equipment; and

DCP objects to the use of an ambiguous or undefined term with respect to a midstream nat. gas processing plant facility, and to the extent this question requires speculation. Remote capture equipment, as DCP understands it from NM agency materials, is a concept that relates to and provides capability at a producer wellhead and relates to wellhead volumes of nat. gas and nat. gas products (liquids) at the producer wellhead. The same concept does not have applicability to a midstream nat. gas processing facility, and the type of technology is not applicable at the scale of a nat. gas processing facility; a midstream nat. gas processing plant, by definition, is removing nat. gas products (liquids) from the inlet material, which is one of its functions.

v. better infrastructure planning and changes to existing infrastructure that connects the downstream and upstream operations to DCP facilities to ensure that there is adequate processing capacity to move produced gas to market.

DCP objects to the use of ambiguous or undefined terms, and to the extent this question requires speculation. As described in the prior responses, DCP's Eunice nat. gas plant processing capacity appropriately and adequately manages relevant producer nat. gas production; the plant does not flare nat. gas due to lacking capacity.

e. For any technically feasible solutions, provide a four-factor analysis. For additional information regarding potential alternative controls to flaring, see the New Mexico Methane Strategy website: https://www.env.nm.gov/new-mexico-methane-strategy/methane-advisory-panel/.

Considering the above requests, DCP is not aware of any additional flaring technology or relevant operational changes that are technically feasible.

f. Please explain the discrepancy between the SSM SO_2 emissions provided in the supplemental flaring analysis (0.68 tpy) and NMED's 2016 emissions inventory (9.9 tpy). Excess emissions from all flares should be included in the analysis.

   The referenced SSM SO2 emission amount only refers to authorized emission and does not include excess emission resulting from unforeseeable events. Table 2 of the December 16, 2019 submitted response is titled "2016 EIQ Reported **Process** Flaring and **SSM** Flaring Emission". The purpose of above referenced table was to identify SSM emission from total emission from the subject unit.

g. If necessary, resubmit the flare cost analysis to account for excess emissions in 2016.

4. Simple Cycle Natural Gas Fueled Turbines

Please provide the following information for the Regenerative Cycle Turbines, Unit Numbers 17A, 18B, 19A, 25A, and 26A.

a. Please provide the Good Combustion Practices and the routine maintenance schedule and procedures that are currently used to help mitigate NO_X emissions and are identified as the base case control.

   DCP objects to the use of an ambiguous or undefined term or phrase, and to the extent this question requires speculation. The turbines at Eunice are equipped with additional monitoring hardware, which provides live data allowing monitoring of equipment health. DCP has historically used the monitoring service offered by OEM vendor, Solar, which affords strong routine inspection and maintenance practices on the turbines. DCP is in the process of transitioning the monitoring service to DCP's internal reliability group. Routine inspection and maintenance activities, such as daily visual inspection, water wash, borescope inspection, and all other interval preventive maintenance activities, are tracked through DCP's asset management/maintenance software to ensure that they are executed appropriately and timely. In addition, Solar technicians are brought in to supervise DCP's turbine technicians when performing major maintenance or overhauls.

b. Provide vendor specifications for the SoLoNO$_X$ Dry Low NO_X (DLN) combustion technology to include the guaranteed NO_X emission rates used in the cost analysis, the cost information, recommendations, and equipment specifications for the turbine control estimates.

   Please refer to *Attachment C – SoLoNOx and SCR estimate*

c. Provide the statement by the turbine vendor supporting the basis given for why water injection is not technically feasible for Solar turbines.

   Please refer to *Attachment D – Solar Wet NOx Letter*, which states that Solar does not offer Wet-NOx technology and reason behind discontinuation of Wet-NOx package.

d. Provide the vendor quotes used in the cost calculations for selective catalytic reduction (SCR) control technology.

   Please refer to *Attachment C – SoLoNOx and SCR estimate*

e. Verify that the regulatory costs of handling and storing ammonia and disposing of used catalysts is included in the cost analysis. If not, please add these costs.

Regulatory cost of handling and storing ammonia and disposing of used catalyst was not included in the cost analysis submitted on DCP's 2019 four factor analysis. Given the time limitation for this request, DCP was unable to obtain accurate cost estimates.

f. Provide the reasons for stating that the non-air environmental impacts for using, storing, and disposing of ammonia solution is a significant factor for eliminating SCR as a control. The reasons must be based on the site specific limitations at the Eunice Gas Plant.

SCR was not eliminated as a control option in the Nov 2019 Four Factor Analysis report. The potential harmful effect of ammonia handling was referenced, as well as DCP's stance on increasing risk to the health and safety of facility operators.

g. Please consider and include a discussion on the feasibility and cost of technology that limits turbine capacity to reduce NO_X emissions. Also evaluate limitations on turbine operating hours or shutting down turbines that are no longer needed to reduce emissions.

DCP objects to the use of an ambiguous or undefined term or phrase, and to the extent this question requires speculation. DCP objects to the extent it does not understand the retrofit technology referred to. DCP objects to this request as it may pre-suppose re-definition of the facility process equipment (e.g., limiting capacity), in this case properly authorized, permitted, and operating nat. gas-fired turbines – re-defining a source is not a retrofit control technology, and is beyond the authority of the Regional Haze rule to consider as a Reasonable Progress measure. Accordingly, it is not required that DCP discuss this topic.

Without waiving objections, please see following table representing 2016 hours of operation for turbines at Eunice as reported through emission inventory.

Unit No.	2016
	Run Hour
Unit 17A (Solar T-4002 Turbine)	8,760
Unit 18B (Solar T-4502 Turbine)	8,760
Unit 19A (Solar T-4002 Turbine)	8,664
Unit 25A (Solar T-4002 Turbine)	8,293
Unit 26A (Solar T-4002 Turbine)	7,161

As represented by the operating hours shown in above table, limitations on turbine operating hours or shutting down turbines that are no longer needed is not feasible without curtailing plant processing capacity currently permitted at Eunice Plant.

h. Please consider and include a discussion on the feasibility of replacing natural gas-fueled turbines with commercial electric powered compressors.

DCP objects to this request as it pre-supposes re-definition of the facility process equipment, in this case properly authorized, permitted, and operating nat. gas-fired turbines – re-defining a source is not a retrofit control technology, and is beyond the authority of the Regional Haze rule to consider as a Reasonable Progress measure. Accordingly, it is not required that DCP discuss this topic.

Without waiving objections, the replacement of the existing natural gas-fueled turbines with electric compressor motors are not technically feasible with existing infrastructure at Eunice. Electric compressor motors require significant electric power supply, and would require of construction of infrastructure to accommodate the increase electric need.

Construction of infrastructure does not guarantee electricity, which would depend on generation capacity and, for example, whether or not the conductors need to be resized to handle the load. Exclusive of cost considerations, including consideration of the cost of electric power supply on a regular basis, technical feasibility of electric turbines would require a feasibility study by XCEL Energy, which can take longer than 18-24 Months.

i. Provide the electronic spreadsheets used for control technology calculations.

Spreadsheet will be attached to the submission of this response.

j. Please include a discussion of the following control options to reduce NO_X emissions: catalytic combustion such as a XONON™ developed by Catalytic Combustion Systems, Incorporated (CESI), lean and staged combustion combustors (DLN) from turbine manufacturers other than Solar and complete a four-factor analysis on technically feasible options.

DCP objects to the use of an ambiguous or undefined term or phrase, and to the extent this question requires speculation. DCP is not familiar with the referenced technology, and therefore cannot offer any concrete opinion on its potential technical feasibility on these particular turbines. Given the time limitation for this request, DCP was unable to and did not initiate a discussion between DCP's engineering and operations functions with the XONON technology manufacturer with whom the agency is suggesting DCP speak. DCP has no knowledge of this technology being applied in nat. gas midstream industry service

Please note, NMED must document the cost and engineering information used to analyze potential control measures. If you feel that your supplemental information should be classified as confidential business information (CBI), it will need to be reviewed and approved as such by NMED and EPA. Submit CBI with the word 'confidential' included in the electronic file name and on each page of the document. Do not combine non-confidential business information and CBI in the same files. Also, the claimant must satisfy the conditions in 20.2.1.115.B(3)(a)-(d) NMAC when the CBI is submitted. Until NMED and EPA determines if the information qualifies as CBI, the information will not be disclosed to anyone other than those listed in 20.2.1.115 NMAC.

If you have any questions or concerns, please feel free to contact me directly by phone at 432-215-8514 or via email at hshong@dcpmidstream.com.

Sincerely,

Sam Hong
Environmental Engineer
DCP Midstream, LP

Enclosures

Attachment A – Eunice Flare Summary

DCP Eunice Gas Plant

AI 595 Flare summary

Four Flares 111, 112A, 113, 114A
One SRU and thermal oxidizer Unit 31 controlling amine unit still vent

Flare descriptions in permit:

- 111 Plant Acid Gas Flare – SSM plant turnaround, plant startup (post turnaround), condensate tank degassing during VRU downtime, gas piping degassing, pig launcher degassing, vacuum trucks, engine startup, turning blowdown, compressor blowdown, acid gas flares (units 111 and 113).
- 112A ESD flare – SSM during ESD
- 113 SRU acid gas flare (#2)- SSM
- 114A Amanda Booster Flare - SSM
- 31 SRU incinerator (Thermal Oxidizer) Amine units Still vent. Amine flash gas is routed back to the inlet. The SRU is the control for the Amine over heads.
- SRU-TO is equipped with continuous emission rate monitor (CERMS)

Limits for flares in Table 106.A are for pilot and purge gas only.

Equipment Table 104

Unit No.	Source Description	Make	Model	Serial No.	Construction/ Reconstruction Date	Manufacture Date	Manufacturer Rated Capacity /Permitted Capacity
Amine-01	Amine Unit Contactor	UCARASOL	N/A	4387	Pre-1974	Pre-1974	120 MMscf/day
31	Sulfur Incinerator (SRU)	Unknown	N/A	N/A	1974	1974	24.5 MMBtu/hr
111	Plant Acid Gas Flare	Unknown	N/A	N/A	Pre-1972	Pre-1972	1.98 MMBtu/hr
112A	ESD Flare	Unknown	N/A	N/A	Pre-1972	Pre-1972	1.98 MMBtu/hr
113	SRU Acid Gas Flare (#2)	Unknown	N/A	N/A	1975	1975	1.98 MMBtu/hr
114A	Amanda Booster Flare	Unknown	N/A	N/A	1974	1975	1.98 MMBtu/hr

Control Equipment Table

Control	Control Description	Pollutant being Controlled	Control for Unit No.

Equipment Unit No.			
31	SRU Incinerator	H_2S	[2]Amine-01
111, 112A, 113, 114A	Flares (Process & Emergency)	VOC	Plant Processes

2 Amine flash gas is routed back to the inlet. The SRU is the control for the Amine over heads.

Table 106 limits

Unit No.	[1]NO_x pph	NO_x tpy	CO pph	CO tpy	VOC pph	VOC tpy	SO_2 pph	SO_2 tpy
31	3.6	15.8	4.0	17.7	0.2	0.87	629.7[6]	2758
111 [3]	0.082	0.36	0.45	2.0	-	-	0.008 7	0.038
112 A [3]	0.43	1.9	2.3	10.2	-	-	0.45	0.2
113 [3]	0.1	0.36	0.45	2.0	-	-	0.008 7	0.038
114 A [3]	0.1	0.46	0.57	2.5	-	-	0.011	0.048

3 Compliance with emergency flare emission limits is demonstrated by limiting combustion to pilot and/or purge gas only.

Table 107 limits

Unit No.	NO_x pph	NO_x tpy	CO pph	CO tpy	VOC pph	VOC tpy	SO_2 pph	SO_2 tpy	H2S pph	H2S tpy
SSM-111	1.19	0.42	6.47	2.3	0.8	0.01 9	562.7	13.9	6.1	0.15
SSM-112A	252.8	8.7	1375.7	47.4	865.3	23.4	3819.5	105.6	41.4	1.1
SSM-113	8.57	0.92	46.7	5.0	5.9	0.18	4233.9	128.8	52.9	1.37
SSM-114A	40.79	0.93	222.0	5.1	238.6	2.78	752.2	9.0	8.2	0.10

Attachment B – Flare Emission Calculation.

Start Date:	**Version: 1.0**	**Equip_Int_ID:**	

Emissions Calculation: FLARES

Facility ID: **Facility:** Eunice

Equipment Information

Source ID Number:	111-114	Model:	Other: Flare
Name 2:		Serial Number:	
Name 3:		Service Date:	
Coordinates:		Manufacture Date:	
Northing:		Permit Status:	
Easting:		SCC:	31000205
Source Location Zone:			

Ownership:	DEFS owned	Pilot Gas Flow (mscf/hr)	1.9
Status:	Active	Fuel Heat Value (btu/scf):	1000
Flare Type:	Elevated, non-assisted	Pilot Heat Input (mmbtu/hr):	1.9
Fuel Type:	Natural Gas		

Potential fuel usage (MMscf/yr): 16.64

Stack Parameters

Stack Name:		Height (ft):	
Stack Number:		Diameter (ft):	
Emission Percent:		Temperature (^oF):	
Stack Angle (^{o}):		Flow (ACFM):	
Raincap:	No	Velocity (ft/s):	

Control Model

Emission Controls:

AP42 -- External Combustion

Potential operation: 8760 hr/yr

Potential Emissions

Pollutant	Emission Factor		Nominal Rating	Hrs of Operation	Estimated Emissions		Source of Emission Factor
	EF	Units	(MMBtu/hr)	(hrs/yr)	(lb/hr)	(tpy)	
Nitrogen Oxides	0.068	lb/mmBTU	1.9	8760	0.1	0.6	AP42
Carbon Monoxide	0.37	lb/mmBTU	1.9	8760	0.7	3.1	AP42
VOC	0.014	lb/mmBTU	1.9	8760	0.03	0.1	AP42
Benzene	0.0021	lb/mmscf	1.9	8760	0.00	0.00	AP42 -- External Combustion
Formaldehyde	0.075	lb/mmscf	1.9	8760	0.00	0.00	AP42 -- External Combustion
n-Hexane	1.8	lb/mmscf	1.9	8760	0.00	0.01	AP42 -- External Combustion
Total HAPs	1.88	lb/mmscf	1.9	8760	0.004	0.02	AP42 -- External Combustion

Notes **Notes Date:**

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: FLARES GHG

Facility ID: **Facility:** Eunice

Equipment Information

Source ID Number:	111-114	Model:	Other: Flare
Name 2:		Serial Number:	
Name 3:		Service Date:	
Coordinates:		Manufacture Date:	
Northing:		Permit Status:	
Easting:		SCC:	31000205
Source Location Zone:			
Ownership:	DEFS owned	Pilot Gas Flow (mscf/hr)	1.9
Status:	Active	Fuel Heat Value (btu/scf):	1000
Flare Type:	Elevated, non-assisted	Pilot Heat Input (mmbtu/hr):	1.9
Fuel Type:	Natural Gas		
		Potential fuel usage (MMscf/yr):	16.64

Potential operation: 8760 # hr/yr

Potential Emissions

CH_4 Calculation[1] (Eq 4-16)

$$E_{CH4} = \frac{16.6 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{0.731 \text{ scf } CH_4}{\text{scf gas}} \times \frac{0.005 \text{ scf noncombusted } CH_4}{\text{scf } CH_4 \text{ total}} \times \frac{\text{lbmole } CH_4}{379 \text{ scf C}} \times \frac{16 \text{ lb } CH_4}{\text{lbmole } CH_4} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

CH_4 = 1.16 tonnes CH_4 / yr
CH_4 = 1.28 ton CH4 / yr

1 tonne = 1.10231 ton

CO_2 Calculation[2] (Eq 4-15)

$$CO_2 = \frac{16.6 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{\text{lbmole gas}}{379.3 \text{ scf gas}} \times \left[\left(\frac{0.730795 \text{ lbmole } CH_4}{\text{lbmole gas}} \times \frac{1 \text{ lbmole C}}{\text{lbmole } CH_4} + \frac{0.1013 \text{ lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2 \text{ lbmole C}}{\text{lbmole } C_2H_6} + \frac{0.06236 \text{ lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3 \text{ lbmole C}}{\text{lbmole } C_3H_8} + \frac{0.00933 \text{ lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4 \text{ lbmole C}}{\text{lbmole } C_4H_{10}} + \frac{0.004515 \text{ lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5 \text{ lbmole C}}{\text{lbmole } C_5H_{12}} + \frac{0.00275 \text{ lbmole } C_6H_{14}}{\text{lbmole gas}} \times \frac{6 \text{ lbmole C}}{\text{lbmole } C_6H_{14}} \right) \times \frac{0.98 \text{ lbmole formed}}{\text{lbmole gas}} + \frac{0.0299 \text{ lbmole } CO_2}{\text{lbmole gas}} \right] \times \frac{44 \text{ lb } CO_2}{\text{lbmole } CO_2} \times \frac{\text{tonne}}{2204.62 \text{ lb}}$$

CO_2 = 1050.56 tonnes CO_2 / yr
0.00 ton CO_2 / yr

Start Date: **Version: 1.0** **Equip_Int_ID:**

Emissions Calculation: FLARES GHG

Facility ID: **Facility:** Eunice

Equipment Information

Source ID Number:	111-114	Model:	Other: Flare
Name 2:		Serial Number:	
Name 3:		Service Date:	
Coordinates:		Manufacture Date:	
Northing:		Permit Status:	
Easting:		SCC:	31000205
Source Location Zone:			

Ownership:	DEFS owned	Pilot Gas Flow (mscf/hr)	1.9
Status:	Active	Fuel Heat Value (btu/scf):	1000
Flare Type:	Elevated, non-assisted	Pilot Heat Input (mmbtu/hr):	1.9
Fuel Type:	Natural Gas		
		Potential fuel usage (MMscf/yr):	16.64

Potential operation: 8760 # hr/yr

Potential Emissions

N_2O Calculation[3] (Eq 4-17)

$$E_{N2O} = \frac{16.6 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{1.5 \times 10^{-6} \text{ tonnes } N_2O}{10^{6} \text{ scf gas}}$$

E_{N2O} = **2.49E-05 tonnes N_2O / yr**
2.74E-05 ton N_2O / yr

*Calculations from the Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry August 2009

TOTAL CO2e

Emission Totals

Emission Type	GHG Emissions	CH_4[1]	CO_2	N_2O[2]	CO_2e
	Unit	TPY	TPY	TPY	TPY
Flare	Flare	1.28	0	2.74E-05	26.9

1 warming potential of CH4 is 21 times greater than CO2
2 warming potential of N2O is 310 times greater than CO2
1 tonne = 1.102311 ton
Mole fractions are averaged from gas analyses Eunice 200# Inlet and Eunice 550# Inlet, March 2010

Attachment C – SoLoNOx and SCR estimate

Hong, Hyung S

From: Javier Marquez <Marquez_Javier@solarturbines.com>
Sent: Tuesday, October 1, 2019 3:52 PM
To: Hong, Hyung S
Cc: Cook, John W
Subject: RE: Sam Hong from DCP Midstream contact

Hi Sam,

We have not done many SCR's through our company but the quotes we do have ranged from 850K-1,200,00 depending on what the starting emissions were to what the required target was. From what I can tell it does not looked like we have executed any of the SCR projects. The few of our customers that do have SCR's went directly to the SCR vendors.

Regards,

Javier Marquez
Account Manager, Western Region
Solar Turbines Incorporated
Email: Marquez_Javier@solarturbines.com
Mobile: (432)-559-7430

Caterpillar: Confidential Green

From: Hong, Hyung S <HSHong@dcpmidstream.com>
Sent: Tuesday, October 1, 2019 1:31 PM
To: Javier Marquez <Marquez_Javier@solarturbines.com>
Cc: Cook, John W <JWCook@dcpmidstream.com>
Subject: Sam Hong from DCP Midstream contact

Javier,

Thank you for speaking with me over the phone.

Please see below contact information!

Sam Hong
DCP Midstream
10 Desta Dr. Ste 500W
Midland, TX 79705
432.620.5463 (O) | 432.215.8514 (M)

From: Cook, John W
Sent: Tuesday, October 1, 2019 3:56 AM

	Eunice				
	#1	#2	#3	#4	#5
Best Available in NM	25PPM	25PPM	25PPM	25PPM	25PPM
OH Estimate	$400,000.00	$400,000.00	$400,000.00	$400,000.00	$400,000.00
NOx Conversion Fee to Best Available	$117,606.00	$117,606.00	$117,606.00	$117,606.00	$117,606.00
Required Package Upgrades	$984,667.00	$984,667.00	$984,667.00	$984,667.00	$984,667.00
Total	$1,502,273.00	$1,502,273.00	$1,502,273.00	$1,502,273.00	$1,502,273.00
Site Total	**$7,511,365.00**				

Attachment D – Solar Wet NOx Letter

February 18, 2020
DCP SENM
Attn: John Cook

SUBJECT: Wet Nox on SENM Solar Turbines

Dear Mr. Cook:

Thank you for your questions regarding emissions controls on the South East New Mexico turbines. Currently our emissions controls offering on our 2-shaft turbines are limited to SoLoNOx technology. In the past we have offered Wet-Nox emissions controls on our generator set packages. This technology is no longer offered as our SoLoNOx technology offers lower emissions control with a lower operational cost to our customers. Attached below are the current SoLoNOx emissions limits as well as our historical best available Wet-Nox limits.

Regards,
Javier Marquez
Western Region Aftermarket Account Manager
(432)-559-7430
Marquez_Javier@Solarturbines.com

SoLoNOx-Natural Gas Fuel (ppmvd @15%O2)

Combustor	Pollutant	Taurus 70	Taurus 60	Centaur 50	Centaur 40
		10802S 10302S	7802S	6102S	4702S
SoLoNOx	ISO Nox ppm	15	15	25	25
	CO ppm	25	25	25	50
	UHC Nox ppm	25	25	25	25

Water Injection - Natural Gas Fuel (ppmvd @15% O_2)

Combustor	Pollutant	*Taurus* 70 [m]	*Taurus* 60	*Centaur* 50	*Centaur* 40	*Saturn* 20
		10801 10301	7901	6201	4700	1601
Conventional [a] with Water Injection	ISO NOx ppm (mg/Nm^3)	60 (125)	42 (88)	42 (88)	42 (88)	42 (88)
	CO ppm (mg/Nm^3)	50 (64)	50 (64)	50 (64)	50 (64)	50 (64)
		200 (254)	200 (254)	200 (254)	200 (254)	200 (254)
	UHC ppm (mg/Nm^3)	25 (18)	25 (18)	25 (18)	50 (36)	25 (18)