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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 – Linam Ranch 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 Linam Ranch 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.

Flares

Thank you for providing the flaring supplement to the four-factor analysis for startup, shutdown, and/or maintenance (SSM) flaring emissions. The Department still requires the following information for the flares at the DCP Midstream Linam Gas Plant, Unit Numbers 2, 4A and AGI Flare.

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

   Unit No. 2 (Amine Acid Gas Flare) and Unit No. AGI Flare are both in service providing both emergency as well as startup, shutdown, maintenance/malfunction ("SSM&M") flare function for Linam Ranch Gas Plant's ("Linam Ranch's") acid gas service. Both flares will flare pilot, purge, assist gas and any acid gas flow to the flare that results from SSM&M and other emergency events.

   Unit No. 4A (ESD Flare) serves as an emergency/SSM&M flare and as a process flare to Linam Ranch. The ESD flare will flare pilot, purge, and emission from TEG dehydrator during steady state operations and any gas flow to the flare that results from SSM&M and other emergency events.

   Refer to *Attachment A – Process Flow Diagram and Flare Emission Calculation* as reference.

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

   Steady-state emission from the flares are represented on *Attachment A*.

   Other flaring events include permit-authorized planned SSM flaring events and unplanned flaring events, *e.g*., malfunction-related or emergency flaring events. Planned SSM flaring events are triggered by routine maintenance at frequencies recommended by the manufacturer or as regularly scheduled by DCP as part of planned maintenance. Allowable emission limits in the facility's air permit represent the maximum amount of emissions authorized to occur during planned maintenance activities and startup/shutdown events anticipated pre- and post-maintenance. However, these planned maintenance events do not occur at the same sequence or frequency generally reflected in a permit, *i.e*. quarterly, annually, biennially, etc., therefore, actual emissions that occur at the facility can differ 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 for various unforeseeable, unexpected or unpredictable reasons, such as equipment malfunction, third party power loss, emergencies, *etc*. Excess emission resulting from these events, to the extent they are not reflected in the facility air permit SMM&M allotment, are reported to NMED pursuant to NMAC 20.2.7.110. DCP operates its process equipment and emission control equipment in a manner consistent with good air pollution control practices for minimizing emissions, including minimizing to the extent practicable the duration of unplanned flaring events and the volume of material subjected to such flaring.

3. Discuss potential alternative control options or operational changes that could reduce nitrogen oxides (NO_X) and/or sulfur dioxide (SO_2) flaring emissions, including:

DCP objects to this question 3 to the extent it uses ambiguous or undefined terms, requires speculation, and for the objections referenced above. Preserving those objections, DCP responds as follows.

a. infrastructure that allows re-routing or recirculating the gas within the facility or outside of the facility until an SSM event is over;

Linam Ranch's current infrastructure supports nat. gas re-routing, and off-loading when feasible under certain circumstances, each of which serve to reduce flaring emissions. Linam Ranch has the ability, when necessary, to close the nat. gas inlet to the facility, which significantly limits or prevents flaring at the facility. Linam Ranch 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 Linam Ranch 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. DCP would note that with its operational practices and improvements Linam Ranch has operated within its permitted SSM&M flaring parameters in the last year, and has had minimal or no unanticipated, e.g., malfunction- or third party-related flaring events, so flaring at the facility has been positively managed.

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

The Linam Ranch 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 Linam Ranch 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 Linam Ranch; they would not meaningfully reduce the concentration of H2S that would recognizably affect the amount of sulfur received by the Linam Ranch plant.

c. Gas Capture Plans with facilities located downstream and upstream similar to those required for producers to better synchronize upstream and downstream services with the facility;

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 Linam Ranch plant, is by definition designed to receive and process the producer's nat. gas; DCP's Linam Ranch 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.

d. use of remote capture equipment;

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.

e. 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 Linam Ranch 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.

Note that flaring at an up or downstream facility to avoid flaring at the Linam Gas Plant is not considered to be an actual reduction in flared emissions rates under the four-factor analysis.

4. 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.

5. DCP states in its December 16th letter that "since the sources of SSM emission originates from normal plant activities….notes that it's impractical to employ such measure in order to decrease flaring…and the facility has an existing BMP *[best management practices]* process"….DCP concludes that there are no reasonable nor technically feasible emission reduction measure for flare sources ……" Provide details of the existing BMPs employed at the facility to reduce flaring emissions.

   The referenced passage, above, refers to planned/routine SSM events. Facility equipment has routine maintenance schedules in order to maintain the equipment in good working order.

   Examples of existing BMPs employed at the Linam Ranch Plant to reduce flaring during planned/routine SSM events includes:

   - Coordination/communication between upstream entities (producers), DCP, and downstream entities and facilities prior to and during planned outages to minimize volumes of nat. gas directed to the Linam Ranch nat. gas plant during these events.
   - When practicable and feasible, DCP temporary re-routing of upstream nat. gas to other DCP facilities.
   - When practicable and feasible, producer or DCP use of nat. gas off-load agreements to temporarily route upstream nat. gas to third party facilities.
   - Actions at the facility to minimize the duration/number of SSM events and volume flared through:
     - Critical Spare Program to ensure necessary equipment is on site and lacking such does not delay to duration of a planned event.
     - Coordination between operation and maintenance teams to ensure efficient implementation of a planned event.
     - DCP tracks and documents all work orders for needed maintenance or repairs through an asset management software to ensure that necessary work orders are executed appropriately and on time, which reduces the likelihood of having to have an off-cycle turnaround or maintenance event and associated SSM flaring.

6. The allowable flaring emission limits for NO_X are all less than 5 tons per year (TPY) and Unit AGI Flare has a limit less than 5 tpy for SO_2 which are less that the threshold that NMED established for sources to submit a four-factor analysis. However, in 2016, actual emissions reported for each flare exceeded their allowable limits and DCP's emissions inventory for years 2014 through 2018 show that the AGI flare and amine plant flare consistently exceeded allowable limits. (See Table 1.) Please explain the discrepancy between the SSM SO_2 emissions provided in the supplemental flaring analysis and NMED's 2016 emissions inventory. As the permitted limits do not reflect actual operations at the facility, please resubmit the four-factor analysis for the flares based on actual emissions reported in 2016. (See Table 1.)

Table 1 SSM Flare Emission Rates and Limits		
Flare Unit	NO_X tpy	SO_2 tpy
Emission Limits		
2	0.51	46.0
4A	3.3	18.9
AGI Flare	0.34	4.06
Emissions reported in 2016 Emissions Inventory		
2	1.84	26.97
4A	0.09	35.86
AGI Flare	1.84	242.85
Emissions Reflected in Four-Factor Supplement Dec 16, 2019		
2	0	3.28
AGI Flare	0	0
Malfunction	0.04	9.79

The SSM SO2 emission amount described in DCP's Dec. 16, 2019, letter only refers to authorized/permitted emissions and does not include reported excess emissions resulting from unforeseeable or unplanned, *e.g.*, malfunction-related events. Table 2 of the December 16, 2019 submitted response is titled "2016 EIQ Reported **Process Flaring** and **SSM Flaring** Emission".

The reported excess emissions not included in the above table can differ from year to year and are, by nature, unforeseeable/unanticipated. These events are addressed through facility's continuous improvement efforts to reduce such events by, for example, identifying causes and addressing them through equipment investments and/or operational improvements. As a result, Linam Ranch had zero excess emission events since February 10, 2019, and recently celebrated one year without an excess emission event.

Turbines

1. Provide documentation from Solar that they do not manufacture turbines with steam injection technology and that the Centaur 40 is not capable of being retrofitted to accept this technology.

   Please reference DCP's original November 2019 four factor analysis report on this topic. The report does not indicate that the Solar Turbine is not capable of being retrofitted to accept this technology, but rather states that "[s]team injection is not discussed as an option for these Solar turbines at Linam because Solar does not manufacture turbines with steam injection technology", meaning Solar no longer offers steam injection retrofit packages because they are obsolete. Please refer to *Attachment B – Solar Wet NOx Letter*, which states that Solar does not offer Wet-NOx technology.

2. Consider and include a discussion of the technical feasibility of other types of catalytic combustion, such as XONON^{TM} developed by Catalytic Combustion Systems, Inc.

   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.

3. Provide more detail of the Good Combustion Practices that have been implemented on the turbines, including routine inspections, maintenance and training schedules. It is unclear if these practices are fully optimized or conform to permit conditions alone.

DCP objects to the use of an ambiguous or undefined term or phrase, and to the extent this question requires speculation. The turbines at Linam Ranch 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.

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

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 Linam Ranch. The four turbines subject to the Four Factor Analysis (Units 29, 30, 31 and 32B) have total site rating horsepower of 28,291 HP. Accommodating nearly 30,000 HP electric motor capacity is not feasible with the present electric infrastructure at Linam Ranch, would require significant electric power supply analysis, and would, for example, potentially require construction of a new 100 MW substation.
Construction of a substation 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 for this HP equivalent, technical feasibility would require a feasibility study by XCEL Energy, which can take longer than 18-24 Months.

Please refer to *Attachment C – Priority Power Discussion*.

5. Provide copies of vendor quotes used to determine the cost of compliance.

DCP notes that in its initial report provided a vendor estimate of expected costs for retrofitting existing turbines; this was not a vendor quote providing more accuracy with respect to costs, and it is what was available in the time provided.

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

Engines

1. Provide more detail of the Good Combustion Practices that have been implemented on the two-stroke lean-burn (2SLB) engines, including routine inspections, maintenance and training schedules. It is unclear if these practices are fully optimized or conform to permit conditions alone.

   DCP objects to the use of an ambiguous or undefined term or phrase, and to the extent this question requires speculation. Linam's two-stroke lean-burn (2SLB) engine's Good Combustion Practices includes routine inspection and preventative maintenance. Also, prior to every quarterly preventative maintenance, DCP use specialized tool to monitor engine running condition and check for presence of any abnormal vibration. Routine inspection and all interval PM activities are tracked through DCP's asset management and maintenance system to ensure they are implemented appropriately and in a timely manner. Inspection/Maintenance is appropriately optimized for the emission units based on DCP's long history/experience operating such engines.

2. Provide more detail on why the age of the 2SLB engines prohibits retrofitting these units with Clean Burn Technology, including a discussion on why the installation of high energy ignition systems (HEIS) is not feasible. It would be beneficial to submit detailed documentation from the vendor on why none of the CBT options is technically feasible.

   Referencing the initial four factor analysis report submitted for Linam Ranch, the report states that "*2SLB engines are mechanically capable of being retrofit with more sensitive air-to-fuel ratio controllers and running on higher air-to-fuel ratio combustion to control NOX emissions. However, based on the advanced age, type of engine, **and discussion with vendor**, DCP has determined that clean burn technology retrofits are physically possible yet deemed technically infeasible for the engines at Linam*."

   Above statement was based on discussion with the vendor, but also with DCP's experienced asset engineers – due to the type and vintage of these particular 2SLB engines, any clean burn retrofit technology would (i) require detailed studies/evaluations of each engine for custom retrofit specific to these engines, and (ii) while hypothetically feasible, such retrofits for this type and vintage engines would be so extensive and invasive that they would be as or more uneconomical than a new engine, so the retrofit emissions control technology is deemed impracticable, otherwise infeasible, for these particular engines.
   DCP believes a retrofit control technology is infeasible and beyond the scope of the Regional Haze rule if the cost of the control technology exceeds the cost of the base authorized/permitted emissions source; with the time limitations afforded, DCP was not able to develop further analyses and details on potential CBT retrofit actions for these particular 2SLB engines.

3. The report references AP-42 Section 3.2 that identifies Selective Catalytic Reduction (SCR) as an available control technology for 2SLB engines. Provide supporting data and information for the determination that SCR systems may result in technical complications and unreliable operation. Documentation from the equipment vendor detailing the technical drawbacks to this technology and the preferred technology for NO_X would be beneficial.

   Please refer to *Attachment E – Engine SCR vendor discussion*.

   After further discussion over the phone with the vendor representative, if an SCR were applied to these 2SLB engines the vendor is not able to guarantee life of catalyst nor accurate emission reduction that SCR system would be intended to achieve. DCP's facility engineer indicates that backpressures imposed by the SCR system will result in de-rated output of the unit. Therefore, DCP deemed this technology too uncertain, and fundamentally affecting the authorized equipment, to be considered as technically feasible control technology for engines at Linam Ranch.

4. The report states that the exhaust oxygen levels for 2SLB engines are not sufficiently low to support that occur during non-selective catalytic reduction (NSCR). Has DCP Midstream verified the average exhaust oxygen levels from each stack to support this assertion?

   DCP has data reflecting exhaust oxygen levels for these engines verified by data in third party stack test reports. Please refer to *Attachment F – EU 10 & 11 Stack Test Report.* These exhaust oxygen levels reflect oxygen levels that are too high to accommodate an NSCR process. There is no requirement to verify average exhaust oxygen levels, so it is unreasonable to expect such is available.

5. Consider and include a discussion on the feasibility and cost of technology that limits engine capacity to reduce NO_X 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 engine capacity), in this case properly authorized, permitted, and operating nat. gas-fired engines – 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.

6. Please consider and include a discussion on the feasibility of replacing the natural gas-fueled engines 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 engines – 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 Linam Ranch gas plant's existing infrastructure does not support replacement of nearly 10,000 HP natural gas-fueled engines with electric driven motors. Please refer to discussion provided on Turbine question 4.

7. Provide copies of vendor quotes used to determine the cost of compliance.

   There are no vendor quotes used for the engines at Linam Ranch.

8. Provide the electronic spreadsheets used for control cost calculations.

   There are no cost calculation spreadsheets for the engines at Linam Ranch.

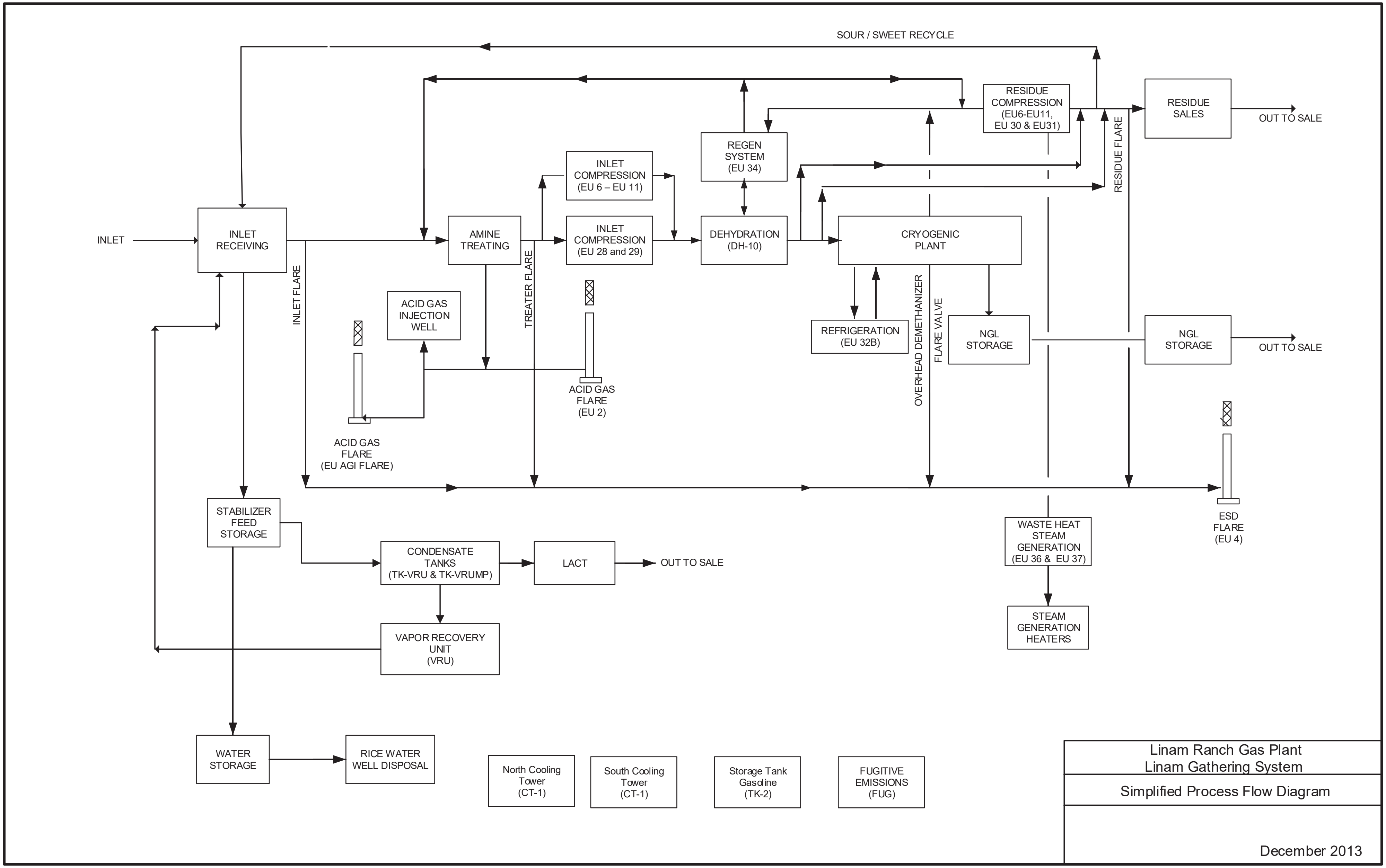
If you have any questions on the specific responses provided, please feel free to contact me directly by phone at 432-215-8514 or via email at hshong@dcpmidstream.com.

Sincerely,

Sam Hong
Environmental Engineer
DCP Midstream, LP

Enclosures

Attachment A – Process Flow Diagram and Flare Emission Calculation



SOUR / SWEET RECYCLE
INLET
INLET RECEIVING
INLET FLARE
AMINE TREATING
TREATER FLARE
INLET COMPRESSION (EU 6 – EU 11)
INLET COMPRESSION (EU 28 and 29)
REGEN SYSTEM (EU 34)
DEHYDRATION (DH-10)
CRYOGENIC PLANT
RESIDUE COMPRESSION (EU6-EU11, EU 30 & EU31)
RESIDUE SALES
OUT TO SALE
RESIDUE FLARE
ACID GAS INJECTION WELL
ACID GAS FLARE (EU 2)
ACID GAS FLARE (EU AGI FLARE)
REFRIGERATION (EU 32B)
OVERHEAD DEMETHANIZER
FLARE VALVE
NGL STORAGE
NGL STORAGE
OUT TO SALE
ESD FLARE (EU 4)
STABILIZER FEED STORAGE
CONDENSATE TANKS (TK-VRU & TK-VRUMP)
LACT
OUT TO SALE
WASTE HEAT STEAM GENERATION (EU 36 & EU 37)
STEAM GENERATION HEATERS
VAPOR RECOVERY UNIT (VRU)
WATER STORAGE
RICE WATER WELL DISPOSAL
North Cooling Tower (CT-1)
South Cooling Tower (CT-1)
Storage Tank Gasoline (TK-2)
FUGITIVE EMISSIONS (FUG)
Linam Ranch Gas Plant
Linam Gathering System
Simplified Process Flow Diagram
December 2013

E. Amine Unit Acid Gas Flare- Acid Gas Analysis (per 11/4/13 DCP Email)

Emission Unit: Acid Gas Flare

Estimated Flared Gas Composition Used for Calculations

Component	MW	Flared Gas[1] Mol%	MW * wet vol %	HHV Btu/scf[2]	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb
Water	18.02	1.13%	0.20	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	18.71%	6.38	637.02	119.2	0.15	11.136	
Carbon Dioxide	44.01	80.65%	35.50	0.0	0.0	0.84	8.623	
Nitrogen	28.01	0.01%	0.00	0.0	0.0	0.00	13.547	
Oxygen	32.00	0.00%	0.00	0.0	0.0	0.00	11.859	
Methane	16.04	0.36%	0.06	1009.7	3.6	0.00	23.65	
Ethane	30.07	0.08%	0.02	1768.7	1.4	0.00	12.62	
Propane	44.10	0.03%	0.02	2517.2	0.9	0.00	8.606	1.094
i-Butane	58.12	0.06%	0.03	3252.6	1.8	0.00	6.529	1.790
n-Butane	58.12	0.02%	0.01	3262	0.8	0.00	6.529	0.764
i-Pentane	72.15	0.01%	0.00	3999.7	0.2	0.00	5.26	0.167
n-Pentane	72.15	0.01%	0.01	4008.7	0.3	0.00	5.26	0.266
Hexanes	86.18	0.05%	0.05	4756.1	2.6	0.00	4.404	1.759
		101%	42.28		130.9	1.00		5.840
NMNEHC (VOC)		0.2%				0.3%		

[1] Based on DCP's recent 11/1/13 Linam Ranch Acid Gas Flare Gas Analysis to provide conservative estimates for sulfur dioxide and heat release estimate.

[2] Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.

Fuel Data

Flare Pilot	500	scf/hr	Engineering judgement
	0.00050	MMscf/hr	
	1000	Btu/scf	Pipeline Gas, HHV, nominal
	0.50	MMBtu/hr	MMscf/hr * Btu/scf
Purge Gas	16	Mscf/day	per DCP Midstream (Jennifer Corser 10/29/13 email)
	0.67	Mscf/hr	Mscf/d / 24 hr/day
	0.001	MMscf/hr	Mscf/hr / 1000
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	0.67	MMBtu/hr	MMscf/hr * Btu/scf
Assist Gas			
	135	Btu/scf	Heating value of Pilot + Purge gas + Flared gas
	500	Btu/scf	target heat content
	1000	Btu/scf	Assist gas-assumed sweet
	0.18	MMscf/hr	Assist gas volume
	182.5	MMBtu/hr	Assist gas heat input
Assist gas - Annual*	5.0	MMscf/yr	Estimated Maximum annual SSM flow rate. Not a requested limit; for calculation only.

Note: Flared gas annual/ ratio of assist gas: flared gas hourly usage) ex: 10.5 MMscf/yr / (1-.8054)

Flared Gas - Short Term	0.25	MMscf/hr	High end representative SSM hourly flowrate taken from 2010 - 2013 Blowdown Data for Unit 2
	131	Btu/scf	Heating value calculated from gas compostion above.
	33	MMBtu/hr	Hourly heat rate = Heating value * Effective hourly flow rate.
Flared Gas - Annual	2.9	MMscf/yr	Estimated Maximum annual SSM flow rate. Taken from avg of 2010 - 2013 SSM blowdown data for Linam Ranch GP. Not a requested limit; for calculation only.
Total	216	MMBtu/hr	**Pilot + Purge gas + Flared gas**

Stack Parameters

	1,832	˚F	Exhaust temperature	
	65.6	ft/sec	Exhaust velocity	
	222.0	ft	Flare height	
Pilot+ Purge Gas only				
	16.04	g/mol	Pilot & Purge gas molecular weight	Mol. wt. of methane, the dominant species
	81,667	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
	65,967		q_n	$q_n = q(1-0.048(MW)^{1/2})$
	0.26	m	Effective stack diameter (D)	$D = (10^{-6} q_n)^{1/2}$
Pilot + Purge Gas+ Flared Gas + Assist Gas				
	42.16	g/mol	Flared gas molecular weight	Volume weighted mol. wt. of all components
	1.52E+07	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
	1.04E+07		q_n	$q_n = q(1-0.048(MW)^{1/2})$
	3.23	m	Effective stack diameter (D)	$D = (10^{-6} q_n)^{1/2}$

E. Amine Unit Acid Gas Flare- Acid Gas Analysis (per 11/4/13 DCP Email)

Emission Unit: Acid Gas Flare

Emission Rates

Pilot+ Purge Gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.068	0.370				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			3.6E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			4.2E-04		lb H_2S/hr	H_2S rate * fuel usage
				7.1E-03	lb S/Mscf	Sweet natural gas fuel, 5 gr S/100scf
				8.3E-03	lb SO_2/hr	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		23.7			ft^3/lb	Specific volume (methane)
		0.00			lb/hr	vol. Gas * mole fraction / specific volume
100%	100%	100%	100%	100%	%	Safety Factor
0.14	0.74				lb/MMBtu	Unit emission rate with Safety Factor
0.16	**0.86**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**1.7E-05**	**1.7E-02**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
0.69	**3.8**	**-**	**7.3E-05**	**7.3E-02**	tpy	8760 hrs/yr

Assist gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.0680	0.3700				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			4E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			6.52E-02		lb H_2S/hr	H_2S rate * fuel usage
				7.1E-03	lb S/Mscf	Purchased sweet natural gas fuel, 5 gr S/100scf
				1.3	lb SO_2/hr	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		23.7			ft^3/lb	Specific volume (methane)
		0.000			lb/hr	vol. Gas * mole fraction / specific volume
12.4	**67.5**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**1.3E-03**	**1.3**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
0.17	**0.92**	**-**	**1.8E-05**	**0.018**	tpy	

Flared Gas

NOx	CO	VOC	H_2S	SO_2	Total HAPs	Units	
0.068	0.370					lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
		0.18%	0.187		0.05%	mol%	Flare Gas
		5.8	11.1		4.4	ft^3/lb	Specific volume
		77.9	4201		31.1	lb/hr	vol. Gas * mole fraction / specific volume
2.2	12.1					lb/hr	lb/MMBtu * MMBtu/hr
2.2	**12**	**78**	**4201**	**7750**	**31**	**lb/hr**	Uncontrolled emissions at maximum rate
0.013	**0.070**	**0.45**	**24**	**46**	**0.18**	**tpy**	

Controlled #2 Acid Gas Flare	NOx	CO	VOC	H_2S	SO_2	HAPs	Units
Pilot + Purge Gas+ Flared Gas	**14.9**	**80.6**	**1.6**	**84.0**	**7751**	**0.62**	lb/hr
	0.88	**4.8**	**0.0090**	**0.48**	**45.6**	**0.0036**	tpy

Total HAPs conservatively assumed to be Hexanes+

GHG Emissions

	CO_2e Short Tons/yr		
CO_2	137	Eq 4-15	API Compendium
CH_4	1.1E-03	Eq 4-16	API Compendium
N_2O	4.8E-06	Eq 4-17	API Compendium
Total CO2e	**137**		

ESD Flare- per 11/11/13 Extended Inlet Gas Analysis

Emission Unit: ESD Flare

Estimated Flared Gas Composition Used for Calculations

Component	MW	Flared Gas[1] Mol%	MW * wet vol %	HHV Btu/scf[2]	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb
Water	18.02	0.00%	0.00	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	0.38%	0.13	637.02	2.4	0.01	11.136	
Carbon Dioxide	44.01	1.61%	0.71	0.0	0.0	0.03	8.623	
Nitrogen	28.01	2.46%	0.69	0.0	0.0	0.03	13.547	
Oxygen	32.00	0.00%	0.00	0.0	0.0	0.00	11.859	
Methane	16.04	73.54%	11.80	1009.7	742.5	0.54	23.65	
Ethane	30.07	12.59%	3.78	1768.7	222.6	0.17	12.62	
Propane	44.10	6.15%	2.71	2517.2	154.7	0.12	8.606	4.863
i-Butane	58.12	0.70%	0.40	3252.6	22.6	0.02	6.529	0.551
n-Butane	58.12	1.62%	0.94	3262	52.8	0.04	6.529	1.281
n- & iso-Pentanes	72.15	0.65%	0.47	3999.7	25.9	0.02	5.26	0.512
Cyclopentane	70.14	0.03%	0.02	4008.7	1.1	0.00	5.26	0.022
C6 HCs	86.18	0.15%	0.13	4747.3	7.1	0.006	4.404	0.118
C7 HCs	100.21	0.04%	0.04	5498.6	2.4	0.002	3.787	0.035
C8 HCs	114.23	0.01%	0.01	6248.9	0.3	0.0003	3.322	0.004
C9 HCs	128.26	0.00%	0.00	6996.3	0.1	0.0001	2.959	0.001
n-Hexane	86.18	0.05%	0.05	4756.1	2.6	0.00213	4.404	0.043
Benzene	78.11	0.03%	0.02	3741.9	1.0	0.00098	4.858	0.022
Toluene	92.14	0.01%	0.01	4474.8	0.3	0.00024	4.119	0.004
Ethyl Benzene	106.17	0.0001%	0.00	5222.1	0.0	0.000005	3.574	0.000
Xylenes	106.17	0.0002%	0.00	5207.8	0.0	0.00001	3.574	0.000
		100%	21.91		1238.6	1.00		7.456
NMNEHC (VOC)		9.4%				21.9%		

[1] *Based on DCP's recent 11/11/13 Linam Ranch inlet gas analysis from 11/6/13 sample to provide accurate estimates for sulfur dioxide and heat release.*

[2] *Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.*

Fuel Data

Flare Pilot	500	scf/hr	Engineering judgement
	0.00050	MMscf/hr	
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	0.50	MMBtu/hr	MMscf/hr * Btu/scf
Purge Gas	63.8	Mscf/day	per DCP Midstream (Jennifer Corser 10/29/13 email)
	2.7	Mscf/hr	Mscf/d / 24 hr/day
	0.0027	MMscf/hr	Mscf/hr / 1000
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	2.7	MMBtu/hr	MMscf/hr * Btu/scf
Flared Gas - Short Term	3.410	MMscf/hr	Maximum Effective hourly flowrate taken from 2010 - 2013 Blowdown Data for AGI Flare
	1,239	Btu/scf	Heating value calculated from gas compostion above.
	4,224	MMBtu/hr	Hourly heat rate = Heating value * Effective hourly flow rate.
Flared Gas - Annual	58.2	MMscf/yr	Estimated Maximum annual SSM flow rate. Taken from avg of 2010 - 2013 SSM blowdown data for Linam Ranch GP. Not a requested limit; for calculation only.
Total	4227	MMBtu/hr	**Pilot + Purge gas + Flared gas**

Stack Parameters

	1,832	˚F	Exhaust temperature	Per Linam 2-H sheet
	65.6	ft/sec	Exhaust velocity	Per Linam 2-H sheet
	175.0	ft	Flare height	
Pilot+ Purge Gas only				
	16.04	g/mol	Pilot & Purge gas molecular weight	Mol. wt. of methane, the dominant species

ESD Flare- per 11/11/13 Extended Inlet Gas Analysis

Emission Unit: ESD Flare

221,083	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
178,582		q_n	$q_n = q(1-0.048(MW)^{1/2})$
0.42	m	Effective stack diameter (D)	$D = (10^{-6} q_n)^{1/2}$

Pilot + Purge Gas+ Flared Gas

21.90	g/mol	Flared gas molecular weight	Volume weighted mol. wt. of all components
2.96E+08	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
2.29E+08		q_n	$q_n = q(1-0.048(MW)^{1/2})$
15.1	m	Effective stack diameter (D)	$D = (10^{-6} q_n)^{1/2}$

Emission Rates

Pilot+ Purge Gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.068	0.370				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			4E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			1.1E-03		lb H_2S/hr	H_2S rate * fuel usage
				7E-03	lb S/Mscf	Sweet natural gas fuel, 5 gr S/100scf
				2E-02	lb SO_2/hr*	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		12.6			ft^3/lb	Specific volume (methane)
		0.00			lb/hr	vol. Gas * mole fraction / specific volume
100%	100%	100%	100%	100%	%	Safety Factor
0.14	0.74				lb/MMBtu	Unit emission rate with Safety Factor
0.43	**2.3**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**4.5E-05**	**4.5E-02**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
1.9	**10.2**	**-**	**2.0E-04**	**2.0E-01**	tpy	8760 hrs/yr

Flared Gas

NOx	CO	VOC	H_2S	SO_2	Total HAPs	Units	
0.068	0.370					lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
		9.43%	0.38%		0.09%	mol%	Flare Gas
		7.5	11		4.1	ft^3/lb	Specific volume
		43,114	1,165		728	lb/hr	vol. Gas * mole fraction / specific volume
287	1563					lb/hr	lb/MMBtu * MMBtu/hr
287	**1563**	**43,114**	**1,165**	**2,148**	**728**	**lb/hr**	Uncontrolled emissions at maximum rate
2.4	**13**	**368**	**9.9**	**19**	**6.2**	**tpy**	

Controlled AGI Flare	**NOx**	**CO**	**VOC**	**H_2S**	**SO_2**	**HAPs**	**Units**
Pilot + Purge Gas+ Flared Gas	**287.8**	**1,564**	**861.8**	**23**	**2,148**	**15**	lb/hr
	4.3	**23.6**	**7.4**	**0.20**	**18.9**	**0.12**	tpy

Total HAPs conservatively assumed to be Hexanes+

GHG Emissions

	CO_2e Short Tons/yr		
CO_2	4,387	Eq 4-15	API Compendium
CH_4	4.5E+00	Eq 4-16	API Compendium
N_2O	9.6E-05	Eq 4-17	API Compendium
Total CO2e	**4,500**		

AGI Flare- Acid Gas Analysis (per 11/4/13 DCP Email)

Emission Unit: AGI Flare

Estimated Flared Gas Composition Used for Calculations

Component	**MW**	**Flared Gas[1] Mol%**	**MW * wet vol %**	**HHV Btu/scf[2]**	**Btu/scf * wet vol %**	**Mass Fraction (wet)**	**Spec. Volume[2] ft^3/lb**	**Spec. Volume VOC ft^3/lb**
Water	18.02	1.13%	0.20	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	18.71%	6.38	637.02	119.2	0.15	11.136	
Carbon Dioxide	44.01	80.65%	35.50	0.0	0.0	0.84	8.623	
Nitrogen	28.01	0.01%	0.00	0.0	0.0	0.00	13.547	
Oxygen	32.00	0.00%	0.00	0.0	0.0	0.00	11.859	
Methane	16.04	0.36%	0.06	1009.7	3.6	0.00	23.65	
Ethane	30.07	0.08%	0.02	1768.7	1.4	0.00	12.62	
Propane	44.10	0.03%	0.02	2517.2	0.9	0.00	8.606	1.094
i-Butane	58.12	0.06%	0.03	3252.6	1.8	0.00	6.529	1.790
n-Butane	58.12	0.02%	0.01	3262	0.8	0.00	6.529	0.764
i-Pentane	72.15	0.01%	0.00	3999.7	0.2	0.00	5.26	0.167
n-Pentane	72.15	0.01%	0.01	4008.7	0.3	0.00	5.26	0.266
Hexane	86.18	0.05%	0.05	4756.1	2.6	0.00	4.404	1.759
		101%	42.28		130.9	1.00		5.840
NMNEHC (VOC)		0.2%				0.3%		

[1] Based on DCP's recent 11/1/13 Linam Ranch Acid Gas Flare Gas Analysis to provide conservative estimates for sulfur dioxide and heat release estimate.
[2] Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.

Fuel Data

Flare Pilot	500	scf/hr	Engineering judgement
	0.0005	MMscf/hr	
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	0.50	MMBtu/hr	MMscf/hr * Btu/scf
Purge Gas	16	Mscf/day	per DCP Midstream (Jennifer Corser 10/29/13 email)
	0.67	Mscf/hr	Mscf/d / 24 hr/day
	0.001	MMscf/hr	Mscf/hr / 1000
	1000	Btu/scf	Pipeline Gas, HHV, nominal from Linam T5 app.
	0.67	MMBtu/hr	MMscf/hr * Btu/scf
Assist Gas			
	134	Btu/scf	Heating value of Pilot + Purge gas + Flared gas
	500	Btu/scf	target heat content
	1000	Btu/scf	Assist gas-assumed sweet
	0.22	MMscf/hr	Assist gas volume
	219	MMBtu/hr	Assist gas heat input
Assist gas - Annual*	0.44	MMscf/yr	Estimated Maximum annual SSM flow rate. Not a requested limit; for calculation only.

Note: Flared gas annual/ ratio of assist gas: flared gas hourly usage) ex: 10.5 MMscf/yr / (1-.8054)

Flared Gas - Short Term	0.30	MMscf/hr	Maximum Effective hourly flowrate taken from 2010 - 2013 Blowdown Data for AGI Flare
	131	Btu/scf	Heating value calculated from gas compostion above.
	39	MMBtu/hr	Hourly heat rate = Heating value * Effective hourly flow rate.
Flared Gas - Annual	0.26	MMscf/yr	Estimated Maximum annual SSM flow rate. Taken from avg of 2010 - 2013 SSM blowdown data for Linam Ranch GP. Not a requested limit; for calculation only.
Total	260	MMBtu/hr	**Pilot + Purge gas + Flared gas**

Stack Parameters

	1,832	˚F	Exhaust temperature	Per Linam 2-H sheet
	65.6	ft/sec	Exhaust velocity	Per Linam 2-H sheet
	210.0	ft	Flare height	
Pilot+ Purge Gas only				
	16.04	g/mol	Pilot & Purge gas molecular weight	Mol. wt. of methane, the dominant species

AGI Flare- Acid Gas Analysis (per 11/4/13 DCP Email)

Emission Unit: AGI Flare

81,667	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
65,967		q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
0.26	m	Effective stack diameter (D)	$D = (10^{-6} q_n)^{1/2}$

Pilot + Purge Gas+ Flared Gas + Assist Gas

42.18	g/mol	Flared gas molecular weight	Volume weighted mol. wt. of all components
1.82E+07	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
1.25E+07		q_n	$q_n = q(1\text{-}0.048(MW)^{1/2})$
3.5	m	Effective stack diameter (D)	$D = (10^{-6} q_n)^{1/2}$

Emission Rates

Pilot+ Purge Gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.068	0.37				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			3.6E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			4.17E-04		lb H_2S/hr	H_2S rate * fuel usage
				7.1E-03	lb S/Mscf	Sweet natural gas fuel, 5 gr S/100scf
				8.3E-03	lb SO_2/hr*	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		13			ft^3/lb	Specific volume (methane)
		0.00			lb/hr	vol. Gas * mole fraction / specific volume
100%	100%	100%	100%	100%	%	Safety Factor
0.14	0.74				lb/MMBtu	Unit emission rate with Safety Factor
0.16	**0.86**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**1.7E-05**	**1.7E-02**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
0.69	**3.8**	-	**7.3E-05**	**7.3E-02**	tpy	8760 hrs/yr

Assist gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.068	0.370				lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
			3.6E-04		lb H_2S/Mscf	Purchased sweet natural gas fuel, 0.25 gr H_2S/100scf
			7.84E-02		lb H_2S/hr	H_2S rate * fuel usage
				7.1E-03	lb S/Mscf	Purchased sweet natural gas fuel, 5 gr S/100scf
				1.6E+00	lb SO_2/hr	SO_2 rate * fuel usage
		0.00%			mol%	Assume no VOC content in purchased fuel (methane)
		12.6			ft^3/lb	Specific volume (methane)
		0.000			lb/hr	vol. Gas * mole fraction / specific volume
14.9	**81.2**				lb/hr	lb/MMBtu * MMBtu/hr
		-	**1.6E-03**	**1.6E+00**	lb/hr	98% combustion H_2S; 100% conversion to SO_2
0.015	**40.6**	-	**1.6E-06**	**1.6E-03**	tpy	

Flared Gas

NOx	CO	VOC	H_2S	SO_2	Total HAPs	Units	
0.0680	0.3700					lb/MMBtu	AP-42 Table 13.5-1 (9/91) (Reformatted 1/95)
		0.18%	18.71%		0.05%	mol%	Flare Gas
		5.840	11.136		4.404	ft^3/lb	Specific volume
		93.5	5,041.4		37.3	lb/hr	vol. Gas * mole fraction / specific volume
2.67	14.53					lb/hr	lb/MMBtu * MMBtu/hr
2.7	**14.5**	**93.5**	**5,041.4**	**9,299.9**	**37.3**	**lb/hr**	Uncontrolled emissions at maximum rate
0.0011	**0.0062**	**0.040**	**2.2**	**4.1**	**0.016**	**tpy**	

Controlled AGI Flare	NOx	CO	VOC	H_2S	SO_2	HAPs	Units
Pilot + Purge Gas+ Flared Gas	**17.9**	**96.6**	**1.9**	**101**	**9,301**	**0.75**	lb/hr
	0.71	**44**	**8.0E-04**	**0.043**	**4.1**	**0.00032**	tpy

Total HAPs conservatively assumed to be Hexanes+

GHG Emissions

	CO_2e Short Tons/yr		
CO_2	0.2	Eq 4-15	API Compendium
CH_4	9.7E-05	Eq 4-16	API Compendium
N_2O	4.2E-07	Eq 4-17	API Compendium
Total CO2e	**0**		

Attachment B – Solar Wet NOx Letter

Solar Turbines

A Caterpillar Company

Powering the Future Through Sustainable, Innovative Energy Solutions

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)

Attachment C – Priority Power Discussion

Hong, Hyung S

From:	Cook, John W
Sent:	Thursday, February 20, 2020 2:03 PM
To:	Tourangeau, Paul R; Hong, Hyung S
Subject:	FW: Xcel - Linam Ranch Gas Plant

From: LAnglois, Kenneth J
Sent: Thursday, February 20, 2020 1:54 PM
To: Cook, John W <JWCook@dcpmidstream.com>
Cc: Admire, John D <JDAdmire@dcpmidstream.com>
Subject: Fwd: Xcel - Linam Ranch Gas Plant

FYI

Kenneth
936-446-8366
Get Outlook for iOS

From: Brian Craig <bcraig@prioritypower.net>
Sent: Thursday, February 20, 2020 11:45 AM
To: LAnglois, Kenneth J
Cc: Smith, Rodney P; Roger Kienast; Kevin Yung
Subject: Xcel - Linam Ranch Gas Plant

Kenneth,
The second part to your question related to the 100 MW is a much more involved issue. Serving a load this size would require a major study on the part of XCEL to see how this load could be served. Any transmission project (regardless of size) must go through XCEL's transmission planning group to see what it would take to serve the load. In this case, the amount of load is so large, that the capacity of the lines now also come into play. Normally our rule of thumb for a 10 MW load would be 18 months to 24 months from the date the customer initiates studies. Increasing the load 10 fold will definitely stretch this out. I would like to tell you it could be done in 3 yrs but that really is going to depend on the generation capacity and whether or not the conductors need to be resized to handle the new load.

Best way to find out is to submit a request to XCEL and let them study it. The request will need a detailed load list showing all the motors, et all that add up to the 100 MW of load. Let me know if this is what you want to do and if so I will reach out to XCEL to get more information.

Thanks,

Brian

Brian Craig | Sr. Director, Business Development

Priority Power Management LLC | *Your Trusted Energy Advisor*
690 E. Lamar Blvd., Suite 500 | Arlington, TX 76011
T 817.453.1411 | F 817.549.0164 | C 817.320.7269
bcraig@prioritypower.net | www.prioritypower.net

From: Brian Craig
Sent: Thursday, February 20, 2020 11:12 AM
To: L'Anglois, Kenneth J <KJLAnglois@dcpmidstream.com>
Cc: Smith, Rodney P <RPSmith@dcpmidstream.com>
Subject: Xcel - Linam Ranch Gas Plant

Kenneth,
See Roger's note below on the capacity of the line being 13.9 MVA. This would indicate you have room to add another 2.500 hp load without issues. However, this only addresses your feeder from the plant to the substation (the one PPM built for you). Still need to check with XCEL on their system and capabilities. I will reach out to them and see what they say.

Brian

Brian Craig | Sr. Director, Business Development

Priority Power Management LLC | *Your Trusted Energy Advisor*
690 E. Lamar Blvd., Suite 500 | Arlington, TX 76011
T 817.453.1411 | F 817.549.0164 | C 817.320.7269
bcraig@prioritypower.net | www.prioritypower.net

From: Roger Kienast <rkienast@prioritypower.net>
Sent: Wednesday, February 19, 2020 12:05 PM
To: Brian Craig <bcraig@prioritypower.net>; Kevin Yung <kyung@prioritypower.net>
Subject: RE: Xcel - Linam Ranch Gas Plant

Brian, we built the DCP Linam one-span feeder with 477 ACSR for this 7.2/12.47kV distribution line. That wire size can handle up to 646amps, which is about 13.9 MVA. However, it should not be loaded up to that amount, as DCP will experience voltage problems before that limit.

Adding more load truly depends on Xcel Energy's approval and ability to serve it. Attached is the PSA from James Delaney in May 2018. Unfortunately, it doesn't list how much they are approved for at the PME. Perhaps you have records of that and/or can get it from Xcel?

Thanks.

Roger Kienast, P.E. | Sr. Project Engineer, Lead

Priority Power Management LLC | *Your Trusted Energy Advisor*
Office: 432.620.9100 Fax: 432.620.9145
Direct: 432.400.2460 Cell: 605.376.5166
5012 Portico Way, Midland, TX 79707
rkienast@prioritypower.net | www.prioritypower.net

From: Brian Craig <bcraig@prioritypower.net>
Sent: Wednesday, February 19, 2020 11:27 AM
To: Kevin Yung <kyung@prioritypower.net>; Roger Kienast <rkienast@prioritypower.net>
Subject: Xcel - Linam Ranch Gas Plant

Can you help me with Kenneth's question?

Current load is as follows:

$ 2,262,538.84 Total Cost of **16 Bills**

	Account Code	Billing Period - 1	Bill Begin Date	Bill End Date	Days
	5483641736	Dec 2019	12/17/2019	01/20/2020	34
	5483641736	Nov 2019	11/14/2019	12/17/2019	33
	5483641736	Oct 2019	10/16/2019	11/14/2019	29
	5483641736	Sep 2019	09/17/2019	10/16/2019	29
	5483641736	Aug 2019	08/16/2019	09/17/2019	32
	5483641736	Jul 2019	07/18/2019	08/16/2019	29
	5483641736	Jun 2019	06/18/2019	07/18/2019	30
	5483641736	May 2019	05/17/2019	06/18/2019	32
	5483641736	Apr 2019	04/18/2019	05/17/2019	29
	5483641736	Mar 2019	03/20/2019	04/18/2019	29
	5483641736	Feb 2019	02/19/2019	03/20/2019	29
	5483641736	Jan 2019	01/18/2019	02/19/2019	32
	5483641736	Dec 2018	12/17/2018	01/18/2019	32
	5483641736	Nov 2018	11/14/2018	12/17/2018	33
	5483641736	Oct 2018	10/15/2018	11/14/2018	30
	5483641736	Sep 2018	09/16/2018	10/15/2018	29

What size line was put in for the Linam Ranch Feeder from the Monument sub (12.5kV or 25kV? Expect there is plenty of capacity regardless for the additional 2,500 hp unit. I am not aware of a study done by XCEL to address the adding of this unit.

Brian

From: LAnglois, Kenneth J <KJLAnglois@dcpmidstream.com>
Sent: Wednesday, February 19, 2020 10:36 AM
To: Brian Craig <bcraig@prioritypower.net>
Cc: Smith, Rodney P <RPSmith@dcpmidstream.com>; Cook, John W <JWCook@dcpmidstream.com>
Subject: Xcel - Linam Ranch Gas Plant

Brian,

Do you have access to the "study" that was done to determine whether or not we could add the 2500 HP 4160V motor at Linam Ranch Gas Plant using the existing dedicated line from the Monument sub-station?

Was that done by Xcel or by your team?

We are getting asked by the NMED what the maximum additional delivery is to Linam on that new dedicated line. The additional 2500 HP motor at the plant could still happen – that project is “on hold” at the moment, but could be re-activated.

I would expect that we would need to pay for a completely new substation (100 MW?) located at the plant to convert all of our existing turbines/engines from fuel-powered to electric.

Best regards,

Kenneth
936-446-8366

Attachment D – 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

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

	Linam Ranch				
	T70 Inlet	T60 Inlet	T70 Residue	T4700	Propane
Best Available in NM	15PPM	Not Subject to Four Factor	15PPM	25PPM	25PPM
OH Estimate	$1,750,000.00		$1,750,000.00	$400,000.00	$400,000.00
NOx Conversion Fee to Best Available	$105,500.00		$105,500.00	$117,606.00	$117,606.00
Required Package Upgrades	$45,000.00		$45,000.00	$984,667.00	$984,667.00
Total	$1,900,500.00		$1,900,500.00	$1,502,273.00	$1,502,273.00
Site Total	**$6,805,546.00**				

Attachment E – Engine SCR vendor discussion

Hong, Hyung S

From: Justin Zimbelman <jzimbelman@catalyticcombustion.com>
Sent: Wednesday, October 9, 2019 10:42 AM
To: Hong, Hyung S
Subject: RE: Linam Clark engines back pressure limit

Hey Sam,

Below is the rough numbers I have come up with, making a lot of assumptions…

Per engine~
Reactor Housing: $200,000
Reactor Housing Install: $75,000
Annual Run time avg cost (urea consumption, maintence): $350,000

Negative side effects:
Particulate Matter "PM" slip will be quite substantial as these are really dirty engines were trying to control
Catalyst Maintenance: because of the level of control and the nature of these engines the catalyst will mask off fairly quickly and require lots of maintenance and service.

Justin Zimbelman
Market Development Manager
Gas Compression Products
Mobile: 715-933-2290

Corporate: 715-568-2882
jzimbelman@catalyticcombustion.com
www.catalyticcombustion.com

Catalytic Combustion Corporation
Cheyenne, WY

From: Hong, Hyung S <HSHong@dcpmidstream.com>
Sent: Wednesday, October 9, 2019 9:17 AM
To: Justin Zimbelman <jzimbelman@catalyticcombustion.com>
Subject: FW: Linam Clark engines back pressure limit

Justin,

Please see below response from our asset engineer!

Sam Hong
DCP Midstream

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

From: Tabery, Ronald S
Sent: Wednesday, October 9, 2019 9:00 AM
To: Hong, Hyung S <HSHong@dcpmidstream.com>; Lynch, Wade J <WJLynch@dcpmidstream.com>
Cc: Cook, John W <JWCook@dcpmidstream.com>
Subject: RE: Linam Clark engines back pressure limit

Sam,

All Clarks have a direct-to-atmosphere exhaust stack (unrestricted flow).
Without measuring to confirm, my *conjecture* is that backpressure is single digit.
OF course any increase in backpressure is concomitant with a decrease in power (unwelcome); for this reason, think big…

Ronald S. Tabery, P.E.
Principal Engineer
Linam/Hobb NM
575-391-5740
432-813-3073 Mobile

From: Hong, Hyung S
Sent: Tuesday, October 8, 2019 3:51 PM
To: Tabery, Ronald S <RSTabery@dcpmidstream.com>; Lynch, Wade J <WJLynch@dcpmidstream.com>
Cc: Cook, John W <JWCook@dcpmidstream.com>
Subject: Linam Clark engines back pressure limit

Ron/Wade,

SCR vendor is wanting to know back pressure limitation on the exhaust to provide quote for correct size SCR system.

Example: a Caterpillar 3616le engine has an engine exhaust backpressure limitation of 20 inches of water. Knowing that we have to size our equipment large enough so that it doesn't restrict the exhaust flow rates and de-rate or harm the engines mechanical performance

Is this information available anywhere? I've checked through all of the old air permit applications and could not find anything other than engine parameters and emission guarantees.

I know it's a long shot but maybe on the engine operating manual or anything we can dig into?

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

Attachment F – EU 10 & 11 Stack Test Report

ASTM 6522 Annual

Performance Test Report

Test Date: 12/28/16

Location:
Linam Ranch Gas Plant

Unit:
EU11

County
Lea

State
New Mexico

Source:
Clark HBA-6
Serial #: 36303

Prepared on behalf of:
DCP Midstream LP

Prepared by:
Great Plains Analytical Services
303 West 3rd Street
Elk City, OK 73644
(580) 225-0403

1.0 Key Personnel

Great Plains Analytical Services:	Tyler Burns
DCP Midstream	Anthony Garcia

2.0 Sampling System

The sampling system used consisted of a Stainless steel probe, Non-porous teflon Line, coiled stainless cooler to drop out moisture from line and an Electrochemical Analyzer. Analyzers are housed in the air conditioned cab of the mobile laboratory. The sample system contains a seperate path to deliver EPA protocol gas to the port in order to allow testing of the entire system. A schematic Diagram can also be found in section 4 of this report.

3.0 Methods

EPA Method 1 or 1A

The purpose of the method is to provide guidance for the selection of sampling ports and traverse points at which sampling for air pollutants will be performed pursuant to regulations set forth in this part. This method is designed to aid in the representative measurement of pollutant emissions. This method is used for stacks with a diameter larger than 12 inches. Should the stack not meet that requirment, method 1A will be used. The applicability and principle of Method 1A are identical to Method 1 in stacks.

EPA Method 2 or 2C

This method is applicable for the determination of the average velocity and the volumetric flow rate of a gas stream.

ASTM D6522

This is the standard test method for determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen concentrations in emissions from natural gas fired reciprocating engines, using portable analyzers

5.0 Summary

A Clark HBA-6 located at Linam Ranch Gas Plant and operated by DCP Midstream LP was tested for emissions of Carbon Monoxide (CO), Oxides of Nitrogen (NOx). The test was conducted by Tyler Burns with Great Plains Analytical Services, Inc. All quality assurance and quality control tests were within acceptable tolerances. This test was conducted using (3) 1 hour test runs.

Engine Tag

Pollutant		Test Results (Average)	Federal Permit	State Permit
CO	ppmvd	191.68	-	-
NOx	ppmvd	222.57	-	-
O2	%	0.15	-	-
CO	ppmvd @ 15% O2	191.89	-	-
NOx	ppmvd @ 15% O3	222.81	-	-
CO	g/hp-hr	0.21	-	-
NOx	g/hp-hr	0.41	-	-
CO	lb/hr	0.57	-	24
NOx	lb/hr	1.09	-	47.5
CO	tpy	2.51	-	283
NOx	tpy	4.78	-	566

6.0 Test Results and Engine Data

Run Number			**Run 1**	**Run 2**	**Run 3**	**Run Length**
Test Date & Start Time		12/28/16	8:48 AM	9:55 AM	11:02 AM	1 Hour
Engine/Compressor Specs						
Make			Clark			
Model			HBA-6	Stack Diameter in		18.00
Serial number			36303		Catalyst	Yes
mfg. rated hp			1267			
mfg. rated rpm			300			
Engine/Compressor Operation			**Run 1**	**Run 2**	**Run 3**	**Average**
Test Horsepower			1207	1211	1211	1209
Test RPM			299	298	299	299
Percent Load %			95.23%	95.57%	95.54%	95.45%
Intake Manifold Temperature (F)			103.0	103.0	103.0	103.0
Ambient Conditions				Elevation ft.=	3741	
Ambient Temperature Dry (F)			54	60	67	60
Barometric Pressure ("hg)			30.17	30.17	30.17	30.17
Exhaust Flow Data						
Q Stack (dscfh)			41145	41100	41019	41088
Q Stack (dscmh)			1165	1164	1162	1163
Fuel Flow Data (Irrelevant when using Method 2. Calculated for internal use from Exhaust flow.						
Fuel Consumption (Btu/hp-hr)			1100	1100	1100	1100
Fuel Flow (dscf-hr)			1285	1289	1289	1288
Fuel (Btu/scf)			1033	1033	1033	1033
O2 F factor			8710	8710	8710	8710
Exhaust Gas Concentrations			**Run 1**	**Run 2**	**Run 3**	**Average**
CO (ppmv)			185.99	192.30	196.76	191.68
NOx (ppmv)			199.23	229.82	238.66	222.57
Oxygen						
O2%			15.03%	15.00%	14.99%	15.01%
Exhaust Gas Concentrations						
CO (ppmv) @ 15% O2			186.87	192.32	196.44	191.89
NOx (ppmv) @ 15% O2			200.18	229.84	238.27	222.81
Mass Emissions Rates		**State Limit**				
NOx (lbs/hr)		47.5	0.98	1.13	1.17	1.09
NOx (tpy)		566	4.29	4.94	5.12	4.78
NOx (g/hp-hr)			0.37	0.42	0.44	0.41
CO (lbs/hr)		24	0.56	0.57	0.59	0.57
CO (tpy)		283	2.44	2.52	2.57	2.51
CO (g/hp-hr)			0.21	0.22	0.22	0.21

7.0 Volumetric Flow Rate

Pitot Coefficient Cp(std)	0.99			Velocity Constant K(p)=		85.49
Stack diameter	18	inches	1.5	Feet or	1.77	Sq Feet (A)
			Run 1	Run 2	Run 3	Average
Relative Humidit (RH)		%	26.00	18.00	17.00	20.33
Barometric Pressure (Pbar)		"Hg	30.17	30.17	30.17	30.17
Ambient Temperature		F	54.00	60.00	67.00	60.33
Moisture in Ambient Air (Ba)		Mol Fraction	0.003624	0.003116	0.003762	0.003501
Free Water (w)		%	2.429451	2.429451	2.429451	2.429451
Moisture free water in fuel (Bf)		Mol Fraction	0.000000	0.000000	0.000000	0.000000
Moisture from Hydrogen in Fuel (Bh)		Mol Fraction	0.050314	0.050549	0.050634	0.050499
Moisture in Stack Gas (Bws)		%	0.05	0.05	0.05	0.05
CO2%d		%	0.03	0.03	0.03	0.03
H2O%d		%	0.05	0.05	0.05	0.05
O2%d		%	0.15	0.15	0.15	0.15
CO%d		%	0.02	0.02	0.02	0.02
N2%d		%	0.80	0.80	0.80	0.80
Molecular Weight Stack Gas dry basis (Md)		g/g mole	29.15	29.15	29.15	29.15
Molecular Weight Stack Gas wet basis (Ms)		g/g mole	28.55	28.55	28.54	28.55
Δp (Velocity Head of Stack Gas)		"H2O	0.02	0.02	0.02	0.02
Stack Temperature (Ts)		Deg F	675.00	678.00	681.00	678.00
Stack Temperature(Ts(abs))		Deg R	1135.00	1138.00	1141.00	1138.00
Atmospheric Pressure at Location (Pbar)		"Hg	30.17	30.17	30.17	30.17
Absolute Stack Pressure (Ps)		"Hg	30.17	30.17	30.17	30.17
Stack Gas Velocity (Vs)		Feet/Second	14.57	14.59	14.61	14.59
Stack Gas Dry Volumetric Flow Rate (Qsd)		dscf/hr	41145.34	41099.75	41019.47	41088.11
Δp (Velocity Head of Stack Gas)		"Hg	0.00	0.00	0.00	0.00
Stack Flow Rate Q (cfs)		$Feet^3$/Second	25.75	25.79	25.82	25.79
Stack Gas Wet Volmetric Flow Rate		scf/hr	43491.17	43430.45	43379.13	43433.51

Annual

Performance Test Report

Test Date: 3/9/16

Location:

Linam Gas Plant

Unit:

Unit #3

County

Lea

State

New Mexico

Source:

HBA-6

Serial #: 38288

Prepared on behalf of:

DCP Midstream

Prepared by:

Great Plains Analytical Services
303 West 3rd Street
Elk City, OK 73644
(580) 225-0403

1.0 Key Personnel

Great Plains Analytical Services: Travis Hartley

2.0 Sampling System

The sampling system used consisted of a Stainless steel probe, Non-porous teflon Line, coiled stainless cooler to drop out moisture from line and Testo 350 analyzer.

3.0 Methods

EPA Method 1

The purpose of the method is to provide guidance for the selection of sampling ports and traverse points at which sampling for air pollutants will be performed pursuant to regulations set forth in this part. This method is designed to aid in the represnetative measurement of pollutant emissions. This method is used for stacks with a diameter larger than 12 inches. Should the stack not meet that requirment, method 1A will be used. The applicability and principle of Method 1A are identical to Method 1 in stacks.

EPA Method 2 & 2C

This method is applicable for the determination of the average velocity and the volumetric flow rate of a gas stream.

EPA Method 7E

This method is for measuring nitrogen oxides (Nox) in stationary sources using a continuous instrumental analyzer. Quality assurance and control requiremnents are also included in this method

EPA Method 10

This method is for measuring carbon monoxide in stationary sources using a continuous instrumental analyzer.

6.0 Test Results and Engine Data

Run Number			Run 1	Run 2	Run 3	Average
Test Date & Start Time		03/09/16	3:25 PM	4:32 PM	5:39 PM	
Engine/Compressor Specs						
Make			Clark		Elevation ft.	3,728
Model			HBA-6			
Serial number			38288		Atmospheric	
mfg. rated hp			1267		Pressure. psi	12.829
mfg. rated rpm			300		Stack Diameter i	18.00
					Catalyst	No
Engine/Compressor Operation						
Test Horsepower			1222	1215	1203	1213
Test RPM			302	304	303	303
Percent Load %			96.44%	95.91%	94.97%	95.77%
Intake Manifold Temperature (F)			123	128	124	125
Fuel Flow (scfd)			241297	239975	237633	239635
Q Stack (dscfh)			285400	282479	281066	282982
Ambient Conditions						
Ambient Temperature Dry (F)			65.0	65.0	60.0	63.3
Barometric Pressure (hg)			29.90	29.90	29.90	29.90
Exhaust Flow Data						
Fuel Consumption (Btu/hp-hr)			8500.00	8500.00	8500.00	8500.00
Fuel Flow (dscf-hr)			10054.06	9998.97	9901.38	9984.81
Fuel (Btu/scf)			1033.0	1033.0	1033.0	1033.0
O2 F factor			8710	8710	8710	8710
Exhaust Gas Concentrations	**Limits**					
CO (ppmv)			340.89	405.09	371.69	372.56
NOx (ppmv)			420.24	435.63	400.96	418.94
NO (ppmv)			58.18	61.34	55.66	58.39
NO2 (ppmv)			478.42	496.97	456.62	477.33
Oxygen						
O2%			14.28%	14.24%	14.28%	14.26%
Mass Emissions Rates	**Limits**					
NO (lbs/hr)			1.983	2.070	1.869	1.97
NO2 (lbs/hr)			16.311	16.770	15.331	16.14
NOx (lbs/hr)	47.50		18.295	18.840	17.200	18.11
NO (tpy)			8.688	9.066	8.186	8.65
NO2 (tpy)			71.442	73.453	67.152	70.68
NOx (tpy)			80.130	82.519	75.337	79.33
NO (g/hp-hr)			0.736	0.773	0.705	0.74
NO2 (g/hp-hr)			6.055	6.260	5.779	6.03
NOx (g/hp-hr)			6.792	7.033	6.484	6.77
CO (lbs/hr)	24.00		7.075	8.322	7.598	7.665
CO (tpy)			30.990	36.450	33.277	33.573
CO (g/hp-hr)			2.627	3.106	2.864	2.865