APRIL 2012

NEXT GENERATION PROCESSING, LLC.

Haven Gas Plant

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) PERMIT APPLICATION

Source ID No. 1550133

Prepared By:

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Project Number 824-001

PROVIDENCE

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1.0 EXECUTIVE SUMMARY

1.0 EXECUTIVE SUMMARY

Next Generation Processing, LLC. (NGP) is proposing to construct a new natural gas processing facility (Haven Gas Plant) approximately two miles from Haven, Reno County, Kansas. NGP is submitting this Prevention of Significant Deterioration (PSD) permit application to allow for the authorization to construct the Haven Gas Plant and associated equipment.

The proposed emissions from the Haven Gas Plant will trigger PSD review. Emission calculation details for the impacted emission units are provided in Section 11. **Table 1-1**, below, summarizes the PSD applicability determination, which compares the proposed project potential-to-emit (PTE) in tons per year (tpy) versus PSD Significant Emission Rates (SER).

As of July 2011, emissions of GHGs are regulated under the Clean Air Act and subject to the PSD program. As shown in **Table 1-1**, the proposed Haven Gas Plant has the potential to emit greater than 100,000 tpy of GHG on a CO_2 equivalent basis (CO_2e). Therefore, the facility is a major source for PSD purposes, and all proposed attainment pollutants emitted in amounts greater than or equal to the PSD significance levels are subject to PSD review. As a result, the following pollutants are also subject to PSD review: oxides of nitrogen (NO_x), carbon monoxide (CO) and particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$). In accordance with 40 CFR 60 Part 52(23)(i), ozone is also subject to PSD review because the proposed emissions of NO_x are greater than 40 tpy. Additional information regarding the PSD applicability determination is provided in Section 2 (Construction Details and PSD Applicability).

Table 1-1
Emissions from the Proposed Haven Gas Plant and PSD Applicability

Pollutant	Project Emissions (TPY)	Significant Emission Rate (TPY)	PSD Review Required
NO_X	106.45	40	Yes
SO_2	6.29	40	No
PM	14.73	25	No
PM_{10}	14.73	15	No
$PM_{2.5}$	14.73	10	Yes
CO	121.70	100	Yes
VOC Total	26.31	40	No
Lead	0.00	0.6	No
Ozone (VOC,NO_x)	-	40	Yes
Hydrogen Sulfide	3.31	10	No
(HAPs) Acetaldehyde	0.46	10	No
(HAPs) Acrolein	0.37	10	No
(HAPs) Benzene	0.21	10	No
(HAPs) Ethylbenzene	0.06	10	No
(HAPs) Formaldehyde	1.49	10	No
(HAPs) Proylene Oxide	0.05	10	No
(HAPs) Toluene	0.24	10	No
(HAPs) Xylenes	0.12	10	No
Total HAPs	6.31	25	No
CO_2	323,720.36	NA	NA
N_2O	0.43	NA	NA
CH_4	5.34	NA	NA
CO_2e	323,966.72	100,000	Yes

The facility is located in an area designated as attainment for all applicable National Ambient Air Quality Standards (NAAQS). Therefore, this permitting action is not subject to nonattainment NSR.

This application will trigger the public notice requirements which are specified in K.A.R. 28-19-204.

All information pertaining to the new proposed emission units is presented in this application. This application contains the following sections:

1.0 Executive Summary
2.0 Construction Details and PSD Applicability Determination
3.0 K.A.R. 28-19-300(a) Notification of Construction Form
4.0 K.A.R. 28-19-304(b) Construction Permit Application Fee Form
5.0 Site Location Map
6.0 Plot Plan Showing Proposed Sources
7.0 Process Description
8.0 Process Description Forms
9.0 Control Equipment Forms
10.0 Process Flow Diagram
11.0 Emissions Calculations
12.0 Best Available Control Technology (BACT) Analysis
13.0 State Regulatory Applicability Analysis
14.0 Federal Regulatory Applicability Analysis

Please address permitting questions or comments to:

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Senior Engineer – Air Quality
Providence
11767 Katy Freeway
Suite 430
Houston, TX 77079
Office: (281) 497-5656
Fax: (281) 497-5657

2.0 CONSTRUCTION DETAILS AND PSD APPLICABILITY DETERMINATION

2.0 CONSTRUCTION DETAILS AND PSD APPLICABILITY DETERMINATION

This section provides information regarding details of the proposed construction and the applicability of the PSD permitting program to the proposed project.

2.1 Construction Details

NGP plans to construct the new emission units presented in **Table 2-1**, below. The operating parameters for these new units are provided in Section 8.0 (Process Description Forms). The emission control equipment for each of these units is provided in Section 9.0 (Control Equipment Forms).

Table 2-1
Proposed Emission Units to Construct

EPN	Description
GT-01	Titan 250-30000S Natural Gas Turbine
GT-02	Titan 250-30000S Natural Gas Turbine
TGS-01	Mercury 50-6400R Turbine Generator Set
EGS-01	Waukesha VHP-P9390GSI Generator Set
EGS-02	Waukesha VHP-P9390GSI Generator Set
ASV-01	Amine Still Vent
TK-01	Slop Oil Tank
TRKLD	TK-01 Truck Loading Operations
FUG-01	Equipment Fugitives
GTMSS	GT-01 and GT-02 Maintenance Startup and Shutdown

2.2 PSD Applicability Determination

The PSD rules apply to major modifications at major source locations in attainment areas. Currently, the Haven, KS, area is classified as attainment or unclassified for all pollutants.

For the purpose of PSD review, “major sources” are those that have a PTE of more than 250 ton/yr of any pollutant regulated by the Clean Air Act; for those types of sources not on the “list of 28”, defined in 40 CFR 52.21 (b)(1)(i)(a). The NGP Haven Gas Plant is not classified as one of the types of sources on the “list of 28”. However, as of July 2011, emissions of greenhouse gases (GHG) are regulated under the Clean Air Act and subject to the PSD program. The proposed Haven Gas Plant has the potential to emit greater than 100,000 tpy CO2e. Therefore, the facility is a major source for PSD purposes, and all proposed attainment pollutants emitted in amounts greater than or equal to the PSD SER are subject to PSD review.

Projects at major sources involving new emission units must be evaluated to determine if the project qualifies as a major source and the PSD permitting program is triggered. This evaluation is performed in consecutive steps. If during

any step, the facility is determined not to trigger PSD, the evaluation is complete. This step-by-step review process is outlined in Section 14.0.

3.0 K.A.R. 28-19-300(a) NOTIFICATION OF CONSTRUCTION FORM

Kansas Department of Health and Environment
Bureau of Air and Radiation
Phone (785) 296-1570 Fax (785) 291-3953

Notification of Construction or Modification

(K.A.R. 28-19-300 Construction permits and approvals; applicability)

Check one: ☑ Applying for a Permit under K.A.R. 28-19-300(a) ☐ Applying for an Approval under K.A.R. 28-19-300(b)*

1) Source ID Number: 1550133

2) Mailing Information:
   Company Name: Next Generation Processing, LLC.
   Address: 15914 Stenbury Ct.
   City, State, Zip: Cypress, TX 77429

3) Source Location:
   Street Address: See Section, Township, Range
   City, County, State, Zip: See Section, Township, Range
   Section, Township, Range: S6, T25S, R4W
   Latitude & Longitude Coordinates: 37.904038, -97.810457

4) NAICSC/SIC Code (Primary): 486210 / 4922

5) Primary Product Produced at the Source: This facility is a natural gas liquids plant.

6) Would this modification require a change in the current operating permit for your facility? ☐ Yes ☑ No

   If no, please explain: This construction permit is notification for a new facility.

7) Is a permit fee being submitted? ☑ Yes ☐ No

   If yes, please include the facility's federal employee identification number (FEIN #)

8) Person to Contact at the Site: Greg Ameringer Phone: (281) 744-7647
   Title:

9) Person to Contact Concerning Permit: Greg Ameringer Phone: (281) 744-7647
   Title: President

   Email: greg@ngprocess.com Fax: ( )

Please read before signing:

Reporting forms provided may not adequately describe some processes. Modify the forms if necessary. Include a written description of the activity being proposed, a description of where the air emissions are generated and exhausted and how they are controlled. A simple diagram showing the proposed activity addressed in this notification which produces air pollutants at the facility (process flow diagrams, plot plan, etc.) with emission points labeled must be submitted with reporting forms. Information that, if made public, would divulge methods or processes entitled to protection as trade secrets may be held confidential. See the reverse side of this page for the procedure to request information be held confidential. A copy of the Kansas Air Quality Statutes and Regulations will be provided upon request.

Name and Title :

Address:

Signature: Greg Ameringer Date: 4 / 18 / 2012 Phone: (281) 744-7647

* If you do not know whether to apply for a permit or an approval, follow approval application procedures.

Procedures For Requesting Information To Be Held Confidential

March 15, 2006
Revision 6

Kansas Department of Health and Environment
Bureau of Air and Radiation
Phone (785) 296-1570 Fax (785) 291-3953

Notification of Construction or Modification

(K.A.R. 28-19-300 Construction permits and approvals; applicability)

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1) Source ID Number: 1550133

2) Mailing Information:
Company Name: Next Generation Processing, LLC.
Address: 15914 Stenbury Ct.
City, State, Zip: Cypress, TX 77429

3) Source Location:
Street Address: See Section, Township, Range
City, County, State, Zip: See Section, Township, Range
Section, Township, Range: S6, T25S, R4W
Latitude & Longitude Coordinates: 37.904038, -97.810457

4) NAICSC/SIC Code (Primary): 211112 / 1321

5) Primary Product Produced at the Source: This facility is a natural gas liquids extraction plant.

6) Would this modification require a change in the current operating permit for your facility? ☐ Yes ☑ No

If no, please explain: This construction permit is notification for a new facility.

7) Is a permit fee being submitted? ☑ Yes ☐ No

If yes, please include the facility's federal employee identification number (FEIN #)

8) Person to Contact at the Site: Greg Ameringer Phone: (281) 744-7647
Title:

9) Person to Contact Concerning Permit: Greg Ameringer Phone: (281) 744-7647
Title: President

Email: greg@ngprocess.com Fax: ( )

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Name and Title :

Address:

Signature: _____ Date: 5/22/2012 Phone: (281) 744-7647

* If you do not know whether to apply for a permit or an approval, follow approval application procedures.

Procedures For Requesting Information To Be Held Confidential

4.0 K.A.R. 28-19-304(b) CONSTRUCTION PERMIT APPLICATION FEE FORM

CALCULATING THE CONSTRUCTION PERMIT APPLICATION FEE

[These requirements are found at K.A.R. 28-19-304(b).]

Calculate the construction permit application fee as follows:

Estimated capital cost of the proposed activity for which the application is made, including the total cost of equipment and services to be capitalized.	**Line 1** $ 150,000,000	
Multiply by .05% (.0005)	x .0005	
Total	**Line 2** $ 75,000	
If Line 2 is less than $100, enter $100 on Line 3. If Line 2 is greater than $4,000, enter $4,000 on Line 3.		
Otherwise, copy Line 2 to Line 3.		
Construction permit application fee.	**Line 3** $ 4,000	Minimum fee is $100

Greg Ameringer
(Print)

Certifier of Capital Cost

(Signature)

4/18/2012
Date

K.A.R. 28-19-350 is a complex regulation pertaining to prevention of significant deterioration (PSD). An additional fee of $1,500 will be required if a PSD review is necessary. If you believe the proposed activity in this Notification of Construction or Modification will be subject to the requirements of K.A.R. 28-19-350, contact the Department for further evaluation.

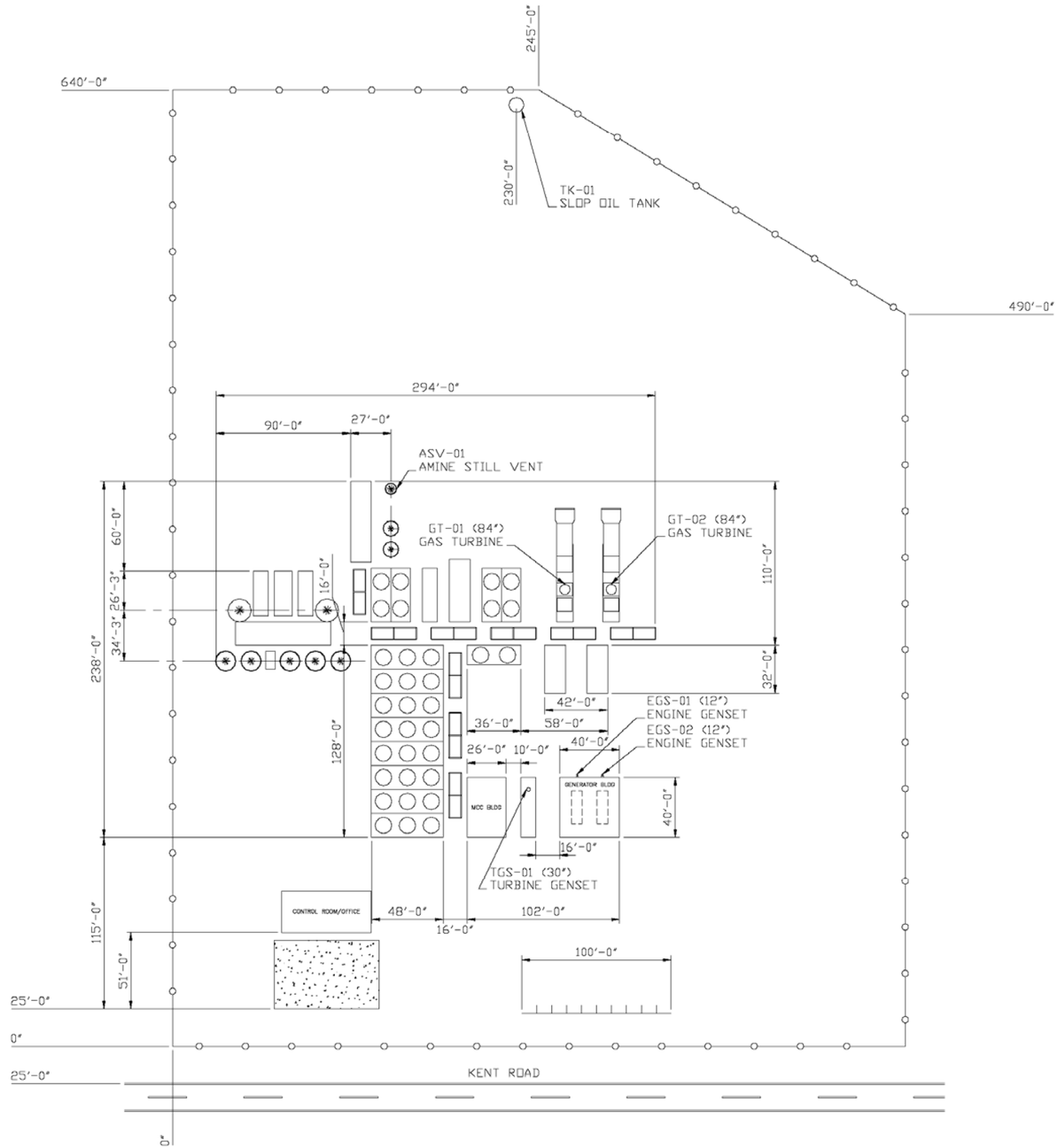
For purposes of construction permit or approval applications, the following are not considered modifications:

1. Routine maintenance or parts replacement.
2. An increase or decrease in operating hours or production rates if:
   a. production rate increases do not exceed the originally approved design capacity of the stationary source or emissions unit; and
   b. the increased potential-to-emit resulting from the change in operating hours or production rates do not exceed any emission or operating limitations imposed as a permit condition.

5.0 SITE LOCATION MAP

Haven Gas Plant
Haven
N

6.0 PLOT PLAN



PLAN
SCALE 3/128" = 1'-0"

NO.	DATE	REVISION	DRW.	DES.	CHK.	APP.
B	04/02/12	REVISED PER MARK UPS	CML			
A	02/20/12	ISSUED FOR REVIEW	CML			

NGP

PRELIMINARY SITE LAYOUT
HAVEN GAS PLANT (1.6 Bcfd)

Project	Unit	DocType	Eng. Code	Seq. No.	Rev.
		DWG			B

SCALE: AS SHOWN
PLOT SCALE: 3/128" = 1'-0"
PROJECT:
LOCATION:
SHT. NO: 1 of 4
REV. B

7.0 PROCESS DESCRIPTION

7.0 PROCESS DESCRIPTION

Natural gas will be transported to the Haven Gas Plant via Panhandle Eastern's Interstate gas pipeline. The proposed natural gas processing plant is being designed with a throughput capacity of 1.4 billion cubic feet per day (bcfd). The proposed plant has both a low pressure gas inlet and a high pressure gas inlet. Approximately 250 MMscf of low pressure inlet gas in the low pressure stream is compressed and then combined with approximately 1,150 MMscf of high pressure inlet gas in the high pressure stream. The inlet compression is performed by a 3,500 hp variable speed electric compressor. The combined inlet stream is then treated for water removal through a mol sieve dehydration system and exits at 840 psig and routed to the Cryogenic Expander Plant. The oily water is then stored in a 100 barrel storage tank, and periodically loaded into tank trucks and shipped off-site.

In the Cryogenic Expander Plant, the inlet gas is chilled and then routed to an expander where the pressure is lowed thus creating the majority of refrigeration required for the plant. The expanded chilled gas is then routed to a demethanizer where methane is removed from the natural gas liquid (NGL) product. The overhead stream from the demethanizer, which is primarily methane, is then heat exchanged against the inlet stream and exits the Cryogenic Plant in Stream 4 at a pressure of 440 psig. The NGL product leaves the bottom of the demethanizer in Stream 7 and then is pumped to high pressure and routed to the Amine Plant. Supplemental process refrigeration is supplied by a mixed refrigeration system being driven by a 2,000 hp electric motor.

The lower pressure demethanizer overhead in Stream 4 is then routed to the plant recompression area. The plant recompression is performed by Two (2) Titan 250-30000S natural gas-fired turbines driving centrifugal gas compressors which compress the gas back to inlet pipeline pressure of 860 psig in Stream 5. The compressed gas is then routed to the appropriate low and high pressure pipelines. Each natural gas fired turbine is rated at 29,299 hp.

Amine treatment operations will treat the NGL product for carbon dioxide (CO_2) and trace amounts of hydrogen sulfide (H_2S). The treated NGL product is then filtered to remove any water and then routed to the NGL takeaway pipeline. The plant product is a comingled stream of un-fractionated raw make consisting of ethane, propane, butanes and natural gasolines.

One (1) natural gas fired Mercury 50-6400R turbine generator set (6196 hp rating) and two (2) natural gas fired Waukesha VHP-P9390GSI generator gets (1,980 hp rating per unit) will be installed to provide electrical power to the facility.

Air emissions will consist primarily of combustion products generated from firing natural gas in the turbines and generator sets. Volatile Organic Compound (VOC) emissions will be generated during loading operations from the oily water tank to tanker trucks, working and breathing losses at the oily water tank, fugitive emissions from equipment leaks and amine treatment operations. Trace amounts of H_2S will also be emitted from the amine treatment operations. Section 10.0 provides a facility process flow diagram, illustrating the major operating components proposed for the Haven Gas Plant.

8.0 K.A.R. PROCESS EQUIPMENT FORMS

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

EQUIPMENT IN VOC SERVICE

(Pumps, Compressors, Pressure Relief Devices, Sampling Connection Systems Open Ended Valves or Lines, Valves, Flanges, & Other Connectors)

1) Source ID Number: 1550133

2) Company/Source Name: Next Generation Processing, LLC./ Haven Gas Plant

3) Normal Operating Schedule: 8760 hrs/yr

4) Process Unit In Which Equipment Is To Be Located: Facility Wide Component Count

5) Design Processing Capacity of the Process Unit: 1,400 MMscf/yr

6) Equipment (Include only that equipment which is in VOC service as defined in 40 CFR Part 60.481. Gas/vapor service, light liquid service, and heavy liquid service are also defined in 40 CFR 60.481):

Equipment Name	Quantity in Gas/Vapor Service	Quantity in Light Liquid Service	Quantity in Heavy Liquid Service
Pumps	N/A	7	N/A
Compressors	6	N/A	N/A
Pressure Relief Devices	23	10	N/A
Sampling Connection Systems	N/A	N/A	N/A
Open Ended Valves or Lines	N/A	N/A	N/A
Valves	187	78	N/A
Flanges	243	101	N/A
Other Connectors	242	101	N/A

7) NSPS Applicability (40 CFR Part 60)
Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Organic Chemicals Manufacturing Industry
Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries
Subpart KKK - Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants

-What is the date of construction or modification of the facility ? TBD

-Does the facility in question have the capacity to produce more than 1,000 Mg/yr?

Yes [✓]; No [ ]

EQUIPMENT IN VOC SERVICE

(Pumps, Compressors, Pressure Relief Devices, Sampling Connection Systems Open Ended Valves or Lines, Valves, Flanges, & Other Connectors)

(cont.)

-Does the facility in question produce heavy liquid chemicals only from heavy liquid feed or raw materials as defined in 40 CFR 60.481? Yes [ ]; No [✓]

-Does the facility in question produce beverage alcohol? Yes [ ]; No [✓]

-Does the facility in question have any equipment in VOC service? Yes [✓]; No [ ]

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

TRUCK LOADING TERMINALS

1) Source ID Number: 1550133

2) Company/Source Name: Next Generation Processing, LLC./ Haven Gas Plant

3) Emission Unit Identification: TRKLD

4) Normal Operating Schedule: N/A hrs/yr

5) Products Loaded and Amounts (Attach MSDS for each product):

Product Name	Maximum Amount Transferred (gal/hr)
Slop Oil (Condensate + Produced Water)	8,400.0

6) Filling Method:
Top-Splash Fill: _____ Top-Submerged Fill: X Bottom Loading: _____
Other (Describe): _____

7) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

8) NSPS Applicability (40 CFR Part 60) N/A
Subpart XX - Standards of Performance for Bulk Gasoline Terminals
-Does the facility operate one or more loading racks at a bulk gasoline terminal which deliver liquid product into gasoline tank trucks? Yes _____; No _____
-Did construction, modification, or reconstruction commence after December 17, 1980?
Yes _____; No _____

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

STATIONARY INTERNAL COMBUSTION ENGINES

1) Source ID Number : 1550133

2) Company/Source Name: Next Generation Processing, LLC. / Haven Gas Plant

3) Type of Engine: Turbine ☐ ; Reciprocating ☑ ; Other _____

4) Engine Manufacturer : Waukesha
   Model No.: VHP-P9390GSI
   Date of Manufacture: TBD
   Serial No.: TBD

5) Use of Engine: Electric power generation ☑; Compressor ☐; Pump ☐; Other - describe _____

6) Maximum Brake horsepower at continuous rating: 1,980 BHP
   Normal operating engine speed: 1,200 RPM
   Rated Brake Horsepower at normal operating RPM: 1,980 BHP
   or
   Maximum Generator Nameplate Capacity: _____kW
   Maximum design heat input rate: _____ BTU/hr

7) Operating schedule: 8760 hrs per year

8) Date of Installation: TBD
   Date of Last modification: Not Applicable

TURBINES

9) Type of Gas Turbine: Simple cycle ☐ ; Co-generation ☐ ; Regenerative ☐ ; Combined cycle ☐

10) Fuel data for all the different types of fuel to be used :
   a) Fuel Type _____ ; Sulfur content % by weight 0.0 ;
      Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
   b) Fuel Type _____ ; Sulfur content % by weight _____ ;
      Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
   c) Fuel Type _____ ; Sulfur content % by weight _____ ;
      Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

11) Heat recovery unit or steam generator unit installed? Yes _____; No _____
Supplementary fired ? Yes _____; No _____ If yes, type of fuel used: _____
Capacity of the burner _____ gals per hr
Fuel heating value _____ BTU per cu ft or gal
Sulfur content of fuel by weight _____ %; Please attach complete supplementary fuel oil/distillate analysis.

12) Emission control system(s) used: Water injection_____ ; Steam injection_____ ;
Selective Catalytic reduction with Water injection _____ ; Selective catalytic reduction _____ ;
Describe Selective Catalytic emission reduction control installed:_____
Manufacturer's name:_____ Model No.: _____

POLLUTANT	MANUFACTURER'S REDUCTION EFFICIENCY %

13) Did construction, modification, or reconstruction commence after October 3, 1977? Yes_____; No _____
If yes, this facility may be subject to NSPS, 40 CFR 60, Subpart GG.

RECIPROCATING ENGINES

14) Engine design details:
Number of cylinders 12
Aspiration: Normal _____ ; Turbo charged X
Ignition: Spark X ; Compression _____
Design class 2 cycle lean burn _____ ; 4 cycle lean burn _____ ; 4 cycle rich burn X

15) 2 or 4 cycle lean burn with combustion modification, increased air/fuel ratio and intercooling ?
Yes _____; No_____
If yes, attach the guaranteed performance of the conversion supplier **or** the actual monitored performance, and the engine operating conditions for the guarantee of performance.

16) Type of integral emission control: Selective Catalytic Reduction _____ ;
Non Selective Catalytic Reduction X ; Combustion Reduction _____(Describe)_____; None _____

17) Fuel(s): Gasoline _____ ; Diesel _____ ; Natural Gas X ; Dual fuel _____

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

18) Fuel Heating Value: Gasoline _____ BTU per gal; Diesel _____ BTU per gal;
Natural Gas 967.50 BTU per cu ft ; Dual fuel mix _ ____ % diesel 100 % natural gas
Sulfur content of diesel by weight 0 %

APPLICABLE TO ALL STATIONARY INTERNAL COMBUSTION ENGINES

19) Enclose available engine manufacturer's emissions data.

20) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

STATIONARY INTERNAL COMBUSTION ENGINES

1) Source ID Number : 1550133

2) Company/Source Name: Next Generation Processing, LLC. / Haven Gas Plant

3) Type of Engine: Turbine ☐ ; Reciprocating ☑ ; Other _____

4) Engine Manufacturer : Waukesha
   Model No.: VHP-P9390GSI
   Date of Manufacture: TBD
   Serial No.: TBD

5) Use of Engine: Electric power generation ☑; Compressor ☐; Pump ☐; Other - describe _____

6) Maximum Brake horsepower at continuous rating: 1,980 BHP
   Normal operating engine speed: 1,200 RPM
   Rated Brake Horsepower at normal operating RPM: 1,980 BHP
   or
   Maximum Generator Nameplate Capacity: _____kW
   Maximum design heat input rate: _____ BTU/hr

7) Operating schedule: 8760 hrs per year

8) Date of Installation: TBD
   Date of Last modification: Not Applicable

TURBINES

9) Type of Gas Turbine: Simple cycle ☐ ; Co-generation ☐ ; Regenerative ☐ ; Combined cycle ☐

10) Fuel data for all the different types of fuel to be used :
   a) Fuel Type _____ ; Sulfur content % by weight 0.0 ;
      Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
   b) Fuel Type _____ ; Sulfur content % by weight _____ ;
      Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
   c) Fuel Type _____ ; Sulfur content % by weight _____ ;
      Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

11) Heat recovery unit or steam generator unit installed? Yes _____; No _____
Supplementary fired ? Yes _____; No _____ If yes, type of fuel used: _____
Capacity of the burner _____ gals per hr
Fuel heating value _____ BTU per cu ft or gal
Sulfur content of fuel by weight _____ %; Please attach complete supplementary fuel oil/distillate analysis.

12) Emission control system(s) used: Water injection_____ ; Steam injection_____ ;
Selective Catalytic reduction with Water injection _____ ; Selective catalytic reduction _____ ;
Describe Selective Catalytic emission reduction control installed:_____
Manufacturer's name:_____ Model No.: _____

POLLUTANT	MANUFACTURER'S REDUCTION EFFICIENCY %

13) Did construction, modification, or reconstruction commence after October 3, 1977? Yes_____; No _____
If yes, this facility may be subject to NSPS, 40 CFR 60, Subpart GG.

RECIPROCATING ENGINES

14) Engine design details:
Number of cylinders 12
Aspiration: Normal _____ ; Turbo charged X
Ignition: Spark X ; Compression _____
Design class 2 cycle lean burn _____ ; 4 cycle lean burn _____ ; 4 cycle rich burn X

15) 2 or 4 cycle lean burn with combustion modification, increased air/fuel ratio and intercooling ?
Yes _____; No_____
If yes, attach the guaranteed performance of the conversion supplier **or** the actual monitored performance, and the engine operating conditions for the guarantee of performance.

16) Type of integral emission control: Selective Catalytic Reduction _____ ;
Non Selective Catalytic Reduction X ; Combustion Reduction _____(Describe)_____; None _____

17) Fuel(s): Gasoline _____ ; Diesel _____ ; Natural Gas X ; Dual fuel _____

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

18) Fuel Heating Value: Gasoline _____ BTU per gal; Diesel _____ BTU per gal;
Natural Gas 967.50 BTU per cu ft ; Dual fuel mix _ ____ % diesel 100 % natural gas
Sulfur content of diesel by weight 0 %

APPLICABLE TO ALL STATIONARY INTERNAL COMBUSTION ENGINES

19) Enclose available engine manufacturer's emissions data.

20) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

Kansas Department of Health and Environment
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Bureau of Air and Radiation

STATIONARY INTERNAL COMBUSTION ENGINES

1) Source ID Number : 1550133

2) Company/Source Name: Next Generation Processing, LLC. / Haven Gas Plant

3) Type of Engine: Turbine ☑ ; Reciprocating ☐ ; Other _____

4) Engine Manufacturer : Solar Turbines, Inc.
   Model No.: Mercury 50-6400R
   Date of Manufacture: TBD
   Serial No.: TBD

5) Use of Engine: Electric power generation ☑; Compressor ☐; Pump ☐; Other - describe _____

6) Maximum Brake horsepower at continuous rating: _____ BHP
   Normal operating engine speed: _____ RPM
   Rated Brake Horsepower at normal operating RPM: _____ BHP
   or
   Maximum Generator Nameplate Capacity: 4620 kW
   Maximum design heat input rate: 40270000 BTU/hr

7) Operating schedule: 8760 hrs per year

8) Date of Installation: TBD
   Date of Last modification: Not Applicable

TURBINES

9) Type of Gas Turbine: Simple cycle ☐ ; Co-generation ☐ ; Regenerative ☑ ; Combined cycle ☐

10) Fuel data for all the different types of fuel to be used :
   a) Fuel Type Natural Gas ; Sulfur content % by weight 0.0 ;
      Lower heating value 872.9 BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
   b) Fuel Type _____ ; Sulfur content % by weight _____ ;
      Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
   c) Fuel Type _____ ; Sulfur content % by weight _____ ;
      Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

11) Heat recovery unit or steam generator unit installed? Yes [ ]; No [✓]
Supplementary fired ? Yes [ ]; No [✓] If yes, type of fuel used: Not Applicable
Capacity of the burner _____ gals per hr
Fuel heating value _____ BTU per cu ft or gal
Sulfur content of fuel by weight _____ %; Please attach complete supplementary fuel oil/distillate analysis.

12) Emission control system(s) used: Water injection_____ ; Steam injection_____ ;
Selective Catalytic reduction with Water injection _____ ; Selective catalytic reduction _____ ;
Describe emission reduction control installed: Dry Low NOx burner
Manufacturer's name: Solar Turbines Model No.: SoLoNOx

POLLUTANT	MANUFACTURER'S PERFOMANCE GUARANTEE
NOx	5.0 ppm at 15% O2
CO	10.0 ppm at 15% O2
UHC	10.0 ppm at 15% O2

13) Did construction, modification, or reconstruction commence after October 3, 1977? Yes [✓]; No [ ]
If yes, this facility may be subject to NSPS, 40 CFR 60, Subpart GG.

RECIPROCATING ENGINES

14) Engine design details:
Number of cylinders _____
Aspiration: Normal _____ ; Turbo charged _____
Ignition: Spark _____ ; Compression _____
Design class 2 cycle lean burn _____ ; 4 cycle lean burn _____ ; 4 cycle rich burn _____

15) 2 or 4 cycle lean burn with combustion modification, increased air/fuel ratio and intercooling ?
Yes [ ]; No [ ]
If yes, attach the guaranteed performance of the conversion supplier **or** the actual monitored performance, and the engine operating conditions for the guarantee of performance.

16) Type of integral emission control: Selective Catalytic Reduction _____ ;
Non Selective Catalytic Reduction _____ ; Combustion Reduction _____(Describe)_____; None _____

17) Fuel(s): Gasoline _____ ; Diesel _____ ; Natural Gas _____ ; Dual fuel _____

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

18) Fuel Heating Value: Gasoline _____ BTU per gal; Diesel _____ BTU per gal;
Natural Gas _____ BTU per cu ft ; Dual fuel mix _ ____ % diesel _____ % natural gas
Sulfur content of diesel by weight _____ %

APPLICABLE TO ALL STATIONARY INTERNAL COMBUSTION ENGINES

19) Enclose available engine manufacturer's emissions data.

20) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

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Bureau of Air and Radiation

STATIONARY INTERNAL COMBUSTION ENGINES

1) Source ID Number : 1550133

2) Company/Source Name: Next Generation Processing, LLC. / Haven Gas Plant

3) Type of Engine: Turbine ☑ ; Reciprocating ☐ ; Other _____

4) Engine Manufacturer : Solar Turbines, Inc.
Model No.: Titan 250-30000S (EPN GT-01)
Date of Manufacture: TBD
Serial No.: TBD

5) Use of Engine: Electric power generation ☐; Compressor ☑; Pump ☐; Other - describe _____

6) Maximum Brake horsepower at continuous rating: 29,299 BHP
Normal operating engine speed: 6,390 RPM
Rated Brake Horsepower at normal operating RPM: 29,299 BHP
or
Maximum Generator Nameplate Capacity: _____kW
Maximum design heat input rate: _____ BTU/hr

7) Operating schedule: 8760 hrs per year

8) Date of Installation: TBD
Date of Last modification: Not Applicable

TURBINES

9) Type of Gas Turbine: Simple cycle ☐ ; Co-generation ☐ ; Regenerative ☐ ; Combined cycle ☑

10) Fuel data for all the different types of fuel to be used :
a) Fuel Type Natural Gas ; Sulfur content % by weight 0.0 ;
Lower heating value 880 BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
b) Fuel Type _____ ; Sulfur content % by weight _____ ;
Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
c) Fuel Type _____ ; Sulfur content % by weight _____ ;
Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

11) Heat recovery unit or steam generator unit installed? Yes [✓]; No [ ]
Supplementary fired ? Yes [ ]; No [✓] If yes, type of fuel used: Not Applicable
Capacity of the burner _____ gals per hr
Fuel heating value _____ BTU per cu ft or gal
Sulfur content of fuel by weight _____ %; Please attach complete supplementary fuel oil/distillate analysis.

12) Emission control system(s) used: Water injection_____ ; Steam injection_____ ;
Selective Catalytic reduction with Water injection _____ ; Selective catalytic reduction _____ ;
Describe Selective Catalytic emission reduction control installed:_____
Manufacturer's name:_____ Model No.: _____

POLLUTANT	MANUFACTURER'S REDUCTION EFFICIENCY %

13) Did construction, modification, or reconstruction commence after October 3, 1977? Yes [✓]; No [ ]
If yes, this facility may be subject to NSPS, 40 CFR 60, Subpart GG.

RECIPROCATING ENGINES

14) Engine design details:
Number of cylinders _____
Aspiration: Normal _____ ; Turbo charged _____
Ignition: Spark _____ ; Compression _____
Design class 2 cycle lean burn _____ ; 4 cycle lean burn _____ ; 4 cycle rich burn _____

15) 2 or 4 cycle lean burn with combustion modification, increased air/fuel ratio and intercooling ?
Yes [ ]; No [ ]
If yes, attach the guaranteed performance of the conversion supplier **or** the actual monitored performance, and the engine operating conditions for the guarantee of performance.

16) Type of integral emission control: Selective Catalytic Reduction _____ ;
Non Selective Catalytic Reduction _____ ; Combustion Reduction _____(Describe)_____; None _____

17) Fuel(s): Gasoline _____ ; Diesel _____ ; Natural Gas _____ ; Dual fuel _____

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

18) Fuel Heating Value: Gasoline _____ BTU per gal; Diesel _____ BTU per gal;
Natural Gas _____ BTU per cu ft ; Dual fuel mix _ ____ % diesel _____ % natural gas
Sulfur content of diesel by weight _____ %

APPLICABLE TO ALL STATIONARY INTERNAL COMBUSTION ENGINES

19) Enclose available engine manufacturer's emissions data.

20) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

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STATIONARY INTERNAL COMBUSTION ENGINES

1) Source ID Number : 1550133

2) Company/Source Name: Next Generation Processing, LLC. / Haven Gas Plant

3) Type of Engine: Turbine ☑ ; Reciprocating ☐ ; Other _____

4) Engine Manufacturer : Solar Turbines, Inc.
Model No.: Titan 250-30000S (EPN GT-02)
Date of Manufacture: TBD
Serial No.: TBD

5) Use of Engine: Electric power generation ☐; Compressor ☑; Pump ☐; Other - describe _____

6) Maximum Brake horsepower at continuous rating: 29,299 BHP
Normal operating engine speed: 6,390 RPM
Rated Brake Horsepower at normal operating RPM: 29,299 BHP
or
Maximum Generator Nameplate Capacity: _____kW
Maximum design heat input rate: _____ BTU/hr

7) Operating schedule: 8760 hrs per year

8) Date of Installation: TBD
Date of Last modification: Not Applicable

TURBINES

9) Type of Gas Turbine: Simple cycle ☐ ; Co-generation ☐ ; Regenerative ☐ ; Combined cycle ☑

10) Fuel data for all the different types of fuel to be used :
a) Fuel Type Natural Gas ; Sulfur content % by weight 0.0 ;
Lower heating value 880 BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
b) Fuel Type _____ ; Sulfur content % by weight _____ ;
Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon
c) Fuel Type _____ ; Sulfur content % by weight _____ ;
Lower heating value _____ BTU per cu ft; **or** _____ BTU per lb; **or** _____ BTU per gallon

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

11) Heat recovery unit or steam generator unit installed? Yes [✓]; No [ ]
Supplementary fired ? Yes [ ]; No [✓] If yes, type of fuel used: Not Applicable
Capacity of the burner _____ gals per hr
Fuel heating value _____ BTU per cu ft or gal
Sulfur content of fuel by weight _____ %; Please attach complete supplementary fuel oil/distillate analysis.

12) Emission control system(s) used: Water injection_____ ; Steam injection_____ ;
Selective Catalytic reduction with Water injection _____ ; Selective catalytic reduction _____ ;
Describe Selective Catalytic emission reduction control installed:_____
Manufacturer's name:_____ Model No.: _____

POLLUTANT	MANUFACTURER'S REDUCTION EFFICIENCY %

13) Did construction, modification, or reconstruction commence after October 3, 1977? Yes [✓]; No [ ]
If yes, this facility may be subject to NSPS, 40 CFR 60, Subpart GG.

RECIPROCATING ENGINES

14) Engine design details:
Number of cylinders _____
Aspiration: Normal _____ ; Turbo charged _____
Ignition: Spark _____ ; Compression _____
Design class 2 cycle lean burn _____ ; 4 cycle lean burn _____ ; 4 cycle rich burn _____

15) 2 or 4 cycle lean burn with combustion modification, increased air/fuel ratio and intercooling ?
Yes [ ]; No [ ]
If yes, attach the guaranteed performance of the conversion supplier **or** the actual monitored performance, and the engine operating conditions for the guarantee of performance.

16) Type of integral emission control: Selective Catalytic Reduction _____ ;
Non Selective Catalytic Reduction _____ ; Combustion Reduction _____(Describe)_____; None _____

17) Fuel(s): Gasoline _____ ; Diesel _____ ; Natural Gas _____ ; Dual fuel _____

STATIONARY INTERNAL COMBUSTION ENGINES
(cont.)

18) Fuel Heating Value: Gasoline _____ BTU per gal; Diesel _____ BTU per gal;
Natural Gas _____ BTU per cu ft ; Dual fuel mix _ ____ % diesel _____ % natural gas
Sulfur content of diesel by weight _____ %

APPLICABLE TO ALL STATIONARY INTERNAL COMBUSTION ENGINES

19) Enclose available engine manufacturer's emissions data.

20) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

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NATURAL GAS LIQUID TREATMENT PLANT

1) Source ID Number: 1550133

2) Company/Source Name: Next Generation Processing, LLC. / Haven Gas Plant

3) Emission Unit Identification: ASV-01

4) Normal Operating Schedule: 8760 hrs/yr

5) Type of process used to remove H_2S: Amine [✓] Solid Bed Absorption [ ]
Carbonate [ ] Physical Absorption [ ]
Other, describe _____

6) Hydrogen sulfide content of natural gas before treatment 1.36 lb/hr ; after treatment 0.59 lb/hr

7) Amount of NGL to be treated: 1,400 10^6 ft^3/day

8) If amine process is used, list the tail gas disposal method:
flared [ ] vented to atmosphere [✓] sulfur recovery plant [ ]
Other, describe _____

9) Emissions discharged to the atmosphere 70 ft above grade through a stack or duct _____ ft in diameter at _____ °F at _____ ft^3/min and 90 ft/sec velocity.

10) If using an internal combustion engine, complete the INTERNAL COMBUSTION ENGINE form 8-1.0.

11) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting.

12) Did construction, modification, or reconstruction commence after January 20, 1984? Yes [✓]; No [ ]
Does the plant have a design capacity less than 2 long tons per day of hydrogen sulfide in the acid gas?
Yes [✓]; No [ ]
Does the plant produce acid gas that is completely reinjected into oil-or-gas-bearing geological strata or that is otherwise not released to the atmosphere? Yes [ ]; No [✓]
If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart KKK or Subpart LLL.

9.0 K.A.R. CONTROL EQUIPMENT FORMS

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

CONTROL CATALYST
(Stationary Internal Combustion Engine)

1) Source ID Number: 1550133

2) Company/Source Name: Next Generation Processing, LLC./ Haven Gas Plant

3) Catalyst identification number or designation: EC-TW-PX-RO-3350-0000-35

4) What emission unit(s) or source(s) of emissions is(are) associated with the catalyst?
   a. EGS-01
   b. _____
   c. _____
   d. _____

5) Description of pollutant(s) collected: NOx, CO, VOC, Formaldehyde

6) Engine:
   Manufacturer: Waukesha Model No. P9390GSI Serial No. _____
   Maximum HP: 1,980

7) Catalyst:
   Manufacturer: EmeraChem Model No. EC-3350-16-S-CS Serial No. _____
   Operating temperature range of catalyst: 990 °F to 1150 °F
   Temperature at which over temperature protection switch activates: _____°F
   Describe any situations that could render the catalyst ineffective:
   There are two elements to the catalyst, one on each bank of the engine. Both units are necessary for the catalyst to be effective.

   List the parameters and ranges that will define the proper operation of the catalyst:
   (e.g.: Output: __ to __ HP; O_2 Sensor: __ to __ volts; Exhaust temperature: __ to __°F)
   Pressure Drop 4.3 inches H2O, 1127 degrees F.

8) Air/Fuel Ratio Controller:
   Manufacturer: N/A Model No. _____ Serial No. _____

CONTROL CATALYST
(cont.)

9) Emissions Reduced	Emission Factor (after converter) in grams/hp-hr
NOx	0.1
CO	0.3
Nonmethane Nonethane Hydrocarbons	0.008
Other: Formaldehyde	0.005

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

CONTROL CATALYST
(Stationary Internal Combustion Engine)

1) Source ID Number: 1550133

2) Company/Source Name: Next Generation Processing, LLC./ Haven Gas Plant

3) Catalyst identification number or designation: EC-TW-PX-RO-3350-0000-35

4) What emission unit(s) or source(s) of emissions is(are) associated with the catalyst?
   a. EGS-02
   b. _____
   c. _____
   d. _____

5) Description of pollutant(s) collected: NOx, CO, VOC, Formaldehyde

6) Engine:
   Manufacturer: Waukesha Model No. P9390GSI Serial No. _____
   Maximum HP: 1,980

7) Catalyst:
   Manufacturer: EmeraChem Model No. EC-3350-16-S-CS Serial No. _____
   Operating temperature range of catalyst: 990 °F to 1150 °F
   Temperature at which over temperature protection switch activates: _____°F
   Describe any situations that could render the catalyst ineffective:
   There are two elements to the catalyst, one on each bank of the engine. Both units are necessary for the catalyst to be effective.

   List the parameters and ranges that will define the proper operation of the catalyst:
   (e.g.: Output: __ to __ HP; O_2 Sensor: __ to __ volts; Exhaust temperature: __ to __°F)
   Pressure Drop 4.3 inches H2O, 1127 degrees F.

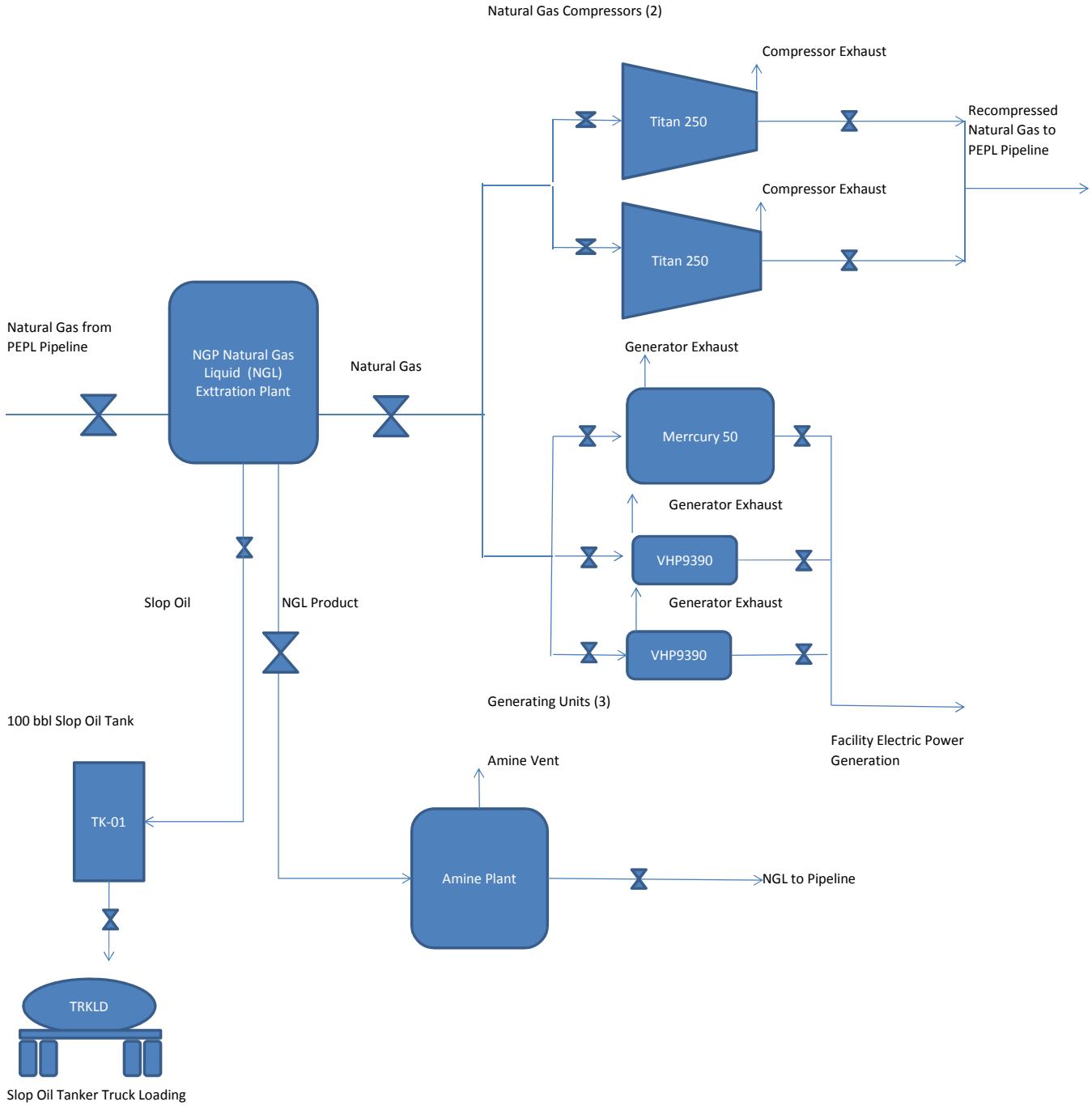
8) Air/Fuel Ratio Controller:
   Manufacturer: N/A Model No. _____ Serial No. _____

CONTROL CATALYST
(cont.)

9) Emissions Reduced	Emission Factor (after converter) in grams/hp-hr
NOx	0.1
CO	0.3
Nonmethane Nonethane Hydrocarbons	0.008
Other: Formaldehyde	0.005

10.0 PROCESS FLOW DIAGRAM

Next Generation Processing, LLC.
Haven Gas Plant



11.0 EMISSION CALCULATIONS

11.0 EMISSIONS CALCULATIONS

This section provides the emission calculation methodology for all emission units presented in this application.

11.1 Summary of Proposed Emissions

Emission calculations are provided in the following pages for eight groups of sources. Sources for which the emissions were calculated in a similar manner were grouped together. The following is a list of emission unit groupings and the location of the applicable emission calculations.

Emissions Calculations Included:

- Titan 250-30000S Natural Gas Turbine Stack Emissions
- Mercury 50-6400R Turbine Generator Set Stack Emissions
- Waukesha VHP-P9390GSI Generator Set Stack Emissions
- Storage Tank Working and Breathing Emissions
- Storage Tank Loading Operations
- Amine Still Venting Emissions
- Titan 250-30000S Natural Gas Turbine Maintenance Startup and Shutdown Emissions
- Equipment Fugitives

Titan 250-30000S Natural Gas Turbine Emission Calculations

Stack emissions for the two (2) Titan 250 turbines are based on engineering calculations that use an emission factor approach. The Titan 250 turbine operating data for loading capacity, horsepower and fuel consumption were based upon Solar Turbine, Inc.'s manufacturing specifications. Emission factors for NO_x, CO and CO_2 were based on the manufactured specifications. Emission factors for PM, HAPs and total VOC were based upon the EPA's *Emission Factors and AP-42, Compilation of Air Pollutant Emission Factors,* Chapter 3 – Stationary Internal Combustion Sources. Combustion emission factors for N_2O and CH_4 were taken from 40 CFR 60 Part 98 Subpart C. The annual emission rate for each species of GHG was multiplied by the applicable global warming potential to determine total GHG emission on a CO_2 equivalency basis.

Mercury 50-6400R Turbine Generator Emission Calculations

Stack emissions for the Mercury 50 generator are based on engineering calculations that use an emission factor approach. The Mercury 50 generator operating data for loading capacity, horsepower and fuel consumption were based on Solar Turbine, Inc.'s manufacturing specifications. Emission factors for NO_x, and CO were based on the manufactured specifications. Emission factors for PM, HAPs and total VOC were based on the EPA's *Emission Factors and AP-42, Compilation of Air Pollutant Emission Factors,* Chapter 3 – Stationary Internal

Combustion Sources. Combustion emission factors for CO_2, N_2O and CH_4 were taken from 40 CFR 60 Part 98 Subpart C. The annual emission rate for each species of GHG was multiplied by the applicable global warming potential to determine total GHG emission on a CO_2 equivalency basis.

Waukesha VHP-P9390 Generator Emission Calculations

Stack emissions for the two (2) Waukesha VHP-9390 internal combustion (IC) engines are based on engineering calculations that use an emission factor approach. The Waukesha VHP-9390 IC engine operating data for loading capacity, horsepower and fuel consumption were based on Dresser's manufacturing specifications. The IC engine combustion emissions will be controlled with dual non-selective catalytic reduction (NSCR) elements. The pollutant reduction efficiencies were provided by EmeraChem manufacturing specifications, and the reduction efficiency has been applied to emissions of NO_x, CO, non-methane and non-ethane hydrocarbon emissions (NMNEHC) and formaldehyde. Emission factors for PM, HAPs and total VOC were based upon the EPA's *Emission Factors and AP-42, Compilation of Air Pollutant Emission Factors,* Chapter 3 – Stationary Internal Combustion Sources. Combustion emission factors for CO_2, N_2O and CH_4 were taken from 40 CFR 60 Part 98 Subpart C. The annual emission rate for each species of GHG was multiplied by the applicable global warming potential to determine total GHG emission on a CO_2 equivalency basis.

Storage Tank Working and Breathing Emission Calculations

TK-01 is scheduled to be installed at the Haven Gas Plant to collect slop oil (primarily condensate and produced water) from the NGL. VOC emissions will be generated from the working and breathing losses that occur as part of normal operation. The emissions from TK-01 have been estimated using the EPA's latest version of the tank emission calculation software program – *TANK4.09d.* All input data for *TANK4.09d* was based on site specific process knowledge and local meteorological conditions. The results for the *TANK4.09d* program have been included with the facility emission calculations.

Storage Tank Loading Emission Calculations

In addition to the emissions generated from normal working and breathing losses from TK-01, VOC emissions will also be generated from tanker truck loading operations that will remove the slop oil to an off-site location. These emissions have been based on engineering calculations using the *Loading Loss Equation* from the EPA's *Emission Factors and AP-42, Compilation of Air Pollutant Emission Factors* – Chapter 5. Tank throughput parameters were taken from the results of *TANK4.09d*; all other parameters were based on site specific process knowledge.

Amine Still Venting Emission Calculations

Emissions from the amine still vent (ASV-01) have been determined using a mass balance approach. A conservative approach was taken to determine average flow and composition, in addition to an extended spot analysis. *HYSIM* Process Simulator was then used to determine a maximum case operating scenario. A propriety Pro-Treat Process Simulator was then run to determine optimized gas treatment operations. A summary of results and additional comments has been included with the emission calculations.

Titan 250-30000S Maintenance Startup and Shutdown Emission Calculations

The emission calculations for EPN GTMSS are based upon Solar Turbine, Inc.'s manufacturing specifications for the Titan 250-30000S natural gas turbine model. Solar Turbine manufacturing specifications provide average emission factors per scheduled startup and shutdown event. The pollutants generated from GTMSS emissions for EPN GT-01 and GT-02 include: NO_x, CO, total VOC and CO_2. The event schedule has been based upon process knowledge for operating EPN GT-01 and GT-02 at 100% load capacity.

Equipment Fugitive Emission Calculations

Fugitive emission calculations have been calculated using the Average Emission Factor Approach outlined in the EPA's *Protocol for Equipment Leak Emission Estimates* (EPA 453/R-95-017). This methodology assumes an average, default emission rate for each type of component in gas, light liquid or heavy liquid service. Equipment component counts were based upon site specific process knowledge. Emissions of Total VOC, CH_4 and CO_2 were then calculated using site specific gas analysis, provided in **Appendix C**. Based on process knowledge, it has been assumed that gas and light liquid service have approximately the same composition.

Details of the emission calculations for each emission point are provided below.

Company	Facility	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Titan 250-30000S Natural Gas Turbine	824-001	GT-01

Operating Data[1]		
Manufacturer	Solar Turbines	
Model	Titan 250-30000S	
Rating	29,299	hp
	6,431.62	Btu/hp-hr
	188.44	MMBtu/hr
Load Capacity	100	%
Fuel Type	Natural Gas	
Hours of Operations	8760	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
NO_X	6.00E-02	lb/MMBtu	Manufacturer Specification	11.31	11.31	49.52
SO_2	3.40E-03	lb/MMBtu	AP-42, Table 3.1-2a	0.64	0.64	2.81
CO	6.10E-02	lb/MMBtu	Manufacturer Specification	11.49	11.49	50.35
$PM/PM_{10}/PM_{2.5}$[2]	6.60E-03	lb/MMBtu	AP-42, Table 3.1-2a	1.24	1.24	5.45
VOC Total	2.10E-03	lb/MMBtu	AP-42, Table 3.1-2a	0.40	0.40	1.73
(HAPs) Acetaldehyde	4.00E-05	lb/MMBtu	AP-42, Table 3.1-3	0.01	0.01	0.03
(HAPs) Acrolein	6.40E-06	lb/MMBtu	AP-42, Table 3.1-3	0.00	0.00	0.01
(HAPs) Benzene	1.20E-05	lb/MMBtu	AP-42, Table 3.1-3	0.00	0.00	0.01
(HAPs) Ethylbenzene	3.20E-05	lb/MMBtu	AP-42, Table 3.1-3	0.01	0.01	0.03
(HAPs) Formaldehyde	7.10E-04	lb/MMBtu	AP-42, Table 3.1-3	0.13	0.13	0.59
(HAPs) Propylene Oxide	2.90E-05	lb/MMBtu	AP-42, Table 3.1-3	0.01	0.01	0.02
(HAPs) Toluene	1.30E-04	lb/MMBtu	AP-42, Table 3.1-3	0.02	0.02	0.11
(HAPs) Xylenes	6.40E-05	lb/MMBtu	AP-42, Table 3.1-3	0.01	0.01	0.05
CO_2	128.80	lb/MMBtu	Manufacturer Specification	24,272.00	24,272.00	106,311.36
N_2O	2.20E-04	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.04	0.04	0.18
CH_4	2.20E-03	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.42	0.42	1.82
CO_2e[3]	-	-	40 CFR 60 Part 98 Subpart C, Table A-1	-	-	106,405.98

(1) Provided by: Next Generation Processing, LLC

(2) All Particulate Matter assumed less than 1 micron in diameter based on Solar Turbine PIL 171 "Particulate Matter Emission Estimates"

(3) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(4) Emission rates calculated as follows:

*Example 1: Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) * Emission Factor (lb/MMBtu)*

Example 2: CO_2e *Emiision rate (TPY) =* CO_2 *ER (TPY)*GWP +* N_2O *ER (TPY)*GWP+* CH_4 *ER (TPY)*GWP*

Company	Facility	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Titan 250-30000S Natural Gas Turbine	824-001	GT-02

Operating Data[1]		
Manufacturer	Solar Turbines	
Model	Titan 250-30000S	
Rating	29,299	hp
	6,431.62	Btu/hp-hr
	188.44	MMBtu/hr
Load Capacity	100	%
Fuel Type	Natural Gas	
Hours of Operations	8760	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
NO_X	6.00E-02	lb/MMBtu	Manufacturer Specification	11.31	11.31	49.52
SO_2	3.40E-03	lb/MMBtu	AP-42, Table 3.1-2a	0.64	0.64	2.81
CO	6.10E-02	lb/MMBtu	Manufacturer Specification	11.49	11.49	50.35
$PM/PM_{10}/PM_{2.5}$[2]	6.60E-03	lb/MMBtu	AP-42, Table 3.1-2a	1.24	1.24	5.45
VOC Total	2.10E-03	lb/MMBtu	AP-42, Table 3.1-2a	0.40	0.40	1.73
(HAPs) Acetaldehyde	4.00E-05	lb/MMBtu	AP-42, Table 3.1-3	0.01	0.01	0.03
(HAPs) Acrolein	6.40E-06	lb/MMBtu	AP-42, Table 3.1-3	0.00	0.00	0.01
(HAPs) Benzene	1.20E-05	lb/MMBtu	AP-42, Table 3.1-3	0.00	0.00	0.01
(HAPs) Ethylbenzene	3.20E-05	lb/MMBtu	AP-42, Table 3.1-3	0.01	0.01	0.03
(HAPs) Formaldehyde	7.10E-04	lb/MMBtu	AP-42, Table 3.1-3	0.13	0.13	0.59
(HAPs) Propylene Oxide	2.90E-05	lb/MMBtu	AP-42, Table 3.1-3	0.01	0.01	0.02
(HAPs) Toluene	1.30E-04	lb/MMBtu	AP-42, Table 3.1-3	0.02	0.02	0.11
(HAPs) Xylenes	6.40E-05	lb/MMBtu	AP-42, Table 3.1-3	0.01	0.01	0.05
CO_2	128.80	lb/MMBtu	Manufacturer Specification	24,272.00	24,272.00	106,311.36
N_2O	2.20E-04	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.04	0.04	0.18
CH_4	2.20E-03	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.42	0.42	1.82
CO_2e[3]	-	-	40 CFR 60 Part 98 Subpart C, Table A-1	-	-	106,405.98

(1) Provided by: Next Generation Processing, LLC

(2) All Particulate Matter assumed less than 1 micron in diameter based on Solar Turbine PIL 171 "Particulate Matter Emission Estimates"

(3) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(4) Emission rates calculated as follows:

*Example 1: Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) * Emission Factor (lb/MMBtu)*

Example 2: CO_2e *Emiision rate (TPY) =* CO_2 *ER (TPY)*GWP +* N_2O *ER (TPY)*GWP+* CH_4 *ER (TPY)*GWP*

Company	Facility	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Mercury 50-6400R Turbine Generator Set	824-001	TGS-01

Operating Data[1]		
Manufacturer	Solar Turbines	
Model	Mercury 50-6400R	
Rating	6,196	hp
	6,499.86	Btu/hp-hr
	40.27	MMBtu/hr
Load Capacity	100	%
Fuel Type	Natural Gas	
Hours of Operations	8760	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
NO_X	2.00E-02	lb/MMBtu	Manufacturer Specification	0.81	0.81	3.53
SO_2	3.40E-03	lb/MMBtu	AP-42, Table 3.1-2a	0.14	0.14	0.60
CO	2.40E-02	lb/MMBtu	Manufacturer Specification	0.97	0.97	4.23
$PM/PM_{10}/PM_{2.5}$[2]	6.60E-03	lb/MMBtu	AP-42, Table 3.1-2a	0.27	0.27	1.16
VOC Total	2.10E-03	lb/MMBtu	AP-42, Table 3.1-2a	0.08	0.08	0.37
(HAPs) Acetaldehyde	4.00E-05	lb/MMBtu	AP-42, Table 3.1-3	0.00	0.00	0.01
(HAPs) Ethylbenzene	3.20E-05	lb/MMBtu	AP-42, Table 3.1-3	0.00	0.00	0.01
(HAPs) Formaldehyde	7.10E-04	lb/MMBtu	AP-42, Table 3.1-3	0.03	0.03	0.13
(HAPs) Propylene Oxide	2.90E-05	lb/MMBtu	AP-42, Table 3.1-3	0.00	0.00	0.01
(HAPs) Toluene	1.30E-04	lb/MMBtu	AP-42, Table 3.1-3	0.01	0.01	0.02
(HAPs) Xylenes	6.40E-05	lb/MMBtu	AP-42, Table 3.1-3	0.00	0.00	0.01
CO_2	116.89	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-1	4,707.12	4,707.12	20,617.20
N_2O	2.20E-04	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.01	0.01	0.04
CH_4	2.20E-03	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.09	0.09	0.39
CO_2e[3]	-	-	40 CFR 60 Part 98 Subpart C, Table A-1	-	-	20,637.42

(1) Provided by: Next Generation Processing, LLC

(2) All Particulate Matter assumed less than 1 micron in diameter based on Solar Turbine PIL 171 "Particulate Matter Emission Estimates"

(3) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(4) Emission rates calculated as follows:

*Example 1: Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) * Emission Factor (lb/MMBtu)*

*Example 2: CO_2e Emiision rate (TPY) = CO_2 ER (TPY)*GWP + N_2O ER (TPY)*GWP+ CH_4 ER (TPY)*GWP*

Company	Facility	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Waukesha VHP-P9390GSI Generator Set	824-001	EGS-01

Operating Data[1]		
Manufacturer	Dresser	
Model	Waukesha VHP - P9390GSI	
Rating	1,980	bhp
	7,930.00	Btu/bhp-hr
	15.70	MMBtu/hr
Catalyst Model	EC-TW-PX-RO-3350-0000-35	
Catalyst Type	NSCR (Dual Element)	
	NO_X Reduction Efficiency	99.20%
	CO Reduction Efficiency	96.70%
	NMNEHC Reduction Efficiency	92.00%
	CH_2O Reduction Efficiency	90.00%
Load Capacity	100	%
Fuel Type	Natural Gas	
Hours of Operations	8760	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
NO_X	0.10	g/bhp-hr	Manufacturer Specification w/ Catalyst	0.44	0.44	1.91
SO_2	5.88E-04	lb/MMBtu	AP-42, Table 3.2-3	0.01	0.01	0.04
CO	0.30	g/bhp-hr	Manufacturer Specification w/ Catalyst	1.31	1.31	5.74
PM[2]	1.94E-02	lb/MMBtu	AP-42, Table 3.2-3	0.30	0.30	1.33
$PM_{10}/PM_{2.5}$[3]	1.94E-02	lb/MMBtu	AP-42, Table 3.2-3	0.30	0.30	1.33
VOC Total	8.00E-03	g/bhp-hr	Manufacturer Specification w/ Catalyst	0.03	0.03	0.15
(HAPs) Acetaldehyde	2.79E-03	lb/MMBtu	AP-42, Table 3.2-3	0.04	0.04	0.19
(HAPs) Methanol	3.06E-03	lb/MMBtu	AP-42, Table 3.2-3	0.05	0.05	0.21
(HAPs) Benzene[4]	1.58E-03	lb/MMBtu	AP-42, Table 3.2-3	0.00	0.00	0.01
(HAPs) Acrolein	2.63E-03	lb/MMBtu	AP-42, Table 3.2-3	0.04	0.04	0.18
(HAPs) Formaldehyde	5.00E-03	g/bhp-hr	Manufacturer Specification w/ Catalyst	0.02	0.02	0.10
CO_2	479.00	g/bhp-hr	Manufacturer Specification	2,090.91	2,090.91	9,158.18
N_2O	2.20E-04	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.00	0.00	0.02
CH_4	2.20E-03	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.03	0.03	0.15
CO_2e[5]	-	-	40 CFR 60 Part 98 Subpart C, Table A-1	-	-	9,166.06

(1) Provided by: Next Generation Processing, LLC

(2) Combined PM Condensable and Filterable Emissions

(3) Assumes less than 1 μm in aerodynamic diameter. Therefore, for $PM_{10} = PM_{2.5}$.

(4) Non-Methane, Non-Ethane Hydrocarbon Catalyst Reduction Efficiency Applied

(5) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(6) Emission rates calculated as follows:

*Example 1: Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) * Emission Factor (lb/MMBtu)*

*Example 2: Emiision rate (lb/hr) = Operating Rate (bhp) * Emission Factor (g/bhp-hr) / 453.6 (g/lb)*

*Example 3: CO_2e Emiision rate (TPY) = CO_2 ER (TPY)*GWP + N_2O ER (TPY)*GWP+ CH_4 ER (TPY)*GWP*

Company	Facility	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Waukesha VHP-P9390GSI Generator Set	824-001	EGS-02

Operating Data[1]		
Manufacturer	Dresser	
Model	Waukesha VHP - P9390GSI	
Rating	1,980	bhp
	7,930.00	Btu/bhp-hr
	15.70	MMBtu/hr
Catalyst Model	EC-TW-PX-RO-3350-0000-35	
Catalyst Type	NSCR (Dual Element)	
	NO_X Reduction Efficiency	99.20%
	CO Reduction Efficiency	96.70%
	NMNEHC Reduction Efficiency	92.00%
	CH_2O Reduction Efficiency	90.00%
Load Capacity	100	%
Fuel Type	Natural Gas	
Hours of Operations	8760	hrs/year

Pollutant	Emission Factor		Reference	Emission Rates		
				Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
NO_X	0.10	g/bhp-hr	Manufacturer Specification w/ Catalyst	0.44	0.44	1.91
SO_2	5.88E-04	lb/MMBtu	AP-42, Table 3.2-3	0.01	0.01	0.04
CO	0.30	g/bhp-hr	Manufacturer Specification w/ Catalyst	1.31	1.31	5.74
PM[2]	1.94E-02	lb/MMBtu	AP-42, Table 3.2-3	0.30	0.30	1.33
$PM_{10}/PM_{2.5}$[3]	1.94E-02	lb/MMBtu	AP-42, Table 3.2-3	0.30	0.30	1.33
VOC Total	8.00E-03	g/bhp-hr	Manufacturer Specification w/ Catalyst	0.03	0.03	0.15
(HAPs) Acetaldehyde	2.79E-03	lb/MMBtu	AP-42, Table 3.2-3	0.04	0.04	0.19
(HAPs) Methanol	3.06E-03	lb/MMBtu	AP-42, Table 3.2-3	0.05	0.05	0.21
(HAPs) Benzene[4]	1.58E-03	lb/MMBtu	AP-42, Table 3.2-3	0.00	0.00	0.01
(HAPs) Acrolein	2.63E-03	lb/MMBtu	AP-42, Table 3.2-3	0.04	0.04	0.18
(HAPs) Formaldehyde	5.00E-03	g/bhp-hr	Manufacturer Specification w/ Catalyst	0.02	0.02	0.10
CO_2	479.00	g/bhp-hr	Manufacturer Specification	2,090.91	2,090.91	9,158.18
N_2O	2.20E-04	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.00	0.00	0.02
CH_4	2.20E-03	lb/MMBtu	40 CFR 60 Part 98 Subpart C, Table C-2	0.03	0.03	0.15
CO_2e[5]	-	-	40 CFR 60 Part 98 Subpart C, Table A-1	-	-	9,166.06

(1) Provided by: Next Generation Processing, LLC

(2) Combined PM Condensable and Filterable Emissions

(3) Assumes less than 1 μm in aerodynamic diameter. Therefore, for $PM_{10} = PM_{2.5}$.

(4) Non-Methane, Non-Ethane Hydrocarbon Catalyst Reduction Efficiency Applied

(5) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(6) Emission rates calculated as follows:

*Example 1: Emiision rate (lb/hr) = Operating Rate (MMBtu/hr) * Emission Factor (lb/MMBtu)*

*Example 2: Emiision rate (lb/hr) = Operating Rate (bhp) * Emission Factor (g/bhp-hr) / 453.6 (g/lb)*

*Example 3: CO_2e Emiision rate (TPY) = CO_2 ER (TPY)*GWP + N_2O ER (TPY)*GWP+ CH_4 ER (TPY)*GWP*

Company	Facility	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Slop Oil Tank	824-001	TK-01

Operating Data[1]		
Tank Volume	100	bbl
Operating Rate	1,441.38	bbl/yr
Hours of Operation	8,760	hrs/year

Pollutant	Emission Factor	Reference	Emission Rates		
			Avg (lb/hr)	Max (lb/hr)	Annual (tons/yr)
Total VOC	NA	Tank 4.09d	0.05	0.05	0.24

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TK-01
City:	Haven
State:	Kansas
Company:	Next Generation Processing
Type of Tank:	Vertical Fixed Roof Tank
Description:	Slop Oil Tank

Tank Dimensions

Shell Height (ft):	12.00
Diameter (ft):	8.00
Liquid Height (ft) :	11.50
Avg. Liquid Height (ft):	10.00
Volume (gallons):	4,200.00
Turnovers:	14.00
Net Throughput(gal/yr):	60,538.12
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	1.00
Slope (ft/ft) (Cone Roof)	0.25

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Wichita, Kansas (Avg Atmospheric Pressure = 14.04 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-01 - Vertical Fixed Roof Tank
Haven, Kansas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Gasoline (RVP 7)	Jan	45.53	40.88	50.18	56.23	2.5734	2.3259	2.8419	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Feb	48.19	42.96	53.42	56.23	2.7246	2.4342	3.0426	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Mar	53.29	47.43	59.16	56.23	3.0343	2.6803	3.4254	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Apr	58.61	52.28	64.93	56.23	3.3869	2.9709	3.8491	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	May	62.94	56.58	69.29	56.23	3.6983	3.2487	4.1970	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Jun	67.65	61.13	74.18	56.23	4.0633	3.5654	4.6159	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Jul	70.20	63.49	76.90	56.23	4.2721	3.7399	4.8638	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Aug	68.97	62.57	75.37	56.23	4.1702	3.6712	4.7226	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Sep	64.49	58.66	70.32	56.23	3.8155	3.3907	4.2823	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Oct	58.89	53.14	64.65	56.23	3.4067	3.0245	3.8273	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Nov	52.23	47.39	57.08	56.23	2.9677	2.6782	3.2822	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3
Gasoline (RVP 7)	Dec	46.93	42.52	51.35	56.23	2.6522	2.4105	2.9133	68.0000			92.00	Option 4: RVP=7, ASTM Slope=3

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-01 - Vertical Fixed Roof Tank
Haven, Kansas

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):	6.8181	7.4875	10.7041	12.9022	15.0563	17.0174	19.3947	17.8533	13.8774	12.1685	8.2265	6.7022
Vapor Space Volume (cu ft):	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861
Vapor Density (lb/cu ft):	0.0323	0.0340	0.0375	0.0414	0.0448	0.0488	0.0511	0.0500	0.0461	0.0416	0.0367	0.0332
Vapor Space Expansion Factor:	0.0766	0.0897	0.1080	0.1256	0.1346	0.1488	0.1596	0.1489	0.1258	0.1143	0.0870	0.0738
Vented Vapor Saturation Factor:	0.7586	0.7480	0.7271	0.7048	0.6862	0.6656	0.6543	0.6598	0.6794	0.7036	0.7315	0.7530
Tank Vapor Space Volume:												
Vapor Space Volume (cu ft):	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861	117.2861
Tank Diameter (ft):	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000
Vapor Space Outage (ft):	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333
Tank Shell Height (ft):	12.0000	12.0000	12.0000	12.0000	12.0000	12.0000	12.0000	12.0000	12.0000	12.0000	12.0000	12.0000
Average Liquid Height (ft):	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000
Roof Outage (ft):	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333
Roof Outage (Cone Roof)												
Roof Outage (ft):	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333	0.3333
Roof Height (ft):	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Roof Slope (ft/ft):	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500
Shell Radius (ft):	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000
Vapor Density												
Vapor Density (lb/cu ft):	0.0323	0.0340	0.0375	0.0414	0.0448	0.0488	0.0511	0.0500	0.0461	0.0416	0.0367	0.0332
Vapor Molecular Weight (lb/lb-mole):	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.5734	2.7246	3.0343	3.3869	3.6983	4.0633	4.2721	4.1702	3.8155	3.4067	2.9677	2.6522
Daily Avg. Liquid Surface Temp. (deg. R):	505.2012	507.8642	512.9624	518.2771	522.6076	527.3235	529.8687	528.6394	524.1613	518.5621	511.9035	506.6048
Daily Average Ambient Temp. (deg. F):	29.5000	34.8000	45.4000	56.4000	65.6000	75.7000	81.3500	79.3000	70.3000	58.6000	44.6000	33.0000
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731
Liquid Bulk Temperature (deg. R):	515.9025	515.9025	515.9025	515.9025	515.9025	515.9025	515.9025	515.9025	515.9025	515.9025	515.9025	515.9025
Tank Paint Solar Absorptance (Shell):	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	790.0023	1,036.5211	1,359.8192	1,713.2580	1,923.6080	2,126.0263	2,170.1268	1,926.4634	1,540.6631	1,204.6742	833.4683	688.4759
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:	0.0766	0.0897	0.1080	0.1256	0.1346	0.1488	0.1596	0.1489	0.1258	0.1143	0.0870	0.0738
Daily Vapor Temperature Range (deg. R):	18.5924	20.9178	23.4647	25.2911	25.4284	26.1039	26.8178	25.5860	23.3176	23.0142	19.3753	17.6771
Daily Vapor Pressure Range (psia):	0.5160	0.6083	0.7451	0.8783	0.9482	1.0505	1.1238	1.0514	0.8916	0.8028	0.6040	0.5028
Breather Vent Press. Setting Range(psia):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.5734	2.7246	3.0343	3.3869	3.6983	4.0633	4.2721	4.1702	3.8155	3.4067	2.9677	2.6522
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	2.3259	2.4342	2.6803	2.9709	3.2487	3.5654	3.7399	3.6712	3.3907	3.0245	2.6782	2.4105
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	2.8419	3.0426	3.4254	3.8491	4.1970	4.6159	4.8638	4.7226	4.2823	3.8273	3.2822	2.9133
Daily Avg. Liquid Surface Temp. (deg R):	505.2012	507.8642	512.9624	518.2771	522.6076	527.3235	529.8687	528.6394	524.1613	518.5621	511.9035	506.6048
Daily Min. Liquid Surface Temp. (deg R):	500.5531	502.6348	507.0963	511.9543	516.2505	520.7975	523.1642	522.2429	518.3319	512.8085	507.0597	502.1855
Daily Max. Liquid Surface Temp. (deg R):	509.8493	513.0937	518.8286	524.5999	528.9647	533.8494	536.5731	535.0359	529.9907	524.3156	516.7474	511.0241
Daily Ambient Temp. Range (deg. R):	20.6000	22.2000	23.6000	23.8000	22.6000	22.2000	22.9000	22.8000	22.2000	24.0000	21.4000	20.0000
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:	0.7586	0.7480	0.7271	0.7048	0.6862	0.6656	0.6543	0.6598	0.6794	0.7036	0.7315	0.7530
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	2.5734	2.7246	3.0343	3.3869	3.6983	4.0633	4.2721	4.1702	3.8155	3.4067	2.9677	2.6522
Vapor Space Outage (ft):	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333	2.3333
Working Losses (lb):	21.0191	22.2541	24.7833	27.6640	30.2071	33.1885	34.8938	34.0616	31.1643	27.8258	24.2396	21.6629
Vapor Molecular Weight (lb/lb-mole):	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000	68.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.5734	2.7246	3.0343	3.3869	3.6983	4.0633	4.2721	4.1702	3.8155	3.4067	2.9677	2.6522
Net Throughput (gal/mo.):	5,044.8433	5,044.8433	5,044.8433	5,044.8433	5,044.8433	5,044.8433	5,044.8433	5,044.8433	5,044.8433	5,044.8433	5,044.8433	5,044.8433
Annual Turnovers:	14.0000	14.0000	14.0000	14.0000	14.0000	14.0000	14.0000	14.0000	14.0000	14.0000	14.0000	14.0000
Turnover Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Maximum Liquid Volume (gal):	4,200.0000	4,200.0000	4,200.0000	4,200.0000	4,200.0000	4,200.0000	4,200.0000	4,200.0000	4,200.0000	4,200.0000	4,200.0000	4,200.0000
Maximum Liquid Height (ft):	11.5000	11.5000	11.5000	11.5000	11.5000	11.5000	11.5000	11.5000	11.5000	11.5000	11.5000	11.5000
Tank Diameter (ft):	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000	8.0000
Working Loss Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Total Losses (lb):	27.8372	29.7416	35.4874	40.5661	45.2633	50.2059	54.2885	51.9149	45.0418	39.9942	32.4661	28.3651

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

TK-01 - Vertical Fixed Roof Tank
Haven, Kansas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Gasoline (RVP 7)	332.96	148.21	481.17

Company	Facility	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
TK-01 Truck Loading Operations	824-001	TRKLD

Parameter		Unit
Saturation Factor[1]	0.60	
Temperature of bulk liquid loaded[2]	515.90	R
True Vapor Pressure of liquid loaded[3]	3.50	PSI
Molecular Weight of Vapor[2]	68.00	
Loading Loss Factor = 12.46*S*VP*MW/T		
Loading Loss Factor	3.45	lb/1000 gal
Truck Max Loading Rate	8,400.00	gal/hr
Tank Throughput[2]	60,538.12	gal/yr
Max Loadout VOC Emissions	28.971	lb/hr
Total Loadout VOC Emissions	0.104	TPY

(1) Saturation factor from AP-42 Fifth Edition, Table 5.2-1

(2) Tanks 4.09d, metorological data used in Emission Calculations: Wichita, KS.

(3) AP-42 Fifth Edition, Table 7.1-2. Properties of Selected Petroluem Liquids. Based upon RVP 7 at 60 ^{o}F.

Company	Facility	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Amine Still Vent	824-001	ASV-01

Amine Still Vented Emissions[1]							
Pollutant	**Mass Rate Before Amine Treatment**		**Mass Rate After Amine Treatment**		**Vented Emission Rates**		
					Avg lb/hr	Max lb/hr	TPY[3]
Hydrogen Sulfide	1.36	lb/hr	0.59	lb/hr	0.77	0.77	3.31
VOC Total	154,490.00	lb/hr	154,485.02	lb/hr	4.98	4.98	21.51
CO_2	17,565.00	lb/hr	868.00	lb/hr	16,697.00	16,697.00	72,131.04
CH_4	1,588.00	lb/hr	1,587.84	lb/hr	0.16	0.16	0.69
CO_2e[2]	-	lb/hr	-	lb/hr	-	-	72,145.56

(1) Emission rates determined using process simulations, provided by NGP. An explanation of the rates can be found below.

(2) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(3) Emission rates based on 360 days per year of operation.

(3) Emission rates calculated as follows:

Example 1: Vented Emission Rate (lb/hr) = Mass Rate Before Treatment (lb/hr) - Mass Rate After Treatment (lb/hr)

*Example 2: CO_2e Emiision rate (TPY) = CO_2 ER (TPY)*GWP + N_2O ER (TPY)*GWP+ CH_4 ER (TPY)*GW*

Steps in Determining ASV-01 Emission Rates:

STEP 1 Using 5 year average flow and composition data combined with a Spot Extended Analysis determine Base Case Gas Plant Inlet Composition.

STEP 2 Using HYSIM Process Simulator determine the Base Case NGL Product Stream which is the Feed into the Amine Plant Liquid / Liquid Contactors. (See Base Case Feed Below).

Base Case NGL Feed into Amine Liquid / Liquid Contactor

(lb/hr)	Base Case NGL Feed
CO-2	12,177
H2S	0.58
Water	0
Methane	944
Ethane	140,303
Propane	35,279
N-Butane	4,615
I-Butane	3,066
C5+	4,403
TOTAL	200,788

STEP 3 Considering potential new gas sources, determine a MAXIMUM CASE to be used in Design and Emissions Permitting.

Maximum Case NGL Feed into Amine Liquid / Liquid Contactor

(lb/hr)	Base Case NGL Feed	Maximum Case Feed
CO-2	12,177	17,565
H2S	0.58	1.36
Water	0	0
Methane	944	1,588
Ethane	140,303	206,190
Propane	35,279	92,090
N-Butane	4,615	12,659
I-Butane	3,066	26,651
C5+	4,403	23,090
TOTAL	200,788	379,834

STEP 4 Give Maximum Case to Ineos to simulate Amine Plant using their proprietary amine mixes.

Ineos uses the Pro Treat Process Simulator from Optimized Gas Treating. Results from simulation provided in the above summary table.

Company	**Facility**	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Maintenance Startup and Shutdown	824-001	GTMSS

Start up Emissions - 10 Minute Startup[1]									
Description	Events per Year	NO_X		CO		VOC		CO_2	
		Avg (lb/event)	TPY	Avg (lb/event)	TPY	Avg (lb/event)	TPY	Avg (lb/event)	TPY
Titan 250-30000S Natural Gas Turbine - GT-01	6	3.10	0.01	284.80	0.85	16.30	0.05	1,794.00	5.38
Titan 250-30000S Natural Gas Turbine - GT-02	6	3.10	0.01	284.80	0.85	16.30	0.05	1,794.00	5.38
Total Startup Emissions			**0.02**		**1.71**		**0.10**		**10.76**

Shutdown Emissions - 10 Minute Shutdown[1]									
Description	Events per Year	NO_X		CO		VOC		CO_2	
		Avg (lb/event)	TPY	Avg (lb/event)	TPY	Avg (lb/event)	TPY	Avg (lb/event)	TPY
Titan 250-30000S Natural Gas Turbine - GT-01	6	3.60	0.01	313.40	0.94	17.90	0.05	1,918.00	5.75
Titan 250-30000S Natural Gas Turbine - GT-02	6	3.60	0.01	313.40	0.94	17.90	0.05	1,918.00	5.75
Total Shutdown Emissions			**0.02**		**1.88**		**0.11**		**11.51**
Total MSS Emissions			**0.04**		**3.59**		**0.21**		**22.27**

(1) Emissions data and maintenance sheduling provided by Solar Turbine Product Information Letter 170, "Emission Estimates at Start-up, Shutdown, and Commissioning for SoLowNOx Combustion Products."

Company	Facility	
Next Generation Processing, LLC	Haven Gas Plant	
Descriptive Name of Emission Point	**Project No.**	**Emission Point ID No.**
Equipment Fugitives	824-001	FUG-01

Natural Gas Composition				
Component	**Molecular Weight (lb/lb-mole)**	**Composition (mol%)**	**xi*MW**	**Mass Fraction (%)**
carbon dioxide	44.01	0.48%	0.21	1.24%
nitrogen	27.99	2.05%	0.57	3.35%
methane	16.04	93.34%	14.97	87.29%
ethane	30.07	3.43%	1.03	6.02%
propane	44.09	0.47%	0.21	1.20%
n-butane	58.24	0.10%	0.06	0.33%
isobutane	57.05	0.05%	0.03	0.16%
n-pentane	70.51	0.03%	0.02	0.11%
isopentane	72.15	0.03%	0.02	0.11%
hexanes plus	94.32	0.04%	0.03	0.20%
Totals	-	100.00%	17.15	100.00%
TOC wt %				96.65%
VOC wt %				2.10%
CH_4 wt %				87.29%
CO_2 wt %				1.24%

(1) Natural Gas Composition Data Provided by NGP

Equipment Fugitive Emissions												
Component Type	**Service Type**	**Component Count(2)**	**Emission Factor(3)**		**TOC Emissions(4)**		**VOC Emissions(5)**		**Methane Emissions(5)**		**Carbon Dioxide$_2$(5)**	
					lb/hr	TPY	lb/hr	TPY	lb/hr	TPY(6)	lb/hr	TPY(6)
Valves	Gas	187	2.86E-05	lb/hr	5.17E-03	0.02	1.16E-04	5.10E-04	4.83E-03	2.12E-02	6.87E-05	3.01E-04
	Light Liquid	78	9.46E-05	lb/hr	7.13E-03	0.03	1.61E-04	7.03E-04	6.66E-03	2.92E-02	9.48E-05	4.15E-04
Pressure Relief Device	Gas	23	2.64E-04	lb/hr	5.87E-03	0.03	1.32E-04	5.79E-04	5.48E-03	2.40E-02	7.80E-05	3.42E-04
	Light Liquid	10	2.86E-04	lb/hr	2.76E-03	0.01	6.22E-05	2.73E-04	2.58E-03	1.13E-02	3.67E-05	1.61E-04
Flanges/Connectors	Gas	485	9.24E-05	lb/hr	0.04	0.19	9.75E-04	4.27E-03	4.05E-02	1.77E-01	5.76E-04	2.52E-03
	Light Liquid	202	1.76E-05	lb/hr	3.44E-03	0.02	7.74E-05	3.39E-04	3.21E-03	1.41E-02	4.57E-05	2.00E-04
Compressors	Gas	5	2.64E-04	lb/hr	1.28E-03	0.01	2.87E-05	1.26E-04	1.19E-03	5.22E-03	1.70E-05	7.43E-05
Pump Seals	Light Liquid	7	1.19E-03	lb/hr	8.04E-03	0.04	1.81E-04	7.93E-04	7.51E-03	3.29E-02	1.07E-04	4.68E-04
Totals					0.08	0.34	1.73E-03	7.59E-03	0.07	0.32	1.02E-03	4.48E-03
CO_2e Total									-	6.62		4.48E-03

(2) Component Count provided by NGP; based on process knowledge.

(3) Emission Factors taken from AP-42, Chapter 5, "Protocol For Equiment Leak Emission Estimates-Table 2.3" Converted from kg/hr to lb/hr

(4) Calculations based on "Average Emission Factor Approach" in the Protocol For Equipment Leak Emission Estimates

(5) VOC, CO_2 and Methane Emissions calculated based on Section 2.4.6 of the Protocol For Equipment Leak Emission Estimates

(6) Global Warming Potentials (GWP) taken from 40 CFR 60 Part 98 Subpart A, Table A-1

(7) Laboratory Analysis provided in Appendix C. Gas and light liquid service assumed same composition.

12.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

12.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

This section presents a BACT analysis for each pollutant emitted at the proposed Haven Gas Plant that is subject to PSD review. In accordance with 40 CFR 52.21, PSD regulations require new major stationary sources to conduct a BACT analysis for each emission unit with the potential-to-emit (PTE) a regulated NSR pollutant at a rate that would be greater than or equal to the significant emission rates identified in 40 CFR 52.21(b)(23).

BACT is defined as an achievable emission limitation based on the maximum degree of reduction while taking into account energy, environmental, and economic impacts and other costs on a case-by-case basis. The BACT analysis must separately address air pollution controls for each emissions unit or pollutant-emitting activity that emits a pollutant that is subject to PSD review.

The BACT analysis must demonstrate that a new major stationary source meets the applicable emission standards and standards of performance identified in 40 CFR Part 60 – *Standards of Performance for New Stationary Sources (NSPS)*, 40 CFR Part 61 – *National Emission Standards for Hazardous Air Pollutants (NESHAPS)* and 40 CFR Part 63 – *National Emission Standards for Hazardous Air Pollutants for Source Categories.*

12.1 BACT Applicability

BACT applies to each new and modified emission unit, and is performed on a pollutant-by-pollutant basis. **Table 12-1** lists the emission units and pollutants for which a BACT analysis is required.

Table 12-1
NGP Emission Units and Pollutants Subject to BACT

EPN	Description	Source Type	Pollutants
GT-01	Titan 250-30000S Natural Gas Turbine	Internal Combustion	NO_x CO CO_2e $PM_{2.5}$
GT-02	Titan 250-30000S Natural Gas Turbine	Internal Combustion	
TGS-01	Mercury 50-6400R Turbine Generator Set	Internal Combustion	
EGS-01	Waukesha VHP-P9390GSI Generator Set	Internal Combustion	
EGS-02	Waukesha VHP-P9390GSI Generator Set	Internal Combustion	
FUG-01	Fugitive Emissions	Process Fugitives	CH_4
ASV-01	Amine Still Vent	Amine Treatment	CO_2e

As discussed in Section 2.0, the proposed Haven Gas Plant is a new major stationary source that has the potential to emit greater than 100,000 tpy of GHG on a CO_2e basis. Therefore, the facility is a major source for PSD purposes, and all proposed attainment pollutants emitted in amounts greater than or equal to the PSD SER are subject to PSD review.

12.2 BACT Analysis Methodology

In accordance with the requirements to conduct a BACT analysis and determination as outlined in 40 CFR Part 52.21(j), a BACT analysis has been conducted using the EPA top-down method. The top-down method provides that all available control technologies are ranked in descending order of control effectiveness.[1] Based on the top-down examination, the most stringent control alternative is selected as BACT unless it can be demonstrated, and the permitting authority agrees, that the most stringent technology is not 'achievable' based on technical considerations, or energy, environmental, or economic impacts. If it is determined that the most stringent technology be eliminated as BACT, then the next most stringent technology is considered, and so on.[1] The five steps of the top-down method are described below:

Step 1 – Identify All Control Technologies

The first step is to identify, for each emission unit under BACT review, all available control options; where available control option means an air pollution control technology or technique with practical application to the emission unit and pollutant being reviewed in the BACT analysis. These technologies and techniques include: add-on controls, inherently lower-polluting processes, methods, fuel treatment or innovative fuel combustion techniques. Technology transfer from similar source categories should also be considered when determining the control technologies and techniques.

A search of nationally permitted control technology options was conducted using EPA's RACT/BACT/LAER Clearinghouse (RBLC), the South Coast Air Quality Management District's (SCAQMD) LAER/BACT Determinations for Major Polluting Facilities, and the San Joaquin Valley Air Pollution Control District's (SJVAPCD) BACT Clearinghouse, technical journals, reports and newsletters, and air pollution control seminars. The search options included inherently lower-emitting processes/practices and add-on controls.

Step 2 – Eliminate Technically Infeasible Options

The second step of the BACT analysis is to consider the technical feasibility of each of the control options selected in step one based on unit specific factors. The technical infeasibility of a control option should be based upon physical, chemical or engineering principal that would prevent the control option from being successfully implemented to the specific emission unit. After technical infeasibility has been thoroughly demonstrated, the control option under review is eliminated from the BACT determination.

[1] US EPA, "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting." (Oct., 1990).

Step 3 – Rank Remaining Control Options By Effectiveness

Once technically infeasible control options have been eliminated from the BACT determination, the remaining control options are then ranked, in descending order, by control effectiveness. Information regarding control efficiency, emission rate, emission reduction and the impacts associated with environmental, economic and energy considerations should be documented. If the most stringent technology or technique available from the remaining technically feasible control options is proposed as BACT, economic and other detailed analysis for the alternative controls need not be considered further in the BACT analysis.

Step 4 – Evaluate Most Effective Controls and Document Results

Once the technically feasible control options have been identified, a BACT determination is made based on the energy, environmental and economic impacts. If the most stringent control option is proposed as BACT, then the direct impact of that option should be reviewed to determine if the next most stringent control option is more appropriate, and so on.

Step 5 – Select BACT

Based on the control option review, conducted in the first four steps of the BACT analysis, the most effective control option remaining is proposed as BACT for the pollutant and emission unit under review.

12.3 BACT Summary

The results of the top-down BACT analysis conducted for all criteria pollutants under PSD review and for each applicable emission unit are summarized in **Table 12-2.** The results of the top-down BACT analysis conducted for all GHG pollutants, and all applicable emission units are summarized in **Table 12-3**. BACT determinations were based upon technical feasibility, environmental impacts, energy impacts and economic impacts in accordance with EPA guidelines for conducting a top-down approach. Detailed analysis for each emission unit and each air pollutant required to undergo PSD review are provided in Section 12.4 through Section 12.6.

Table 12-2
Proposed Criteria Pollutant BACT Determinations for the Haven Gas Plant

Emission Unit	BACT Determination and Emission Limits		
	NO_x	CO	$PM_{2.5}$
GT-01	Dry Low NO_x Burners and Good Combustion Practice	Dry Low NO_x Burners and Good Combustion Practice	Good Combustion Practice and Burn Only Natural Gas
	15 ppmv @ 15% O_2	25 ppmv @ 15% O_2	1.24 lb/hr
	11.31 lb/hr	11.49 lb/hr	
GT-02	Dry Low NO_x Burners and Good Combustion Practice	Dry Low NO_x Burners and Good Combustion Practice	Good Combustion Practice and Burn Only Natural Gas
	15 ppmv @ 15% O_2	25 ppmv @ 15% O_2	1.24 lb/hr
	11.31 lb/hr	11.49 lb/hr	
TGS-01	Dry Low NO_x Burners and Good Combustion Practice	Dry Low NO_x Burners and Good Combustion Practice	Good Combustion Practice and Burn Only Natural Gas
	5 ppmv @ 15% O_2	10 ppmv @ 15% O_2	0.27 lb/hr
	0.81 lb/hr	0.97 lb/hr	
EGS-01	Dual Non-Selective Catalytic Reduction and Good Combustion Practice	Dual Non-Selective Catalytic Reduction and Good Combustion Practice	Good Combustion Practice and Burn Only Natural Gas
	0.10 g/bhp-hr	0.30 g/bhp-hr	0.30 lb/hr
EGS-02	Dual Non-Selective Catalytic Reduction and Good Combustion Practice	Dual Non-Selective Catalytic Reduction and Good Combustion Practice	Good Combustion Practice and Burn Only Natural Gas
	0.10 g/bhp-hr	0.30 g/bhp-hr	0.30 lb/hr

Table 12-3
Proposed GHG Pollutant BACT Determinations for the Haven Gas Plant

GHG BACT Emission Limits			
Emission Unit	**Pollutant**	**BACT Limit lb/MMscf**	**BACT Determination**
GT-01	CO_2	134,606.45	Good Combustion Practice and Burn Only Natural Gas
	CH_4	2.27	
	N_2O	0.23	
	CO_2e	134,724.30	
GT-02	CO_2	134,606.45	Good Combustion Practice and Burn Only Natural Gas
	CH_4	2.27	
	N_2O	0.23	
	CO_2e	134,724.30	
TGS-01	CO_2	120,161.99	Good Combustion Practice and Burn Only Natural Gas
	CH_4	2.27	
	N_2O	0.23	
	CO_2e	120,279.83	
EGS-01	CO_2	116,472.25	Good Combustion Practice and Burn Only Natural Gas
	CH_4	2.27	
	N_2O	0.23	
	CO_2e	116,590.10	
EGS-01	CO_2	116,472.25	Good Combustion Practice and Burn Only Natural Gas
	CH_4	2.27	
	N_2O	0.23	
	CO_2e	116,590.10	
ASV-01	CO_2	6.015 lb/bbl	Natural Gas Feed Stocks Only
	CH_4	5.76E-5 lb/bbl	
	CO_2e	6.017 lb/bbl	

12.4 BACT Analysis – Combustion Turbines

This section provides a pollutant-by-pollutant BACT determination for the Titan 250-30000S gas turbines (EPNs GT-01 and GT-02) and the Mercury 50-6400R gas turbine generator set (EPN TGS-01) proposed for the Haven Gas Plant. NGP is proposing to install two (2) combined-cycle Titan 250-30000S gas turbines with lean-premix annular-type combustion (SoLoNO$_x$) for natural gas compression. These emission units are combined-cycle turbines that will incorporate circular waste heat recovery and combust only natural gas. It is

anticipated that these units will operate at 100% load capacity with no limitation for annual operation. NGP anticipates that these turbines will only be taken offline for planned maintenance startup and shutdown (MSS) events. Manufacturing estimates indicate that each shutdown event for the Titan-250-30000S turbine requires 10 minutes and each startup event requires 10 minutes. Based upon process knowledge, NGP anticipates that no more than six (6) planned MSS events per turbine (EPN GTMSS) will be required annually.

In addition, NGP is proposing to install one (1) recuperated Mercury 50-6400R gas turbine generator set for electrical power generation at the Haven Gas Plant. The Mercury 50-6400R is an annular type combustor unit with ultra-lean-premix (ULP) technology that will burn only natural gas. The Mercury 50-6400R is essentially a simple-cycle gas turbine with an added heat exchanger, called a regenerator or recuperator, which is used to preheat the combustion air. Preheating the combustion air reduces the amount of fuel required to reach design combustor temperatures, which improves the overall efficiency over that of simple-cycle operation. It is anticipated that this unit will only be taken offline once per year for planned MSS events. Based on manufacturing estimates, the shutdown event takes approximately 9 minutes and the startup event takes approximately 20 minutes.

Based on the similarities of the Solar Turbines, Inc. (Solar) combustion design for both the combined-cycle gas turbines (EPNs GT-01 and GT-02) and the recuperated gas turbine (TGS-01) and the available control techniques and add-on control technologies available to all stationary gas turbines, both combined-cycle and recuperated gas turbines are concurrently reviewed in the BACT analysis for combustion turbines provided in Section 12.4.

12.4.1 Nitrogen Oxide Formation

NO_X formation occurs by three fundamentally different mechanisms. The principal mechanism of NO_X formation in natural gas and hydrogen combustion is thermal NO_X. The thermal NO_X mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air.[2] Most NO_X formed through the thermal NO_X mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NO_X is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NO_X emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas/hydrogen fired boilers. Emission levels vary considerably with the type and size of the combustor and with operating conditions (*e.g.*, combustion air temperature, volumetric heat release rate, load, and excess oxygen level). Most thermal NO_X is formed in high temperature stoichiometric flame

[2] US EPA. Emissions Standards Division "Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines (EPA-453/R-93-007)." (Jan, 1993). http://yosemite1.epa.gov/ee/epa/ria.nsf/vwAN/A9346.pdf/$file/A9346.pdf.

pockets downstream of the fuel injectors where combustion air has mixed sufficiently with the fuel to produce the peak temperature fuel/air interface. The second mechanism, called prompt NO_X, is formed from early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X forms within the flame and is usually negligible when compared to the amount of thermal NO_X formed.[2]

The third mechanism, fuel NO_X, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Natural gas has negligible chemically-bound fuel nitrogen. Based on extended gas analysis, the natural gas entering the proposed Haven Gas Plant will have a nitrogen content of approximately 3.5 percent by weight (wt%).

12.4.2 NO_x Control Candidates – Combustion Turbines

Based upon a search of nationally permitted control technology options conducted using EPA's RACT/BACT/LAER Clearinghouse (RBLC), the South Coast Air Quality Management District's (SCAQMD) LAER/BACT Determinations for Major Polluting Facilities, and the San Joaquin Valley Air Pollution Control District's (SJVAPCD) BACT Clearinghouse, the following control options are available control candidates for combined-cycle and simple-cycle turbines combusting natural gas:

- *Wet Controls - Water and Steam Injection;*
- *Dry Low NO_x (DLN) Combustor Technology;*
- *Selective Catalytic Reduction (SCR); and*
- *Selective Non-Catalytic Reduction (SNCR).*

Additional control candidates available to control NO_x emissions from combined-cycle turbine(s) and simple-cycle turbine(s), not listed in the EPA's Technology Transfer Network, include the following:

- *Rich/Quench/Lean (RQL) Combustion;*
- *Catalytic Combustion – Xonon™;*
- *EMxGT Catalytic Oxidation/Absorption; and*
- *Alternate Lower FBN (fuel-bound nitrogen) Fuels.*

12.4.2.1 Wet Controls – Water and Steam Injection

Water and steam injection directly into the flame area of the turbine combustor provides a heat sink that lowers the flame temperature and reduces thermal NO_x formation; however, fuel NO_x formation is not reduced with this technique.[2] The water or steam injection rate is typically described on a mass basis by a water-to-fuel ratio (WFR) or steam-to-fuel ratio (SFR). Higher WFRs and SFRs translate to greater NO_x reductions, but may also cause potential flame outs; increasing maintenance requirements and reducing turbine efficiency. During startup and shutdown events for the combined-cycle turbines,

introduction of water or steam injection into the proposed DLN combustors while firing natural gas would cause severe disruption to combustion dynamics and would likely result in damage to the combustion system and related components. Accordingly, the use of water or steam injection during natural gas-fired operations will be precluded from further considerations in this BACT analysis for EPNs GT-01 and GT-02.

Wet controls can be added as a retrofit to most gas turbine installations; however, wet control configurations have not been applied effectively to regenerative cycle applications.[2] Therefore, wet controls are not considered as a control candidate for EPN TGS-01 and are not included in further BACT analysis.

Based on discussions with Solar, water or steam injection aren't commercially available options for the Titan 250 or Mercury 50 designs. Water injection is employed with diffusion flame (conventional) combustion technology. Neither the Titan 250, nor the Mercury 50, is available with diffusion flame.

12.4.2.2 Dry Low NO_x (DLN) Combustion Technology

DLN combustion control techniques reduce NO_x emissions without the use of water or steam injection. Two DLN combustion designs are available: lean pre-mixed combustion and rich/quench/lean staged combustion (discussed in Section 12.4.2.3). Historically, gas turbine combustors were designed for operation with unit (1) primary zone equivalence ratios (an equivalence ratio of one indicates a stoichiometric ratio of fuel and air). However, with fuel-lean combustion (sub-stoichiometric conditions), the additional excess air cools the flame and reduces the rate of thermal NO_x formation. With reduced residence time combustors, dilution air is added sooner than with standard combustors resulting in the combustion gases attaining a high temperature for a shorter time, thus reducing the rate of thermal NO_x formation. Pilot flames are used to maintain combustion stability to maintain the fuel-lean conditions. The Solar Titan 250-30000S combined-cycle turbines proposed at the Haven Gas Plant are implemented with the Solar Turbines, Inc. $SoLoNO_x$ design which is a DLN combustion technology that utilizes lean pre-mixed combustion. The Solar Mercury 50-6400R combustion turbine utilizes similar combustion technology which is an ultra-lean-premix (ULP) DLN combustion design. Therefore, this combustion design technique will be included in further BACT determinations; including add-on control technologies to the existing design.

12.4.2.3 Rich/Quench/Lean (RQL) Combustion Technology

RQL combustors burn fuel-rich in the primary zone and fuel-lean in the secondary zone and reduce both thermal and fuel NO_x. Incomplete combustion under fuel-rich conditions in the primary zone produces an atmosphere with a high concentration of CO and H_2, which replace some of the oxygen for NO_x formation and also act as reducing agents for any NO_x formed in the primary zone. Based on available rig test results, this control alternative is more effective for higher FBN fuels in retarding the rate of fuel NO_x formation. Theoretically, this control alternative is applicable to natural gas-fired turbines; however, based on information presented in the EPA ACT (Alternative Control Techniques) document, RQL combustors are not commercially available for most turbine designs, and there is no known application for only natural gas-fired combined-cycle or regenerative cycle combustion turbines. Because it is not technically feasible and unproven in practice, RQL combustion will be precluded from further consideration in this BACT determination for EPNs GT-01, GT-02 and TGS-01.

12.4.2.4 Add-on Controls: Selective Catalytic Reduction (SCR)

In the SCR process, ammonia (NH_3), usually diluted with air or steam, is injected through a grid system into the flue/exhaust gas stream upstream of a catalyst bed. On the catalyst surface, the NH_3 reacts with NO_x to form molecular nitrogen and water. The basic reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$

$$8NH_3 + 6NO_2 = 7N_2 + 12H_2O$$

The reactions take place on the surface of a catalyst. Usually, a fixed bed catalytic reactor is used for the SCR process. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reactions. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, and design of the ammonia injection system.

Depending on system design and the inlet NO_x level, NO_x removal of up to 70-90 percent and higher is achievable at optimum theoretical conditions. The reaction of NH_3 and NO_x is favored by the presence of excess oxygen. Another variable affecting NO_x reduction is exhaust gas temperature. The greatest NO_x reduction occurs within a reaction window at catalyst bed temperatures between 400°F and 800°F for base metal catalyst types (i.e., conventional SCR applications with lower temperature range platinum catalysts and with higher temperature range 550°F-800°F vanadium-titanium catalysts).

However, base metal catalysts deteriorate quickly when continuously subjected to temperatures above this range or under thermal cycling, which commonly occurs in turbines. In effect, if these catalyst systems are operated beyond their specified temperature ranges, oxidation of the ammonia to either additional nitrogen oxides or ammonium nitrate may result. SCR manufacturers have developed zeolite-based catalyst systems that are purported to handle higher temperatures in the range of 790°F to 1,100°F. These zeolite based catalysts extend the application of SCR not only to combined-cycle turbines, but also to simple-cycle turbines. Therefore, SCR is considered technically feasible, and will be included in further BACT analysis as an add-on control for DLN combustion for both the combined-cycle and regenerative turbines.

An additional review was conducted to determine if a single SCR system was technically feasible to control NO_x emissions from both the Titan 250 combustion turbines. Based on communications with Peerless Mfg. Co., a single SCR add-on control system will create technical concerns regarding the feedback controls for both units.[3] Each turbine system would be controlled by a feed forward signal and then typically adjusted with a feedback signal. Unless each turbine unit was operating at identical operating capacities, and with the same fuel consumption, it would be technical infeasible to control emissions with the single SCR system to 2.5 ppm; which is technically feasible for individual SCR add-on control applications. Moreover, the potential costs for a combined system would be higher for the single SCR system, and no emission guarantees could be warranted.[3] Therefore, a combined SCR add-on control system is being eliminated from further BACT considerations based on the technical infeasibility of the system to effectively control both combustion units, and the resulting emissions from the combined system.

12.4.2.5 Add-on Controls: Selective Non-Catalytic Reduction (SNCR)

SNCR technology involves using ammonia or urea injection similar to SCR technology but at a much higher temperature window of 1,600°-2,200°F. The following chemical reaction occurs without the presence of a catalyst:

$$NO_x + NH_3 + O_2 + H_2O + (H_2) \rightarrow N_2 + H_2O$$

The operating temperature can be lowered from 1,600°F to 1,300°F by injecting readily oxidizable hydrogen with the ammonia. However,

[3] Email Correspondence, Mr. Rance Jett with Mrs. Pamela Murphy, Product Manager – Environmental Systems, Peerless Mfg. Co.

beyond the upper temperature limit, the ammonia is converted to NO_x, resulting in increased NO_x emissions.

Because the exhaust temperatures in gas turbines typically do not exceed 1,250°F, the operative temperature window of this control alternative is not technically feasible for this application. Exhaust temperatures for both gas turbine applications (EPNs GT-01, GT-02 and TGS-01), are between 685-700°F which is well below the range for SNCR application. In addition, this technology has a residence time requirement of 100 milliseconds, which is relatively slow for gas turbine operating flow velocities. Thus, adequate residence time for the NO_x destruction chemical reaction will not be available.

Further, a review of the RBLC database for recent BACT/LAER determinations for this particular source category and discussions with control system vendors do not indicate that SNCR systems have been successfully installed for NO_x control for similar combined-cycle turbines. <u>In view of the above limitations in utilizing SNCR control, this control alternative is not considered technically feasible and will be precluded from further consideration in this BACT determination for EPNs GT-01, GT-02 and TGS-01.</u>

12.4.2.6 Add-on Controls EMxGT (formerly *SCONO$_X$™) Catalytic Oxidation/ Absorption*

This is a catalytic oxidation/absorption technology that has been applied for concomitant reductions of NO_x, CO, and VOC from an assortment of combustion applications that mostly include small turbines, boilers, and lean-burn engines. Note that EMxGT technology is being assessed in this BACT determination as an add-on control option to DLN since it is a competitive technology with SCR.

EMxGT employs a single catalyst for converting NO_x, CO, and VOC. The flue gas temperature should be in the 300°F-700°F range for optimal performance without deleterious effects on the catalyst assembly. The technology was developed as a foil to traditional SCR applications that use ammonia resulting in additional operational safeguards, unfavorable environmental impacts, and excessive costs. In the initial oxidation cycle, CO is oxidized to CO_2, NO is converted to NO_2 and VOC is oxidized to carbon dioxide and water. The NO_2 is then absorbed on the potassium carbonate coated (K_2CO_3) catalyst surface forming potassium nitrites and nitrates (KNO_2, KNO_3). Prior to saturation of the catalyst surface, the catalyst enters the regeneration cycle.

In the regeneration phase, the saturated catalyst section is isolated with the expedient of moving hinged louvers and then exposed to a dilute reducing gas (methane in natural gas) in the presence of a

carrier gas (steam) in the absence of oxygen. The reductant in the regeneration gas reacts with the nitrites and nitrates to form water and elemental nitrogen. Carbon dioxide in the regeneration gas reacts with potassium nitrites and nitrates to recover the potassium carbonate, which is the absorber coating that was on the surface of the catalyst before the oxidation / absorption cycle begins. Water (as steam) and elemental nitrogen are exhausted up the stack and the re-deposited K_2CO_3 allows for another absorption cycle to begin.

EMxGT technology is a variation of traditional SCR technology and for optimal performance it makes similar demands such as stable gas flows, lack of thermal cycling, invariant pollutant concentrations, and residence times on the order of 1-1.5 seconds. However, the benefit of not using ammonia has been replaced by other potential operational problems that impair the effectiveness of the technology. Therefore, this technology is being removed as BACT due to concerns regarding technical feasibility. Incorporation of a EMxGT system for control of emissions from NGP's turbine systems faces the following technical concerns:

- Scale-up is still an issue. The technology has not been demonstrated for larger turbines and the vendor's contention is still being debated;
- The technology is not readily adaptable to high-temperature applications outside the 300°-700°F range and is susceptible to potential thermal cycling;
- The prospect of moving louvers that effect the isolation of the saturated catalyst readily lends itself to the possibility of thermal warp and in-duct malfunctions in general. The process is dependent on numerous hot-side dampers that must cycle every 10 to 15 minutes. Directional flow solutions are not yet known to have been implemented for this technology;
- The K_2CO_3 coating on the catalyst surface is an active chemical reaction and reformulation site, which makes it particularly vulnerable to fouling. On some field installations, the coating has been found to be friable and tends to foul in the harsh in-duct environment;
- During the regeneration step, the addition of the flammable reducing gas (natural gas which contains ~93% methane) into the hot flue gas generates the possibility of LEL (lower explosive limit) exceedances in the event the catalyst isolation is not hermetic or if there is a failure in the carrier steam flow; and
- There is a possibility of some additional SO_2 emissions if the dry scrubber with the tandem "guard-bed" EMxGT unit experiences a malfunction.

In addition to the effective technical applicability and operational issues discussed above, there are also significant energy impacts associated

with the application of EMxGT technology. There is a fuel penalty associated with the use of the catalyst. The increased backpressure in the turbine from the catalyst installation increases the heat input required and reduces the power output of the turbine. Moreover, these technical limitations would be exacerbated during startup and shutdown events on a combined-cycle generating unit, which experiences significant changes in exhaust flow rates and temperatures. Additionally, a current review of the RBLC BACT Clearinghouse indicated that there are no combined-cycle or simple-cycle turbine applications utilizing EMxGT. In view of the above limitations in utilizing EMxGT, this control alternative is precluded from further consideration in this BACT determination for EPNs GT-01, GT-02 and TGS-01.

12.4.2.7 Add-on Controls: Catalytic Combustion – XONON™

Xonon™ is a catalytic combustion technology in development that reduces the production of NO_x. The technology has only been tested on small turbines (less than 10 MW) and it is still not commercially available for the proposed combined-cycle turbines. The vendor has entered into agreement with GE to collaboratively develop the technology for installation on GE E-class and F-class turbines. The vendor has indicated that the complete adaptation of the technology to GE's turbines is not expected for several years.

In a catalytic combustor, the fuel and air are premixed into a fuel-lean mixture and then passed into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame front, thereby reducing peak combustion temperatures below 2,000^{0}F, which is the temperature at which significant amounts of thermal NO_x begin to form. The catalyst manufacturer has indicated that gas turbines retrofitted with the Xonon™ catalyst emit NO_x levels below 3 ppm.[4] However, until such time that the technology is commercially available, catalytic combustors are not considered technically feasible. In addition, discussions with Solar indicated that this technology is not commercially available for any Solar product. In view of the above limitations in utilizing catalytic combustor control, this control alternative is precluded from further consideration in BACT determinations for GT-01, GT-02 and TGS-01.

12.4.2.8 Alternate Lower FBN (Fuel-Bound Nitrogen) Fuels

The utilization of a lower FBN fuel such as coal-derived gas or methanol is not deemed practical based on the nature of the proposed

[4] US EPA. *Emissions Factors & AP-42, Compilation of Air Pollutant Emission Factors*. (Apr, 2000). http://www.epa.gov/ttn/chief/ap42/ch03/final/c03s01.pdf.

operations at the Haven Gas Plant. Thus, this control alternative is not addressed further in this BACT determination.

As previously mentioned, six of the eight proposed NOx control technologies are either technically infeasible or have not been demonstrated in practice for a comparably sized combined-cycle gas turbine or regenerative gas turbine. The two remaining approaches: DLN combustion and DLN combustion with SCR controls are already being utilized at facilities comparable to the Haven Gas Plant for control of NOx during normal operations as well as startup and shutdown events for combined-cycle and regenerative turbines. Accordingly, these control candidates will be reviewed further in the BACT analysis based on economic, environmental and energy impacts.

12.4.3 NO_x BACT Impact Analysis for Combustion Turbines

Based on the technical feasibility review for the combined-cycle gas turbines (EPNs GT-01 and GT-02) and the regenerative gas turbine (EPN TGS-01), the remaining control candidates have been reviewed in Sections 12.4.3.1 through 12.4.3.3 based on the economic, environmental and energy impacts associated with each control candidate.

The two technically feasible BACT control options for reduction of NO_X emissions from the combined-cycle Titan 250-30000S gas turbines and the regenerative (simple-cycle) Mercury 50-6400R gas turbine are the manufactured $SoLoNO_x$ DLN combustors and the $SoLoNO_x$ DLN combustors in combination with an SCR system. **Table 12-4** ranks the available control options by NO_x control efficiency reported in the RBLC BACT and RACT/BACT/LAER Clearinghouses.

Table 12-4
Technically Feasible Control Options Ranked by Reported Emission Factors

Control Technologies / Feasible Configurations[(1)]	Emission Factor Range (lb/MMBtu)			Emission Factor Range (ppm @ 15% O_2)		
	Minimum	Maximum	Average	Minimum	Maximum	Average
DLN Combustion and Selective Catalytic Reduction	6.00E-03	0.17	0.01	2.00	9.00	3.28
DLN Combustion and Good Combustion Practice	0.09	0.15	0.14	25.00	42.00	37.14

[1]Control technologies evaluated for 176 permitted emissions units from the EPA's Technology Transfer Network Clean Air Technology Center – RACT/BACT/LAER Clearinghouse. Emission units ranged in size from 11.5 MW – 1150 MW and 2 MMBtu/hr – 2,876 MMBtu/hr.

Based on the BACT clearinghouse search results, an SCR system installed on a typical DLN combustor manufactured design offers the

lowest achievable emissions rates for NO_x. Additionally, supporting documentation (US EPA, 1993) reports that controlled NO_x emissions with SCR systems are typically 9 ppmv or less, while typical emissions from uncontrolled lean-premix combustion design are reported to be in the range of 25-42 ppmv. The economic, environmental and energy impacts for Solar's $SoLoNO_x$ DLN combustor design versus standard DLN combustor design is provided below. In addition, an impact analysis was also conducted for the $SoLoNO_x$ combustor design with SCR add-on controls, which is provided below.

12.4.3.1 NO_x Candidate Controls for Combustion Turbines – Economic Impacts

An economic impact analysis was conducted for the remaining control candidates to estimate the total capital investment, annual cost, and incremental cost effectiveness. The BACT analysis originally submitted on May 16, 2012 was based on study level interpolations dependent upon the size of the turbines. The study level assumptions were based on information provided in the *Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines – AQPSTR 07-01* (US EPA, 2007).

Based on a conference call with Providence, NGP and KDHE on May 24th, 2012 and email correspondence from KDHE on June 6, 2012, additional information was requested regarding the cost determinations in the BACT impact analysis. Therefore, NGP revised the original cost analysis for SCR based on industry data provided by Solar in order to develop a refined cost analysis to meet the requirements set forth in the EPA *Air Pollution Control Cost Manual* (Jan, 2002). The revised BACT, submitted to KDHE on July 17, 2012 included equipment cost estimates supported by industry data. In addition, total capital investment costs and annualized costs were determined using the EPA *Air Pollution Control Cost Manual* (Jan, 2002) and additional construction estimates provided by Solar.

An additional monetary figure of $272,486 was added to the equipment costs for SCR applications based on heat recovery steam generation (HRSG) modifications. HRSG is an energy recovery heat exchanger that recovers heat from a hot gas stream. The heat recovered from the exchanger can then be used to produce steam in cogeneration processes or power steam generators. Steam generation processes are not planned for the Haven Gas Plant; however, NGP is proposing to incorporate waste heat recovery from the exhaust of the Titan 250 combustion turbines. In order to capture and utilize the waste heat for the hot oil system, a heat exchange coil must be placed into the turbine stack. Hot oil then flows through the heat exchange coil in order to capture the waste heat from the turbine exhaust stream. The captured heat is not used for steam generation, instead, it will be used to

provide the necessary heat requirements for the amine still reboiler, molecular sieve regeneration heater and demethanizer trim reboiler. This hot oil system will eliminate the need for fired-heaters.

The additional monetary figure of $272,486 in the SCR cost analysis is a cost estimate based on the modifications that would have to be made in the turbine stack. Based on conversations with SCR vendors, additional modifications would be needed in order to effectively install the SCR system. Transitional ductwork from the heat recovery system to the catalyst bed would be needed to effectively transition the exhaust to the optimal temperature before it reaches the catalyst bed. Additional duct work would then be installed after the catalyst bed in order to direct the exhaust gases back into the turbine stack, prior to reaching the atmosphere. The additional ductwork requirements would then result in the need for additional steel supporting structure.[5] The monetary value provided by Solar is a construction cost estimate based strictly on the size of their turbine applications. However, based on limited industry data regarding site specific cost estimates for exhaust stack modifications with HRSG applications these costs have been removed from the SCR cost analysis.

Additional construction cost estimates from Solar's Engineering department called for 16% of PE for electrical and 16% of PE for piping. However, based on limited industry data from SCR vendors, the SCR add-on control costs, submitted on July 17, 2012, have been adjusted to 4% of PE for electrical and 2% of PE for piping, as per the EPA's *Air Pollution Control Cost Manual* (Jan, 2002).
The SCR cost analysis submitted on July 17, 2012 applied a catalyst replacement cost of $400/ft for 30 ft^3 per MW. These figures were provided by Solar, and are based strictly on the size of the turbine MW output. Based on the design variability for sizing SCR catalyst housing, NGP has adjusted the costs using the EPA recommended catalyst replacement cost of $383/$ft^3$.

For each $SoLoNO_x$ turbine, the analysis estimates that an SCR add-on system has the potential to reduce the turbine emission level to 2.5 ppm. Based on RBLC search results for SCR applications on combined cycle turbines, the maximum reduction potential was 2 ppm. However, based on vendor contact, the effective reduction potential, over the life of the control application, is 2.5 ppm. Therefore, the equipment skid costs provided are based on the potential to reduce NOx concentrations to 2.5 ppm.[6,7]

[5] Phone conversation, Mr. Rance Jett with Mr. Ghassen Manavi, Mitsubishi Heavy Industries America, Inc.
[6] Phone conversation, Mr. Rance Jett with Mrs. Pamela Murphy, Product Manager – Environmental Systems, Peerless Mfg. Co., August 1, 2012.
[7] Phone conversation, Mr. Rance Jett with Mr. Bryce Coleman, Holman Boiler Works Inc., August 1, 2012.

In addition, the interest rates used for annual cost determinations were lowered to 7%, and the life of the add-on control was increased to 20 years as a conservative measure.

Based on KDHE's August 17, 2012 request for vendor cost quotes for the Titan 250 combustion turbines, Providence contacted Solar for the vendor quotes. After reviewing their records Solar determined that the basic equipment costs of $1,623,000 and the auxiliary equipment cost of $35,000, submitted to KDHE on July 17, 2012, were based on scale-up from a Titan 130 combustion turbine quote. The Titan 250 unit has approximately 7.2 MW of additional output, as compared to the Titan 130. The current equipment costs for basic equipment and auxiliary equipment listed in **Appendix D** is based on actual equipment costs from Peerless Mfg. Co. for a Titan 250 combustion turbine application, which Solar provided to Providence on August 20, 2012. The costs for the CO catalyst and structural supports were excluded from the cost analysis. The cost associated with the CO catalyst option was $200,000, per Peerless Mfg. Co. The cost conservatively assumes that the additional cost for the 10,000 gallon aqueous ammonia tank is split between each of the Titan 250 turbines.

In addition, based on communications between Providence and KDHE on August 21, 2012, EPA Region VII recommended that operating and supervisory labor costs should be excluded from the cost analysis. EPA Region VII also recommended excluding the overhead costs associated with operating and supervisory labor and property taxes from the cost analysis for SCR add-on controls. Therefore, the adjusted cost analysis excludes labor, overhead and property tax costs associated with SCR add-on controls for both Titan 250 combustion turbines and the Mercury 50 generator set. These costs are a conservative estimates and actual costs associated with additional operation labor, overhead and property tax could incur additional costs. The maintenance material and labor costs were included in the direct annual costs and were calculated based on the EPA *Cost Control Manual*, but were conservatively excluded from the indirect annual overhead costs.

The adjusted cost analysis for each emission unit assumes the SoLoNO$_x$ DLN combustion is the base case for the cost analysis. The economic impact analysis was conducted in accordance with the guidelines specified in the EPA's *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting* (October, 1990). When determining the baseline emission level for an incremental cost effectiveness review, the NSR workshop manual states the following:

> *"The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. The*

NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State and local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emissions reduction credit can be taken for use of inherently lower polluting processes."

NGP believes that the lean-premix DLN combustor design inherent with the SoLoNOx design for the Titan 250 turbines and the ULP DLN combustor design inherent with the Mercury 50 genset represent the lower polluting process prior to the addition of SCR add-on controls. Based on communications with KDHE on August 17, 2012, EPA Region VII concluded that the baseline emission level inherent for the Titan 250 combustion turbines and the Mercury 50 generator set should be set to 15 ppm and 5 ppm respectively.[8] Based on discussions with Solar, all turbines sold into the US since 2005 are based on lean-premix design; therefore, the base was set at 15 ppm for the Titan 250 and 5 ppm for the Mercury 50.[9] The adjusted cost analysis summary is provided in **Table 12-5**. The details of the cost analysis have been provided in **Appendix D**.

Table 12-5

Top-Down BACT Economic Analysis for NO_x Control Candidates

Control Technology	EPN	Emission Rate		Total Capital Investment	Total Annual Cost	Incremental Cost Effectiveness ($/ton)
		ppmvd	tpy			
Selective Catalytic Reduction	GT-01	2.5	8.25	$3,990,000	$998,000	$24,184
	GT-02	2.5	8.25	$3,990,000	$998,000	$24,184
	TGS01	2.5	1.77	$2,136,000	$353,200	$200,113
$SoLowNO_x$ Combustion	GT-01	15	49.52	$23,473,800	$8,147,808	Base
	GT-02	15	49.52	$23,473,800	$8,147,808	Base
	TGS01	5	3.53	$6,503,439	$1,939,486	Base
Total Base Costs				$53,451,039	$18,235,102	
Total Costs with SCR Add-on Control				$63,567,039	$20,584,302	

[8] Email Correspondence, Mr. Rance Jett with Ms. Lynelle Ladd, Permitting Engineer, KDHE, August 17, 2012.
[9] Email Correspondence, Mr. Rance Jett with Mrs. Leslie Witherspoon, Manager, Environmental Programs at Solar Turbines, Inc., July 7, 2012.

12.4.3.2 NO_x Candidate Controls for Combustion Turbines – Environmental Impacts

There are no impacts on CO or hydrocarbon emissions; however, ammonia slip from the catalyst reactors results in increased NH_3 emissions to the atmosphere. Ammonia slip is unavoidable because of ammonia injection control limitations and imperfect distribution of the reacting gases. Typical SCR systems can utilize either aqueous or anhydrous ammonia for the reduction reaction. Anhydrous ammonia is nearly 100% pure ammonia. It is a gas at normal atmospheric temperatures; therefore, it must be transported and stored under pressure. As a result, it often requires special permits for transportation and storage. Aqueous ammonia can be transported and stored as a 19% solution, which reduces transport and storage issues. However, aqueous ammonia requires additional storage capacity, and the reduced concentration typically requires that a vaporizer be installed on the SCR application.[10]

12.4.3.3 NO_x Candidate Controls for Combustion Turbines – Energy Impacts

There are several energy impacts associated with retrofitting an SCR system to typical gas turbine applications (both simple-cycle and combined-cycle applications). First, an SCR system increases the back-pressure on the turbine, which in turn decreases the turbine power output by approximately 0.5 percent. The additional backpressure increases result in increased electrical cost, which have been factored into the cost analysis in Section 12.4.3.1. In addition to the increased backpressure, there are additional maintenance requirements associated with controls and monitoring equipment and the recycling of spent catalyst.

12.4.4 NO_x BACT Determination – Combustion Turbines

The economic, environmental and energy impacts analysis associated with the top BACT control candidate was conducted for SCR add-on controls for each of the $SoLoNO_x$ combustion turbines and ULP combustion turbine. Based on **Table 12-4,** the combined capital costs for employing SCR add-on controls to each emission source (EPNs GT-01, GT-02 and TGS-01) would increase the total capital investment for the three turbine units by over $10.1 million. Additionally, the total annual costs for the proposed turbine units would increase by over $2.3 million. The resulting incremental cost effectiveness for each of the Titan 250 units is estimated at $24,184 per ton of NO_x removed, while the incremental cost effectiveness for the smaller Mercury 50 unit is estimated at over $200,113 per ton of NO_x removed.

[10] US EPA (Jan, 2002). "EPA Air Pollution Control Cost Manual" 6th Ed. EPA/452/B-02-001.

Based on the impact analysis, there are additional concerns regarding the energy and environmental impacts associated with SCR add-on controls. The use of anhydrous ammonia for an SCR system would result in additional permit and transportation complications, while the use of a 19% aqueous ammonia solution would result, not only in increased costs, but also reduced space within the proposed facility. The potential costs for purchasing land have not been included in the cost estimates for adding SCR controls. In addition, there will be an increase in maintenance and monitoring demands for the proposed turbine units, as well as, reductions in the power output for each of the turbines.

Based on the economic analysis conducted for the top control candidate, SCR add-on controls, NGP maintains that the increased capital investment and incremental cost effectiveness for the reduction of NO_x emissions from EPNs GT-01, GT-02 and TGS-01 is cost prohibitive. Furthermore, SCR represents the lowest achievable emission rate (LAER) control option. While a top-down BACT analysis also requires that LAER control candidates are included in the control candidate review, they are not strictly required in areas that demonstrate attainment. Currently, there are no non-attainment areas within Kansas. The details of the BACT compliance demonstration for the combustion turbines are provided in Section 12.4.5.

Therefore, NGP proposes that the $SoLoNO_x$ lean-premix (EPNs GT-01 and GT-02) and ULP combustion turbine (EPN TGS-01) represent the top level BACT for the proposed Haven Gas Plant. The proposed NO_x emission rates for the combined-cycle turbines (EPNs GT-01 and GT-02) is 15 ppmvd at 15% O_2 and the proposed NO_x emission rate for the simple-cycle turbine (EPN TGS-01) is 5 ppmvd at 15% O_2. Additionally, turbine manufacturers report no significant performance impacts for lean-premix or ultra-lean-premix combustors and there is no additional energy or environmental impacts. Based on the significant impact analysis (SIA), using the latest version of AERMOD, the dispersion modeling for the NO_2 short-term and annual results showed no significant impacts to any of the local areas. Additionally, NGP proposed alternate operating scenarios for the proposed facility, as a conservative basis, to show there were no short-term or annual significant impacts to the local area, at varies operating loads. **Table 12-6** compares the proposed NO_x emission limitations for EPNs GT-01, GT-02 and TGS-01 with the applicable requirements of Table 1 to 40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines.

Table 12-6
NO_x Emission Limit Requirements

EPN	Combustion Turbine Type	Combustion Turbine Heat Input at Peak Load	NO_x Emission Standard	Proposed NO_x Emission Limit
TGS-01	New turbine firing natural gas, electric generating	<50 MMBtu/hr	42 ppm at 15% O_2	5 ppm at 15% O_2
GT-01	New turbine firing natural gas	>50 MMBtu/hr and < 850 MMBtu/hr	25 ppm at 15% O_2	15 ppm at 15% O_2
GT-02	New turbine firing natural gas	>50 MMBtu/hr and < 850 MMBtu/hr	25 ppm at 15% O_2	15 ppm at 15% O_2

In addition, emissions of NO_x during periods of startup and shutdown will be controlled with good combustion practices and burner design. Good combustion practices involve proper operation and maintenance of the turbines. Creating and maintaining procedures as well as proper training are the best ways to ensure these criteria are being met. The Haven Gas Plant will keep operating logs for startup, shutdown, and malfunction as well as normal operations in accordance with good combustion practices. The advanced $SoLoNO_x$ and ULP DLN combustor design and onboard control system ensures proper combustion efficiency by regulating temperature, inlet and exhaust fuel processing and compressor performance mapping.

12.4.5 NO_x BACT Compliance Demonstration – Combustion Turbines

NGP is proposing lean-premix DLN combustion design for the Titan 250-30000S combined-cycle turbines and ultra-lean-premix DLN combustion design for the Mercury 50-6400R simple-cycle turbine as BACT. These units will be operated in accordance with 40 CFR 60 Subpart KKKK and all applicable regulations incorporated by reference.

NGP will meet the NO_x and SO_2 emissions standards for both the Titan 250 turbines (new turbines firing natural gas >50MMBtu/hr and <=850MMBtu/hr), and the Mercury 50 turbine (new turbine firing natural gas, electrical generating <=50MMBtu/hr). NGP will operate and maintain EPNs GT-01, GT-02 and TGS-01 in a manner consistent with good air pollution control practices for minimizing emissions at all times, including during startup, shutdown and malfunction. Based on the cost analysis provided in Section 12.4.3.2, NGP elects to utilize the CPMS option in order to meet the monitoring, recordkeeping and reporting requirements as outlined in 40 CFR 60.4340, 60.4355 and 60.4375, respectively.

12.4.6 Carbon Monoxide Formation

CO emissions form primarily as the result of incomplete combustion. Available emissions data indicate that the turbine's operating load has a considerable effect on the resulting emission levels. Gas turbines are typically operated at high loads (greater than or equal to 80% of rated capacity) to achieve maximum thermal efficiency and peak combustor zone flame temperatures. With reduced loads, or during periods of frequent load changes, the combustor zone flame temperatures are expected to be lower than the high load temperatures, yielding lower thermal efficiencies and more incomplete combustion. CO results when there is insufficient residence time at high temperature or incomplete mixing to complete the final step in fuel carbon oxidation. The oxidation of CO to CO_2 at gas turbine temperatures is a slow reaction compared to most hydrocarbon oxidation reactions. In gas turbines, failure to achieve CO burnout may result from quenching by dilution air. With liquid fuels, this can be aggravated by carryover of larger droplets from the atomizer at the fuel injector. CO emissions are also dependent on the loading of the gas turbine. For example, a gas turbine operating under a full load will experience greater fuel efficiencies, which will reduce the formation of carbon monoxide. The opposite is also true: a gas turbine operating under a light to medium load will experience reduced fuel efficiencies (incomplete combustion) which will increase the formation of carbon monoxide.

12.4.7 CO Candidate Controls – Combustion Turbines

Based upon a search of nationally permitted control technology options conducted using the RBLC, the SCAQMD LAER/BACT Determinations for Major Polluting Facilities, and the SJVAPCD BACT Clearinghouse the following control options are available control candidates for combined-cycle turbines combustion natural gas:

- *Combustion Control; and*
- *CO Oxidation Catalysts.*

As with NO_x, CO is emitted during startup and shutdown events at rates that are typically higher than what is experienced during normal operation, which is a result of how the combustion turbine transitions through the partial load conditions on its way to normal operating load. However, performance of the considered emission control techniques is generally similar for startup and shutdown events as it is for normal operation, though some technologies may be more or less effective depending on their particular mode of operation.

The previously listed information resources were consulted to determine the extent of applicability of each identified control alternative.

12.4.7.1 Combustion Control

Because CO is essentially a by-product of incomplete or inefficient combustion, it is important that combustion control constitutes the primary mode of reduction of CO emissions. The lean combustion control technology to be incorporated in the gas turbine(s) for the Haven Gas Plant has already been discussed in detail. The Solar Turbine DLN combustor technology for (EPNs GT-01, GT-02 and TGS-01) not only ensures significant NO_x reductions but also compensates for CO emissions.

The basic premise of the technology involves premixing the fuel and air prior to entering the combustion zone, which provides for a uniform fuel/air mixture and prevents local hotspots in the combustor, thereby reducing NO_x emissions. However, the residence time of the combustion gases in these lean premixed combustors must be increased to ensure complete combustion of the fuel to minimize CO emissions.

The Haven Gas Plant incorporates combustion controls to reduce CO emissions concomitantly with NO_x emissions. A review of the RBLC database shows that combustion control is the primary means of reducing CO emissions for similarly sized natural gas-fired turbines. Therefore, combustion control will be considered further in the BACT analysis as a viable control technique.

12.4.7.2 CO Oxidation Catalyst

A review of the previously listed information resources, including the RBLC database, identified several applications of CO oxidation catalysts to similar combined-cycle turbines. Theoretically, a CO oxidation catalyst could reduce CO emissions from a combined-cycle turbine. The optimal working temperature range for CO oxidation catalysts is approximately 850°F to 1,100°F with a minimum exhaust gas stream temperature of 500°F for minimally acceptable CO control. At lower temperatures, the CO conversion efficiency drops off, while at temperatures greater than 1,200°F there is a potential for catalyst sintering. Careful placement considerations are needed to achieve effective operational efficiency. The CO catalyst must be strategically placed within the proper turbine exhaust lateral distribution to evenly distribute the gas flow across the catalyst. Reduction of CO is possible during startup and shutdown events, but at lower efficiencies compared to normal operation, due to the lower exhaust gas temperatures relative to normal operation.

Oxidation catalyst systems serve to remove CO from the turbine exhaust gas rather than limiting pollutant formation at the source. The technology does not require introduction of additional chemicals for the

reaction to proceed. The oxidation of CO to CO_2 uses the excess air present in the turbine exhaust, and the activation energy required for the reaction to proceed is lowered in the presence of the catalyst. CO oxidation catalyst is technically feasible for the combined-cycle turbines and regenerative turbine proposed for the Haven Gas Plant, which will generally have an exhaust temperature between 685-700^{0}F after heat recovery.

12.4.8 CO BACT Impact Analysis for Combustion Turbines

The two technically feasible BACT control options for reduction of CO emissions from the combined-cycle Titan 250-30000S gas turbines and the regenerative (simple-cycle) Mercury 50-6400R gas turbine are combustion control and catalytic oxidation. Based on RBLC search results, catalytic oxidation represents the most stringent technically feasible control candidate, and has the potential to reduce CO emissions by approximately 90%. The economic, environmental and energy impacts for catalytic oxidation add-on controls for the proposed combustion turbines is provided below.

12.4.8.1 CO Candidate Controls for Combustion Turbines – Economic Impacts

Capital costs and annualized costs for catalytic oxidation were estimated from the U.S. *EPA Air Pollution Cost Control Manual* (March, 2002) and vendor cost estimates provided by DCL International. The cost analysis was used to estimate a total capital investment, annual cost and incremental cost effectiveness for catalyst oxidation controls for each combustion turbine (EPNs GT-01, GT-02 and TGS-01). The cost analysis for catalyst oxidation compares the additional add-on costs to the base cost for $SoLoNO_x$ combustion turbines. The results of the cost analysis are summarized in **Table 12-7**.

Additional construction cost estimates from Solar's Engineering department called for 16% of PE for electrical and 16% of PE for piping. However, based on KDHE recommendation, the CO catalyst add-on control costs, submitted on July 17, 2012, have been adjusted to 4% of PE for electrical and 2% of PE for piping, as per the EPA's *Air Pollution Control Cost Manual* (Jan, 2002).

In addition, the interest rates used for annual cost determinations were lowered to 7%, and the life of the add-on control was increased to 20 years as a conservative measure.

Table 12-7
Capital Costs for Additional Add-on Controls: Catalyst Oxidation

Control Technology	EPN	Emission Rate		Total Capital Investment	Total Annual Cost	Incremental Cost Effectiveness ($/ton)
		ppmvd	tpy			
Oxidation Catalyst	GT-01	2.5	5.0	$467,556	$243,886	$5,387
	GT-02	2.5	5.0	$467,556	$243,886	$5,387
	TGS01	1	0.4	$89,977	$105,068	$27,149
DLN Combustion	GT-01	25	50.3	$23,473,800	$8,147,808	Base
	GT-02	25	50.3	$23,473,800	$8,147,808	Base
	TGS01	10	4.3	$6,503,439	$1,939,486	Base
Total Base Costs				$53,451,039	$18,235,102	
Total Costs with CO Add-on Control				$54,476,127	$18,827,942	

The details of the cost analysis have been provided in **Appendix D**.

12.4.8.2 CO Candidate Controls for Combustion Turbines – Environmental Impacts

A CO oxidation catalyst application has detrimental environmental consequences that need to be considered. Besides CO, the catalyst will also oxidize other species in the turbine exhaust. Any sulfur present in the natural gas (nominal fuel sulfur) will be oxidized to gas-phase SO_2 within the combustor and further oxidized to SO_3 across the catalyst. In the presence of moisture, the trioxide will combine to form sulfuric acid mist from the exhaust stack that may manifest as additional PM/PM_{10} emissions.

In addition, disposal of the catalyst could represent a potential environmental impact. The catalysts used must be replaced approximately every three years. The catalyst formulation contains heavy metals that may cause the spent catalyst to be considered a hazardous waste requiring special handling during disposal. Note, however, that catalyst vendors may accept return of spent catalysts for recovery and reuse of the catalyst precious metals.

12.4.8.3 CO Candidate Controls for Combustion Turbines – Energy Impacts

The use of an oxidation catalyst as an add-on control in combination with DLN combustion has the potential to reduce turbine efficiency and output. These system inefficiencies and output losses, in turn, will result in an increase in emissions. Due to the increase in back-pressure associated with an oxidation catalyst in the exhaust gas pathway, output will decrease and the heat rate will increase.

12.4.9 CO BACT Determination – Combustion Turbines

A BACT impact analysis has been conducted for the top control candidate (catalyst oxidation). Based on the economic, environmental and energy impacts review, catalyst oxidation is rejected as BACT because the additional capital investment and incremental cost effectiveness are cost prohibitive. The cost analysis indicates that CO oxidation catalyst add-on controls will increase the capital investment for combustion turbines by over $1 million, while increasing the total annual costs by almost $600 thousand. In addition, the incremental effectiveness for the larger turbines is $5,387/ton above the baseline and approximately $29,149/ton above the baseline for the Mercury 50.

In addition to the economic concerns, there are also concerns regarding the environmental and energy impacts. The presence of sulfur in the natural gas can result in the formation of acid gas, and potentially increase PM emissions. Moreover, the increase in the backpressure has the potential to reduce turbine combustion efficiency.

Furthermore, catalyst oxidation represents the lowest achievable emission rate (LAER) control option. While a top-down BACT analysis also requires that LAER control candidates are included in the control candidate review, they are not strictly required in areas that demonstrate attainment. Currently, there are no non-attainment areas within Kansas. In addition, NGP is not proposing to install CEMS for the combustion turbines due to the increased capital investment and decrease in cost effectiveness, which provides no additional CO emission reduction potential. NGP plans to utilize the continuous parameter monitoring option in 40 CFR 60 Subpart KKKK to demonstrate compliance with the NO_x emission standards, for each of the combustion turbines. The details of the BACT compliance demonstration for the combustion turbines are provided in Section 12.4.10.

Based on the significant impact analysis (SIA), using the latest version of AERMOD, the dispersion modeling for the CO 1-hour and 8-hour results showed no significant impacts to any of the local areas. Additionally, NGP proposed alternate operating scenarios for the proposed facility, as a conservative basis, to show there were no short-term significant impacts to the local area, at varies operating loads.

Based on the economic review, NGP is proposing combustion control as BACT for CO emissions reduction. The proposed CO emissions for the combined-cycle turbines (EPNs GT-01 and GT-02) is 25 ppmvd at 15% O_2 and the proposed CO emissions for the regenerative (simple-cycle) turbine (EPN TGS-01) is 10 ppmvd at 15% O_2. There are no additional costs associated with combustion control since it is inherent in the DLN combustor design. Additionally there are no adverse environmental and energy impacts associated with the proposed BACT for CO emissions.

Therefore, NGP maintains that good combustion practice and combustion controls, inherent with the $SoLoNO_x$ and ULP DLN combustors, is BACT.

12.4.10 CO BACT Compliance Demonstration – Combustion Turbines

NGP proposes to use combustion controls, inherent with $SoLoNO_x$ and ULP DLN combustion design to concomitantly reduce emission of CO and NO_x. As previously discussed NGP plans to utilize the CPMS option in order to meet the monitoring, recordkeeping and reporting requirements as outlined in 40 CFR 60.4340, 60.4355 and 60.4375, respectively. There are no standards for CO in 40 CFR 60 Subpart KKKK; however, NGP will operate the combustion turbines in accordance with good combustion practices and manufacturer recommendations in order minimize emissions of CO.

12.4.11 PM Formation – Combustion Turbines

PM emissions from turbines primarily result from carryover of noncombustible trace constituents in the fuel. PM emissions are negligible with natural gas firing and marginally significant with distillate oil firing because of the low ash content. PM emissions can be classified as "filterable" or "condensable". Filterable PM is that portion of the total PM that exists in the stack in either solid or liquid state and can be measured on an EPA Method 5 filter. Condensable PM is that portion of the total PM that exists as a gas in the stack but condenses in the cooler ambient air to form particulate matter. Condensable PM exists as a gas in the stack, so it passes through the Method 5 filter and is typically measured by analyzing the impingers, or "back half" of the sampling train. The collection, recovery, and analysis of the impingers are described in EPA Method 202 of Appendix M, Part 51 of the Code of Federal Regulations. Condensable PM is composed of organic and inorganic compounds and is generally considered to be all less than 1.0 micrometers in aerodynamic diameter.

12.4.12 $PM_{2.5}$ Candidate Control – Combustion Turbines

Based on a technical review using the previously identified sources, the available control technologies for reduction of potential emissions of $PM_{2.5}$ from the combustion turbines are provided below:

- *Good combustion practice; and*
- *Natural gas fuel.*

Table 12-8 lists the current control technologies available to limit emissions of $PM_{2.5}$ from natural gas-fired turbines.

12.4.13 $PM_{2.5}$ BACT Impact Analysis – Combustion Turbines

NGP is currently proposing to use good combustion practice, while burning only pipeline quality natural gas. Therefore, no additional ranking is necessary. In addition, there are no adverse economic, environmental or energy impacts associated with the available control candidates.

Table 12-8
$PM_{2.5}$ Candidate Control Technologies for Turbines

Control Technology[(1)]	Emission Factor Range (lb/MMBtu)		
	Minimum	Maximum	Average
Good Combustion Practice; Natural Gas Only	3.90E-03	0.06	0.01

[1]Control technologies evaluated for 67 permitted emissions units from the EPA's Technology Transfer Network Clean Air Technology Center – RACT/BACT/LAER Clearinghouse. Emission units ranged in size from 14.5 MW – 480 MW and 495 MMBtu/hr – 2,311 MMBtu/hr.

12.4.14 $PM_{2.5}$ BACT Determination – Combustion Turbines

Based on the review for viable control options, the only available emissions control for the combined-cycle turbines (EPNs GT-01 and GT-02) and the regenerative turbine generator set (EPN TGS-01) is good combustion practice and burning only pipeline quality natural gas. Good combustion practices involve proper operation and maintenance of the turbines (EPNs GT-01, GT-02 and TGS-01). Creating and maintaining procedures as well as proper training are the best ways to ensure these criteria are being met. The Haven Gas Plant will keep operating logs for startup, shutdown, and maintenance as well as normal operations in accordance with good combustion practices. Maintenance logs will also be kept to ensure the turbines are in good condition. In addition, NGP will fire only pipeline quality natural gas with low sulfur content. Therefore, NGP has determined that good combustion practice and natural gas feedstocks are BACT for reduction of $PM_{2.5}$ from both the combined-cycle gas turbines and regenerative gas turbine.

12.5 BACT Analysis – Engine Generator Sets

This section provides a pollutant-by-pollutant BACT determination for the Waukesha VHP-P9390GSI engine generator sets (EPNs EGS-01 and EGS-02) proposed for the Haven Gas Plant. NGP is proposing to install two (2) Waukesha VHP-P9390GSI engine generator sets for electricity generation to power the facility. These engine generator sets will be running concurrently with the Mercury 50-6400R turbine generator set (previously discussed) to generate electricity. These emission units are spark-ignited internal combustion (IC) engines that are rich burn engines, combusting only natural gas. These units are

turbocharged, each with a horsepower rating of 1,980 brake horsepower (bhp). It is anticipated that these units will operate at 100% load capacity with no limitation for annual operation. The results of the BACT analysis for EPNs EGS-01 and EGS-02 are provided in Sections 12.5.1 through 12.5.11.

12.5.1 NO_x Candidate Controls – Engine Generator Sets

From the previously identified sources of information, the technologies available to potentially control NO_x emissions from the IC engines include the following:

- *Non Selective Catalytic Reduction (NSCR); and*
- *SCR.*

The technical feasibility for these control candidates is discussed in Sections 12.6.1.1 and 12.6.1.2.

12.5.1.1 Selective Catalytic Reduction

The SCR process for IC engines is fundamentally the same as for turbines. In the SCR process, ammonia (NH_3) or urea, usually diluted with air or steam, is injected through a grid system into the flue/exhaust gas stream upstream of a catalyst bed. On the catalyst surface the NH_3 and excess oxygen react to reduce NO_x to nitrogen and water. The basic reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 = 7N_2 + 12H_2O$$

The reactions take place on the surface of a catalyst. Usually, a fixed bed catalytic reactor is used for the SCR process. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reactions. Technical factors related to this technology include the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, and design of the ammonia injection system.

Depending on system design and the inlet NO_x level, NO_x removal of up to 70-90 percent and higher is achievable at optimum theoretical conditions. The reaction of NH_3 and NO_x is favored by the presence of excess oxygen. Another variable affecting NO_x reduction is exhaust gas temperature. The greatest NO_x reduction occurs within a reaction window at catalyst bed temperatures between 400°F and 800°F for base metal catalyst types (i.e., conventional SCR applications with lower temperature range platinum catalysts and with higher temperature range 550°F-800°F vanadium-titanium catalysts).
However, base metal catalysts deteriorate quickly when continuously subjected to temperatures above this range. In effect, if these catalyst systems are operated beyond their specified temperature ranges,

oxidation of the ammonia to either additional nitrogen oxides or ammonium nitrate may result. SCR manufacturers have developed zeolite-based catalyst systems that are purported to handle higher temperatures in the range of 790°F to 1,100°F. However, the exhaust temperatures for (EPNs EGS-01 and EGS-02) are approximately 1,180^{0}F; this control alternative is not considered technically feasible and will be precluded from further consideration in this BACT determination.

12.5.1.2 Non Selective Catalytic Reduction (NSCR)

NSCR utilizes a three-way catalyst to promote the reduction of NO_x to nitrogen and water, while oxidizing CO and hydrocarbons (HC) to carbon dioxide and water. This control technology is applicable only to rich-burn IC engines, as lean-burn IC engine exhaust does not contain sufficient CO and HC to promote the reduction of NO_x. This process relies on low oxygen content in the exhaust stream; therefore, typical oxygen levels upstream of the catalyst are less than 0.5%.[11] Controlled emissions achievable with NSCR have been reported below 1 g/bhp-hr, corresponding to emission reductions greater than 90%.

As noted above, only one of the proposed NOx control technologies is technically feasible for IC engine generating units. The remaining approach – NSCR is already being utilized at facilities comparable to the Haven Gas Plant for control of NOx during normal operations. Based on the proposed rich burn IC engines for electricity generation at the Haven Gas Plant, NSCR is considered technically feasible for EPNs EGS-01 and EGS-02 and will be reviewed in further BACT impact analysis.

12.5.2 NO_x BACT Impact Analysis – Engine Generator Sets

Based on the technical feasibility review for the IC engines (EPNs EGS-01 and EGS-02), SCR was eliminated from further BACT review. NSCR is the only technically feasible remaining add-on control technology. NGP is proposing to install the top remaining control technology for EPNs EGS-01 and EGS-02; therefore, no additional impact analysis was necessary.

12.5.3 NO_x BACT Determination – Engine Generator Sets

NGP is proposing to install NSCR add-on controls to both engine generator sets. NSCR is the only control candidate which is technically feasible and proven in practice. Based on vendor conversations with EmeraChem, a leading supplier for catalyst add-on control systems, a dual NSCR system has the potential to reduce NO_x emissions to 0.1

[11] Southern California Gas Company (January, 2008) "Operating Catalytic Emission Reduction Systems". http://www.gaselectricpartnership.com/08CatEmission.pdf

g/bhp-hr (99.2% reduction efficiency). **Table 12-9** compares the proposed NO_x emissions from the dual catalyst NSCR systems and the applicable NO_x emission requirements listed in 40 CFR Part 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Combustion Engines.

Table 12-9
Comparison of Proposed NO_x Emission Rates for EPNs EGS-01 and EGS-02 and the Applicable Standards in 40 CFR Part 60 Subpart JJJJ

EPN	Engine Type and Fuel	Maximum Engine Power	Manufactured Date	Proposed NO_x Emission Limit (g/bhp-hr)	NO_x Emission Standards (g/bhp-hr)
EGS-01	Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG	HP>500	7/1/2010	0.1	1.0
EGS-02	Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG	HP>500	7/1/2010	0.1	1.0

Based on the proposed emission limits identified in 40 CFR Part 60 Subpart JJJJ, NGP maintains that dual element NSCR add-on controls are the most effective, technically feasible control option available.

NGP is also proposing to use Performax catalyst design that offers a three year warranty to effectively reduce maintenance requirements for catalyst replacements. In addition, the Performax catalyst is designed with 4.3 in H_2O pressure drop and a larger surface area to reduce energy requirements associated with any increased back-pressure. Furthermore, the proposed 4-stroke rich burn engines are anticipated to have an oxygen content of 0.3% which will provide an ideal air-to-fuel ratio. To reduce the potential for CO_2 emissions, NGP is proposing to burn only pipeline quality natural gas in combination with good combustion practice. Therefore, NGP maintains that dual NSCR add-on controls to both engine generator sets (EPN's EGS-01 and EGS-02) is BACT for controlling NO_x emissions.

12.5.4 NO_x BACT Compliance Demonstration – Engine Generator Sets

NGP proposes to install two (2) natural gas-fired spark-ignited internal combustion generator sets with dual NSCR catalyst that meet the applicable NSPS emission standards as detailed in 40 CFR Part 60 Subpart JJJJ for the applicable engine size and model year. NGP will comply with all applicable requirements of 40 CFR 60 Subpart JJJJ and all regulations incorporated by reference.

12.5.5 CO Candidate Controls – Engine Generator Sets

From the previously identified sources of information, the technologies available to potentially control CO emissions from stationary natural gas-fired IC engine(s) include the following:

- *NSCR; and*
- *Oxidation Catalysts.*

12.5.5.1 Non Selective Catalytic Reduction

As discussed in Section 12.5.1.2, NSCR uses three-way catalysts to promote the reduction of NO_x to nitrogen and water. Simultaneously, CO and HC are oxidized to carbon dioxide and water in this process. It has been established that NSCR is technically feasible for rich burn IC engines and will be discussed in the BACT impact analysis.

12.5.5.2 Oxidation Catalyst

As discussed in Section 12.5.1.2, oxidation catalysts use a chemical oxidation process in which CO and HCs are combined with oxygen and water to yield CO_2 and water. As such, they require excess O_2 and can only be used with lean-burn engines.[12,13] Therefore, oxidation catalysts are eliminated as a BACT control candidate for the reduction of CO emissions from EPNs EGS-01 and EGS-02 based on technical infeasibility.

12.5.6 CO BACT Impact Analysis – Engine Generator Sets

Based on the technical feasibility review for the IC engines (EPNs EGS-01 and EGS-02), SCR was eliminated from further BACT review. NSCR is the only technically feasible remaining add-on control technology. NGP is proposing to install the top remaining control technology for EPNs EGS-01 and EGS-02; therefore, no additional impact analysis was necessary.

12.5.6 CO BACT Determination – Engine Generator Sets

Based on the technical feasibility review for controlling emissions of CO from the engine generator sets, the only technically feasible add-on control candidate for reducing CO emissions from EPNs EGS-01 and EGS-02 is NSCR. NGP is proposing to use the top remaining control technology.

[12] Reciprocating Internal Combustion Engine Work Group of the Industrial Combustion Coordinated Rulemaking, *Definition of "Rich Burn Engine" for the Reciprocating Internal Combustion Engine (RICE) MACT Standard*. (Sept, 1998). http://www.epa.gov/ttn/atw/iccr/engine/rb97rice.pdf.

[13] Kansas State University, National Gas Machinery Laboratory. *Final Report: Cost-Effective Reciprocating Engine Emissions Control and Monitoring for E&P Field and Gathering Engines*. (Nov, 2011). http://www.netl.doe.gov/technologies/oil-gas/publications/ENVreports/nt15464-final-report.pdf.

NSCR is the only technically feasible and proven in practice add-on control to concomitantly reduce emissions of NO_x and CO. NGP has established that the proposed BACT for reduction of NO_x emissions from the engine generator sets is dual catalyst NSCR. Not only does this system provide a 99.2% reduction in NO_x emissions, but it also offers a 96.7% reduction in emissions of CO. **Table 12-10** compares the proposed CO emission rates from EPNs EGS-01 and EGS-02 with the applicable emission standards identified in 40 CFR Part 60 Subpart JJJJ.

Table 12-10
Comparison of Proposed CO Emission Rates for EPNs EGS-01 and EGS-02 and the Applicable Standards in 40 CFR Part 60 Subpart JJJJ

EPN	Engine Type and Fuel	Maximum Engine Power	Manufactured Date	Proposed CO Emission Limit (g/bhp-hr)	CO Emission Standards (g/bhp-hr)
EGS-01	Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG	HP>500	7/1/2010	0.3	4.0
EGS-02	Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG	HP>500	7/1/2010	0.3	4.0

Due to the potential reduction efficiency for both NO_x and CO emissions, NGP maintains that NSCR is BACT for controlling emissions of CO from EPNs EGS-01 and EGS-02.

12.5.7 CO BACT Compliance Demonstration – Engine Generator Sets

NGP proposes to install two (2) natural gas-fired spark-ignited internal combustion generator sets with dual NSCR catalyst that meet the applicable NSPS emission standards as detailed in 40 CFR Part 60 Subpart JJJJ for the applicable engine size and model year. NGP will comply with all applicable requirements of 40 CFR 60 Subpart JJJJ and all regulations incorporated by reference.

12.5.8 $PM_{2.5}$ Candidate Controls – Engine Generator Sets

Based on a technical review using the previously identified sources, the available control technologies for reduction of potential emissions of $PM_{2.5}$ from the combustion turbines are provided below:

- *Good combustion practice; and*

- *Natural gas fuel.*

Table 12-11 lists the current control technologies available to limit emissions of $PM_{2.5}$ from natural gas-fired turbines.

Table 12-11
$PM_{2.5}$ Candidate Control Technologies for IC Engines

Control Technology[(1)]	Emission Factor Range (g/bhp-hr)		
	Minimum	Maximum	Average
Good Combustion Practice; Natural Gas Only	4.85E-03	0.17	0.05

[1]Control technologies evaluated for 14 permitted emissions units from the EPA's Technology Transfer Network Clean Air Technology Center – RACT/BACT/LAER Clearinghouse. Emission units ranged in size from 440bhp – 8180bhp for lean burn and rich burn IC engines. Emergency engines not included in analysis.

12.5.9 $PM_{2.5}$ BACT Impact Analysis – Engine Generator Sets

NGP is currently proposing to use good combustion practice, while burning only pipeline quality natural gas. Therefore, no additional ranking is necessary. In addition, there are no adverse economic, environmental or energy impacts associated with the available control candidates.

12.5.10 $PM_{2.5}$ BACT Determination – Engine Generator Sets

Based upon the review for viable control options, the only available emissions control for emissions from IC engines is good combustion practice and burning only pipeline quality natural gas. Good combustion practices involve proper operation and maintenance of the IC engines (EPNs EGS-01 and EGS-02). Creating and maintaining procedures as well as proper training are the best ways to ensure these criteria are being met. The Haven Gas Plant will keep operating logs for malfunction as well as normal operations in accordance with good combustion practices. Maintenance logs will also be kept to ensure the generator sets are in good condition. In addition, NGP will fire only pipeline quality natural gas with low sulfur content. <u>Therefore, NGP has determined that good combustion practice and natural gas feedstocks are BACT for PM emissions from EPNs EGS-01 and EGS-02.</u>

12.5.11 $PM_{2.5}$ BACT Compliance Demonstration – Engine Generator Sets

NGP proposes to install two (2) natural gas-fired spark-ignited internal combustion generator sets with dual NSCR catalyst that meet the applicable NSPS emission standards as detailed in 40 CFR Part 60 Subpart JJJJ for the applicable engine size and model year. NGP will

comply with all applicable requirements of 40 CFR 60 Subpart JJJJ and all regulations incorporated by reference.

12.5.12 Ozone Formation and Control Candidates

Ground level ozone is not emitted directly into the air, but is formed from the reactions of NO_x and VOCs in the presence of sunlight. The proposed Haven Gas Plant is not required to perform a BACT review for VOC. In addition, NGP has performed a BACT review for the reduction of NO_x emissions that will concomitantly reduce the formation of ozone. Therefore, ozone is not considered further in this BACT analysis.

12.6 BACT Analysis for Greenhouse Gas (GHG)

In accordance with the GHG Tailoring Rule, which was extended to new major stationary sources on July 1, 2011, the Haven Gas Plant is subject to the PSD requirements for GHGs because of the potential to emit greater than 100,000 tpy of CO_2e. Therefore, a BACT analysis has been conducted for GHGs from the Haven Gas Plant in accordance with 40 CFR 52.21.

The BACT analysis provided below follows the traditional top-down approach; however, in accordance with 40 CFR 52.21(b)(7), conducting a separate analysis for each emissions unit or local grouping is a general recommendation. For new sources requiring PSD review, the CAA and EPA provide discretion for the evaluation of BACT on a facility-wide basis for operations that affect the overall environmental performance of the facility.[14] For GHG specific considerations, it may be more appropriate to consider facility-wide or process-wide energy efficiency strategies to reduce GHG emissions from the proposed new source.[6] The application of methods or techniques to increase energy efficiency is crucial to reducing GHG emissions that fall under the category of 'lower-polluting processes/practices' identified in Step 1 of the top-down approach. Therefore, the availability of energy efficient operational strategies, alternative fuels and process improvements are also considered with the traditional add-on control technology review.

12.6.1 Facility-Wide Energy Efficiency Strategies

Based on EPA guidance from the *PSD and Title V Permitting Guidance for Greenhouse Gases*, this section focuses on the facility-wide energy efficient strategies and carbon capture and storage (CCS).

[14] US EPA (March, 2011) "PSD and Title V Permitting Guidance for Greenhouse Gases". http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

12.6.1.1 Energy Efficient Strategies

NGP is proposing to install a hot-oil system, which utilizes waste heat recovery from the Titan 250 combustion turbines (EPNs GT-01 and GT-02). Heat exchange coils will be installed within the exhaust zone of the Titan 250 turbines, where hot oil flow will be sent through the exchanger coil to recovery the waste heat. The hot oil will then be routed throughout the plant, as necessary, to supply heat to the amine and demethanizing operations. This strategy will eliminate the need for natural gas-fired heaters; thereby, reducing potential GHG emissions.

In addition to the hot oil system, NGP is proposing to use electric power for multiple facility operations, in order to reduce the required heater duty. One (1) 2,000 hp electric engine will be installed to supply the needed supplemental refrigeration to the cryogenic expansion plant. Additionally, a 3,500 hp electric engine will be used for inlet compression of the low pressure gas entering the Haven Gas Plant via the Panhandle Energy Pipeline.

All fired compression and electric generating equipment at the proposed facility will burn only pipeline quality natural gas and utilize good combustion control practices. In addition, NGP estimates that 35% of the facilities' electric needs will be purchased from existing grid sources, reducing the potential electrical generating unit requirements.

12.6.1.2 Carbon Capture and Sequestration (CCS)

CCS is the only potential add-on control technology available to reduce the potential CO_2 emissions from the affected facilities. CCS is composed of three components: CO_2 capture or compression, transport (primarily by pipeline) and storage or injection into subsurface geologic formations.[15] According to the EPA, CCS is 'available' for facilities emitting large amounts of CO_2 including fossil fuel-fired power plants and facilities with high purity CO_2 streams such as hydrogen production, natural gas processing and ethanol production.[3]

In a publication by the Center for Global Development (CGD), the top 100 CO_2 emitting power plants in the US ranged from approximately 7.5 million to 25 million tons of CO_2 per year.[16] The Haven Gas Plant is currently proposing to permit less than 400,000 tpy of CO_2 which is considerably less than fossil fuel-fired power plants. In addition, the proposed CO_2 emissions generated from the Haven Gas Plant are primarily a product of combustion, rather than a high purity CO_2 stream. Moreover, the content of NGL entering the plant via pipeline is

[15] http://www.wri.org/project/carbon-dioxide-capture-storage/ccs-basics
[16] Center for Global Development (November, 2007) "Carbon Dioxide Emissions From Power Plants Rated Worldwide". Science Daily. http://www.sciencedaily.com/releases/2007/11/071114163448.htm

approximately 90% methane, which constitutes less than 0.01% of the total CO_2e emissions proposed.

Additional technical aspects important to the review of CCS as BACT are the methods of carbon capture. There are currently three methods of CO_2 capture available in a CCS system. Post-combustion systems chemically separate the CO_2 from the flue gas with a liquid solvent. A post-combustion system normally uses a liquid solvent to capture the small fraction of CO_2 present in a flue gas stream.

Pre-combustion systems process the primary fuel with steam or oxygen to produce a syngas consisting primarily of CO_2 and hydrogen. Once the hydrogen and CO_2 streams are separated in a secondary reactor, the hydrogen can be used as a fuel source and the CO_2 can be removed for storage. Pre-combustion capture systems are designed to be used at facilities that employ integrated gasification combined cycle (IGCC) technology; and where CO_2 separation is required, such as in synthetic fuels production. Currently, there are no commercial applications of pre-combustion CO_2 capture at electric power plants. Demonstration projects for full-scale pre-combustion capture systems are being planned for IGCC plants combusting coal and petcoke, but startup for these projects isn't expected until 2013 through 2017.[13] Based on the current level of research and application for pre-combustion systems, primarily at IGCC plants, pre-combustion CO_2 capture is being eliminated from further BACT review because this control technology is not proven in practice for natural gas fired-turbines used for compression.

Oxyfuel combustion systems utilize pure oxygen instead of air, normally used for coal combustion, which produces a flue gas consisting primarily of water vapor and CO_2.[17] The resulting flue gas stream is typically greater than 80% by volume. The water vapor is then removed by cooling and compressing the gas stream. Oxyfuel combustion is being developed as an alternative to post-combustion CO_2 capture for conventional coal-fired power plants.[18] This system does not require post combustion controls; however, it requires an air separation unit to generate the pure oxygen (95%-99%) needed for combustion. Roughly three times more oxygen is needed for oxyfuel systems than for an IGCC plant of comparable size. As a method of CO_2 capture in boilers, oxyfuel combustion systems are in the demonstration phase at pilot plant facilities. Oxyfuel systems are also being studied in gas turbine applications, but conceptual designs for such applications are still in the research phase.[12] Based on the current status of oxyfuel combustion design and implementation,

[17] IPCC (2005) "IPCC Special Report: Carbon Dioxide Capture and Storage" http://www.ipcc-wg3.de/publications/special-reports/.files-images/SRCCS-TechnicalSummary.pdf

[18] Congressional Research Service (July, 2010). *Carbon Capture: A Technology Assessment*. http://crs.ncseonline.org/NLE/CRSreports/10Aug/R41325.pdf.

oxyfuel combustion is being eliminated from further BACT considerations because this technology is not proven in practice for turbine applications or for natural gas fuel combustion.

Another important aspect for CCS is transportation. Unless plants are located directly above a geological storage site, captured CO_2 must be transported from the point of capture to an acceptable storage location. The most common method of CO_2 transport is by pipeline. These pipelines operate in the 'dense phase mode' in which there is a continuous progression from gas to liquid, without a dense phase change. In most cases, the pipeline flow is driven by upstream compression.

The final aspect of CCS is associated with the storage of CO_2. The primary geologic formations which have received extensive consideration for the geologic storage of CO_2 include: oil and gas reservoirs, deep saline formations and unminable coal beds. In all cases, geologic storage of CO_2 is accomplished by injecting it in dense form into rock formations. The injection of CO_2 into geologic formations requires existing technologies such as well-drilling technology, injection technology, computer simulations for storage reservoir dynamics and monitoring applications. The storage of CO_2 in hydrocarbon reservoirs and saline formations generally occurs at depths below 800 meters where the temperature and pressure keep the CO_2 in liquid or supercritical state. At this state buoyancy forces drive the CO_2 upwards, which requires a well-sealed cap rock in the proposed storage formation.

Based on the availability of CCS, primarily for facilities emitting large quantities of CO_2 and facilities with high purity CO_2 streams, NGP maintains that CCS is not technically practicable based on the current proposed operations at the Haven Gas Plant. However, for technical completeness, a facility-wide BACT impact analysis was conducted for CCS which included the economic, environmental and energy impacts associated with CCS.

CCS Economic Analysis – Carbon Capture

Based on capital cost analysis for post-combustion carbon capture at natural gas combined-cycle power plants (IPCC, 2005), the percent increase in facility-wide capital costs range from 64-100%. In a report by the Interagency Task Force for Carbon Capture and Storage, total capital investments for new natural gas combined-cycle power plants was reported to be 80% of the total plant capital investment.[19] Currently NGP estimates that the total capitalized cost for the Haven

[19] US DOE. (August, 2010). "Report of the Interagency Task Force on Carbon Capture and Storage". http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf.

Gas Plant is approximately $150 million. This translates to an additional capital cost of $120 million. In addition, the incremental costs associated with capture alone range from 37-74 dollars per ton of CO_2 removed. These costs are representative for larger facilities such as power plants and hydrogen plants where carbon capture technologies have been more extensively developed.

A study level cost analysis was conducted for a post-combustion carbon capture system for the Haven Gas Plant. The annual CO_2 reduction potential for a post-combustion carbon capture system (assumes 90% reduction efficiency)**. Table 12-12** summarizes the potential annual reduction of CO_2 from the affected sources. The cost analysis uses the cost methodology from the EPA *Air Pollution Cost Control Manual* (March, 2002) and total capital investment estimates from the *Report of the Interagency Task Force on Carbon Capture Storage* (August, 2010). A summary of the cost analysis for carbon capture are provided in **Table 12-13**. The detailed cost analysis is provided in **Appendix D**.

Table 12-12
Annual CO_2 Reduction Potential for a Post-Combustion Carbon Capture System

EPN	Potential CO_2 Emissions (tpy)	CO_2 Reduction (tpy)
GT-01	106,311.36	95,680.22
GT-02	106,311.36	95,680.22
TGS-03	20,617.20	18,555.48
ASV-01	72,131.04	64,917.94
EGS-01	9,158.18	8,242.36
EGS-02	9,158.18	8,242.36
Facility-Wide	**323,687.32**	**291,318.59**

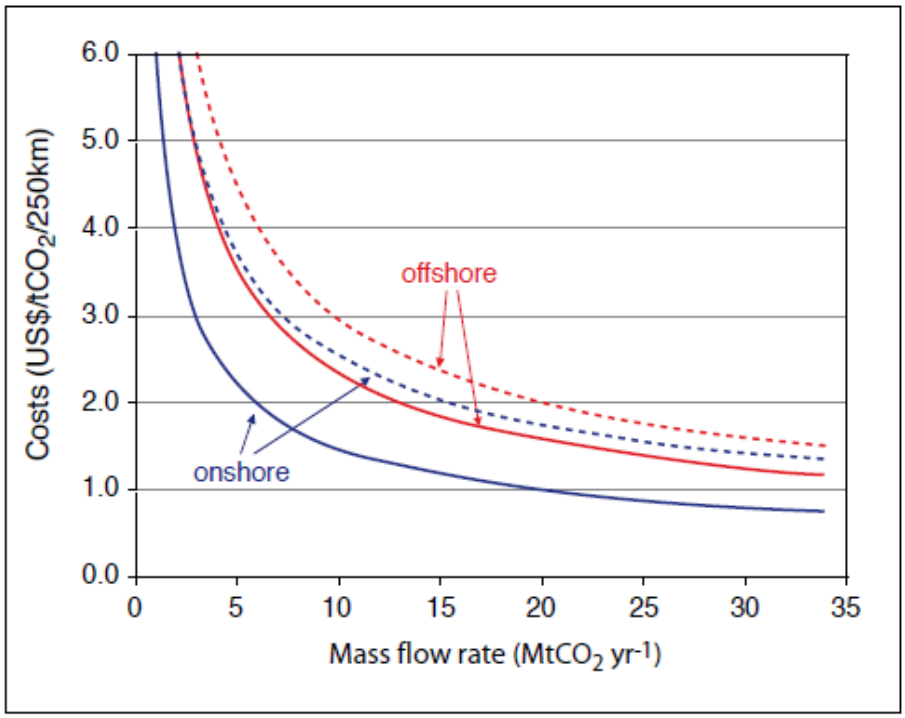
CCS Economic Analysis – Carbon Transport

The costs associated with pipeline transfer are dependent upon the distance and quantity transported. Additionally, the costs associated with pipeline transfer are dependent upon the population density, terrain and onshore vs. offshore transport. **Figure 12-1** illustrates the costs associated with pipeline transport of CO_2 (nominal distance of 250 km).[12]

Based on **Figure 12-1** and the proposed CO_2 emissions at the Haven Gas Plant (less than 400,000 tons CO_2 per year), the associated cost for onshore pipeline transfer becomes increasingly less cost efficient for smaller facilities. A cost analysis for the transportation of captured CO_2 was conducted using the National Energy Technology

Laboratory's *Quality Guidelines for Energy System Studies* (March, 2010). The cost metrics utilized in this study provide estimates for carbon transport, storage and monitoring for typical sequestration projects. The transport costs analysis was broken down into three categories: pipeline costs, related capital expenditures and O&M costs.[20] The cost analysis was dependent upon pipeline length and pipe diameter. The proposed Haven Gas Plant is located within the southwest region of the U.S. DOE NETL regional partnership network. Based on the location of the proposed plant, the closest facility which accepts anthropogenic CO_2 streams is the Enid-Purdy Pipeline located in Central Oklahoma (approximately 140 miles from the proposed Haven Gas Plant).[21] A summary of the cost analysis is provided in **Table 12-13**.

Figure 12-1
Carbon Transport Costs Based on Mass Flow Rate



CCS Economic Analysis – Carbon Storage

Because the technologies and equipment used for geologic storage are widely used in the oil and gas industries, cost estimates can be made with more confidence. However, there is a significant range and

[20] NETL (March, 2010). "Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs". DOE/NETL-2010/1447.
[21] Interstate Oil and Gas Compact Commission. (Sept, 2010) "A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide". http://www.sseb.org/downloads/pipeline.pdf.

variability of costs due to site-specific factors, such as geologic storage formations. Cost per ton of CO_2 stored range from 0.5-8 dollars per ton of CO_2 stored. In addition, cost information for storage monitoring is limited, but estimates range from 0.1-0.3 dollars per ton of CO_2 stored. Based on the location of the proposed gas plant, the closest facility that accepts anthropogenic CO_2 streams is the Enid-Purdy Pipeline, owned and operated by Merit. Currently, NGP is not proposing any contractual agreements with Merit for the storage of CO_2 in geologic formation. Therefore, the cost analysis conservatively assumes there is no cost for the storage of CO_2.

Table 12-13
Cost Analysis Summary for the Post-Combustion Capture, Transport and Storage of CO_2

CCS	Total Capital Investment	Annual Costs	Incremental Cost Effectiveness ($/ton)
Capture	$120,000,000	$32,393,797	111.20
Transport	$81,810,647	$13,495,781	46.30
Storage	$0.00	$0.00	0.00
Total	$201,810,647	$45,889,578	157.52

CCS – Environmental Impacts

During transport, moisture-laden CO_2 is highly corrosive to the carbon-manganese steels typically used in pipeline construction. This would, in turn, require the use of corrosion-resistant alloys which have significantly higher costs than typical pipeline construction alloys.

The leakage from storage of CO_2 in geologic formation has the potential for both global and local risks. While the global risks (climate change) are relatively small, local risks, such as leakage through undetected fractures or through leaking wells, have the potential to affect ground water aquifers and ecosystems where CO_2 accumulates in the zone between the surface and top of the water table. Groundwater can be affected both by CO_2 leakage and by brines that enter the aquifer as a result of displacement during CO_2 injection.

CCS – Energy Impacts

CO_2 capture systems require significant amounts of energy for their operation, which in turn reduce net plant efficiency. For larger facilities such as power plants, fuel consumption has shown to increase between 11-40%.

Just as there are standards for natural gas entering pipelines, there are standards that must be met for CO_2 as well. Current standards, based largely on enhanced oil recovery (EOR), require low nitrogen content, while carbon capture systems do not. In addition, pipeline transport through highly populated areas requires detailed route selection, over-pressure protection and leak detection.

CCS – Facility-Wide BACT Determination

Based on the results of the economic impacts analysis, NGP is rejecting CCS as BACT for facility-wide CO_2 emission controls because the capital investment is cost prohibitive. In addition, based on the availability of CCS, primarily for facilities emitting large quantities of CO_2 and facilities with high purity CO_2 streams, NGP maintains that CCS is not technically practicable based on the current proposed size and operations at the Haven Gas Plant.

12.6.2 GHG BACT Candidate Control – Process Fugitives

Hydrocarbon emissions from leaking components (EPN FUG-01) associated with the proposed Haven Gas Plant include methane. The methane emissions from the process fugitives have been estimated to be 6.62 tpy as CO_2e, approximately 99.9% of the total GHG emissions from EPN FUG-01. Additionally, trace amounts of CO_2 are anticipated to be emitted from the process fugitives; however, it is anticipated that the fugitive emission controls presented in this GHG BACT analysis will provide similar levels of emission reduction for both CO_2 and CH_4. Therefore, the analysis has been combined into a single analysis, and will focus primarily on CH_4 emissions. The leaking components associated with the process fugitives include: valves, pressure relief valves, pump seals, compressor seals, flanges and sampling connections.

The previously identified resources, in addition to permits and permit applications, were reviewed to determine the available control technologies and strategies for reducing GHG emissions from process fugitives. Based on a review of these resources, the following available control technologies were identified:

- *Leakless technology components;*
- *Leak detection and repair programs (LDAR), in accordance with applicable state and federal regulations;*
- *Alternative monitoring programs such as infrared camera monitoring;*
- *Implementation of an audio/visual/olfactory (AVO) monitoring program.*

12.6.2.1 Leakless Technology Components

Emissions from pumps and valves can be reduced through the use of leakless valves and sealless pumps. Common leakless valves include bellow valves and diaphragm valves, and common sealless pumps are diaphragm pumps, canned motor pumps and magnetic drive pumps. Leaks from pumps and compressors can also be reduced by using dual seals with or without barrier fluids.

Leakless valves and sealless pumps are effective at minimizing or eliminating leaks, but their use may be limited by materials of construction considerations and process operating conditions. Additionally, elevated service temperatures can have a negative effect on leakless components. For example, the tensile strength of bellow valves is degraded at higher process temperatures, which reduces the component life-cycle. Installing leakless and sealless equipment components is generally reserved for individual, chronic leaking components and specialized services. Additionally, leakless valves are primarily used where highly toxic materials are in service. Leakless technology components have not been widely adopted as BACT/LAER, and are not considered practical for a facility-wide reduction in process fugitive emissions. <u>However, based on technical completeness, NGP has reviewed the additional impacts associated with the installation of leakless components, where feasible.</u>

12.6.2.2 Leak Detection and Repair (LDAR) Programs

LDAR programs have been traditionally developed for control of VOC emissions. The fundamental elements for all LDAR programs include: identification of components to be included in the program, conducting routine instrument monitoring of identified components, repair of leaking components and reporting of the monitoring results. <u>Monitoring direct emissions of CH_4 with traditional portable hydrocarbon monitoring equipment is technically feasible; therefore, the incorporation of an LDAR program will be considered further in this BACT analysis.</u>

12.6.2.3 Alternate Monitoring Programs

Alternative monitoring programs, such as remote camera sensing, have been shown to be an effective means of hydrocarbon detection that is considered technically feasible for the detection of CH_4.

12.6.2.4 Audio/Visual/Olfactory (AVO) Monitoring Programs

AVO monitoring can be used to detect leaking fugitive components. Natural gas leaks are expected to have discernible odors that are detectable by olfactory means. In addition, large leaks can be detected

by audio and visual means, and secondary visual indications may include condensation around components suspected of leaking.

12.6.3 GHG BACT Impact Analysis – Process Fugitives

Based on the technical feasibility review, there are four potential control candidates available for controlling CH_4 emissions from (EPN FUG-01). These include: leakless components, an LDAR program, alternate modeling using remote sensing, and AVO monitoring.

Design modifications with leakless components have the potential to reduce CH_4 emissions up to 100% for sealless pumps, valves and compressors and welded connections and closed-vent systems.[22] Based on the potential CH_4 emission reductions, leakless components represent the top BACT control candidate.

An LDAR program is designed to identify pieces of equipment that are emitting sufficient amounts of material to warrant reduction of the emissions through repair. These programs are applied to equipment types that can be repaired on-line, resulting in immediate emissions reductions. Reduction potential for an LDAR program is dependent upon the monitoring frequency, component type and component service, but can potential reduce CH_4 emissions by approximately 88%.[22]

Alternate monitoring using remote sensing/infrared imaging is an alternative monitoring method to EPA Method 21. The effectiveness is thus likely comparable to EPA Method 21.

The effectiveness for an AVO inspection program is entirely dependent upon the frequency of observation. This method generally cannot identify leak rates as low as can be detected with instrument monitoring. Therefore, AVO monitoring is effective primarily for identification of large leaks.

The economic, energy and environmental impacts for the remaining control candidates are provided in Section 12.6.3.1.

12.6.3.1 Leakless Components – Economic Impacts

As documented in EPA's *Protocol for Equipment Leak Emission Estimates*, leakless components have the potential to reduce hydrocarbon emissions by 100%, representing the top BACT candidate control technology to reduce emissions of methane from process fugitives.[22] A cursory cost analysis was conducted to determine the

[22] US EPA. Office of Air Quality Planning and Standards. *Protocol for Equipment Leak Emission Estimates.* (Nov, 1995) . EPA 453/R-95-017.

total capital investment, annualized cost and incremental cost effectiveness for installing leakless components on a facility-wide basis. Equipment costs were determined through vendor cost estimates and price schedules for leakless components versus standard components for valves, pumps, pressure relief devices (PRV) and compressors. Annualized costs were determined using EPA's *Air Pollution Control Cost Manual* (Jan, 2002). The cursory cost analysis conservatively assumes there are no additional costs for welded connections. The results of the cursory cost analysis indicate the control effectiveness for leakless components on a facility-wide basis is $263,750 per ton of methane removed. The cursory cost analysis is provided in **Appendix D**. There is no additional adverse energy or environmental impacts associated with leakless components on a facility-wide basis.

There is no adverse environmental, energy or economic impacts associated with the remaining control technologies.

12.6.4 GHG BACT Determination – Process Fugitives

Based on the cursory cost analysis for the top control candidate, the cost for installing leakless components on a facility-wide basis is prohibitive. While NGP maintains that leakless components are cost prohibitive on a facility-wide basis, leakless designs are inherent with the centrifugal compressors proposed for the Haven Gas Plant. The centrifugal compressors proposed for inlet compression, recompression of the processed natural gas and amine regeneration are equipped with tandem dry gas seals, which are a type of leakless seal. Additional discussions regarding the applicability for each of the compressors proposed for the Haven Gas Plant are provided in Section 12.6.5.

Based on the top-down BACT analysis for process fugitives, the most efficient, technically feasible control candidate available for the reduction of CH_4 emissions from process fugitives is an LDAR program. The control effectiveness of an LDAR program for controlling emissions of hydrocarbons from leaking components is approximately 88% with monthly inspections and a leak detection rate of 10,000 ppm.[23] Therefore, NGP proposes an LDAR program as BACT for controlling CH_4 emissions from process fugitives. NGP has selected to utilize the top remaining control technique; therefore, additional alternate modeling techniques and AVO monitoring are not being proposed for the Haven Gas Plant.

[23] US EPA. (Oct., 2007)." Leak Detection and Repair: A Best Practices Guide." EPA-305-D-07-001. http://www.epa.gov/oecaerth/resources/publications/assistance/ldarguide.pdf

12.6.5 GHG BACT Compliance Demonstration – Process Fugitives

NGP plans to develop and implement an LDAR program in accordance with 40 CFR 60 Subpart KKK and all applicable regulations which are incorporated by reference in 40 CFR 60 Subpart VV. In addition, NGP plans to incorporate the applicable requirements of 40 CFR 60 Subpart OOOO, as they become effective.

NGP is planning to install only centrifugal compressors with tandem dry gas seals. These compressors will be used for inlet compression (Tag No. C-1), recompression of the processed natural gas (Tag No. C-2A/B) and regeneration compression (Tag No C-4). Because these centrifugal compressors do not employ wet seals, these units are not subject to the requirements of 40 CFR 60 Subpart OOOO. However, the compressors proposed for refrigeration within the cryogenic expansion plant (Tag No. C-3) and the amine flash tank compressor (Tag No. C-5) are two-stage reciprocating compressors; therefore, these units are subject to 40 CFR 60.5365(c) for reciprocating compressors located at natural gas processing plants. For each reciprocating compressor, NGP will change the rod packing and monitor the hours of operation, and/or, the months since the previous rod packing in accordance with the standards in 40 CFR 60.5385. Additionally, NGP will comply with all applicable notification, recordkeeping and reporting requirements as outlined in in 40 CFR 60 Subpart OOOO and the general requirements outline in 40 CFR 60.7.

12.6.6 GHG BACT Candidate Controls – Combustion Turbines

From the previously listed sources of information, the following control technologies and strategies are available to reduce GHG emissions from the combustion turbines (EPNs GT-01, GT-02 and TGS-01):

- *CCS;*
- *Selecting higher energy efficient turbines;*
- *Waste heat recovery in the exhaust gases;*
- *Efficient process controls and practices; and*
- *Low carbon fuel selection.*

12.6.6.1 CCS

Currently, the only potential add-on control technology available to reduce CO_2 emissions is CCS. CCS has been discussed in Section 12.6.1.2.

12.6.6.2 Selecting Higher Energy Efficient Turbines

Selecting higher energy efficient turbines would reduce the overall heat input requirements for the Haven Gas Plant, thereby reducing the unit requirements and overall GHG emissions.

12.6.6.3 Waste Heat Recovery

Utilizing waste heat recovery from the turbine exhaust for EPNs (GT-01 and GT-02) would provide energy efficiency to the plant and eliminate the need for a fired-heater in the hot oil system of the amine still, which reduce the overall GHG emissions.

12.6.6.4 Efficient Process Controls and Practices

Using good combustion practices, along with efficient process controls would ensure that the turbines are operated as efficiently as possible, while extending operational lifetime.

12.6.6.4 Low Carbon Fuel Selection

Selecting lower carbon fuels would reduce CO_2 formation during the combustion process.

12.6.7 GHG Impact Analysis – Combustion Turbines

Based on a review of the available control candidates for the reduction of GHG emissions from the combustion turbines, CCS has the potential to reduce CO_2 emissions by approximately 90%; representing the most effective control strategy. An impact analysis for the available control candidates for combustion turbines is provided in Sections 12.7.6.1 through 12.7.6.5.

12.6.7.1 CCS

See Section 12.6.1.2 for a discussion of the impacts analysis for CCS.

12.6.7.2 Higher Energy Efficient Turbines

NGP is proposing to install (2) Solar Titan 250-30000S turbines for natural gas compression (EPNs GT-01 and GT-02) and one (1) Solar Mercury 50-6400R for electricity generation (EPN TGS-01). The Titan 250-30000S turbines have a manufactured engine efficiency of 40% with a heat rating of 6,360 Btu/hp-hr. The Mercury 50-6400R has a manufactured cycle thermal efficiency of 37.7% and a net power production rate of 4,218 kW. These units were selected as the only turbines that would reliably meet the necessary power requirements.

12.6.7.3 Waste Heat Recovery

Using waste heat recovery from the turbine exhaust (EPNs GT-01 and GT-02) will increase plant efficiency and reduce the additional heater duty requirements. NGP is already planning to incorporate waste heat recovery by installing a heat exchanger coil into the turbine exhaust and flowing a heat transfer oil through the heat exchanger coil in order

to recovery the waste heat. The captured heat is then used for the amine still reboiler, molecular sieve regeneration heater and demethanizer trim reboiler. NGP has chosen this technique as part of the plant's GHG BACT for EPNs GT-01 and GT-02; therefore. no additional analysis has been conducted.

12.6.7.4 Efficient Process Controls and Practices

The use of good combustion practices, proper maintenance scheduling and efficient controls would ensure a minimization of CO_2 emissions, while extending the operational life of the turbines. Therefore proper operation of the turbines and efficient controls would provide positive environmental and energy impacts.

12.6.7.5 Low Carbon Fuel Selection

Based on the planned operational practices at the proposed Haven Gas Plant, NGP has selected pipeline quality natural gas as the fuel source for EPNs GT-01, GT-02 and TGS-01. Pipeline quality natural gas is the lowest carbon fuel available to minimize CO_2 emissions.

12.6.8 GHG BACT Determination – Combustion Turbines

Currently CCS is the only available add-on control technology for the reduction of CO_2 emissions from the Haven Gas Plant. Based on the BACT impact analysis for the economic, environmental and energy impacts associated with CCS, NGP is rejecting CCS as BACT because the capital investment is cost prohibitive. In addition, current carbon capture systems have been more extensively developed for larger facilities with higher CO_2 purity streams, rendering this technology impracticable based on the proposed size of the Haven Gas Plant.

Other than carbon capture, NGP is proposing to incorporate turbine efficiency, waste heat recovery, efficient process control/practices and low carbon fuels as BACT for reduction of GHG emissions from the proposed Haven Gas Plant. NGP maintains that the Solar turbines selected for natural gas compression and electricity generation are the most efficient and reliable units available. Additionally, EPNs GT-01 and GT-02 will incorporate waste heat recovery in the exhaust streams which will eliminate the need for fired-heaters. In addition, the Solar turbines will be equipped with *Turbotronic* control systems which incorporate engine performance and compression mapping, heat recovery interface software, backup safety shutdown systems and kW controls.

NGP will conduct all operations using good combustion practices in addition to the manufactured recommendations for startup/shutdown operations. In addition, the turbines will burn only pipeline quality natural gas to reduce CO_2 emissions. As mentioned previously, the NGL entering

the facility via pipeline is approximately 90% methane (<0.01% of total emissions) and 0.55% CO_2.

To reduce fossil fuel combustion, as much as practicable, NGP is proposing to purchase 35% of the plant's electrical power needs from existing grid sources. It is anticipated that all natural gas-fired turbines will operate at 100% capacity to ensure the maximum combustion efficiency and reduce the total unit requirements for natural gas compression and electricity generation. Therefore, NGP maintains that turbine efficiency, waste heat recovery, efficient process controls and practices, and low carbon fuel selection are BACT for the compression units (GT-01 and GT-02) and electrical generating unit (TGS-01). Additionally, NGP anticipates that 35% of the facility-wide electrical requirements will be purchased from existing grid sources.

12.6.9 GHG BACT Control Candidates – Amine Treatment

Amine treatment operations are being proposed to treat the NGL product following cryogenic expansion. The NGL product will be treated with liquid amine to remove approximately 95% of the CO_2 in order to meet downstream requirements.

From the previously listed sources of information, the following control technologies and strategies are available to reduce CO_2 emissions from the amine still vent (ASV-01):

- *CCS;*
- *Waste heat recovery; and*
- *Routing amine vent gases to a control device.*

12.6.9.1 CCS

CCS could be utilized to capture the CO_2 gases vented from the amine still, where they would be purified, compressed and transferred via pipeline to either a storage location or pipeline for use in enhanced oil recovery (EOR) operations. The details of CCS have been discussed in Section 12.6.1.2.

12.6.9.2 Waste Heat Recovery

Currently, NGP is proposing to use waste heat recovery from the exhaust of the compression turbines (EPNs GT-01 and GT-02). Utilizing the waste heat recovered from the turbine exhaust in the plant's hot oil system eliminates the requirements for a natural gas-fired amine still reboiler. Therefore, the heat input requirements for amine solution regeneration would be satisfied by waste heat recovery; thereby, reducing potential CO_2 emissions from a natural gas-fired amine still reboiler.

12.6.9.3 Routing Amine Vent Gases to a Control Device

NGP is currently proposing cryogenic expansion operations at the Haven Gas Plant, which include a demethanization process. The demethanizer will reduce the mass flow rate of CH_4 to the amine treater to approximately 1,588 lb/hr. Additionally, it is estimated that only 0.16 lb/hr of CH_4 will actually be vented to the amine still. The remainder of the CH_4, in the NGL product stream, will be transferred via pipeline to downstream markets. Therefore, the total CH_4 emissions from amine treatment represent less than 0.001% of the total CO_2e emissions

Routing the amine vent gases to a control device, such as a flare or thermal oxidizer, has the potential to further reduce CH_4 emissions; as the destruction of CH_4 would result in the creation of a stoichiometrically equivalent amount of CO_2, which has a lower global warming potential. As the CH_4 content is 0.16 lb/hr, the warming potential is 3.36 lb/hr CO_2e. However, given the low VOC content of the amine still vent stream, the operation of thermal control device is not feasible without the addition of auxiliary fuel. As shown in **Table 12-14**, the heating value of the amine still vent gas is only 4.19 Btu/scf. Per 40 CFR 60.18(C)(3)(ii), the minimum net heating value for a flare is 200 Btu/scf, if unassisted, or 300 Btu/scf if steam or air assisted. To increase the vent stream heating value to the federally-mandated minimum of 200 Btu/scf would require the combustion of an additional 1,169 lbs/hr of natural gas. Additional CO_2 from combustion of this auxiliary fuel would result in greater overall CO_2e emissions than the uncontrolled amine still vent stream.

Similarly, the installation and operation of a thermal oxidizer is unlikely to decrease net CO_2e emissions. The amine still vent stream is very lean; the sum VOC content is only 0.23%. As shown on **Table 12-15**, the lower flammability limit for the mixture of combustibles in the vent stream is 2.88%. As such, considerable auxiliary fuel would need to be added to maintain combustion and bring the oxidizer to the typical operating temperature of 1,500 °F. The additional CO_2e emissions due to the combustion of this fuel would be greater than the uncontrolled CO_2e emissions from the amine still vent. Additionally, since the process stream does not contain significant amounts of oxygen, a considerable stream of oxygen or combustion air would need to be introduced into the oxidizer, resulting in secondary CO_2e

Table 12-14
Calculation of Heat Content of Amine Still Vent Stream

Species	Vent (lb/hr)	Heating Value (Btu/lb)	Heating Rate (Btu/hr)	Specific Gravity	Density of air (lb/scf)	Density (lb/scf)	Flow Rate (scf/hr)	Heat Content (Btu/scf)
CO_2e	16697	0.00	0.00	1.52	0.08	0.12	136049.80	4.19
H_2S	0.767	7479.00	5736.39	1.18		0.10	8.07	
Water	641	0.00	0.00	0.62		0.05	12758.39	
Methane	0.16	23811.00	3809.76	0.55		0.04	3.57	
Ethane	22.9	22198.00	508334.20	1.04		0.08	273.09	
Propane	4.4	21564.00	94881.60	1.52		0.12	35.78	
N-Butane	0.58	21640.00	12551.20	2.01		0.16	3.58	
I-Butane	0	21640.00	0.00	2.01		0.16	0.00	
C5+	0	20908.00	0.00	2.49		0.20	0.00	

emissions from pumping. Therefore, NGP maintains that routing the amine gases to a control device, such as a thermal oxidizer, would be ineffective at reducing emissions of GHG, and is therefore technically infeasible.

Table 12-15
Calculation of Lower Flammability of Amine Still Vent Stream

Species	Vent (lb/hr)	Specific Gravity	Density of air (lb/scf)	Density (lb/scf)	Flow Rate (scf/hr)	VOC Volume Fraction	Lower Flammability Limit (%)	Le Chatelier's Fraction (xi/LELi)	Lower Flammability Limit of Mixture
CO_2e	16697.00	1.52	0.08	0.12	136049.80	0.0000	0.00%	0.00	2.88%
H_2S	0.77	1.18		0.10	8.07	0.0249	4.30%	0.58	
Water	641.00	0.62		0.05	12758.39	0.0000	0.00%	0.00	
Methane	0.16	0.55		0.04	3.57	0.0110	5.00%	0.22	
Ethane	22.90	1.04		0.08	273.09	0.8426	3.00%	28.09	
Propane	4.40	1.52		0.12	35.78	0.1104	2.10%	5.26	
N-Butane	0.58	2.01		0.16	3.58	0.0110	1.86%	0.59	
I-Butane	0.00	2.01		0.16	0.00	0.0000	1.80%	0.00	
C5+	0.00	2.49		0.20	0.00	0.0000	1.40%	0.00	

12.6.10 GHG Impact Analysis – Amine Still Vent

Based on a review of the available control candidates for the reduction of GHG emissions from the amine still vent, CCS has the potential to reduce CO_2 emissions by approximately 90%; representing the most effective control strategy. An impact analysis for the available control candidates for the amine still vent is provided in Sections 12.7.6.1 through 12.7.6.5.

12.6.10.1 CCS

A full impacts analysis for CCS has been discussed in Section 12.6.1.2. NGP is rejecting CCS as BACT for CO_2 reduction based on the cost prohibitive capital investment.

12.6.10.2 Waste Heat Recovery

NGP is currently proposing to use waste heat recovery from the combustion turbines (EPNs GT-01 and GT-02) to provide the needed heat input for the plant's hot oil system. The hot oil system, in turn, will eliminate the need for a natural gas-fired amine still reboiler; reducing the potential GHG emissions. NGP is planning to use this control strategy; therefore, no additional impact analysis has been conducted.

12.6.11 GHG BACT Determination – Amine Still Vent

NGP is proposing to incorporate waste heat recovery as BACT for the amine still vent (EPN ASV-01). The hot oil system, fueled by the waste heat recovered from the combustion turbines will eliminate the need for natural gas-fired reboilers, not only for the amine still, but also for the molecular sieve regeneration heater and demethanizer trim reboiler. This technique will lower the plant's energy requirements, while reducing potential emissions of CO_2 from combustion.

In addition, the demethanizing operations in the cryogenic expansion process will reduce the CH_4 entering the amine treater. The demethanizer will therefore lower the potential emissions of CH_4 emissions which have a higher global warming potential (GWP) than CO_2.

12.6.12 GHG BACT Control Candidates – Engine Generator Sets

NGP is proposing to install two (2) Waukesha VHP-P9390GSI engine generator sets for electricity generation to power the facility. These engine generator sets will be running concurrently with the Mercury 50-6400R turbine generator set (previously discussed) to generate electricity. These emission units are spark-ignited internal combustion (IC) engines that are rich burn engines, combusting only natural gas. These units are turbocharged, each with a horsepower rating of 1,980 brake horsepower (bhp). It is anticipated that these units will operate at 100% load capacity with no limitation for annual operation. These engine generator sets have the potential to emit GHG emissions of CO_2, CH_4 and N_2O because they combust hydrocarbon fuel (pipeline quality natural gas).

From the previously listed sources of information, the following control technologies and strategies are available to reduce GHG emissions from the engine generator sets (EPNs EGS-01 and EGS-02):

- *CCS;*
- *Selecting higher energy efficient engine generators;*
- *Efficient process controls and practices; and*
- *Low carbon fuel selection.*

12.6.12.1 CCS

CCS could be utilized to capture the CO_2 gases vented from the engine generators, where they would be purified, compressed and transferred via pipeline to either a storage location or pipeline for use in enhanced oil recovery (EOR) operations. The details of CCS have been discussed in Section 12.6.1.2.

12.6.12.2 Selecting Higher Energy Efficient Engine Generators

The selection of more energy efficient engine generator sets would reduce the overall heat input requirements and the CO_2 emissions from hydrocarbon fuel combustion. Therefore, the selection of a higher energy efficient design is considered as a potential control candidate.

12.6.12.3 Efficient Process Controls and Practices

Using good combustion practices, along with efficient process controls would ensure that the turbines are operated as efficiently as possible, while extending operational lifetime.

12.6.12.4 Low Carbon Fuel Selection

Selecting lower carbon fuels would reduce CO_2 formation during the combustion process.

12.6.13 GHG Impact Analysis – Engine Generator Sets

Based on a review of the available control candidates for the reduction of GHG emissions from the engine generators, CCS has the potential to reduce CO_2 emissions by approximately 90%; representing the most effective control strategy. An impact analysis for the available control candidates for engine generators is provided in Sections 12.6.13.1 through 12.6.13.4.

12.6.13.1 CCS

Based on the economic, environmental and energy impacts discussed in Section 12.6.1.2, CCS has been determined to be cost prohibitive and is eliminated as BACT.

12.6.13.2 Selecting Higher Energy Efficient Engine Generators

Based on the plant's operations, two (2) Waukesha VHP-P9390GSI natural gas-fired reciprocating IC engine generating units were selected for their reliability to generate the electrical needs of the plant. Each of the two generating units will provide 1406 kWe, with an approximate generator efficiency of 95.2%.

Initially, NGP considered installing three (3) Caterpillar G3520C natural gas-fired lean burn reciprocating engines for electrical power. These engine generators were rated at 1950 kWe, each. However, NGP selected the Waukesha VHP-P9390GSI units, in combination with the Mercury 50-6400R turbine generating unit, because these are rich burn engines that allow for NSCR add-on controls, which are being proposed to reduce emissions of criteria pollutants.

12.6.13.3 Efficient Process Controls and Practices

The use of good combustion practices, proper maintenance scheduling and efficient controls would ensure a minimization of CO_2 emissions, while extending the operational life of the turbines. Therefore proper operation of the turbines and efficient controls would provide positive environmental and energy impacts.

12.6.13.4 Low Carbon Fuel Selection

Based on the planned operational practices at the proposed Haven Gas Plant, NGP has selected pipeline quality natural gas as the fuel source for EPNs EGS-01 and EGS-02. Pipeline quality natural gas is the lowest carbon fuel available to minimize CO_2 emissions.

12.6.14 GHG BACT Determination – Engine Generators

NGP is proposing the following control candidates as BACT for the engine generator units:

- *Selection of higher efficiency engines;*
- *Good combustion practices; and*
- *Pipeline quality natural gas.*

NGP is proposing to install two (2) Waukesha VHP-9390GSI reciprocating IC engines for electricity generation, in combination with one (1) Mercury 50-6400R turbine generator (previously discussed). These units were chosen for their generator efficiency, output power and reliability. Additionally, the selection of rich-burn IC engines will allow NGP to add dual catalyst NSCR to reduce emissions of criteria pollutants.

These units will be maintained using good combustion practices and manufacturer recommended maintenance in order to promote combustion efficiency and engine life. NGP proposes to burn only pipeline quality natural gas in EPNs EGS-01 and EGS-02 to minimize the combustion of hydrocarbons.

13.0 STATE REGULATORY APPLICABILITY ANALYSIS

13.0 STATE REGULATORY APPLICABILITY ANALYSIS

As required by K.A.R. 28-19-300(a) Notification of Construction or Modification and K.A.R. 28-19-511 Class I Operating Permit Application Form GI-09, this section addresses the assurance of state regulatory compliance by NGP during operation of the Haven Gas Plant. A separate Class 1 Operating Permit will be submitted to the Kansas Department of Health and Environment (KDHE) under a separate cover letter.

13.1 K.A.R. 28-19-20 Particulate Matter Emission Limitations

In accordance with K.A.R. 28-19-20(a), no person shall cause, suffer, allow or permit the emission of particulate matter from any processing machine, equipment, device or other articles, or combination thereof, in excess of the amounts allowed in table P-1 during any one hour. NGP will comply with the requirements of this part and the emission limitations in Table P-1.

13.2 K.A.R. 28-19-23 Hydrocarbon Emissions – Stationary Sources

The slop oil tank TK-01 is not subject to the requirements of K.A.R. 28-19-23 because it has a storage capacity of less than 40,000 gallons. No other requirements of this section apply to the proposed activities at the Haven Gas Plant.

13.3 K.A.R. 28-19-24 – Control of Carbon Monoxide Emissions

The Haven Gas Plant is not subject to the requirements of K.A.R. 28-19-24 because carbon monoxide emissions from grey iron cupolas or catalyst regeneration activities for petroleum processing are not being proposed.

13.4 K.A.R. 28-19-26 – Sulfuric Acid Mist Emissions

The Haven Gas Plant is not subject to the requirements of K.A.R. 28-19-26 because the facility will not be engaged in “sulfuric acid production” operations or emit H_2SO_4 in excess of 0.5 pounds of acid mist per ton of acid production.

13.5 K.A.R. 28-19-30 through 28-19-32 – Indirect Heating Emissions

NGP is not proposing to construct or operator any indirect heating operations; therefore, the Haven Gas Plant is not subject to the requirements of K.A.R. 28-19-30 through K.A.R. 28-19-32.

13.6 K.A.R. 28-19-40 through K.A.R. 28-19-43 – Incinerator Emissions

NGP is not proposing to construct or operator any incinerators, pyrolysis units or modified open burning operations; therefore, the Haven Gas Plant is not subject to the requirements of K.A.R. 28-19-40 through K.A.R. 28-19-43.

13.7 K.A.R. 28-19-40 through K.A.R. 28-19-650 – Emissions Opacity Limits

NGP will comply with the requirements of K.A.R. 28-19-650 for new facilities constructed after January 1, 1971. All emission sources will comply with the 20% opacity limitations; and NGP will conduct opacity testing in accordance with 40 CFR Part 60 Appendix A, Method 9, as adopted in K.A.R. 28-19-720.

NGP will meet, on a timely basis, all applicable requirements that will become effective during the permit term.

13.8 Measurement of Air Contaminants

Emissions of air contaminants from the new emission sources presented in this application will be measured by observing for visual emissions from the sources, control devices, and emission points as a part of routine operations. Sampling ports and locations to measure air contaminants will be available in accordance with TCEQ guidance.

13.9 Best Available Control Technology

The demonstration of BACT is provided in Section 12.0 of this amendment application.

13.10 Compliance Demonstration (Achieve Performance)

The Haven Gas Plant will comply with all applicable regulatory and permit requirements. The emission calculations presented in Section 11.0 document all data and assumptions used to verify compliance.

13.11 Atmospheric Dispersion Modeling

The results of the air dispersion modeling analysis are included in Section 14.0.

13.12 Emission Cap and Trade

The Haven Gas Plant is located in Reno County, which is in attainment for all pollutants. Therefore, emission cap and trade does not apply.

14.0 FEDERAL REGULATORY APPLICABILITY ANALYSIS

14.0 FEDERAL REGULATORY APPLICABILITY ANALYSIS

This section addresses the applicability of federal regulatory requirements to the Haven Gas Plant.

14.1 40 CFR 52.21, Prevention of Significant Deterioration (PSD)

The PSD rules applicable to sources in Kansas are found at K.A.R. 28-19-350; these incorporate by reference most of the requirements of 40 CFR 52.21. PSD review applies to the installation of the proposed emission units. The PSD rules contain several different requirements that must be satisfied and are discussed below.

14.1.1 Control Technology Analysis, 52.21(j)

In accordance with 40 CFR 52.21(j), a new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts. The BACT analysis for the proposed Haven Gas Plant is described in Section 12.0.

14.1.2 Air Quality Analysis, 52.21(k) and (m)

An air quality analysis is required to determine if the proposed project will cause or significantly contribute to an exceedance of the NAAQS or PSD Increment. The analysis is performed using computer dispersion models. The PSD rules require the analysis to be performed according to 40 CFR 51 Appendix W.

In general, the air quality analysis consists of three basic steps:

Significance Modeling: The net emission increase for the proposed project is modeled by itself to determine if refined modeling is required. The results of the significance modeling are compared to the modeling significant impact level (SIL). If the modeled impacts are less than the significance levels, the analysis is complete; otherwise, the analysis must continue. A radius of impact (ROI) is determined from the significance modeling, defined as the maximum distance from the facility where the modeled concentrations exceed the significance levels. The modeling parameters for each emission unit modeled in the screening analysis are presented in **Appendix A**. The results of the significance modeling for all pollutants subject to PSD review are listed in **Table 14-1.** Based upon the current proposed site configuration and equipment selected for compression and power generation, an alternative facility operating scenario was also conducted at 75% of plant capacity. Scenario 2 assumes that two (2) Titan 250-30000S gas turbines are operating at 75% capacity, one Mercury 50-6400R turbine generator is operating at 100% capacity, one (1) Waukesha engine generator is operating at 100%

capacity and one (1) Waukesha engine generator is offline. The results of modeling for Scenario 2 are provided in **Table14-3**.

Table 14-1
Screening Results: Scenario 1

Pollutant	Averaging Period	Modeling Year	5 Year Maximum Modeled Concentration ($\mu g/m^3$)
NO_2(1)	1-Hour(2)	2006-2010	6.37
	Annual	2006-2010	0.33
$PM_{2.5}$	24-Hour	2006-2010	0.58
	Annual	2006-2010	0.08
CO(3)	1-Hour	2006-2010	7.69
	8-Hour	2006-2010	6.62

[1]NO_2 was modeled using the EPA regulatory default option. The Tier I methodology was used for the modeling analysis, which assumes 100% conversion of NO_2 to NO_x.

[2]NO_2 1-hour NAAQS was promulgated January 22, 2010. Modeling was compared to the KDHE interim SIL.

The screened modeling results listed in **Table 14-1** were then compared to the applicable SIL for each pollutant and averaging period. The significance results are listed in **Table 14-2**.

Table 14-2
Comparison of the Screened Results and Appropriate SIL

Pollutant	Averaging Period	5 Year Maximum Modeled Concentration ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
NO_2	1-Hour	6.37	10(1)
	Annual	0.33	1
$PM_{2.5}$	24-Hour	0.58	1.2
	Annual	0.08	0.3
CO	1-Hour	7.69	2000
	8-Hour	6.62	500

[1] NO_2 1-hour NAAQS was promulgated January 22, 2010. Modeling was compared to the KDHE interim SIL.

Table 14-3
Screening Results: Scenario 2

Pollutant	Averaging Period	Modeling Year	5 Year Maximum Modeled Concentration (µg/m^3)
NO_2[(1)]	1-Hour[(2)]	2006-2010	6.76
	Annual	2006-2010	0.33
$PM_{2.5}$	24-Hour	2006-2010	0.40
	Annual	2006-2010	0.05
CO[(3)]	1-Hour	2006-2010	6.26
	8-Hour	2006-2010	5.35

[1]NO_2 was modeled using the EPA regulatory default option. The Tier I methodology was used for the modeling analysis, which assumes 100% conversion of NO_2 to NO_x.

[2]NO_2 1-hour NAAQS was promulgated January 22, 2010. Modeling was compared to the KDHE interim SIL.

The screened modeling results listed in **Table 14-3** were then compared to the applicable SIL for each pollutant and averaging period. The significance results are listed in **Table 14-4**.

Table 14-4
Comparison of the Screened Results and Appropriate SIL

Pollutant	Averaging Period	5 Year Maximum Modeled Concentration (µg/m^3)	Significant Impact Level (µg/m^3)
NO_2	1-Hour	6.76	10[(1)]
	Annual	0.33	1
$PM_{2.5}$	24-Hour	0.40	1.2
	Annual	0.05	0.3
CO	1-Hour	6.26	2000
	8-Hour	5.35	500

[1] NO_2 1-hour NAAQS was promulgated January 22, 2010. Modeling was compared to the KDHE interim SIL.

As shown in **Table 14-2** and **Table 14-4,** the screening results for NO_2, $PM_{2.5}$ and CO were all below the applicable SIL for all averaging periods and operating scenarios. Therefore, additional NAAQS analysis and incremental analysis are not required for Scenario 1 (100% capacity) or Scenario 2 (75% capacity).

NAAQS Analysis: Emissions from the entire facility are modeled along with emissions from surrounding facilities. Included in the analysis are all

surrounding facilities within a circle, centered on the proposed facility and within a radius equal to the ROI plus 20-50km. Background concentrations are added to the modeled concentrations, and the sum is compared to the NAAQS. **Table 14-2** and **Table 14-4** show that NGP is not required to conduct a NAAQS analysis.

PSD Increment Analysis: As with the NAAQS analysis, the proposed source is modeled along with nearby sources. However, only those changes in emission rates from the PSD baseline date are modeled, in order to determine the impact of sources constructed since the baseline date. The results are then compared to the allowable Class I and II PSD increment levels. **Table 14-2** and **Table 14-4** shows that NGP is not required to conduct an increment analysis.

An additional air dispersion modeling protocol was submitted to KDHE on March 3, 2012 with details regarding the procedures used in the significance screening for the Haven Gas Plant. The screening modeling methodology reported in *824-001 Next Generation Processing, LLC. Modeling Protocol: Haven Gas Plant*, submitted on March 3, 2012 has been updated with the following recommendations from EPA Region 7 and KDHE:

- The current version of AERMOD (12060) was used in combination with BEEST 10.0.
- The Tier I modeling procedure was used for modeling concentrations of NO_2, which assumes 100% conversion of NO_2 to NO_x.
- Additional air quality impacts analysis (AQIA) for ozone will be provided in section 14.1.3.
- The updated stack operating parameters for each emission unit modeling are provided in **Appendix A**.

All modeling input data including met data, terrain data files, ozone monitoring data, stack parameters and building locations will be provided to the KDHE by CD upon submission of this construction permit application.

14.1.3 Pre-Construction Monitoring, 52.21(m)

Unless exempted, sources must perform pre-construction ambient air monitoring for all pollutants for which there is a NAAQS and a significant net emission increase. Exemptions can be made if the source can either demonstrate that the proposed source has ambient air impacts less than the monitoring significance levels of 51.21(i)(8) or demonstrate that the representative monitored concentration is below the monitoring significance level. The latter can be accomplished by either (1) analysis of data from existing monitoring sites or (2) dispersion modeling on all

nearby sources; either way, the analysis must predict ambient concentrations that are less than the monitoring significance level.

The results listed in **Table 14-2** indicate that NO_2, $PM_{2.5}$ and CO are below their respective SILs. KDHE has determined that background monitoring data will be appropriate for the signifance determination of ozone. Therefore, NGP requests the use of background ambient ozone monitoring data from the Sedgwick station to satisfy the pre-construction ozone monitoring requirement. As recommended by KDHE on April 11, 2012, this monitoring location will provide the most accurate representation for back ground ozone values for the Haven Gas Plant. This monitoring location is currently below the NAAQS for the 75 ppb ozone standard.

14.1.4 Additional Impacts Analysis, 52.21(o)

Sources are required to predict the impact of the proposed project in terms of impairment of visibility, soils and vegetation, as well as general commercial, residential, industrial or other growth.

Visibility: The Clean Air Act Amendments of 1990 require the applicant to evaluate emissions from the proposed project to determine potential impacts on visibility in Class I areas. Mandatory Class I areas include national parks, national wilderness areas, and national monuments. It is not expected that emissions from the facility will have a detrimental effect on any Class I area. The closest Class I area to the facility is the Hercules Glades Wilderness Area located in southwestern Missouri, approximately 445km from the proposed Haven Gas Plant. There are no Class I Areas located within Kansas; however, the EPA screening tool VISCREEN was used to determine, if any, the visual impacts on the closest Class I area. Using current EPA guidance from the *Workbook for Plume Visual Impact Screening and Analysis* (October, 1992), Level 1 screening analysis was conducted for the Hercules Glades Wilderness Area. The results indicate that there are no exceedances of the screening criteria inside or outside of the Hercules Glades Wilderness Area. Therefore, there are no potential visibility impacts for any Class I areas that would require additional screening. The results summary and output data are included in **Appendix B**.

In accordance with the visibility regulations for new source review identified in 40 CFR 51.307 and the regulations of visibility from sources in attainment areas identified in 40 CFR 52.27 no additional visibility impacts analysis are required for areas not classified as Class I areas or integral vistas. Additionally, as outlined in 40 CFR 81 Part D – Identification of Mandatory Class I Federal Areas Where Visibility is an Important Issue, there are no integral vistas or mandatory Class I areas located in Kansas that would require an additional visibility impacts analysis. The analysis of the impairment to visibility is outlined above for the closest Class I area;

however, there are no visibility standards of compliance outlined in 40 CFR 52.21(o) for Class II areas. However, per KDHE request, NGP has also conducted a Level 2 Screening analysis for the Haven High School to demonstrate that visibility to the local area will not be adversely impacted. The Level 2 visibility impact analysis was provided to KDHE on June 6, 2012. The results of the Level 2 visibility analysis is provided in **Appendix B**.

Soils and Vegetation: The CAA amendments of 1990 require the EPA to establish National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health and the environment. Per 40 CFR 60.50, the EPA has established two types of standards. Primary standards provide public health protection, including protecting the health of sensitive populations. Secondary standards provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings.[24] Available guidance in the EPA *New Source Review Workshop Manual* lends support to the establishment of these standards by stating:

"For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards (NAAQS) will not result in harmful effects. However, there are sensitive vegetation species (e.g. soybeans and alfalfa) which may be harmed by long-term exposure to low ambient air concentrations of regulated pollutants for which are no NAAQS."

Therefore, to ensure there are no harmful effects on soils and vegetation, NGP has conducted an analysis to determine the potential impairment to soils and vegetation that may occur as a result of the proposed Haven Gas Plant. This analysis relied upon the EPA's guidance document, *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals*, and the NAAQS to evaluate the potential impacts on soil and vegetation.

The approach taken in this screening procedure is similar to the "de minimis" approach used in the PSD air quality analysis. The minimum levels at which adverse effects have been reported in the literature are used as screening concentrations. These screening concentrations can be concentrations of pollutants in the ambient air, in soils, or in aerial plant tissues. The criteria pollutants subject to PSD review include: NO_2, CO, and $PM_{2.5}$ and ozone (as NO_x). While screening concentrations are available for ozone, the EPA has not established a procedure for estimating the ozone impact of a single source.[25] No screening concentrations were available for PM as $PM_{2.5}$ fraction; therefore, the

[24] US EPA. "Air and Radiation: National Ambient Air Quality Standards (NAAQS)." (Jul, 2012). http://www.epa.gov/air/criteria.html.

[25] US EPA Office of Air Quality Planning and Standards, "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals". (Dec, 1980). EPA 450/2-81-078.

NAAQS were the only available literature used for evaluating effects on soils and vegetation.

Two pathways by which air pollutants can affect vegetation were considered in the analysis. The first is the direct exposure of plant to a gaseous pollutant in the ambient air. The second involves indirect exposure to trace elements through deposition of the pollutant in the soil and later uptake by the plant. Additionally, effects of pollutants can be classified as acute or chronic. Acute effects result from short-term exposures to relatively high concentrations. Chronic effects result from exposure to lower concentrations for times ranging from months to several years. The screening criteria are tabulated in **Table 14-5.** The screening values represent the minimum concentrations at which adverse growth effects or tissue injury in exposed vegetation were reported in the literature studies used in the EPA's screening procedure.

Table 14-5

EPA Screening Concentrations for Exposure to Ambient Air Concentrations

Pollutant	Averaging Period	Minimum Reported Level For Vegetation Sensitivity					
		Sensitive		Intermediate		Resistant	
		ppmv	µg/m^3	ppmv	µg/m^3	ppmv	µg/m^3
NO_2	4-Hour	2.0	3,760	5.0	9,400.00	9.0	16,920
	8-Hour	2.0	3,760	4.0	7,520.00	8.0	15,040
	1-Month	0.30	564	0.30	564.00	0.30	564
	Annual	0.05	94	0.05	94.00	0.05	94
CO	1-Week	1,000	1,800,000	-	-	10,000	18,000,000
$PM_{2.5}$	24-Hour	-	35	-	-	-	-
	Annual	-	15	-	-	-	-

As a conservative approach, the H1H modeled concentrations from the air quality analysis were compared to the sensitive screening values. Additionally, the NO_2 1-hour modeled concentrations were compared to the 4-hour, 8-hour and 1-month screening values. The CO 1-hour modeled concentration was compared to the 1-week screening value. For the annual comparison, the annual H1H modeled concentrations were compared to the annual screening values. The results of the screening comparison are provided in **Table 14-6**.

Table 14-6
Comparison of the EPA Sensitivity Screening Concentrations to the H1H Modeled Concentrations

Pollutant	Averaging Period	Sensitivity (μg/m^3)	Modeled Impacts (μg/m^3)	Background (μg/m^3)	Modeled + Background (μg/m^3)	Exceeds Screening Thresholds
NO_2	4-Hour	3,760	6.37	49	55.37	No
	8-Hour	3,760	6.37	49	55.37	No
	1-Month	564	6.37	49	55.37	No
	Annual	94	0.33	7.5	7.83	No
CO	1-Week	1,800,000	7.69	4.6	12.29	No
$PM_{2.5}$	24-Hour	35	0.58	20	20.58	No
	Annual	15	0.08	9	9.08	No

Background monitoring data sets for NO_2 and $PM_{2.5}$ are from the Peck Monitoring Station. CO background monitoring data sets are taken from Wichita Department of Health. All background monitoring data provided by KDHE on September 13, 2012.

Based on the results provided in **Table 14-6**, the modeled concentrations, added to the appropriate background concentration, are well below sensitivity screening concentrations. Therefore, NGP anticipates that the impacts to soils and vegetation will be negligible. Additionally, the air dispersion modeling analysis will demonstrate that the proposed project will comply with all applicable NAAQS. This includes secondary standards for protection against visibility impairment and damage to animals, crops, vegetation, and buildings.

Growth: The growth analysis is intended to review the potential impact that the project will have on industrial growth and associated secondary emissions in the vicinity of the facility. Secondary emissions are those that can occur as a result of the project or operation of the facility but are not emissions from the facility itself. It is not anticipated that the construction and operation of the Haven Gas Plant will result in excess secondary emissions during either the construction phase or the general operation of the facility.

Though traffic will increase both during the construction phase of the project and during operation, it is not anticipated that this traffic will cause an excessive amount of emissions from either exhaust or entrainment of particulate matter from the roads. NGP will take all practical measures to limit particulate emissions from vehicle travel.

The construction phase of this project will require numerous temporary construction jobs. Industrial growth is not expected to increase

significantly in the area due to construction of the facility. The operation of the Haven Gas Plant will require approximately 10 employees. NGP anticipates a portion of the employees will be hired from the local area. The air quality impact attributed to residential growth, therefore, will be negligible due to the small number of employees transferring into the local area in relation to the existing population base. Similarly, associated growth in commercial business and industrial support will be minimal due to the close proximity to a large area of commercial and industrial sources of goods and services.

14.1.5 Class I Area Impacts Analysis, 52.21(p)

52.21(p) requires that the applicant perform an analysis of the impact of the project on air quality related values (AQRVs) in affected Class I areas. Although FLMs (e.g., National Park Service, US Forest Service) have developed guidance on *how* to perform the AQRV analysis, there is no "bright-line" guidance from FLMs on exactly *when* a Class I area analysis is triggered.

If requested by the Federal Land Managers (FLMs), NGP will prepare an AQRV analysis for Class I areas specified by the FLMs.

40 CFR 51.165 and 52.24, Nonattainment New Source Review

The Haven Gas Plant is located in Reno County, which is currently designated as an attainment area for all pollutants. Therefore, nonattainment new source review is not applicable.

40 CFR 60, New Source Performance Standards (NSPS)

40 CFR 60 Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels

This subpart applies to each storage vessel with a capacity greater than or equal to 75 cubic meters that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. The slop oil tank (TK-01) is exempt from NSPS Subpart Kb (Storage Vessels) because the storage capacity is less than 75 cubic meters.

40 CFR 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Combustion Engines

Owners and operators of stationary ICE with a maximum engine power greater than 500 hp that commence construction after June 12, 2006 and are manufactured after July 1, 2007 are subject to this regulation. The two (2) generator sets (EPNs EGS-01 and EGS-02) are subject to the requirements of 40 CFR 60 Subpart JJJJ.

40 CFR 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines

Stationary combustion turbines with a heat input at peak load equal to or greater than 10 MMBtu per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005, are subject to this subpart. the two (2) Titan 250-30000S gas turbines (EPNs GT-01 and GT-02) and the Mercury 50-6400R Turbine Generator Set (EPN TGS-01) are subject to the requirements of 40 CFR 60 Subpart KKKK (Stationary Combustion Turbines) because the heat input rates at peak loads, for each turbine, exceeds 10 MMBtu per hour.

In accordance with 40 CFR 60.4305(b), the two (2) Titan 250-30000S gas turbines (EPNs GT-01 and GT-02) and the Mercury 50-6400R Turbine Generator Set (EPN TGS-01) are subject to the requirements of 40 CFR 60 Subpart KKKK and are exempt from the requirements of 40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines.

40 CFR 60 Subpart LLL – Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions

The provisions of this subpart are applicable to natural gas processing facilities that operator sweetening units or sweetening units followed by sulfur recovery units. In accordance with 40 CFR 60.640(b), the Haven Gas Plant is only subject to the recordkeeping requirements of 40 CFR 60.647(c).

40 CFR 60 Subpart OOOO – Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution

The provisions of this subpart will become applicable to the reciprocating compressor proposed for the Haven Gas Plant. All centrifugal compressors are planning to be equipped with tandem dry gas seals, and are therefore not subject to the requirements of this subpart. In addition, this subpart also requires compliance with specific provisions of 40 CFR 60 Subpart VVa – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

40 CFR 61, National Emission Standards for Hazardous Air Pollutants (NESHAP)

There are no NESHAPs that apply to the proposed emission units discussed in this PSD application.

14.2 40 CFR 63, Maximum Achievable Control Technology (MACT)

14.2.1 40 CFR 63 Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The Haven Gas Plant is not a major source of HAPs and therefore is considered an area source of HAPs. The two (2) generator sets (EPNs EGS-01 and EGS-02) are considered new RICE at an Area Source and are required to comply with the requirements of 40 CFR 60 Subpart JJJJ, per 40 CFR 63.6590(c)(1). No other requirements of Subpart ZZZZ apply to these engines.

14.3 40 CFR 70, Title V Air Operating Permits

In accordance with K.A.R. 28-19-500, NGP will submit a separate Class I Operating Permit Application under a different cover letter.

APPENDIX A – SCREEN MODELING STACK PARAMETERS

Next Generation Processing, LLC. - Haven Gas Plant Stack Parameters

EPN	EPN Description	UTM E	UTM N	Stack Height	Stack Exit Temp	Stack Velocity	Stack Exit Diameter	Exhaust Gas Flow Rate	NO_2/NO_x in-stack Ratio(1)
		(m)	(m)	(ft)	(deg F)	(ft/sec)	(ft)	(acfm)	%
GT-01	TITAN 250-30000S Natural Gas Turbine	604574.00	4195835.00	100.000	700.000	120.838	7.0000	279,024.00	0.3
GT-01	TITAN 250-30000S Natural Gas Turbine	604574.00	4195824.00	100.000	700.000	120.838	7.0000	279,024.00	0.3
TGS-01	Solar Mercury 50 Turbine Generator Set	604536.74	4195846.55	100.000	685.000	107.000	2.5000	31,514.10	0.15
EGS-01	Waukesha VHP9330GSI Generator Set	604539.17	4195836.49	100.000	1176.998	210.000	1.0000	9,896.02	0.5
EGS-02	Waukesha VHP9330GSI Generator Set	604539.17	4195831.62	100.000	1176.998	210.000	1.0000	9,896.02	0.5

(1) NO_2/NO_x in-stack ratios for EPNs GT-01, GT-02 and TGS-01 provided by Solar Turbine Manufacturing Specifications. The EPA default option of 0.5 was applied to EPNs EGS-01 and EGS-02 because manufacured specification for in-stack ratios not available.

(2) All data based upon 100% Load Capacity.

APPENDIX B – VISCREEN RESULTS

Visual Effects Screening Analysis for
Source: Haven Gas Plant
Class I Area: Hercules Glades Wilderne

*** Level-1 Screening ***

Input Emissions for

Particulates	4.36	LB /HR
NOx (as NO2)	24.29	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.00	LB /HR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	40.00 km
Source-Observer Distance:	445.00 km
Min. Source-Class I Distance:	445.00 km
Max. Source-Class I Distance:	459.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	93.	459.0	75.	2.00	.000	.05	.000
SKY	140.	93.	459.0	75.	2.00	.000	.05	.000
TERRAIN	10.	93.	459.0	75.	2.00	.000	.05	.000
TERRAIN	140.	93.	459.0	75.	2.00	.000	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	0.	1.0	169.	*****	.000	5.53	.000
SKY	140.	0.	1.0	169.	52.97	.000	5.53	.000
TERRAIN	10.	0.	1.0	169.	*****	.000	5.53	.000
TERRAIN	140.	0.	1.0	169.	52.97	.000	5.53	.000

```
"Haven Gas Plant          "
"Hercules Glades Wilderne"
    4    3
     4.360    24.290      .000      .000      .000
   445.000   445.000   459.000    40.000
    1     1.500    3
    1     2.500    8
    1     2.500    6
    1     2.000    1
    1     1.500    4
    1      .040     1.000    6
    1    11.250
 34
  1 0     5.0  163.8  138.6  310.2  368.8  .08   .050   2.24    .00   2.00    .00   2.24    .00   2.00
.00
  2 0    10.0  158.8  213.2  239.5  316.9  .11   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
  3 0    15.0  153.8  260.4  196.3  279.7  .13   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
  4 0    20.0  148.8  293.4  167.3  252.1  .16   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
  5 0    25.0  143.8  318.0  146.8  231.0  .18   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
  6 0    30.0  138.8  337.5  131.7  214.7  .20   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
  7 0    35.0  133.8  353.3  120.2  201.9  .22   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
  8 0    40.0  128.8  366.8  111.3  192.0  .24   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
  9 0    45.0  123.8  378.4  104.4  184.3  .26   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 10 0    50.0  118.8  388.8   99.0  178.6  .27   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 11 0    55.0  113.8  398.2   94.8  174.4  .28   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 12 0    60.0  108.8  407.0   91.7  171.8  .29   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 13 0    65.0  103.8  415.2   89.4  170.5  .30   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 14 0    70.0   98.8  423.1   87.8  170.5  .31   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 15 0    75.0   93.8  430.8   87.0  171.8  .31   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 16 0    80.0   88.8  438.3   86.8  174.4  .31   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 17 1    85.0   83.8  446.0   87.3  178.6  .31   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 18 1    90.0   78.8  453.7   88.5  184.3  .31   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 19 0    95.0   73.8  461.8   90.4  192.0  .30   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 20 0   100.0   68.8  470.2   93.1  201.9  .29   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 21 0   105.0   63.8  479.3   96.8  214.7  .28   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 22 0   110.0   58.8  489.1  101.5  231.0  .27   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 23 0   115.0   53.8  500.1  107.7  252.1  .25   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 24 0   120.0   48.8  512.6  115.5  279.7  .24   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 25 0   125.0   43.8  527.1  125.5  316.9  .22   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 26 0   130.0   38.8  544.6  138.7  368.8  .20   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 27 0   135.0   33.8  566.4  156.3  445.0  .18   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 28 0   140.0   28.8  594.7  180.5  566.3  .15   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 29 0   145.0   23.8  633.8  215.6  786.8  .13   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 30 0   150.0   18.8  692.2  270.1  999.0  .10   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 31 0   155.0   13.8  791.2  365.3  999.0  .08   .050   2.34    .00   2.00    .00   2.34    .00   2.00
.00
 32 0      .0  168.7    1.0  444.0  444.5  .01  5.529 162.00    .00  52.97    .00 162.00    .00  52.97
.00
 33 1    84.4   84.4  445.0   87.2  178.0  .31   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
```

```
 34 1    93.3   75.4  459.0   89.7  189.2  .30   .050   2.00    .00   2.00    .00   2.00    .00   2.00
.00
 34
  1 0   5.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
  2 0  10.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
  3 0  15.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
  4 0  20.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
  5 0  25.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
  6 0  30.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
  7 0  35.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
  8 0  40.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
  9 0  45.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 10 0  50.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 11 0  55.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 12 0  60.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 13 0  65.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 14 0  70.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 15 0  75.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 16 0  80.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 17 1  85.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 18 1  90.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 19 0  95.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 20 0 100.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 21 0 105.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 22 0 110.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 23 0 115.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 24 0 120.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 25 0 125.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 26 0 130.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 27 0 135.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 28 0 140.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 29 0 145.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 30 0 150.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 31 0 155.000   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 32 0    .025  5.529   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 33 1  84.375   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
 34 1  93.311   .050   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000   .000
```

NGP_824-001_Level_2_VISCREEN_Analysis_Secondary_Site_Report

Visual Effects Screening Analysis for
Source: Haven Gas Plant
Class I Area: Haven High School

*** User-selected Screening Scenario Results ***

Input Emissions for

Particulates	4.36	LB /HR
NOx (as NO2)	24.29	LB /HR
Primary NO2	.00	LB /HR
Soot	.00	LB /HR
Primary SO4	.00	LB /HR

PARTICLE CHARACTERISTICS

	Density	Diameter
Primary Part.	2.5	1
Soot	2.0	1
Sulfate	1.5	4

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	40.00 km
Source-Observer Distance:	2.74 km
Min. Source-Class I Distance:	2.74 km
Max. Source-Class I Distance:	2.97 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	5
Wind Speed:	5.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	107.	3.0	62.	6.05	.325	.10	-.001
SKY	140.	107.	3.0	62.	2.00	.126	.10	-.000
TERRAIN	10.	84.	2.7	84.	3.05	.224	.11	.000
TERRAIN	140.	84.	2.7	84.	2.00	.098	.11	.001

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	5.	.9	164.	2.00	1.859	.05	-.008
SKY	140.	5.	.9	164.	2.00	.727	.05	-.003
TERRAIN	10.	5.	.9	164.	2.00	1.583	.05	.004
TERRAIN	140.	5.	.9	164.	2.00	.547	.05	.007

```
"Haven Gas Plant          "
"Haven High School        "
    4    3
     4.360    24.290      .000      .000      .000
     2.740     2.740     2.970    40.000
    0     1.500    3
    0     2.500    8
    0     2.500    1
    0     2.000    1
    0     1.500    4
    0      .040     5.000    5
    0    11.250
 34
  1 0     5.0  163.8     .9    1.9    2.3 2.46   .050   2.00   1.86   2.00    .73
2.00   1.58   2.00    .55
  2 0    10.0  158.8    1.3    1.5    2.0 4.26   .050   2.00   1.15   2.00    .45
2.00    .92   2.00    .33
  3 0    15.0  153.8    1.6    1.2    1.7 5.90   .050   2.28    .86   2.00    .34
2.00    .67   2.00    .25
  4 0    20.0  148.8    1.8    1.0    1.6 7.45   .050   2.80    .70   2.00    .27
2.00    .54   2.00    .20
  5 0    25.0  143.8    2.0     .9    1.4 8.91   .054   3.29    .60   2.00    .23
2.00    .45   2.00    .18
  6 0    30.0  138.8    2.1     .8    1.310.28   .062   3.76    .52   2.00    .20
2.00    .40   2.00    .16
  7 0    35.0  133.8    2.2     .7    1.211.55   .069   4.21    .47   2.00    .18
2.07    .36   2.00    .15
  8 0    40.0  128.8    2.3     .7    1.212.72   .076   4.63    .43   2.00    .17
2.24    .33   2.00    .14
  9 0    45.0  123.8    2.3     .6    1.113.78   .083   5.00    .40   2.00    .15
2.39    .31   2.00    .13
 10 0    50.0  118.8    2.4     .6    1.114.72   .088   5.34    .37   2.00    .14
2.53    .29   2.00    .12
 11 0    55.0  113.8    2.5     .6    1.115.55   .093   5.63    .35   2.00    .14
2.64    .27   2.00    .12
 12 0    60.0  108.8    2.5     .6    1.116.26   .098   5.88    .34   2.00    .13
2.75    .26   2.00    .11
 13 0    65.0  103.8    2.6     .6    1.016.85   .101   6.08    .33   2.00    .13
2.84    .25   2.00    .11
 14 0    70.0   98.8    2.6     .5    1.017.30   .104   6.24    .32   2.04    .12
2.91    .24   2.00    .11
 15 0    75.0   93.8    2.7     .5    1.117.64   .106   6.36    .31   2.08    .12
2.97    .23   2.00    .10
 16 0    80.0   88.8    2.7     .5    1.117.84   .107   6.43    .31   2.10    .12
3.02    .23   2.00    .10
 17 1    85.0   83.8    2.7     .5    1.117.91   .107   6.45    .31   2.11    .12
3.06    .22   2.00    .10
 18 1    90.0   78.8    2.8     .5    1.117.86   .107   6.43    .31   2.10    .12
3.08    .22   2.00    .10
 19 1    95.0   73.8    2.8     .6    1.217.67   .106   6.37    .31   2.08    .12
3.09    .22   2.00    .09
 20 1   100.0   68.8    2.9     .6    1.217.36   .104   6.26    .31   2.05    .12
3.08    .21   2.00    .09
 21 1   105.0   63.8    3.0     .6    1.316.92   .102   6.11    .32   2.00    .12
3.06    .21   2.00    .09
 22 0   110.0   58.8    3.0     .6    1.416.35   .098   5.91    .33   2.00    .13
3.03    .21   2.00    .09
 23 0   115.0   53.8    3.1     .7    1.615.66   .094   5.67    .35   2.00    .13
2.99    .21   2.00    .09
 24 0   120.0   48.8    3.2     .7    1.714.85   .089   5.38    .36   2.00    .14
2.93    .21   2.00    .09
 25 0   125.0   43.8    3.2     .8    2.013.92   .084   5.05    .38   2.00    .15
2.85    .21   2.00    .09
```

```
 26 0   130.0   38.8    3.4     .9    2.312.87   .077   4.68    .41   2.00    .16
2.77    .20   2.00    .08
 27 0   135.0   33.8    3.5    1.0    2.711.72   .070   4.27    .45   2.00    .17
2.66    .20   2.00    .08
 28 0   140.0   28.8    3.7    1.1    3.510.46   .063   3.82    .49   2.00    .19
2.55    .19   2.00    .07
 29 0   145.0   23.8    3.9    1.3    4.8 9.10   .055   3.36    .55   2.00    .21
2.44    .16   2.00    .06
 30 0   150.0   18.8    4.3    1.7    8.0 7.65   .050   2.87    .62   2.00    .24
2.35    .11   2.00    .04
 31 0   155.0   13.8    4.9    2.2   24.0 6.09   .050   2.34    .72   2.00    .28
2.26    .01   2.00    .01
 32 0     6.3  162.4    1.0    1.8    2.2 2.96   .050   2.00   1.58   2.00    .62
2.00   1.32   2.00    .46
 33 1    84.4   84.4    2.7     .5    1.117.91   .107   6.45    .31   2.11    .12
3.05    .22   2.00    .10
 34 1   106.6   62.1    3.0     .6    1.416.75   .100   6.05    .32   2.00    .13
3.05    .21   2.00    .09
 34
  1 0   5.000   .050  -.008   .004  -.003   .007  -.026   .011  -.024   .012  -.002
 .002   .003   .006
  2 0  10.000   .050  -.005   .002  -.002   .004  -.016   .006  -.015   .007  -.001
 .001   .002   .003
  3 0  15.000   .050  -.003   .001  -.001   .003  -.012   .004  -.011   .005  -.001
 .001   .001   .003
  4 0  20.000   .050  -.003   .001  -.001   .003  -.010   .003  -.009   .004  -.001
 .000   .001   .002
  5 0  25.000   .054  -.002   .001  -.001   .002  -.008   .002  -.008   .003  -.001
 .000   .001   .002
  6 0  30.000   .062  -.002   .001  -.001   .002  -.007   .002  -.007   .002  -.001
 .000   .001   .001
  7 0  35.000   .069  -.002   .001  -.001   .002  -.007   .002  -.006   .002  -.001
 .000   .001   .001
  8 0  40.000   .076  -.002   .001  -.001   .001  -.006   .002  -.006   .002  -.000
 .000   .001   .001
  9 0  45.000   .083  -.002   .001  -.001   .001  -.006   .001  -.005   .002  -.000
 .000   .001   .001
 10 0  50.000   .088  -.001   .000  -.001   .001  -.005   .001  -.005   .002  -.000
 .000   .000   .001
 11 0  55.000   .093  -.001   .000  -.001   .001  -.005   .001  -.005   .002  -.000
 .000   .000   .001
 12 0  60.000   .098  -.001   .000  -.001   .001  -.005   .001  -.004   .001  -.000
 .000   .000   .001
 13 0  65.000   .101  -.001   .000  -.000   .001  -.005   .001  -.004   .001  -.000
 .000   .000   .001
 14 0  70.000   .104  -.001   .000  -.000   .001  -.004   .001  -.004   .001  -.000
 .000   .000   .001
 15 0  75.000   .106  -.001   .000  -.000   .001  -.004   .001  -.004   .001  -.000
 .000   .000   .001
 16 0  80.000   .107  -.001   .000  -.000   .001  -.004   .001  -.004   .001  -.000
 .000   .000   .001
 17 1  85.000   .107  -.001   .000  -.000   .001  -.004   .001  -.004   .001  -.000
 .000   .000   .001
 18 1  90.000   .107  -.001   .000  -.000   .001  -.004   .001  -.004   .001  -.000
 .000   .000   .001
 19 1  95.000   .106  -.001   .000  -.000   .001  -.004   .001  -.004   .001  -.000
 .000   .000   .001
 20 1 100.000   .104  -.001   .000  -.000   .001  -.004   .001  -.004   .001  -.000
 .000   .000   .001
 21 1 105.000   .102  -.001   .000  -.000   .001  -.005   .001  -.004   .001  -.000
 .000   .000   .001
 22 0 110.000   .098  -.001   .000  -.000   .001  -.005   .001  -.004   .001  -.000
 .000   .000   .001
```

23	0	115.000	.094	-.001	.000	-.001	.001	-.005	.001	-.004	.001	-.000	.000	.000	.001
24	0	120.000	.089	-.001	.000	-.001	.001	-.005	.001	-.005	.002	-.000	.000	.000	.001
25	0	125.000	.084	-.001	.001	-.001	.001	-.005	.001	-.005	.002	-.000	.000	.000	.001
26	0	130.000	.077	-.002	.001	-.001	.001	-.006	.001	-.005	.002	-.000	.000	.001	.001
27	0	135.000	.070	-.002	.001	-.001	.001	-.006	.002	-.006	.002	-.001	.000	.001	.001
28	0	140.000	.063	-.002	.001	-.001	.001	-.007	.002	-.006	.002	-.001	.000	.001	.001
29	0	145.000	.055	-.002	.001	-.001	.002	-.008	.002	-.007	.002	-.001	.000	.001	.001
30	0	150.000	.050	-.003	.001	-.001	.001	-.009	.001	-.008	.002	-.001	.000	.001	.001
31	0	155.000	.050	-.003	.000	-.001	.000	-.010	.000	-.009	.000	-.001	.000	.001	.000
32	0	6.328	.050	-.006	.003	-.003	.006	-.022	.009	-.021	.010	-.002	.001	.002	.005
33	1	84.375	.107	-.001	.000	-.000	.001	-.004	.001	-.004	.001	-.000	.000	.000	.001
34	1	106.618	.100	-.001	.000	-.000	.001	-.005	.001	-.004	.001	-.000	.000	.000	.001

APPENDIX C – GAS ANALYSIS

CERTIFICATE OF WORK ORDER

Number : 25736

Customer:	Panhandle Eastern Pipeline	**Sales Order #:**	25736
Report to:	Panhandle Eastern Pipeline		
Attention:	Jon Law		
Street :	12610 South Kent Road		
City, State ZipCode:	Haven , KS 67543		

Station / Meter Number:		**Report Date:**	12/04/11
Field / Station Name:	Haven,CK 400 Line	**Sample By:**	
Location:	Haven, KS	**Sample Type:**	Spot
Sample Point:		**Sample Date:**	11/17/11 00:00
Cylinder Number:	1073 SI	**Sample Conditions:**	720.5 psi, @ N.A. ºF

Comments: EXTENDED

ANALYTICAL RESULTS

Components	Mol %	Wt%	GPM at 14.730 psia	Method	Lab Tech.	Date Analyzed
				GPA-2261	FD	12/01/11
Nitrogen	2.050	3.346				
Carbon Dioxide	0.484	1.242				
Methane	93.335	87.292				
Ethane	3.431	6.016	0.917			
Propane	0.467	1.201	0.129			
iso Butane	0.049	0.163	0.016			
n-Butane	0.096	0.326	0.030			
iso Pentane	0.025	0.105	0.009			
n-Pentane	0.027	0.111	0.010			
Hexanes Plus	0.036	0.198	0.016			
	100.000	100.000	1.127			

	C2+	C3+	iC5+
GPM TOTAL	1.127	0.210	0.035

Relative Density at 60 ºF (air =1) Real Gas		0.5936
Calculated Molecular Weight		17.15
Compressibility Factor		0.9978
Calculated Gross BTU per ft3 @ 14.730 psia & 60 ºF		
Real Gas	Dry Basis	1030
	Saturated Basis	1012

Laboratory Manager

CERTIFICATE OF ANALYSIS

Number : 25736

Jon Law
Panhandle Eastern Pipeline
12610 South Kent Road
Haven, KS 67543

Sales Order 25736

Station Name: Haven CK 400 Line
Station Number:
Location: Haven, KS
Sample Point:
Cylinder #: DCG 1073 SI

Report Date: 12/04/11
Sample of / Type: Nat. Gas, Spot
Sample Date: 11/17/2011
Sample Conditions: 720.5 psig @ 84.6°F.
Sample By: PEPL

Comments: Sulfur Breakdown
On Site H2S NG

Analytical Data

Test ASTM	Method D-5504	Result	Unit S	32.066	Compound	Lab Chemist	Date Analyzed
	ppm Wt S	ppm Cmpd		M.W.	ppm Mol.		
COS	0.026	0.049		60.07	0.013	FD	11/30/2011
* **H2S**	**0.306**	0.325		34.0809	0.153		
SO2	0.000	0.000		64.065	0.000		
CS2	0.190	0.226		76.13	0.048		
Methyl Mercaptan	0.027	0.041		48.1	0.014		
Ethyl Mercaptan	0.044	0.085		62.13	0.022		
Thiophene	0.000	0.000		84.14	0.000		
DMS	0.011	0.021		62.13	0.006		
Iso-Propyl Merc.	0.277	0.658		76.16	0.139		
N-Propyl Merc.	0.000	0.000		76.16	0.000		
t-Butyl Mercaptan	0.000	0.000		88.15	0.000		
Iso Buty/Sec B Merc.	0.000	0.000		90.18	0.000		
EMS	0.129	0.306		76.156	0.065		
N-Butyl Merc.	0.000	0.000		90.18	0.000		
3MThio	0.000	0.000		98.162	0.000		
DMDS	0.000	0.000		94.2	0.000		
DES	0.427	1.201		90.19	0.214		
2EThio	0.000	0.000		112.189	0.000		
MEDS	0.000	0.000		108.13	0.000		
2,5-DMThio	0.000	0.000		112.189	0.000		
Terta Hydro Thio	0.000	0.000		88.167	0.000		
DEDS	0.000	0.000		122.25	0.000		
Heavy Sulfurs	**0.484**	2.038		135	0.242		
Total Sulfur	**1.921**		**Total**				
GPA 2199	**ppm Wt S**		**ppm Mol.**		**0.914**		

Grains/100 Cu. Ft. **0.0606**

Comments:

Laboratory Manager

Detailed Hydrocarbon Analysis Summary Report -

Report Date: 12/1/2011 2:16:33 PM

RawFile: L:\LAB\INSTRU\DHA\DATA\120111\SIG2000005.D\SIG2000005.CDF
Sample: 1073
Processed 16 Peaks
Reference File: L:\LAB\Dragon DHA\Dragon References\C6+ Reference #31318 NGL 5 11 10 2011.DHA
Comments:

Acquired: 12/01/11 10:06:19
Analyzed: 12/1/2011 2:15:49 PM
Normalized to 100.0000%

SUMMARY REPORT

Group Type	Total(Mass%)	Total(Vol%)	Total(Mol%)
Paraffins:	31.6032	32.7597	31.0102
I-Paraffins:	51.4480	53.3336	50.1347
Olefins:	0.0000	0.0000	0.0000
Napthenes:	37.6649	34.0684	36.8647
Aromatics:	1.4357	1.1307	1.6348
Total C14+:	0.0000	0.0000	0.0000
Total Unknowns:	0.0000	0.0000	0.0000

Oxygenates:

Total:	0.0000(Mass%)	0.0000(Vol%)
Total Oxygen Content:	0.0000(Mass%)	

Multisubstituted Aromatics: 0.0000(Mass%) 0.0000(Vol%)

Average Molecular Weight: 88.9489

Relative Density: 0.6922

Reid Vapor Pressure @ 100F: 4.6327

Calculated Octane Number: 62.9598

	IBP	T10	T50	T90	FBP
BP by Mass (Deg F)	BP Distribution Not Calculated...				
BP by Vol (Deg F)	BP Distribution Not Calculated...				

Percent Carbon: 84.4547 Percent Hydrogen: 15.5453
Bromine Number (Calc): 0.0000

Detailed Hydrocarbon Analysis Detail Report -

Report Date: 12/1/2011 2:16:35 PM

RawFile: L:\LAB\INSTRU\DHA\DATA\120111\SIG2000005.D\SIG2000005.CDF
Acquired: 12/01/11 10:06:19
Sample: 1073
Analyzed: 12/1/2011 2:15:49 PM
Processed 16 Peaks
Reference File: L:\LAB\Dragon DHA\Dragon References\C6+ Reference #31318 NGL 5 11 10 2011.DHA
Comments:
Normalized to 100.0000%

Molecular Weight and Relative Density Data

Group	Avg Mw.	Avg Rel. Density
C1	0.0000	0.0000
C2	0.0000	0.0000
C3	0.0000	0.0000
C4	0.0000	0.0000
C5	0.0000	0.0000
C6	85.5010	0.6848
C7	99.3929	0.7156
C8	114.2320	0.6919
C9	0.0000	0.0000
C10	0.0000	0.0000
C11	0.0000	0.0000
C12	0.0000	0.0000
C13	0.0000	0.0000
Total Sample:	88.90	0.69

Detailed Hydrocarbon Analysis Detail Report -

Report Date: 12/1/2011 2:16:35 PM

RawFile: L:\LAB\INSTRU\DHA\DATA\120111\SIG2000005.D\SIG2000005.CDF
Acquired: 12/01/11 10:06:19
Sample: 1073
Analyzed: 12/1/2011 2:15:49 PM
Processed 16 Peaks
Reference File: L:\LAB\Dragon DHA\Dragon References\C6+ Reference #31318 NGL 5 11 10 2011.DHA
Normalized to 100.0000%
Comments:

Totals by Group Type & Carbon Number (in Mass Percent)

	Paraffins	I-Paraffins	Olefins	Napthenes	Aromatics	Unknowns	Total
C1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C3	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C4	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C5	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C6	20.46588	33.63138	0.00000	18.17620	1.43567	0.00000	73.70913
C7	11.13735	14.20873	0.00000	19.48869	0.00000	0.00000	44.83477
C8	0.00000	3.60791	0.00000	0.00000	0.00000	0.00000	3.60791
C9	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C10	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C11	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C12	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C13	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Total:	31.60323	51.44802	0.00000	37.66489	1.43567	0.00000	122.15181

Oxygenates 0.00000 Total C14+: 0.00000
Total Unknowns: 0.00000 Grand Total: 122.15181

Totals by Group Type & Carbon Number (in Volume Percent)

	Paraffins	I-Paraffins	Olefins	Napthenes	Aromatics	Unknowns	Total
C1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C3	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C4	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C5	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C6	21.48390	35.42497	0.00000	16.46847	1.13070	0.00000	74.50804
C7	11.27582	14.29915	0.00000	17.59988	0.00000	0.00000	43.17485
C8	0.00000	3.60947	0.00000	0.00000	0.00000	0.00000	3.60947
C9	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C10	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C11	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C12	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C13	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Total:	32.75972	53.33360	0.00000	34.06835	1.13070	0.00000	121.29236

Oxygenates 0.00000 Total C14+: 0.00000
Total Unknowns: 0.00000 Grand Total: 121.29236

Detailed Hydrocarbon Analysis Detail Report -

Report Date: 12/1/2011 2:16:35 PM

RawFile: L:\LAB\INSTRU\DHA\DATA\120111\SIG2000005.D\SIG2000005.CDF
Acquired: 12/01/11 10:06:19
Sample: 1073
Analyzed: 12/1/2011 2:15:49 PM
Processed 16 Peaks
Reference File: L:\LAB\Dragon DHA\Dragon References\C6+ Reference #31318 NGL 5 11 10 2011.DHA
Normalized to 100.0000%
Comments:

Totals by Group Type & Carbon Number (in Mol Percent)

	Paraffins	I-Paraffins	Olefins	Napthenes	Aromatics	Unknowns	Total
C1	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C2	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C3	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C4	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C5	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C6	21.12392	34.71273	0.00000	19.21001	1.63480	0.00000	76.68145
C7	9.88628	12.61265	0.00000	17.65469	0.00000	0.00000	40.15362
C8	0.00000	2.80936	0.00000	0.00000	0.00000	0.00000	2.80936
C9	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C10	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C11	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C12	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
C13	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Total:	31.01020	50.13474	0.00000	36.86470	1.63480	0.00000	119.64444

Oxygenates 0.00000 Total C14+: 0.00000

Total Unknowns: 0.00000 Grand Total: 119.64444

Detailed Hydrocarbon Analysis Detail Report -

Report Date: 12/1/2011 2:16:35 PM

RawFile: L:\LAB\INSTRU\DHA\DATA\120111\SIG2000005.D\SIG2000005.CDF
Acquired: 12/01/11 10:06:19
Analyzed: 12/1/2011 2:15:49 PM
Sample: 1073
Processed 16 Peaks
Reference File: L:\LAB\Dragon DHA\Dragon References\C6+ Reference #31318 NGL 5 11 10 2011.DHA
Normalized to 100.0000%
Comments:

Hold

Components Listed in Chromatographic Order

Minutes	Index	Group	Component	Mass %	Volume %	Mol %
7.293	536.630	I6	2,2-dimethylbutane	2.4131	2.5733	2.4907
7.770	564.860	I6	2,3-dimethylbutane	5.4441	5.6959	5.6191
7.865	569.710	I6	2-methylpentane	16.7366	17.7386	17.2747
8.171	584.060	I6	3-methylpentane	9.0376	9.4172	9.3282
8.560	600.000	P6	n-hexane	20.4659	21.4839	21.1239
9.373	629.190	N6	methylcyclopentane	8.6496	7.9979	9.1416
10.454	659.400	A6	benzene	1.4357	1.1307	1.6348
10.554	661.830	N6	cyclohexane	9.5266	8.4705	10.0684
10.797	667.580	I7	2-methylhexane	3.2135	3.2779	2.8525
10.905	670.030	I7	2,3-dimethylpentane	0.9256	0.9217	0.8216
11.208	676.680	I7	3-methylhexane	3.6218	3.6487	3.2150
11.552	683.790	N7	1t,3-dimethylcyclopentane	1.3463	1.2445	1.2196
11.688	686.500	I7	3-ethylpentane	1.4130	1.4011	1.2543
11.828	689.210	I8	2,2,4-trimethylpentane	1.8040	1.8047	1.4047
12.416	700.000	P7	n-heptane	5.5687	5.6379	4.9431
13.677	720.870	N7	methylcyclohexane	8.3981	7.5554	7.6077

APPENDIX D: BACT COST ANALYSIS

DLN COMBUSTION CONTROL – BASE COSTS

Mercury 50-6400R ULP Combustion Cost Analysis

Description of Cost				Cost Factor		Cost ($)	Source
Direct Capital Costs (DC):							
Purchased Equip. Cost (PE):							
Basic Equipment (A):	4.6 MW		40.27 MMBtu/hr		$	3,739,800	Solar
Auxiliary Equipment (B):					$	-	Estimate
Freight:					$	84,200	Solar
Sales Tax				0.03 (A+B)	$	112,194	OAQPS
PE Total:					**$**	**3,936,194**	
Direct Installation Costs (DI):							
Foundation & supports:				0.08 PE	$	314,896	OAQPS
Handling and erection:				0.14 PE	$	551,067	OAQPS
Electrical:				0.04 PE	$	281,700	OAQPS
Piping:				0.02 PE	$	78,724	OAQPS
Insulation:				0.01 PE	$	39,362	OAQPS
Painting:				0.01 PE	$	39,362	OAQPS
Additional HRSG					$	-	Estimate
Site Preparation/Excavation					$	-	Site Specific
DI Total:					**$**	**1,305,110**	
DC Total (PE+DI):					**$**	**5,241,304**	
Indirect Costs (IC):							
Engineering:				0.10 PE	$	393,619	OAQPS
Construction and field expenses:				0.05 PE	$	196,810	OAQPS
Contractor fees:				0.10 PE	$	393,619	OAQPS
Commissioning Parts, Start-up and Performance Testing					$	160,000	Solar
Contingencies:				0.03 PE	$	118,086	OAQPS
IC Total:					**$**	**1,262,134**	
Total Capital Investment (TCI = DC + IC):					**$**	**6,503,439**	

Direct Annual Costs (DAC):							
Operating Costs (O):							
Operator Labor: 1 hr/shift, 3 shifts/day, $30/hr					$	32,850	OAQPS
Supervisor:	15% of operator				$	4,928	OAQPS
Maintenance Costs (M):							
Labor:	hr/shift:	0.5	labor pay ($/hr):	30	$	16,425	OAQPS
Material:	% of labor cost:	100%			$	16,425	OAQPS
[1]Utility Costs:							
Natural Gas:	2.70	$/MMBtu			$	952,466	US EIA
Total DAC:					**$**	**1,023,094**	
Indirect Annual Costs (IAC):							
Overhead:	60% of O&M				$	42,377	OAQPS
Administrative:				0.02 TCI	$	130,069	OAQPS
Insurance:				0.01 TCI	$	65,034	OAQPS
Property tax:				0.01 TCI	$	65,034	OAQPS
Capital recovery:	interest rate (%):	7					
	period (years):	20		0.09 TCI	$	613,879	OAQPS
Total IAC:					**$**	**916,393**	
Total Annual Cost (DAC + IAC):					**$**	**1,939,486**	

Solar Turbines Incorporated
Budgetary Quotation for

Inquiry # prepared on March 28, 2012

For more information contact:

Lisa Marlo Conley, 858 694-6523, lisamarloconley@solarturbines.com

(Prices shown below quoted in US Dollars $)

This quote is provided for budgetary purposes only and does not represent a firm quote.

Gas Turbine Equipment		
(1) Natural Gas Fuel MERCURY 50-6000R Turbine Generator Set……		$3,739,800
Commissioning Parts, Startup, and Site Testing……		$160,000
Electrical Equipment		
Power and Utility Breaker Control Options……	$28,500	
Switchgear and MCC (design description below)……	$253,200	
Switchgear, motor control center, auxiliary power transformer, and generator grounding resistor.		
Switchgear and MCC are shipped loose.		
Total for Electrical Equipment……		$281,700
Mechanical Equipment		
No Mechanical Equipment Selected		
Miscellaneous		
Construction Estimate……..		by others
Project Management & Engineering (Loose Ship Equipment Only)……		$19,700
Shipping……		$84,200
Development Costs……		$0
Special or Avoided Capital Items……		$0
0% Balance of Plant Contingency……		$0
Total for BOP Equipment (installation not included)……		$385,600
Grand Total for Turbomachinery and Balance of Plant……		**$4,285,400**
Estimation of cost per ISO rating kilowatt for selected equipment……		$931

*Duties and taxes not included in estimate.

Caterpillar Confidential: Green

CEP Ver. 6.10

MERCURY 50-6000R Generator Set Package Features

Engine:

Single shaft turbine, designed for industrial use
Axial compressor design
Annular type combustor employing dry, low NOx technology

Basic Options:

Fully enclosed, generator set package requiring 460V, 3-phase, 60 Hz AC power
Rated Class I, Div II, Groups C,D per NEC
120V, 1-phase, 50/60 Hz internal lighting and heater power
Gas turbine engine in upward oriented air inlet, and upward oriented exhaust outlet
1800 rpm; 60 Hz Gearbox
Continuous Duty, Open Drip Proof generator rated for 13,800 VAC with Class F insulation, B rise

Included Package Features:

Direct AC start motor system
Duplex lube oil filter system
Allen-Bradley based Turbotronics IV control system including:

- Ethernet network interface
- Touch Screen display with Engine Performance map
- Software for heat recovery interface (without diverter valve control)
- Software for CO2 system "lock out" (maintenance access to enclosure)
- Backup Safety Shutdown System
- kW Control
- kVAR/Power Factor Control

Included Factory Testing/Customer Witness/Quality Control Documentation:

Standard package dynamic testing
Factory vibration testing
Factory emissions testing per Solar's ES 9-97
Observation on "Non-Interference" basis
Quality Control documentation (Level 1)

Field-installed Ancillary Equipment (excludes ducting):

Medium velocity, three-stage Camil-Farr air inlet filter
Engine air inlet silencer
Exhaust bellows (interface to waste heat recovery equipment)
"Elbow" type enclosure inlet/exhaust ventilation system with silencer

Included "Off-Skid" Components/Systems:

Remote desktop PC/monitor and Printer/Logger
Gas fuel flow meter (for Gas-only and Dual Fuel configurations)
AC motor-driven Liquid Fuel boost pump skid (for Liquid Fuel configurations)
3-micron duplex filter/coalescer with auto drain (for Liquid Fuel configurations)
CO_2 system cabinet
Air/Oil lube oil cooler
VRLA Batteries with 120V DC charging system (back-up post lube)
Portable engine cleaning cart

Miscellaneous

Short-term preservation for shipment
Four (4) paper copies of Solar's Instruction, Operation and Maintenance manuals
Four (4) CD-ROM copies of Solar's Instruction, Operation and Maintenance manuals
UV Light and Gas Sensor test kit
Internal equipment handling system
Recuperator removal tool

Cogeneration Plant Estimated Performance Summary

0

Solar Turbines Incorporated

March 28, 2012

Performance listed below is estimated, not guaranteed.

Gas Turbine:		
KW Gross Output @ ISO Conditions:	4,600	kW
Site Ambient Temperature for Performance Analysis:	59	°F
Site Elevation for Performance Analysis:	1,500	feet
Site Ambient Relative Humidity for Performance Analysis:	60	%
Turbine Inlet Pressure Loss:	4.0	"H2O
Turbine Outlet Pressure Loss:	1.0	"H2O
Turbine Fuel Consumption @ specified site conditions (LHV):	38.2	MMBtu/hr
KW Gross Output @ specified site conditions:	4,258	kW
Gas Compressor Power Consumption:	0	KW
Turbine Auxiliary Power Consumption:	40	kW
Total Auxiliary Power Consumption:	40	kW
Net Turbine Power Production:	4,218	kW
Black Start kW Requirement (Turbine Generator Set Only)	206	kW

Cycle Performance (lower heating value basis)**:**		
Net Turbine Heat Rate:	9,050	Btu/kWHR
Gross Plant Heat Rate (Process steam or Tons converted to equivalent KW):	9,050	Btu/kWHR
Overall Cycle Thermal Efficiency (LHV):	37.7	%

Caterpillar Confidential: Green

CEP Ver. 6.10

Titan 250-30000S SoLowNO$_x$ Combustion Cost Analysis (GT-01)

Description of Cost				Cost Factor		Cost ($)	Source
Direct Capital Costs (DC):							
Purchased Equip. Cost (PE):							
Basic Equipment (A):	21.9 MW		188.44 MMBtu/hr		$	13,500,000	Solar
Auxiliary Equipment (B):					$	-	Estimate
Freight:				0.05 (A+B)	$	675,000	OAQPS
Sales Tax				0.03 (A+B)	$	405,000	OAQPS
PE Total:					**$**	**14,580,000**	
Direct Installation Costs (DI):							
Foundation & supports:				0.08 PE	$	1,166,400	OAQPS
Handling and erection:				0.14 PE	$	2,041,200	OAQPS
Electrical:				0.04 PE	$	583,200	OAQPS
Piping:				0.02 PE	$	291,600	OAQPS
Insulation:				0.01 PE	$	145,800	OAQPS
Painting:				0.01 PE	$	145,800	OAQPS
Additional HRSG					$	-	Estimate
Site Preparation/Excavation					$	-	Site Specific
DI Total:					**$**	**4,374,000**	
DC Total (PE+DI):					**$**	**18,954,000**	
Indirect Costs (IC):							
Engineering:				0.10 PE	$	1,458,000	OAQPS
Construction and field expenses:				0.05 PE	$	729,000	OAQPS
Contractor fees:				0.10 PE	$	1,458,000	OAQPS
Start-up				0.02 PE	$	291,600	OAQPS
Performance Testing				0.01 PE	$	145,800	OAQPS
Contingencies:				0.03 PE	$	437,400	OAQPS
IC Total:					**$**	**4,519,800**	
Total Capital Investment (TCI = DC + IC):					**$**	**23,473,800**	

Direct Annual Costs (DAC):							
Operating Costs (O):							
Operator Labor: 8 hr/shift, 3 shifts/day, $30/hr					$	262,800	OAQPS
Supervisor:	15% of operator				$	39,420	OAQPS
Maintenance Costs (M):							
Labor:	hr/shift:	0.5	labor pay ($/hr):	30	$	16,425	OAQPS
Material:	% of labor cost:	100%			$	16,425	OAQPS
*Utility Costs:							
Natural Gas:	2.70	$/MMBtu			$	4,456,983	US EIA
Total DAC:					**$**	**4,792,053**	
Indirect Annual Costs (IAC):							
Overhead:	60% of O&M				$	201,042	OAQPS
Administrative:				0.02 TCI	$	469,476	OAQPS
Insurance:				0.01 TCI	$	234,738	OAQPS
Property tax:				0.01 TCI	$	234,738	OAQPS
Capital recovery:	interest rate (%):	7					
	period (years):	20		0.09 TCI	$	2,215,761	OAQPS
Total IAC:					**$**	**3,355,755**	
Total Annual Cost (DAC + IAC):					**$**	**8,147,808**	

Titan 250-30000S SoLoNO$_x$ Combustion Cost Analysis (GT-01)

Description of Cost			Cost Factor		Cost ($)	Source
Direct Capital Costs (DC):						
Purchased Equip. Cost (PE):						
Basic Equipment (A):	21.9 MW	188.44 MMBtu/hr		$	13,500,000	Solar
Auxiliary Equipment (B):				$	-	Estimate
Freight:			0.05 (A+B)	$	675,000	OAQPS
Sales Tax			0.03 (A+B)	$	405,000	OAQPS
PE Total:				**$**	**14,580,000**	
Direct Installation Costs (DI):						
Foundation & supports:			0.08 PE	$	1,166,400	OAQPS
Handling and erection:			0.14 PE	$	2,041,200	OAQPS
Electrical:			0.04 PE	$	583,200	OAQPS
Piping:			0.02 PE	$	291,600	OAQPS
Insulation:			0.01 PE	$	145,800	OAQPS
Painting:			0.01 PE	$	145,800	OAQPS
Additional HRSG				$	-	Estimate
Site Preparation/Excavation				$	-	Site Specific
DI Total:				**$**	**4,374,000**	
DC Total (PE+DI):				**$**	**18,954,000**	
Indirect Costs (IC):						
Engineering:			0.10 PE	$	1,458,000	OAQPS
Construction and field expenses:			0.05 PE	$	729,000	OAQPS
Contractor fees:			0.10 PE	$	1,458,000	OAQPS
Start-up			0.02 PE	$	291,600	OAQPS
Performance Testing			0.01 PE	$	145,800	OAQPS
Contingencies:			0.03 PE	$	437,400	OAQPS
IC Total:				**$**	**4,519,800**	
Total Capital Investment (TCI = DC + IC):				**$**	**23,473,800**	

Direct Annual Costs (DAC):						
Operating Costs (O):						
Operator Labor: 8 hr/shift, 3 shifts/day, $30/hr				$	262,800	OAQPS
Supervisor:	15% of operator			$	39,420	OAQPS
Maintenance Costs (M):						
Labor:	hr/shift:	0.5	labor pay ($/hr): 30	$	16,425	OAQPS
Material:	% of labor cost:	100%		$	16,425	OAQPS
*Utility Costs:						
Natural Gas:	2.70	$/MMBtu		$	4,456,983	US EIA
Total DAC:				**$**	**4,792,053**	
Indirect Annual Costs (IAC):						
Overhead:	60% of O&M			$	201,042	OAQPS
Administrative:			0.02 TCI	$	469,476	OAQPS
Insurance:			0.01 TCI	$	234,738	OAQPS
Property tax:			0.01 TCI	$	234,738	OAQPS
Capital recovery:	interest rate (%):	7				
	period (years):	20	0.09 TCI	$	2,215,761	OAQPS
Total IAC:				**$**	**3,355,755**	
Total Annual Cost (DAC + IAC):				**$**	**8,147,808**	

Solar® Turbines
A Caterpillar Company

13105 Northwest Freeway
Suite 400
Houston, TX 77040

www.solarturbines.com

COMMERCIAL PROPOSAL, Revision 1

DATE: 04 January 2012

TO: NGP
Greg E. Ameringer, President
Next Generation Processing, LLC.
281 744-7647
greg@ngprocess.com

FROM: Briz B. Garcia – Sales Engineer, Solar Turbines Incorporated

Subject: **HO11-0070 – NGP Gas Plant**

Mr. Ameringer,

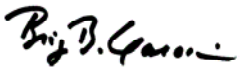
Solar Turbines Incorporated is pleased to provide the following updated quote for the NGP Gas Plant Project.

We believe our SoLoNOx (Dry Low Emissions) system is the best application for the NGP Gas Plant, with a guaranteed DLE operation range of 40-100% load, guaranteed emission levels (gas fuel, 15 ppm NOx and 25 ppm CO), and a wide allowable operation range on fuel composition (± 10% or more) on Wobbe index.

As we discussed, our integrated on-skid controls design, with integral package lube oil tank, and enclosure, make for an efficient installation. This simple design not only helps with commissioning, but drives higher reliability and availability.

We look forward to working with you on this project. Please let me know if you have any questions.

Best regards,



Briz B. Garcia
Sales Engineer
Solar Turbines Incorporated
(713) 895-4286
brizbgarcia@solarturbines.com

PRICING AND COMMERCIAL CONSIDERATIONS

PACKAGE PRICING

Note: Prices do not include sales, use, excise, value added, or royalty taxes.

Pricing

Two (2) Titan 250 Compressor Sets	USD $13.5MM per unit

Validity

This pricing is valid until 31 March 2012.

Delivery

Equipment quoted herein is typically available as follows.

First Titan 250 Compressor Set	52 weeks, Ex-Works Factory
Second Titan 20 Compressor Set	56 weeks, Ex-Works Factory

SELECTIVE CATALYTIC REDUCTION ADD-ON CONTROL COST ANALYSIS

Mercury 50-6400R ULP - SCR Add-On Controls Cost Analysis

DATA INPUT

Unit	Mercury 50
Turbine Configuration	Simple Cycle (Hi Temp)
Ammonia Source	Aqueous
Turbine Nox Conc.	25 ppmv or 42 ppmv (S20) or 5 ppmv (M50)
Exhaust Conc.	2.5 ppmv
Ammonia Slip	5 ppmv
Duct Burner Heat Input	SELECT ONE OF:
NOx lb/mmbtu Ductburner Emission factor (HHV)	0.06
Annual Operating Hours	8760
Include CEM ? (y/n)	n

NONE	☑	0 MMBTU/HR
@ 1600F	☐	36.7 MMBTU/HR
@ 2800F	☐	94.8 MMBTU/HR

Description of Cost		Cost Factor		Cost ($)	Source
Direct Capital Costs (DC):					
Purchased Equip. Cost (PE):					
Basic Equipment (A):	4.6 MW		$	1,193,000.00	Vendor
Auxiliary Equipment (B):			$	35,000.00	Estimate
Taxes and freight:		0.08 (A+B)	$	98,000.00	OAQPS
PE Total:			**$**	**1,326,000.00**	
Direct Installation Costs (DI):					
Foundation & supports:		0.08 PE	$	106,000.00	OAQPS
Handling and erection:		0.14 PE	$	186,000.00	OAQPS
Electrical:		0.04 PE	$	53,000.00	OAQPS
Piping:		0.02 PE	$	27,000.00	OAQPS
Insulation:		0.01 PE	$	13,000.00	OAQPS
Painting:		0.01 PE	$	13,000.00	OAQPS
Additional HRSG			$	-	Variable
Site Preparation/Excavation			$	-	Site Specific
DI Total:			**$**	**398,000.00**	
Installed CEM Costs			**$**	**-**	EPA Model
DC Total (PE+DI+CEM Costs):			**$**	**1,724,000.00**	
Indirect Costs (IC):					
Engineering:		0.10 PE	$	133,000.00	OAQPS
Construction and field expenses:		0.05 PE	$	66,000.00	OAQPS
Contractor fees:		0.10 PE	$	133,000.00	OAQPS
Start-up:		0.02 PE	$	27,000.00	OAQPS
Performance testing:		0.01 PE	$	13,000.00	OAQPS
Contingencies:		0.03 PE	$	40,000.00	OAQPS
IC Total:			**$**	**412,000.00**	
Total Capital Investment (TCI = DC + IC):			**$**	**2,136,000.00**	
Direct Annual Costs (DAC):					
Maintenance Costs (M):					
Labor and Material:		0.015 TCI	$	32,000.00	OAQPS
CEM Annual Costs			$	-	EPA Model
Utility Costs:					
Additional Pressurre Drop	6	iwc			
Perf. loss: (%):	0.20	(% per inch)			
Electricity cost ($/kwh):	0.1	Performance loss cost penalty:	$	48,000.00	variable
Catalyst Costs					
Catalyst Life (yrs) 7					
Interest Rate (%) 7	8.654	Capital Recovery			
Catalyst replace:	assume 30 ft^3 catalyst per MW, $383/$ft^3$		$	6,000.00	EPA
Catalyst dispose:	$15/$ft^3$*30 ft^3/MW*MW		$	200.00	variable
Hourly Ammonia Usage	0.3	lb/hr			
Ammonia: ($/ton):	360	(1:1 Molar Ratio)	$	-	variable
NH_3 inject skid: (blower, kw):	0.3	(NH_3/H_2O pump, kw): 1	$	1,000.00	variable
			$	87,200.00	
Total DAC:			**$**	**87,200.00**	
Indirect Annual Costs (IAC):					
Administrative:		0.02 TCI	$	43,000.00	OAQPS
Insurance:		0.01 TCI	$	21,000.00	OAQPS
Capital recovery: interest rate (%):	7.0				
period (years):	20	0.09 TCI	$	202,000.00	OAQPS
Total IAC:			**$**	**266,000.00**	
Total Annual Cost (DAC + IAC):			**$**	**353,200.00**	

Turbine NO_x Emission Rate (tons/yr):			3.53
Duct Burner Nox (tons/yr):			0.0
NO_x Removed (tons/yr):	control device removal eff.:	50 %	1.77
Cost Effectiveness ($/ton):			$200,113
Electricity Cost Increment (¢/kwh):			0.88

Assume 19% aqueous ammonia
Basic Equipment Includes: AIG, Reactor, AFCU, and Catalyst
Auxillary Equipment Includes: Tanks, pump skip (aqueous), Control Panel/PLC

Titan 250 30000S SoLoNO$_x$ - SCR Add-On Controls Cost Analysis (GT-01)

DATA INPUT

Unit	Titan 250
Turbine Configuration	CHP
Ammonia Source	Aqueous
Turbine Nox Conc.	15 ppmv
Exhaust Conc.	2.5 ppmv
Ammonia Slip	5 ppmv
Duct Burner Heat Input	SELECT ONE OF:
NOx lb/mmbtu Ductburner Emission factor (HHV)	0.06
Annual Operating Hours	8760
Include CEM ? (y/n)	n

NONE	☑#	0 MMBTU/HR
@ 1600F	☐#	116.1 MMBTU/HR
@ 2800F	☐#	338.2 MMBTU/HR

Description of Cost		Cost Factor		Cost ($)	Source
Direct Capital Costs (DC):					
Purchased Equip. Cost (PE):					
Basic Equipment (A):	21.7 MW		$	2,100,000.00	Peerless Mfg. Co.
Auxiliary Equipment (B): PLC, Allen Bradley CompactLogix PLC			$	55,000.00	Peerless Mfg. Co.
Auxiliary Equipment (C): 10,000 gallon aqueous ammonia storage tank			$	150,000.00	Peerless Mfg. Co.
Taxes and freight:		0.08 (A+B+C)	$	172,000.00	OAQPS
PE Total:			**$**	**2,477,000.00**	
Direct Installation Costs (DI):					
Foundation & supports:		0.08 PE	$	198,000.00	OAQPS
Handling and erection:		0.14 PE	$	347,000.00	OAQPS
Electrical:		0.04 PE	$	99,000.00	OAQPS
Piping:		0.02 PE	$	50,000.00	OAQPS
Insulation:		0.01 PE	$	25,000.00	OAQPS
Painting:		0.01 PE	$	25,000.00	OAQPS
Additional HRSG			$	-	Variable
Site Preparation/Excavation			$	-	Site Specific
DI Total:			**$**	**744,000.00**	
Installed CEM Costs			**$**	**-**	EPA Model
DC Total (PE+DI+CEM Costs):			**$**	**3,221,000.00**	
Indirect Costs (IC):					
Engineering:		0.10 PE	$	248,000.00	OAQPS
Construction and field expenses:		0.05 PE	$	124,000.00	OAQPS
Contractor fees:		0.10 PE	$	248,000.00	OAQPS
Start-up:		0.02 PE	$	50,000.00	OAQPS
Performance testing:		0.01 PE	$	25,000.00	OAQPS
Contingencies:		0.03 PE	$	74,000.00	OAQPS
IC Total:			**$**	**769,000.00**	
Total Capital Investment (TCI = DC + IC):			**$**	**3,990,000.00**	
Direct Annual Costs (DAC):					
Maintenance Costs (M):					
Labor and Material:		0.015 TCI	$	59,900.00	OAQPS
CEM Annual Costs			$	-	EPA Model
Utility Costs:					
Additional Pressurre Drop	10	iwc			Peerless Mfg. Co.
Perf. loss: (%):	0.20	(% per inch)			
Electricity cost ($/kwh):	0.1	Performance loss cost penalty:	$	380,000.00	variable
Catalyst Costs					
Catalyst Life (yrs) 7					
Interest Rate (%) 7	8.654	Capital Recovery			
Catalyst replace:	assume 30 ft^3 catalyst per MW, $383/ft		$	29,000.00	EPA
Catalyst dispose:	$15/ft^3*30 ft^3/MW*MW		$	1,100.00	variable
Hourly Ammonia Usage	7.0	lb/hr			
Ammonia: ($/ton):	360	(1:1 Molar Ratio)	$	5,000.00	variable
NH_3 inject skid: (blower, kw):	6.2	(NH_3/H_2O pump, kw): 24	$	26,000.00	variable
			$	501,000.00	
Total DAC:			**$**	**501,000.00**	
Indirect Annual Costs (IAC):					
Administrative:		0.02 TCI	$	80,000.00	OAQPS
Insurance:		0.01 TCI	$	40,000.00	OAQPS
Capital recovery: interest rate (%):	7.0				
period (years):	20	0.09 TCI	$	377,000.00	OAQPS
Total IAC:			**$**	**497,000.00**	
Total Annual Cost (DAC + IAC):			**$**	**998,000.00**	

Turbine NO$_x$ Emission Rate (tons/yr):			49.52
Duct Burner Nox (tons/yr):			0.0
NO$_x$ Removed (tons/yr):	control device removal eff.:	83 %	41.27
Cost Effectiveness ($/ton):			$24,184
Electricity Cost Increment (¢/kwh):			0.53

Assume 19% aqueous ammonia
Basic Equipment Includes: AIG, Reactor, AFCU, and Catalyst
Auxillary Equipment Includes: Tanks, pump skip (aqueous), Control Panel/PLC
Cost for 10,000 gallon storage tank split between EPN GT-01 and GT-02

Titan 250 30000S SoLoNO$_x$ - SCR Add-On Controls Cost Analysis (GT-02)

DATA INPUT

Unit	Titan 250
Turbine Configuration	CHP
Ammonia Source	Aqueous
Turbine Nox Conc.	15 ppmv
Exhaust Conc.	2.5 ppmv
Ammonia Slip	5 ppmv
Duct Burner Heat Input	SELECT ONE OF:
NOx lb/mmbtu Ductburner Emission factor (HHV)	0.06
Annual Operating Hours	8760
Include CEM ? (y/n)	n

NONE	☑#	0 MMBTU/HR
@ 1600F	☐#	116.1 MMBTU/HR
@ 2800F	☐#	338.2 MMBTU/HR

Description of Cost	Cost Factor		Cost ($)	Source
Direct Capital Costs (DC):				
Purchased Equip. Cost (PE):				
Basic Equipment (A): 21.7 MW		$	2,100,000.00	Peerless Mfg. Co.
Auxiliary Equipment (B): PLC, Allen Bradley CompactLogix PLC		$	55,000.00	Peerless Mfg. Co.
Auxiliary Equipment (C): 10,000 gallon aqueous ammonia storage tank		$	150,000.00	Peerless Mfg. Co.
Taxes and freight:	0.08 (A+B+C)	$	172,000.00	OAQPS
PE Total:		**$**	**2,477,000.00**	
Direct Installation Costs (DI):				
Foundation & supports:	0.08 PE	$	198,000.00	OAQPS
Handling and erection:	0.14 PE	$	347,000.00	OAQPS
Electrical:	0.04 PE	$	99,000.00	OAQPS
Piping:	0.02 PE	$	50,000.00	OAQPS
Insulation:	0.01 PE	$	25,000.00	OAQPS
Painting:	0.01 PE	$	25,000.00	OAQPS
Additional HRSG		$	-	Variable
Site Preparation/Excavation		$	-	Site Specific
DI Total:		**$**	**744,000.00**	
Installed CEM Costs		**$**	**-**	EPA Model
DC Total (PE+DI+CEM Costs):		**$**	**3,221,000.00**	
Indirect Costs (IC):				
Engineering:	0.10 PE	$	248,000.00	OAQPS
Construction and field expenses:	0.05 PE	$	124,000.00	OAQPS
Contractor fees:	0.10 PE	$	248,000.00	OAQPS
Start-up:	0.02 PE	$	50,000.00	OAQPS
Performance testing:	0.01 PE	$	25,000.00	OAQPS
Contingencies:	0.03 PE	$	74,000.00	OAQPS
IC Total:		**$**	**769,000.00**	
Total Capital Investment (TCI = DC + IC):		**$**	**3,990,000.00**	
Direct Annual Costs (DAC):				
Maintenance Costs (M):				
Labor and Material:	0.015 TCI	$	59,900.00	OAQPS
CEM Annual Costs		$	-	EPA Model
Utility Costs:				
Additional Pressurre Drop 10 iwc				Peerless Mfg. Co.
Perf. loss: (%): 0.20 (% per inch)				
Electricity cost ($/kwh): 0.1 Performance loss cost penalty:		$	380,000.00	variable
Catalyst Costs				
Catalyst Life (yrs) 7				
Interest Rate (%) 7 8.654 Capital Recovery				
Catalyst replace: assume 30 ft^3 catalyst per MW, $383/ft		$	29,000.00	EPA
Catalyst dispose: $15/ft^3*30 ft^3/MW*MW		$	1,100.00	variable
Hourly Ammonia Usage 7.0 lb/hr				
Ammonia: ($/ton): 360 (1:1 Molar Ratio)		$	5,000.00	variable
NH_3 inject skid: (blower, kw): 6.2 (NH_3/H_2O pump, kw): 24		$	26,000.00	variable
		$	501,000.00	
Total DAC:		**$**	**501,000.00**	
Indirect Annual Costs (IAC):				
Administrative:	0.02 TCI	$	80,000.00	OAQPS
Insurance:	0.01 TCI	$	40,000.00	OAQPS
Capital recovery: interest rate (%): 7.0 period (years): 20	0.09 TCI	$	377,000.00	OAQPS
Total IAC:		**$**	**497,000.00**	
Total Annual Cost (DAC + IAC):		**$**	**998,000.00**	

Turbine NO$_x$ Emission Rate (tons/yr):			49.52
Duct Burner Nox (tons/yr):			0.0
NO$_x$ Removed (tons/yr):	control device removal eff.:	83 %	41.27
Cost Effectiveness ($/ton):			$24,184
Electricity Cost Increment (¢/kwh):			0.53

Assume 19% aqueous ammonia
Basic Equipment Includes: AIG, Reactor, AFCU, and Catalyst
Auxillary Equipment Includes: Tanks, pump skip (aqueous), Control Panel/PLC
Cost for 10,000 gallon storage tank split between EPN GT-01 and GT-02

PEERLESS

SOLAR TURBINES, INC.

BRIZ GARCIA

for

[redacted]

PROJECT REFERENCE: HO12-0015 – SET TEAM 2014
PEERLESS PROPOSAL REFERENCE NUMBER: 24649

MAY 17, 2012

Property Rights: The information, figures, and drawings contained in this printed piece are confidential and proprietary to Peerless Mfg. Co., Dallas, Texas. They are provided in confidence with the understanding that they will not be reproduced or copied without the expressed written permission of Peerless Mfg. Co., and that they will not be used adversely to Peerless. All patent rights are reserved.

BUDGETARY PRICE SUMMARY: AQUEOUS ELECTRIC EMISSIONS CONTROL SYSTEM FOR SIMPLE CYCLE TITAN 250 (10" H_20 TOTAL SYSTEM PRESSURE DROP)

ITEM	QUANTITY	DESCRIPTION	PRICE
B	1	Inlet transition ductwork	
C	1	Reactor Housing	
D	1	Outlet transition ductwork	
E	1	Expansion joint at stack	
F	1	CO Catalyst Support Structure and Seals	
G	1	CO Catalyst	
H	1	SCR Catalyst Support Structure and Seals (including space for future catalyst)	
I	1	SCR Catalyst	
J	1	Silencer (85 dBa @ 3 feet)	
K	1	Stack (80 feet tall)	
L	1	Ammonia Flow Control Unit (AFCU)	
M	1	Ammonia Injection Manifold	
N	1	Ammonia Injection Grid (AIG)	
O	1	Tempering / purge air skid with interconnecting ductwork and injection piping (2x100%)	
P	1	Interconnecting piping from AFCU to manifold and from manifold to AIG (< 25 linear feet)	
Q	1	Computational fluid dynamics modeling	
		TOTAL BUDGETARY PRICE FOR ONE (1) EMISSION CONTROL SYSTEMS, EX-WORKS, MANUFACTURING POINT	**US$2,300,000**
1	**OPTION**	Freight is on a pre-pay and add basis, billed at cost (base bid scope of supply only)	To be determined
2	**OPTION**	**Deduct** to remove stack with silencer from scope of supply	To be determined
3	**OPTION**	**Adder** for Peerless standard PLC, Allen Bradley CompactLogix PLC	US$55,000/unit
3	**OPTION**	**Adder** for electric hoist / electrical monorail	US$60,000/unit
5	**RECOMMENDED OPTION**	**Adder** for physical flow modeling	US$45,000
6	**OPTION**	**Adder** for 10,000 gallon aqueous ammonia storage tank with instruments, pump skid, and truck unloading stand	US$300,000
7	**OPTION**	Construction and Field Service Supervision	See Section X

All Purchase Orders based on this Quote, which is not an offer, are subject to acceptance by Seller at its principal office in Dallas, Texas. Unless otherwise expressly provided in Seller's acceptance, the terms and conditions set forth herein shall constitute a part of any agreement resulting from Seller's acceptance of an order for all or part of the goods covered by this Quote. This Quote serves as notice to Buyer of Seller's objection to any terms and conditions of Buyer that in any way conflict with, modify, condition, add to, or differ from the terms and conditions specified herein, unless such terms and conditions of Buyer are expressly included in Seller's acceptance of Buyer's order. Silence on the part of Seller shall not be construed, under any circumstances, as acceptance of Buyer's terms and conditions. If not previously revoked or otherwise provided herein, this Quote shall terminate and cease to exist thirty (30) days from the date of this Quote.

Pamela Murphy
Product Manager
pmurphy@peerlessmfg.com

II. COMMERCIAL TERMS

A. PROPOSAL PRICE: The price proposed is for the design, materials, or components listed. If specific design conditions differ from the inquiry, the specifications shall be modified and an equitable adjustment shall be made in the contract price or delivery schedule, or both. Any changes in this quotation will be submitted and approved in writing.

B. DELIVERY: Typical delivery for catalyst and all equipment is within fifty-two (52) weeks from the order date, contingent upon the timely return of approved drawings/documents. Storage fees will be charged if delivery is delayed beyond the project schedule for delays not caused by Peerless Mfg. Co. (Peerless). These charges will be imposed at the time of the delay.

C. TRANSPORTATION: Shipment of the equipment shall be via Motor Freight, Ex Works, Manufacturing Point. No allowance has been made for any freight charges, special packaging, or export packaging / crating.

D. EXCLUDED ITEMS: The quoted price does not include any custom duties, tariffs, import fees, income tax, nor any other taxes, duties, levies, etc., imposed by governmental organizations. Equipment delivered to the following states will require a Tax Exemption Certificate to exclude those current state taxes from our invoice: Arizona, California, Georgia, Kentucky, Tennessee, and Texas.

E. VALIDITY: The offered price is valid for thirty (30) days from the proposal date, and thereafter, is subject to our acceptance. Due to the current fluctuation in steel prices, all pricing in this proposal must be confirmed at time of purchase order.

F. PAYMENT TERMS: Payment shall be made, net 30 days, according to the following schedule:
10% - upon receipt of order
10% - upon submittal of approval drawings
25% - upon Peerless' release to purchase materials
25% - upon Peerless' notification to proceed with fabrication
30% - upon Peerless' notification that equipment is ready for shipment.

G. CHANGES / CANCELLATION SCHEDULE: Any changes to or cancellation of the Agreement, once accepted, are subject to written approval by Peerless under conditions that shall include, among other things, protection against any loss to Peerless.

Cancellation Schedule:
25% - after receipt of purchase order
50% - after submittal of general arrangement drawings
90% - after release to purchase materials
100% - upon release to fabricate

H. WARRANTY:

1. All hardware is under warranty for eighteen (18) months from contracted delivery or twelve (12) months from scheduled start-up, whichever occurs first. The extent of the warranty includes replacement of defective components, and is limited to material only.

2. Peerless is not responsible for any damage resulting from mis-operation or improper maintenance of the unit as described in the Peerless Operation & Maintenance Manuals for this project. Warranty is voided if the system is not operated and maintained in accordance with the Operation & Maintenance Manual.

3. The aqueous ammonia must be reagent grade, diluted with fully de-ionized water to 19% by weight.

CATALYST WARRANTY CRITERIA:

1. Each SCR and CO catalyst bed performance is under warranty for thirty-six (36) months from initial start-up, or thirty-nine (39) months from contracted delivery, or 24,000 operating hours, whichever occurs first. This warranty is contingent on items discussed in the paragraph below and all requirements and contingencies provided by the SCR and CO catalyst vendor.

2. The catalyst must be handled, operated, and maintained according to the catalyst vendor's instructions. Peerless is not responsible for any damage due to operation above or below temperatures or pressures other than those design conditions shown on the specification sheet provided by Peerless, nor any damage resulting from mis-operation or improper maintenance of the unit as described in the Peerless Operation & Maintenance Manuals for this project. The purchaser must give Peerless access to the relevant process operating logs if requested by Peerless.

3. The SCR catalyst face temperature must be a minimum of 450 degrees F (232 degrees C) for natural gas and 550 degrees F (288 degrees C) for oil before ammonia injection will be allowed.

4. Unit operating conditions shall be within the limits of design cases provided.

5. The catalyst vendor is not responsible for catalyst degradation caused by reagent drainage or other liquid contact to catalyst.

6. The catalyst vendor is not responsible for catalyst degradation caused by catalyst poisons. Design for natural gas applications is based on impurities found in typical United States pipeline quality natural gas applications. Impurities in the fuel were not available for evaluation. The impact of impurities can significantly impact the proposed design. A fuel specification including trace components must be provided to ensure that the catalyst design is adequate for the application.

    a. Fine Particulate (ash)
    b. Ammonia-Sulfur Compounds
    c. Alkaline Metals (Family includes sodium, potassium, cesium, lithium, francium, rubidium)
    d. Alkaline earth metals (Family includes calcium, magnesium, barium, strontium)
    e. Non-Metals (phosphorus, arsenic, silicas, siloxanes)
    f. Halogens (fluorine, chlorine)
    g. Transition and Other Metals (Family includes iron, antimony, chrome, copper, lead, mercury, nickel, tin, zinc, vanadium, platinum, rhodium, palladium)

    In the event that the catalyst contains, either singularly or collectively, levels of the above contaminants in excess of 450 mg / m3 or 15 mg / ft3 (as determined by ICP-OES, or glow discharge mass spectrophotometry) then the warranty shall be voided.

7. If applicable, Purchaser shall clean catalyst masked or plugged by firing of particulate producing fuel discovered by means of periodic visual inspections.

8. Purchaser must provide catalyst samples to Peerless, if requested during the warranty period, in order to maintain warranties. Seller will provide an advance written request of a need to obtain catalyst samples, construction and sampling method that permits ease of extraction and replacement of samples, and schedule coordination for the operating plant's convenience.

9. Purchaser will provide a copy of all procedures and methods of analysis to be employed in catalyst evaluation for Acceptance and anytime throughout the warranty period.

10. The NO/NOx ratio must be greater than 0.80 at the AIG and SCR catalyst inlet for optimum performance and NOX reduction warranties to be met. (NO_2 speciation must be less than or equal to 20% of the total NOx.)

11. Peerless will not accept spent catalyst as part of the disposal process. Catalyst disposal is the responsibility of others.

CATALYST WARRANTY FULLFILLMENT REMEDY

In the event that the Purchaser suspects the catalyst to be in non-compliance with the Contract and subsequent on-site tests during the warranty period indicate that the warranted values are not being met, Peerless will conduct an on-site investigation to determine the cause of non-performance. If the catalyst is suspect, Peerless will conduct laboratory tests, according to the conditions specified in the Technical Specifications, to verify the catalyst performance. The costs for the Peerless' on-site investigations and subsequent testing shall be born by Peerless.

If the results of the laboratory tests indicate that the warranted values are being met, or Peerless' Subcontractor(s) warranties will be deemed in fulfillment at this time and Purchaser will continue their investigation to determine the cause of non-fulfillment. In this event, Purchaser will compensate Peerless for the cost of laboratory evaluation.

If the results of the laboratory tests indicate that the warranted values are not being met during the first (1st) through the twelfth (12th) month of operation, Peerless shall have the option to:

a) Replace the non-performing catalyst at Peerless' expense; or
b) Repair the non-performing catalyst at Peerless' expense.

Warranty remedies include the cost of the replacement catalyst or catalyst repair and shipping costs to and from the jobsite only. The cost of labor and lifting equipment, if required, to perform the removal and installation of catalyst covered by warranty is not included and is to be provided by the Purchaser.

In the event the Catalyst fails to perform as described above during the thirteenth (13th) through the guaranteed month of operation, Peerless shall have the option to:

(a) Replace the non-performing Catalyst with Peerless responsible for that proportion of the replacement catalyst price equal to guaranteed service hours minus the number of hours since start-up, divided by guaranteed service life (i.e., XX months.-N) / XX months); and Owner responsible for the balance; or
(b) Repair the non-performing Catalyst with Peerless responsible for that proportion of the repair equal to guaranteed service months minus the number of months since start-up, divided by guaranteed service months; and the Owner responsible for the balance.

Warranty remedies include the cost as stipulated above of the replacement catalyst or catalyst repair and shipping costs to and from the jobsite only. The cost of labor and lifting equipment, if required, to perform the removal and installation of catalyst covered by warranty is not included and is to be provided by the Purchaser.

Peerless' warranties are fulfilled at the end of the period stated in this proposal if the results of on-site tests indicate that the performance values shown in this proposal are met.

I. PROPRIETARY RIGHTS:

1. All engineering and application information given in Peerless' Proposal is proprietary. Such information is to be used only in the evaluation of this offer. If an order does not result from this Proposal, such proprietary information must be held in confidence, and never used in any manner by the prospective purchaser.

2. If an order results from the Proposal, such proprietary information becomes the property of the Purchaser for use in the design, manufacture, and operation of the specific unit proposed, and cannot be used on any other item or in any other manner without approval from Peerless.

K. NON-UNION LABOR: All Peerless labor facilities are non-union. Non-union employees will complete all Peerless fabrication work. UA labeled pipe can be supplied for an additional cost, if required.

III. GENERAL SCOPE OF SUPPLY

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
BASIC ENGINEERING AND DESIGN				
Drawing and Document Index (if requested)	X			
P&IDs	X			
System Control logic (SAMA diagrams)	X			
Component Specification	X			
ISA Datasheets	X			
Paint Specification	X			
Piping Specification	X			
I-O List	X			
Dilution air or exhaust blower & motor data (includes fan curves, motor drawing, motor wiring diagrams, motor performance sheet, cut sheets of auxiliary equipment)	X			
Inspection and Test Plan	X			
Utility Consumption List (includes electricity and air users)	X			
Weld Procedures and Supporting PQRs	X			
Spare Parts List	X			
Shipping Bill of Material	X			
Operation & Maintenance manuals – one (1) CD copy and two (2) hardcopies. Additional hardcopy manuals are $100.00 each. (Vendor data sheets are provided on CD-ROM only in English.)	X			
Equipment general arrangement drawings (including location of anchor bolts)	X			
Design of anchor bolts (size and length)			X	
Design of insulation (if applicable)	X			
Supply and installation of insulation (if applicable)			X	
PE Stamp (can be included for an additional cost)		X		

Design, supply, and installation of heat tracing or instrument protection (if applicable)			X	
Computation Fluid Dynamics (CFD) Modeling	X			

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
AMMONIA SYSTEM				
Aqueous Electric Ammonia Flow Control Unit:				
Ammonia Flow Control Train				
Y-type strainers (2 x 100%)	X			
Manual isolation valves (ball or gate) – multiple	X			
Differential pressure gauge across strainers (one)	X			
Pressure gauge (one)	X			
Coriolis style flowmeter/transmitter (one)	X			
Ammonia Flow Control Valve (one)	X			
Actuated ball valve (shut-off valve) (one)	X			
Dilution Air Line				
Ambient air blowers and motors (2 x 100%) (480V, 3-Phase, 60 Hz power)	X			
Power wiring for fan motors			X	
Filter-silencers (2 x 100%) – on inlet of each blower	X			
Annubar style flowmeter/transmitter (one)	X			
Butterfly valve (manual) (one per blower – on outlet of blower)	X			
Check valve (manual) (one per blower – on outlet of blower)	X			
Pressure gauge (one)	X			
Motor starters (Main disconnect breaker is not included)			X	
Ammonia Vaporization and Dilution Chamber (1 x 100%) Chamber is a counter-current flow packed tower. Chamber Material: SA-36 * Atomizing air is not required. ** ASME code design is not required.				
Immersion style electric heater (1 x 100%)	X			
Heater power panel (1 x 100%)	X			
Pressure gauge (one)	X			
Thermocouple and thermowell (at vaporizer sump) (one)	X			
Temperature transmitter (at vaporizer sump) (one)	X			
Thermocouple and thermowell (at vaporizer sump) (one)	X			
Temperature transmitter (at vaporizer sump) (one)	X			
Instrument Air Line				
Manual isolation valves (ball valves) – (multiple)	X			
Junction Box (one – houses analog instrument signals, discrete instrument signals, and 120VAC instrument power)	X			
Foundation / Support of AFCU			X	
PLC Local Control Panel:				
Peerless Standard PLC Control Panel Allen Bradley CompactLogix PLC • PLC Controller o Analog Input (4-20mA) o Analog Output (4-20mA) o Analog Thermocouple Input o Digital Input /Output		X		

o Serial Data Comm (to HMI) • HMI –10" Color Touchscreen • Enclosure – Painted CS, NEMA 4 • Non-hazardous Electrical Classification • Standard terminals, wire, and accessories. **Options:** • Stainless steel Nema 4X enclosure upgrade (Add $1500) • Bebco Purge system for Class I, Div 2 area classification (Add $3500) • PLC processor with Ethernet comms and a 5-port industrial Ethernet switch for HMI and DCS comms (Add $3,170) • Upgrade from 10" to 12" PanelView Plus Color Touch-screen (Add $1580) • Upgrade from 10" to 12" High-Bright, UV Protected, PanelView Plus Color Touch- screen (Add $2,660)				
Manifold:				
Ammonia injection manifold Orientation: Vertical on one side Material: A-53B carbon steel welded pipe	X			
Expansion joints in main header (as required)	X			
Pressure gauge (near manifold inlet)	X			
Orifice plate at each branch take-off	X			
Throttling valve (butterfly or gate valve) at each branch take-off	X			
Differential pressure indicators at each branch take-off	X			
Tubing and fittings for plumbing differential pressure indicators to orifice plates (tubing is shipped loose, in bulk, to job site for field erection)	X			
Insulation			X	
Supports for manifold			X	
Ammonia Injection Grid:				
Ammonia injection grid (EDGE™): Each branch of ammonia injection grid is shipped loose for field installation Material: Carbon Steel - Tube Steel	X			
Interconnecting Piping: *Supply of interconnecting piping is based on the AFCU being within 25 feet of the ammonia injection location. Supply is based on no site obstructions that would require additional elbows or piping.*				
Interconnecting pipe (AFCU to manifold) Material: A-53B carbon steel welded pipe	X			
Interconnecting pipe (Manifold to AIG) Material: A-53B carbon steel welded pipe	X			
Insulation			X	
Support of interconnecting piping			X	

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
CATALYST				
SCR catalyst bed	X			
SCR catalyst test coupons	X			
CO catalyst bed	X			
CO catalyst test coupons	X			

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
DUCTWORK AND STRUCTURE				
SCR catalyst support structure & sealing mechanism Material: Carbon Steel	X			
CO catalyst support structure & sealing mechanism Material: Carbon Steel				
Expansion Joint at Turbine Exhaust			X	
Flow distribution correction (if required)	X			
Inlet transition ducting to reactor housing SCR and CO reactor housing Outlet ducting from reactor housing (including lifting lugs with dead load limit, lifting plan by others) Duct Casing Material: Carbon Steel Casing Thickness: 0.25" minimum Internal Liner: 409 S/S (14 ga. - walls and ceiling; 12 ga. - floor) Internal Insulation: 8 lb/ft^3 ceramic fiber blanket – 4" thickness Casing Design temperature is < 140ºF	X			
Test Ports for Catalyst	X			
Reactor instrumentation Differential Pressure Transmitter Temperature Transmitter Note: Instrumentation is shipped loose and installed in the field by others. Note: Includes instrument trim / fittings / drains	X			
Hoist and monorail: Electric hoist / electric trolley Includes cable hoist, electric trolley, electrical cable reel, and control pendant Standard electric voltage: 480 VAC, 3 phase		X		
Catalyst installation / access door	X			
Ductwork platforms and ladder access Material: Galvanized				X
Expansion joint at stack	X			
Stack: Height: 80 feet Casing Material: Carbon Steel Casing Thickness: 0.25" minimum Internal Liner: 409 S/S (12 ga.) Internal Insulation: 8 lb/ft^3 ceramic fiber blanket – 4" thickness Casing Design temperature is < 140ºF	X			
CEMS test ports	X			
Stack platform and ladders Material: Galvanized	X			
Silencer (85 dBa @ 3 feet)				

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
TEMPERING / PURGE AIR FANS				
Tempering / purge air fans (2 x 100%)	X			
Wiring of fan motors			X	
Motor starters (Main disconnect breaker is not included)			X	
Support of tempering / purge air fans			X	
Ducting from tempering / purge air fans to injection plenum	X			
Support of ducting	X			

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
AQUEOUS AMMONIA STORAGE SYSTEM				
Ammonia storage tank: Material: SA516-70 Designed to ASME Code Section VIII, Div. 1 National Board Stamped Orientation: Horizontal Gross water capacity: 10,000 gallons Useable capacity: ~90% by volume of gross capacity Design Pressure: 50 psig Design Temperature: -20ºF / 150ºF Corrosion Allowance: 1/16” Manway: One (1) 24” RF		X		
Valves and Instrumentation (shipped loose to be installed in field by others): Two (2) pneumatic valves One (1) level transmitter One (1) level indicator One (1) thermometer One (1) pressure gauge One (1) pressure relief valve (sized for blocked flow) One (1) vacuum breaker valve		X		
Instrument Trim / Fittings / Drains		X		
Ladders and Platforms		X		
Ammonia Pump Skid (Aqueous Ammonia):				
Ammonia Pump Skid: 2 x 100% Mag-drive type forwarding pumps Open loop system Skid piping material: SA-312-TP304L S/S Skid tubing material: SA269TP 316H S/S		X		
Valves and Instrumentation: Two (2) pressure gauges Two (2) pressure safety valves One (1) pressure relief valves / control valves One (1) back pressure regulator One (1) ammonia outlet pressure transmitter Two (2) Y-type strainers Two (2) swing check valves		X		
Instrument Trim / Fittings / Drains		X		
Support of ammonia pump skid			X	
Motor Starters (120V)			X	
Truck Unloading Station:				
Truck Unloading Stand: Skid pipe material: SA-106B C/S		X		
Valves and Instrumentation: One 2-inch liquid sight flow indicator Two shutoff valves with ACME adapters, dust caps, and local drains One swing check valve for liquid fill line		X		
Truck Unloading Pump				X
Interconnecting Piping:				
Interconnecting piping from truck unloading to tank			X	
Interconnecting piping from tank to pump skid			X	
Interconnecting piping from pump skid to AFCU			X	
Support of interconnecting piping			X	
Accessories:				
Ambient area monitor (4 point system)			X	
Water fogger system			X	

Shower / eyewash station			X	
Tempered water heater for shower station			X	

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
ANALYZER / CEM SYSTEM				
NOx analyzers at reactor inlet			X	
NOx analyzers at reactor outlet			X	
CO analyzer at reactor outlet			X	
O_2 analyzer			X	
CEM system PLC			X	
CEM data acquisition and handling system			X	
CEM analyzer certification			X	
CEM probe with filter and sample line			X	
Calibration Kit with regulators			X	
Sample conditioner			X	
Applicable EPA reporting software			X	
Analyzer / CEM shelter			X	

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
GENERAL				
Supply of anchor bolts			X	
Supply and installation of external insulation			X	
Supply and installation of heat tracing			X	

DESCRIPTION	Peerless	Optional	Buyer	Out of Scope
SITE WORK				
Field Service / Supervision				
Interconnecting wiring, ground frames, and conduits			X	
Electrical supply and controls for pumps, fans			X	
Final field and touch-up painting			X	
Unloading and storage at job site			X	
Civil/foundation design and work, anchor bolts and frames			X	
Labor, equipment, consumables, and materials for erection of the equipment at the job site			X	

IV. PEERLESS STANDARD DESIGN SPECIFICATIONS:

Paint Specification:

Surface Preparation: SSPC SP-6, Commercial Blast Cleaning
Primer: Inorganic Zinc Primer, Carboline, Carbo Zinc 11, Gray #0700, 2-3 mils DFT
Top Coat: Carboline Carbothane 133HB, 2-2.5 mils, 4701 Gray White Color

** Applies to all CS surfaces that are not ultimately insulated (either in Peerless' shop, other shop, or in the field):*
*** All stainless steel surfaces (ferric or austenitic) will be SSPC SP-1 solvent cleaned only.*
**** Valves will not be painted (primer or top coat) regardless of material of valve or material of line in which the valve is installed*

Piping Design, Fabrication, and Testing Specifications:

Aqueous Ammonia Systems: ASME/ANSI B31.1

** Please note the AIG lances are considered specialty equipment, not piping, and therefore are not subjected the above design codes.*

All structural welding (e.g., AFCU skid base) will be designed, fabricated, and tested to ASME code, Section IX

Electrical Classification:
Enclosure Type: NEMA 4
IEC Enclosure Class: IP56
Area Classification: Non-hazardous

Native format of all drawings: AutoCAD 2006
Native format of all documents: Microsoft Word, Excel, Adobe Acrobat

** Please note all drawings and documents will be officially submitted in Adobe Acrobat format*

Peerless Standard Instrument Suppliers:

Component	Standard Supplier	Technically Acceptable Alternates (Additional cost may apply)
Dilution Blower (high temp exhaust)	Robinson	
Dilution Blower (ambient air)	Chicago Blower	
Dilution Blower motors (either type)	TECO Westinghouse	Reliance, Baldor, Siemens, GE
Electric heater (flanged immersion style)	Chromalox	Watlow, CCI Thermal
Electric heater power panels	Peerless	Chromalox
Valves – Gate (forged, smaller than 2")	Vogt	Powell, Velan
Valves – Gate (cast, 2" and larger)	Powell	Velan, Vogt
Valves – ball	Marwin	Velan, KF Contromatics, Metso (Jamesbury)
Valves – check (wafer style)	Crane	Champion
Valves – butterfly	Keystone	WKM
Valves – globe	Velan	Vogt
Damper	Advanced Valve Design	Shanrod
Thermocouple/thermowell	Rosemount	STI
RTD/thermowell	Rosemount	STI
Temperature indicator (thermometer)	Wika	Ashcroft
Temperature transmitter	Rosemount	Honeywell
Pressure gauge	Wika	Ashcroft, 3D Instruments
Differential pressure gauge	Midwest	Ashcroft
Pressure transmitter	Rosemount	Honeywell
Differential pressure transmitter	Rosemount	Honeywell
Pressure switch	SOR	Ashcroft
Flowmeter/transmitter (ammonia) – coriolis	Micromotion	
Flowmeter/transmitter (dilution media) –annubar	Rosemount	Veris
Orifice plates	Fluidic Techniques (Vickery-Simms)	Primary Flow Signal, Triad, Daniel Industries
Flow control valve (ammonia line) • Valve • Actuator (pneumatic) • Positioner (I/P) • Air regulator	 Fisher-Baumann Baumann Fisher Fisher	
Actuated Damper (exhaust line) • Damper • Actuator (pneumatic) • Solenoid valve • Limit Switches • Air regulator	 Advanced Valve Design Tyco-Morin ASCO Westlock Fisher	 Shanrod Fisher (Field Q) Burkett Topworx, Tyco-Avid SMC
Actuated ball valve (ammonia line) • Valve • Actuator (pneumatic) • Solenoid valve • Limit switch • Air regulator	 Marwin Tyco-Morin ASCO Westlock Fisher	 Velan, KF Contromatics, Metso (Jamesbury) Rotork Burkett Topworx, Tyco-Avid SMC
Needle Valves	AGCO	Hex
Instrument Root Valves	AGCO	Hex
Instrument Manifold Valves	AGCO	Hex
Pressure regulator	Fisher	
Strainers	Armstrong	
Expansion Joints (metallic)	American Boa	Unaflex
Expansion Joints (rubber)	General Rubber	
Expansion Joints (fabric)	Johnson Expansion Joints	
Excess flow check valve	MGM	Rego
Level Indicator (float style)	Rochester	
Level indicator (bridled, magnetic flag style)	Magnetrol	K-TEK, Jerguson
Level Transmitter (guided wave radar style)	Magnetrol	Rosemount
Flow sight glass (unloading station)	Penberthy	
Remote level indication (unloading station)	Rosemount	
Pressure relief valve (vapor ammonia)	Crosby	Rego, Farris
Hydrostatic relief valve (liquid ammonia)	Rego	Crosby
Vacuum breaker valve (storage tank)	Groth	
Emergency shut-off valve (unloading station)	Fisher	Rego
Ammonia gas detectors	Scott Instruments	
Junction boxes	Peerless	
PLC's	Allen Bradley (Compact Logix)	GE Fanuc (9030 series)

***Peerless reserves the right to provide alternate suppliers.**

V. DESIGN CRITERIA

A. DESIGN CONDITIONS: The proposed SCR System design is based on the following design conditions; the data is for one (1) unit. Should the actual gas conditions be different from the design data, the performance shall be re-evaluated, based on the corrected design data.

See Attachment Labeled: 24648 Design Data (SCR-CO Reduction) 2012-05-15

B. CATALYST DESIGN DETAILS:

SCR CATALYST DATA			
Catalyst Manufacturer	Cormetech	Haldor Topsoe	Equal (with Buyer approval)
Catalyst Type	Honeycomb Ceramic Vanadium / Titanium	Honeycomb Vanadium / Titanium	Honeycomb or Plate Vanadium / Titanium
Gas Flow	Horizontal	Horizontal	Horizontal

CO CATALYST DATA			
Catalyst Manufacturer	BASF	Equal (with Buyer approval)	
Catalyst Type	Platinum / Palladium	Platinum / Palladium	
Gas Flow	Horizontal	Horizontal	

C. UTILITY CONSUMPTION (AQUEOUS ELECTRIC AMMONIA FLOW CONTROL UNIT):

DESCRIPTION	QUANTITY	UNITS
Design Flow Rate **Aqueous Ammonia** (19% by Weight)	25	Lbs/Hr/Unit
Ammonia Supply Pressure	40	PSIG
Ammonia Inlet Temperature	Ambient	F Minimum for NH_3
Ammonia Inlet Temperature	Ambient	F for NH_4OH
AFCU Electric Air Heater		
Capacity	30	kW
Consumption at Maximum Operating Ammonia Flow Rate (Estimated)	TBD	kW
Instrument Air (-20 F Dew Point or Better)		
Supply Pressure	80-125	PSIG
Maximum Steady State Air Consumption	1	SCFM
Maximum Instantaneous Air Supply Demand	5	SCFM
AFCU Dilution Air Blowers		
Nominal Motor Rating (Estimated Only)	5	HP
Operating Power Consumption (Estimate)	75% of rated capacity	BHP
Cooling Air Blowers		
Nominal Motor Rating (Estimated Only)	200	HP
Operating Power Consumption (Estimate)	75% of rated capacity	BHP

VI. LIST OF DOCUMENTS RECEIVED WITH INQUIRY:

Peerless has designed the equipment in accordance with the following specifications with exception to the items listed under Section VI of this proposal. Referenced specifications will be considered only if copies are provided with the proposal inquiry. State and local codes and/or regulations will be considered only if applicable copies are attached to the proposal inquiry.

- Project specifications were not included with the inquiry documents.

VII. TECHNICAL CLARIFICATIONS AND EXCEPTIONS:

- No exceptions noted at this time.

VIII. COMMERCIAL CLARIFICATIONS AND EXCEPTIONS:

- See attached document labeled “New CON1000A Peerless Acceptance Form” dated July 8, 2010.

IX: DESIGN NOTES / ANSWERS TO FREQUENTLY ASKED QUESTIONS:

1. Required Control Input Signals (by others): load signal, CEMS output signals, inlet analyzer signals

X. PEERLESS STANDARD TERMS AND CONDITIONS:

1. PRICE. Unless otherwise specified in this Quotation, prices exclude all taxes (imposed by any state, country or other governmental entity), duties, packing and freight costs (including, without limitation, the cost of loading goods on board a carrier) and related costs and expenses, all of which shall be added to such prices and paid by Buyer. In addition, Buyer shall pay, or reimburse Seller for, reasonable out-of-pocket expenses, including, without limitation, travel and travel-related expenses, incurred by Seller in connection with the performance of its obligations or incurred by Seller at the request or with the approval of Buyer. Should Buyer request any change in goods or services covered by this Quotation, Seller shall not be obligated to proceed with such change until Seller agrees in writing to proceed with such change. If Seller determines that any such change may cause an increase in Seller's costs or the time required for provision of goods or services, or may raise other issues of concern to Seller, an equitable adjustment shall be made with respect to price, schedule or otherwise in order to address such issues.

2. PAYMENT. Unless otherwise specified in this Quotation, payment for goods and services covered by this Quotation shall be made, in cash, within thirty (30) days from date of Seller's invoice. Unless otherwise specified in this Quotation, U.S. dollars shall be the currency of account, for all purposes, with respect to this Quotation. Amounts not paid when due by Buyer shall bear interest at the highest lawful rate on the unpaid amount from the due date until paid; provided, however, extended payment terms are acceptable only if agreed upon in writing by Seller.

3. SCHEDULES. All dates or schedules specified in this Quotation are approximate and are based upon Buyer's and other parties' timely provision of information, and performance of related work and obligations, necessary for Seller to perform its obligations hereunder. Seller shall be excused from any failure to meet such dates or schedules, where such failure is occasioned by any of the circumstances or conditions enumerated in paragraph 13 below. If any failure to meet dates or schedules is occasioned by the fault of Seller, Seller shall make commercially reasonable efforts to remedy such failure as soon as reasonably practicable. Any installation or use of goods or services by Buyer shall constitute a waiver of all claims for delay. Seller has the right to deliver goods at one time or in installments, from time to time, within the period provided for delivery. In the event of partial shipments, Seller may immediately invoice Buyer for the amount(s) due in respect thereof, which amount(s) shall be due and payable in accordance with paragraph 2 above. Delivery of nonconforming goods, or a default of Seller of any nature in relation to one or more installments, shall not substantially impair the value of this transaction, as a whole, and shall not constitute a default hereunder, as a whole.

4. SECURITY INTEREST. Seller shall retain, and Buyer hereby grants to Seller, a security interest in goods covered by this Quotation, now owned or hereafter acquired, wherever located, including all returns, repossessions and parts, and all chattel paper, instruments, documents, accounts, general intangibles, contract rights and security agreements (resulting from the sale or other disposition of such goods) and all cash and non-cash proceeds of any of the foregoing, which shall secure the payment of all amounts due from Buyer to Seller as specified in this Quotation. Buyer shall, at the request of Seller, execute, and hereby grants Seller the right to execute in the name of Buyer, any documents necessary to grant to Seller a security interest in such goods and any filings necessary to perfect such security interest in all jurisdictions where Seller deems such filings to be necessary to protect its interest.

5. INSPECTION. Buyer shall have the right to inspect goods fabricated hereunder prior to acceptance provided (i) such inspection shall occur at the place of fabrication, during the period of fabrication, (ii) such inspection shall be conducted by an authorized and qualified representative of Buyer, during normal working hours after reasonable notice to Seller and without interference with operations, (iii) Buyer shall ensure that all persons involved in such inspection comply with applicable security and other procedures relating to the place of fabrication and (iv) Buyer shall promptly notify Seller, in writing, in the event that any person involved in such inspection shall discover any defects or other problems with respect to the goods. Any inspection at the facilities of a supplier or subcontractor of Seller shall be subject to securing permission from such supplier or subcontractor, and Seller shall make commercially reasonable efforts to obtain such permission. Buyer shall accept goods, or part thereof, as soon as they are reasonably tendered to Buyer, unless during inspection at the place of fabrication Buyer has notified Seller of the unacceptability of such goods and confirms such notice in writing within ten (10) days of such inspection, but not later than the regularly scheduled shipment of such goods. Buyer may not revoke its acceptance. This paragraph 5 in no way modifies or affects Buyer's remedies or Seller's warranties set forth elsewhere in this Quotation.

6. INSTALLATION/SERVICE. Unless otherwise specified in this Quotation, all goods shall be installed by and at the expense of Buyer. If so specified in this Quotation, Seller shall furnish technical personnel to assist in installation and start up of goods, in which case Buyer shall pay Seller, at Seller's then current commercial billing rates, for the resources utilized in connection with such assistance. In the event of service calls, exclusive of service calls necessitated by Seller's beach of the warranties set forth elsewhere in this Quotation, Buyer shall pay Seller, at Seller's then current commercial billing rates, for the resources utilized in connection with such service calls.

7. SPECIFICATIONS. In the event Buyer is to specify the form, measurement, features or other specifications for goods, or to provide other information with respect to goods or services, Buyer shall deliver and secure Seller's written acceptance of such information on or before the agreed date or, if no date has been agreed upon, within a reasonable time after receipt of a request from Seller. Seller's quality assurance and other procedures, specifications and drawings, as approved Buyer, shall be deemed for all purposes to comply with any procedures, specifications and drawings of Buyer and to supersede any conflicting terms thereof.

8. COOPERATION. Buyer shall cooperate with Seller in connection with Seller's performance of its obligations through, among other things, performing its responsibilities set forth in this Quotation, securing performance of related work by other parties and making available, as reasonably requested by Seller, access, management decisions, information, approvals and acceptances in order that Seller may perform its obligations in a timely manner.

9. WARRANTIES.

a) General. Seller warrants to Buyer that, under normal use, each item of goods covered by this Quotation shall be free from defects in workmanship and material for a period of twelve (12) months from the date of installation or eighteen (18) months from date of shipment, whichever occurs first. In the event this Quotation specifies a performance warranty or guaranty, Seller warrants to Buyer that, under normal use, each item of goods covered by this Quotation shall perform, in all material respects, in a manner consistent with such performance warranty or guaranty for the period specified in such performance warranty or guaranty or, if no such period is specified, for the period specified in the immediately preceding sentence. "Normal use", as used herein, includes only such uses under such conditions as have been fully disclosed, in writing, to Seller prior to the date of this Quotation. In addition, Seller warrants to Buyer that Seller shall use reasonable care in providing services covered by this Quotation and that such services shall be provided in a workmanlike manner. In the event there are any nonconformities with these warranties, which nonconformities are reported by Buyer to Seller during the applicable warranty period, Seller shall promptly repair or replace the nonconforming goods and re-perform the nonconforming services.. In the event Buyer claims a nonconformity with these warranties, Seller or its appointee shall have the right to finally approve or disapprove such claim. In each instance of nonconforming goods, Buyer may elect, at its option, to (i) return goods, or part thereof, covered by this Quotation and to which the nonconformity relates, to Seller, at Seller's fabrication facility, risk of loss en route to Seller's facility to lie with Buyer, for Seller's inspection and approval or disapproval or (ii) demand an on-site inspection of such goods. If Seller approves a claim, all transportation costs and other incidental costs incurred in Seller's inspection of the goods, or part thereof, shall be borne by Seller; otherwise, Buyer shall bear all such costs.

b) Exceptions. Notwithstanding anything to the contrary, if any nonconformities with these warranties arise, in whole or part, as a result of work performed by, or the act or omission of, Buyer or any other party, the maintenance or modification of goods other than by Seller, Vendor Items (as hereinafter defined), operation or use of goods or services in a manner inconsistent with any design conditions or other than as anticipated by applicable specifications or other than in accordance with operating instructions provided by Seller, failure to maintain catalyst and other consumables in accordance with manufacturer recommendations or any services, software, equipment or other items provided by Buyer or a third party, such nonconformity shall not constitute a nonconformity with these warranties and Seller shall not be responsible therefor. Notwithstanding anything to the contrary, and except as otherwise specifically agreed in writing by Seller, Seller shall have no responsibility for suggesting, specifying or confirming the appropriateness of Buyer's specification of any goods, materials or other items used in the fabrication of goods or any other thing and no warranty in respect thereof is made by Seller. No failure which directly or indirectly relates, in whole or part, to such goods, materials or other items shall be, in any respect, the responsibility of Seller or a nonconformity with these warranties. These warranties shall not apply to any goods, materials, items or services supplied to Seller by Buyer. Seller hereby assigns to Buyer any warranties given by Seller's suppliers or subcontractors ("Vendors") in connection with any goods, materials items or services obtained by Seller from such Vendors ("Vendor Items") and included as a part of goods or services covered by this Quotation, to the extent such warranties are so assignable at no additional cost to Seller. To the extent that any such warranties are not assignable, Seller shall, upon the written request of Buyer and at Buyer's expense, take commercially reasonable actions to enforce any applicable warranty which is enforceable by Seller in its own name. However, Seller shall have no obligation to resort to litigation or other formal dispute resolution procedures to enforce any such warranty. With the exception of applicable Vendor's warranties which Seller is able to pass through for Buyer's benefit, Vendor Items are provided on an "AS IS" basis without warranty and, notwithstanding anything to the contrary, Buyer agrees to look solely to the applicable Vendor for any and all warranty claims respecting Vendor Items.

c) Disclaimer. THESE WARRANTIES ARE EXPRESSLY IN LIEU OF ALL OTHER EXPRESS OR IMPLIED WARRANTIES, INCLUDING ANY IMPLIED WARRANTY OF MERCHANTABILITY, FITNESS, TITLE OR NONINFRINGEMENT OF ANY PATENT OR OTHER PROPRIETARY RIGHT AND OF ANY OTHER OBLIGATION ON THE PART OF SELLER, except as may be otherwise specified in this Quotation. Other warranties specified in this Quotation, if any, are strictly limited to their respective terms and in no way modify, alter, or waive the general effect of this disclaimer as to all other express or implied warranties. No agent, distributor or representative of Seller has any authority to bind Seller to any affirmation, representation or warranty, either written or oral, concerning goods or services covered by this Quotation or any other matter or thing and, unless an affirmation, representation or warranty made by an agent, distributor or representative is specifically included within this

Quotation, it shall not be enforceable by Buyer. The remedies set forth in this paragraph 9 constitute Buyer's sole and exclusive remedies for any nonconformity with these warranties.

d) Suspension. Notwithstanding anything to the contrary, Seller's may, at its option, suspend performance under this paragraph 9 in the event Buyer is not in full compliance with this Quotation and its obligations hereunder. While, during any such suspension, Seller shall have no obligations under this paragraph 9, such suspension shall not result in any extension of applicable warranty periods or otherwise modify these warranties.

10. BUYER'S REMEDIES. Buyer's exclusive and sole remedies, except as provided in paragraph 9 above, for any default hereunder by Seller, are strictly limited to either, at Seller's option, (a) refund of the price paid by Buyer for goods and services in question and return of such goods to Seller or (b) repair and/or replacement of nonconforming goods, or parts thereof, and re-performance of nonconforming services. Notwithstanding anything to the contrary, in the event this Quotation provides for liquidated damages or any other specified amount to be paid, or indemnification or any other specified action to be taken, by Seller, such amount or action shall constitute Buyer's sole and exclusive remedy for the circumstance or condition upon which such amount or action is based. Under no circumstances shall (i) Buyer have the right to claim or recover any punitive, exemplary, incidental or consequential damages or (ii) Seller be liable, in the aggregate for any and all matters arising out of, under, or in connection with this Quotation, whether based on an action or claim in contract, equity, negligence, intended conduct, tort or otherwise, for more than the amount paid by Buyer for goods and services covered by this Quotation.

11. SELLER'S REMEDIES. All of Seller's remedies set forth in this Quotation, in the event Buyer fails to comply with this Quotation or any of its obligations hereunder, shall be cumulative and in addition to, and not in lieu of, any other remedies available to Seller at law, in equity or otherwise, and may be enforced concurrently or from time to time and Seller shall additionally be entitled to recover its reasonable attorney's fees and costs incurred by Seller in the enforcement of its rights and remedies. Without limiting the foregoing, in the event Buyer fails to make one or more payments when due, or otherwise defaults in the performance of any of its obligations, Seller may, at its option, suspend performance hereunder until such default is cured or terminate its obligations hereunder, or both.

12. RISK OF LOSS AND PASSAGE OF TITLE. Unless otherwise specified in this Quotation, all goods to be delivered by Seller are sold ex works (as defined in Incoterms 2000, ICC Publication NO. 460) and title to such goods shall pass to Buyer at the earlier of (i) the date when Buyer obtains physical possession of such goods or part thereof or (ii) the date such goods are loaded on a carrier for delivery to Buyer. If no carrier is specified by Buyer sufficiently in advance of the required date(s) of shipment, Seller may select any mode(s) of transportation and any common carrier satisfactory to Seller and such selection shall conclusively be deemed satisfactory to Buyer. In the absence of a written agreement to the contrary, Buyer bears all risks of shipment of any goods sold hereunder.

13. FORCE MAJEURE. Seller shall be excused from performance hereunder for any period, and to the extent, that it is hindered or prevented from performing pursuant hereto, in whole or in part, as a result of delays caused by Buyer or third parties, floods or other acts of God, war, revolution, terrorism or civil disturbance, governmental action, statute, ordinance or regulation, court order, strike or other labor dispute, fire, damage to or destruction in whole or in part of goods or place of fabrication, lack or inability to obtain raw materials, labor, fuel or supplies or any other circumstances or conditions beyond Seller's reasonable control. In the event of nonperformance occasioned by any of the foregoing circumstances or conditions, the time for performance shall be extended to the extent of such delay. Such nonperformance shall not be a default hereunder or a ground for termination hereof and shall not excuse Buyer from its payment obligations hereunder or extend the time for such payment.

14. VERIFICATION OF INFORMATION. This Quotation, including, without limitation, prices, schedules and specifications set forth herein, is based upon information furnished by Buyer to Seller. Buyer believes that such information is accurate and complete. However, if any such information should prove to be inaccurate or incomplete in any material respect, Seller may, at its option and by giving written notice thereof to Buyer, make appropriate adjustments to the provisions hereof including, without limitation, prices, schedules and specifications.

15. OWNERSHIP. Unless otherwise specified in this Quotation, Buyer shall not obtain any rights or interests in any patent, copyright, proprietary right or confidential know-how, trademark or process owned by Seller or any other party. Any and all intellectual property rights, including rights of patent, copyright and trademark, in any reports, drawings, documents, specifications, calculations, confidential know-how, materials, or processes (the "Intellectual Property Rights") owned or created by Seller and used or embodied in goods or services covered by this Quotation shall remain the sole property of Seller. Any and all Intellectual Property Rights developed by Seller, whether in the provision of goods and services covered by this Quotation or independently thereof, shall belong to Seller. Any and all right, title or interest that Buyer or any other party may have or obtain in or to Seller's Intellectual Property Rights is hereby assigned to Seller and Buyer shall take, or cause to be taken, all necessary or appropriate actions to vest such Intellectual Property Rights in Seller.

16. CONFIDENTIALITY. Buyer shall handle confidentially all designs and specifications and technical, commercial, financial and other information which Buyer receives from Seller pursuant to this transaction and shall not use, copy or communicate such information to others except in the performance of Buyer's obligations pursuant to this Quotation or as necessary for operation and use of the goods, without prior written consent of and the payment of fair compensation to Seller. If Buyer discloses such information to any other party, as permitted by this paragraph 16, Buyer shall secure such party's written agreement to the same confidentiality restrictions as stipulated herein and shall cause such party to comply with such confidentiality restrictions.

17. BUSINESS RELATIONSHIP. Seller, in providing goods and services to Buyer, is acting only as an independent contractor and under no circumstances shall Seller be deemed to be in any relationship with Buyer carrying with it fiduciary or trust responsibilities, whether through partnership or otherwise. Unless otherwise specified in this Quotation, Seller has the sole right and obligation to supervise, manage and direct the provision of all goods and services covered by this Quotation. Seller does not undertake by this Quotation or otherwise to perform any obligation of Buyer, whether regulatory or contractual, or to assume any responsibility for Buyer's business or operations. Buyer shall (i) accurately represent goods and services covered by this Quotation, including, without limitation, as to quality, function, purpose and compatibility, (ii) not attempt or purport to create any obligation of Seller with respect to goods, services or otherwise, (iii) not add, remove, obstruct, conceal, change or deface any notice, legend, logo, designation or other mark on, or affixed to, any goods or any packing or other materials provided with goods, (iv) permit operation, maintenance and use of goods only in accordance with, and in a manner anticipated by, applicable design conditions, specifications and operating instructions and (v) market and distribute goods and services only in the form provided to Buyer by Seller. Buyer shall indemnify, defend and hold Seller harmless from any and all damages, liabilities, costs, and expenses, including without limitation, reasonable attorneys' fees and expenses, arising out of, under or in connection with any claim, demand, charge, action, cause of action or other proceeding relating to the conduct of Buyer's business, including without limitation, the acquisition, transfer, operation and/or use of goods and services covered by this Quotation. This Quotation is not intended to confer any rights or benefits on any third party, including, without limitation, any employee, customer, business associate, creditor or affiliate of Buyer.

18. WAIVER. Waiver or nonenforcement by either Seller or Buyer of a right or privilege with regard to, or of a default by the other of, any term or condition of this Quotation shall not be deemed a waiver of future compliance therewith, and such terms or conditions shall remain in full force and effect.

19. ASSIGNMENT. Buyer shall not assign or transfer its rights or obligations under this Quotation, or any part hereof, without Seller's prior written consent.

20. HEADINGS. The headings contained in this Quotation are for reference purposes only and shall not in any way affect the meanings or interpretations hereof.

21. CHOICE OF LAW AND FORUM. This Quotation shall be governed by and construed in accordance with the laws of the State of Texas, without giving effect to principles of conflict of laws. The United Nations Convention on the International Sale of Goods shall not be applicable to this transaction. Any dispute that may arise out of or in connection with this transaction shall be subject to the exclusive jurisdiction of the courts of the State of Texas and the U.S. federal courts located in such state, and Buyer irrevocably submits to the personal jurisdiction of such courts for purposes of any suit, action or proceeding involving any such dispute.

22. ENTIRE AGREEMENT. The terms and conditions set forth in this Quotation constitute the entire agreement between the parties with respect to the subject matter hereof. This Quotation wholly cancels, terminates and supersedes any and all letters, requests for quotes, quotes, purchase orders, acknowledgments, bills of lading, agreements and understandings, whether oral or written, between Buyer and Seller with respect to the subject matter hereof. Terms and conditions set forth in any letter, request for quote, quote, purchase order, acknowledgment, bill of lading, agreement or other document utilized or exchanged by the parties shall not be incorporated herein or binding unless expressly agreed upon in writing by Seller. This Quotation may not be modified or terminated orally, and no modification, termination or waiver shall be binding on Seller unless accepted and acknowledged by a written instrument signed by a duly authorized representative of Seller.

23. EXPORTS. If all or any portion of the goods to be provided pursuant to this Quotation are to be exported from the United States, Buyer agrees that such exportation is subject in all respects to, and Buyer shall comply in all respects with, United States laws with respect to such export and subsequent re-export of such goods. Seller makes no representation or warranty relative to the export or re-export of such goods.

24. SURVIVAL. All representations, warranties, covenants and indemnities made in this Quotation shall survive the consummation of the transactions contemplated by this Quotation. Termination of all or any part of this Quotation, for any reason, shall not release Buyer from any liabilities or obligations set forth in this Quotation which (i) expressly survive any such termination or (ii) remain to be performed or by their nature would be intended to be applicable following any such termination.

25. SAVINGS CLAUSE. If any provision of this Quotation is declared or found to be illegal, unenforceable or void, then obligations arising under such provision shall be null and void and each provision not so affected shall be enforced to the full extent permitted by law.

26. ARBITRATION. Any controversy arising out of this transaction shall be finally settled by arbitration. The arbitration shall be carried out pursuant to the commercial arbitration Rules of the American Arbitration Association then in force by one or more arbitrators appointed in accordance with such rules. The arbitration shall take place in Dallas, Texas, U.S.A., and the award shall be deemed a State of Texas award. The English language shall be used in the arbitration proceedings. The award shall be made and shall be payable in U.S. dollars free of any tax or other deduction. The award shall include interest from the date of any breach or other violation of this Agreement to the date when the award is paid in full at an appropriate rate of interest fixed by the arbitrators. Judgment upon the award may be entered in any court of appropriate jurisdiction.

XI. START-UP SUPPORT AND FIELD SERVICE RATES (DOMESTIC):

DOMESTIC FIELD SERVICE RATE SHEET (Effective 3/1/09)
FIELD SERVICE includes inspection, direction of installation or repair (labor by others), startup, initial adjustments, readjustment, test and general inspection of plant personnel for the operation and maintenance of Peerless Mfg. Co.'s and related equipment in a plant system. The field service is performed by Peerless Mfg. Co.'s Authorized Service Representative(s) or by representatives from other companies hired by Peerless Mfg. Co. to perform a specific task. This service does not include the supply of any parts. It is performed only on the basis of a bona fide purchase order for field service issued by the ultimate customer or his authorized representative, covering the specific type of service desired. Peerless Mfg. Co.'s service is subject to the Field Service Terms & Conditions shown on the following page.

Service Category	Type of Service	Daily Rates (8 hours)
A	Maintenance Service	$1500.00 plus expenses
B	Startup Service	$1500.00 plus expenses
C	Classroom Instruction	$1500.00 plus expenses
D	Engineering Consultation	Consult PMC-Dallas
E	Annual Equipment Inspection	$1200.00 plus expenses
F	Construction Supervision	$1800.00 plus expenses
G	PLC-Commissioning / Programming	$1800.00 plus expenses

Billing will be based on rates in effect at the time service is rendered. Rates apply within the continental United States only.

Notes:
A) "Time" is based on travel time to the job from the man's regularly assigned office location, on-the-job work hours and return travel to the office location. Travel time will be billed as straight time and will not exceed 8 hours. Travel time from job to job will be a prorated charge.

B) “Overtime” applies to all time spent working in excess of 8 hours during a normal working day, any time other than a normal day shift and any time on Saturdays. Overtime will be billed at 1-1/2 times the regular rate. Time on Sundays and holidays recognized by Peerless Mfg. Co. will be billed at 2 times the regular rate.

C) A "man day" is considered as 8 hours time per man during a normal day shift working hours. The minimum amount invoiced shall be for one man day (or eight hours).

D) “Standby time” is chargeable on-call time during which the service representative is available but unable to proceed with work functions due to jobsite delays. On-site standby time is chargeable at the applicable rate. Off-site standby time is chargeable at full applicable rate. While off-site time on weekdays, beyond 8 hours or weekends and holidays is considered non-chargeable personnel time, the field representative can be made available on an "on-call" basis, if required. This availability, when requested, becomes chargeable at applicable straight time rates. On-site time required becomes chargeable at the applicable overtime rate.

E) Peerless Mfg. Co. does not guarantee that the customer's personnel who participate in instruction sessions are sufficiently trained to properly operate the equipment.

F) For service visits which extend beyond two weeks, the service representative will be allowed to travel home on the second weekend with time and expenses chargeable at the applicable rate.

G) When Peerless Mfg. Co. finds it necessary to hire service representatives from other companies to place major equipment for service, we shall invoice for this service at cost, plus 10% to cover handling charges.

H) Field Service may be obtained by contacting Peerless Mfg. Co., SCR Systems Division, Dallas, Texas.

I) Two weeks’ advance written notice, including a purchase order referencing this document, is required to guarantee that a site representative will be dispatched to the job site. A US$3,000.00 cancellation fee will apply if the site visit is canceled within three (3) working days of departure.

J) A minimum notice of 72 hours is required on all cancelations.

Expenses:
A) Travel – Round trip plane tickets, private or rental automobile charges from the point of regularly assigned location of the service representative plus any required local travel. Private automobile charges will be 60 cents per mile. Tolls and parking fees are additional. When our service representative goes from job to job rather than returning to his corporate office, travel charges will be distributed on a prorated basis.

B) Living – Lodging, meals, and incidental costs are living expenses.

C) Receipts for air travel, automobile rental and lodging will be available upon request. Receipts for meals and incidental costs are not required by Peerless Mfg. Co., but will be supplied upon prior arrangements.

D) Special Equipment – If necessary for start-up or is requested by the customer, Peerless Mfg. Co. will furnish any special equipment:

- Portable emissions analyzer – charged at $75.00 per hour
- Rented equipment – charged at rental cost plus 10% administration fee.

E) 10% administration fee will be applied to all expenses.

XII. PEERLESS MFG. CO. FIELD SERVICE TERMS & CONDITIONS:

The following Terms & Conditions of Sale shall govern all orders and take precedence when Terms & Conditions Between Peerless Mfg. Co. and the Customer differ in substance and/or are in conflict.

General Conditions:
Peerless is not responsible for the performance of equipment when startup and adjustment is performed by persons who are not Peerless Mfg. Co. Field Authorized Service Representatives. Satisfactory equipment operation is dependent upon proper ammonia, air and/or temperature control; limit devices; operating permissiveness; and sound operating practices.

In view of the nature of application and frequent interrelatedness of Peerless Mfg. Co.'s equipment with that of other companies' equipment, minor resizing of critical parts may become desirable and necessary at startup or during early operation in order to improve the application. Any such changes shall not affect nor change normal warranty or liability or validity of the customer's purchase order(s) for equipment or services. Any parts required for such modifications are considered a no-charge warranty replacement. However, additional startup service required to make such minor changes at time of startup (e.g. flow meters, spray nozzles, to optimize system operation) is not covered by warranty and is chargeable to the customer. All necessary parts will be supplied on a no charge warranty basis. However, Peerless Mfg. Co.'s service labor will be invoiced separately.

Peerless Mfg. Co. maintains the following insurance coverage: Commercial General Liability, Foreign Worldwide Liability, and Employers' Liability and Business Automobile liability. A Statutory Insurance Certificates is available upon request. Customers who order service without a purchase order will be charged a $75.00 administrative fee to be named as an additional insured.

Specific Term:

1. Pricing
Purchase orders are subject to review and acceptance by Peerless Mfg.

2. Terms of Payment
Invoices are to be in cash, net 15 days from invoice date. All overdue accounts will be subject to a late charge of 1.5% per month from due date until paid. Peerless Mfg. Co. does not hereby agree to give further time for payment, but rather intends to impose a charge for late payment. Peerless Mfg. Co. hereby reserves any right it may have to file a mechanic's lien against the site at which Peerless Mfg. Co. performs service.

3. Limitations of Liability
Peerless Mfg. Co. shall not be responsible for the acts and workmanship of the employees, contractors, sub-contractors or agents of the Customer. Peerless Mfg. Co. shall not be liable to the Customer for any loss or injury to persons or property caused by negligence of the Customer, its employees, contractors, suppliers or their employees, agents or sub-contractors. In no event shall Peerless Mfg. Co. be liable, whether arising under contracts, tort (including strict liability and negligence) or otherwise, for loss of anticipated profits, loss by reason of plant shutdown, non-operation or increased expense of operation, service and erection, cost of purchase of replacement power, or for any special, indirect, incidental or consequential loss or damage of any nature arising at time or from any cause whatsoever.

4. Indemnification
Peerless Mfg. Co. will defend and indemnify the customer against all damages, liability, claims, losses and expenses (including attorneys' fees) for injury or death to persons or damage to property of other arising out of, or resulting in any way from any defect in the services purchased hereunder or from any negligent act or omission of them, its agents, employees or subcontractors, provided a request is made within 90 days after the services are rendered. In that event, Peerless Mfg. Co. will not be liable for bodily injury or property damage beyond $1,000,000 per occurrence and in the aggregate.

5. Arbitration
In the event any dispute arises out of or relating to this Agreement, the parties shall attempt to resolve their differences by negotiation failing which either party may submit the matter to arbitration. The arbitration shall be conducted in accordance with the Commercial Rules of the American Arbitration Association and judgment on the award may be entered in any court having jurisdiction. There shall be one arbitrator, to be selected by mutual agreement of the parties. If the parties cannot agree on such arbitrator within thirty days after commencement of discussions regarding such arbitrator, then either party, on behalf of both may request appointment of the arbitrator by the then presiding judge of the Federal District Court for the State of Texas. Each party shall pay the fees of its own attorneys, and the expenses of its witnesses and all other expenses connected with presenting its case. Other costs of the arbitration, including the costs of any record or transcription of the arbitration, administrative fees and the fee of the arbitrator shall be borne equally by the parties.

CATALYST OXIDATION ADD-ON CONTROL COST ANALYSIS

Mercury 50-6400R ULP - Oxidation Catalyst Add-On Controls Cost Analysis

DATA INPUT

Turbine Configuration	Simple Cycle or unfired HRSG	
Turbine CO Conc.	10	(@ 15% O2)
Control Efficiency	90%	
Duct Burner Heat Input	0	MM BTU_{HHV}/hr
Ductburner Emission factor	0.1	lb/MM BTU_{HHV}
Annual Operating Hours	8760	
Include CEM ? (y/n)	y	

Direct Capital Costs (DC):						
Purchased Equip. Cost (PE):						
Basic Equipment (Framed Catalyst and Housing	4.6 MW			$	39,413	DCL International
Transition ducting & expansion joints				$	14,000	CS estimate
						CS estimate
Taxes and freight:			0.08 (A+B+CEM)	$	3,000	OAQPS
PE Total:				**$**	**56,413**	
Direct Installation Costs (DI):						
Foundation & supports:			0.08 PE	$	5,000	OAQPS
Handling and erection:			0.14 PE	$	8,000	OAQPS
Insulation(catalyst housing only):			0.01 A	$	1,000	estimate
Painting:			0.01 PE	$	1,000	OAQPS
Additional HRSG cost to "split" boiler.				$	-	CS estimate
CEM Installation				$	-	EPA Model
Site Preparation/Excavation				$	-	Site Specific
DI Total:				**$**	**15,000**	
Installed CEM Costs				**$**	**-**	**Vendor**
DC Total (PE+DI):				**$**	**71,413**	
Indirect Costs (IC):						
Engineering:			0.10 PE	$	6,000	OAQPS
Construction and field expenses:			0.05 PE	$	3,000	OAQPS
Contractor fees:			0.10 PE	$	6,000	OAQPS
Start-up:			0.02 PE	$	1,000	OAQPS
CEM: Startup Test, QA/QC Plan				$	-	EPA Model
Performance testing:			0.01 PE	$	564	Inclu. In CEM
Contingencies:			0.03 PE	$	2,000	OAQPS
IC Total:				**$**	**18,564**	
Total Capital Investment (TCI = DC + IC):				**$**	**89,977**	

Direct Annual Costs (DAC):						
Operating Costs (O):						
Operator:	hr/shift:	0.3	operator pay ($/hr): 30	$	8,000	OAQPS
Supervisor:	15% of operator			$	2,000	OAQPS
Maintenance Costs (M):						
Labor:	hr/shift:	0.3	labor pay ($/hr): 35	$	10,000	OAQPS
Material:	% of labor cost:	100%		$	10,000	OAQPS
CEM Annual Costs				$	26,000	EPA Model
Utility Costs:						
Additional Pressurre Drop		1.8	iwc			Specified
Perf. loss:	(%):	0.5	(0.25% per inch)			Estimate
Electricity cost	($/kwh):	0.1	Performance loss cost penalty:	$	18,000	Estimate
Catalyst Costs						
Catalyst Life (yrs)	7					
Interest Rate (%)	7	8.654	Capital Recovery			
Annualized catalyst replace:assume 2.8 ft3 catalyst per MW, $2300/ft3				$	3,000	vendor
Annualized catalyst dispose(included w/ catalyst cost)						
Annualized Precious Metal Credit				$	(1,932)	vendor
Total DAC:				**$**	**75,068**	
Indirect Annual Costs (IAC):						
Overhead:	60% of O&M				18,000	OAQPS
Administrative:			0.02 TCI		2,000	OAQPS
Insurance:			0.01 TCI		1,000	OAQPS
Property tax:			0.01 TCI		1,000	OAQPS
Capital recovery:	interest rate (%):	7				
	period (years):	20	0.09 TCI		8,000	OAQPS
Total IAC:					**30,000**	
Total Annual Cost (DAC + IAC):					**$105,068**	

CO Exhaust Concentration	**1 ppmv**
Turbine CO Emission Rate (tons/yr):	4.3
Duct Burner CO (tons/yr):	0.0
CO Removed (tons/yr):	3.9
Cost Effectiveness ($/ton):	$27,149
Electricity Cost Increment (¢/kwh):	0.261

Notes:

1) Basic Equipment includes: monolithic Pt Catalyst welded in SS frame and housing for simple cycle. Carbon steel used on low temp.

2) CEM Costs include: platform,analyzers and auxillary equipment,installation, initial performance test, and QA/QC plan.

3) Additional Ducting for Simple Cycle includes: transition piece and expansion joint each side of catalyst housing.

4) OAQPS data is for VOC reduction catalyst with supplemetal fuel.

5) Vendors Contacted: Prototech, Engelhard, Johnson Matthey. BASF does not sell monolithic, only pelletized.

6) Catalyst works best in the 500-1200 F range with max UHC removal at the higher temps. Exhaust stream must be cooled before contacting catalyst. Therefore, must install within boiler (I.e. split boiler) at substantial added cost.

7) Catalyst Performance (eff) strong function of temp and flow. Since Duct Burner adds little flow (1%), catalyst control efficiency is relatively unaffected by duct burner addition.

Titan 250 30000S - Oxidation Catalyst Add-On Control Cost Analysis (GT-01)

DATA INPUT

Turbine Configuration	Simple Cycle or unfired HRSG	
Turbine CO Conc.	25	(@ 15% O2)
Control Efficiency	90%	
Duct Burner Heat Input	0	MM BTU_{HHV}/hr
Ductburner Emission factor	0.1	lb/MM BTU_{HHV}
Annual Operating Hours	8760	
Include CEM ? (y/n)	y	

Description of Cost				Cost Factor	Cost ($)	Source
Direct Capital Costs (DC):						
Purchased Equip. Cost (PE):						
Basic Equipment (Framed Catalyst and Housing)(	21.7 MW				$ 251,550	DCL International
Transition ducting & expansion joints					$ 29,000	CS estimate
						CS estimate
Taxes and freight:				0.08 (A+B+CEM)	$ 20,000	OAQPS
PE Total:					**$ 300,550**	
Direct Installation Costs (DI):						
Foundation & supports:				0.08 PE	$ 25,000	OAQPS
Handling and erection:				0.14 PE	$ 42,000	OAQPS
Insulation(catalyst housing only):				0.01 A	$ 3,000	estimate
Painting:				0.01 PE	$ 4,000	OAQPS
Additional HRSG cost to "split" boiler.					$ -	CS estimate
CEM Installation					$ -	EPA Model
Site Preparation/Excavation					$ -	Site Specific
DI Total:					**$ 74,000**	
Installed CEM Costs					**$ -**	**Vendor**
DC Total (PE+DI):					**$ 374,550**	
Indirect Costs (IC):						
Engineering:				0.10 PE	$ 30,000	OAQPS
Construction and field expenses:				0.05 PE	$ 15,000	OAQPS
Contractor fees:				0.10 PE	$ 30,000	OAQPS
Start-up:				0.02 PE	$ 6,000	OAQPS
CEM: Startup Test, QA/QC Plan					$ -	EPA Model
Performance testing:				0.01 PE	$ 3,006	OAQPS
Contingencies:				0.03 PE	$ 9,000	OAQPS
IC Total:					**$ 93,006**	
Total Capital Investment (TCI = DC + IC):					**$ 467,556**	
Direct Annual Costs (DAC):						
Operating Costs (O):						
Operator:	hr/shift:	0.3	operator pay ($/hr):	30	$ 8,000	OAQPS
Supervisor:	15% of operator				$ 2,000	OAQPS
Maintenance Costs (M):						
Labor:	hr/shift:	0.3	labor pay ($/hr):	35	$ 10,000	OAQPS
Material:	% of labor cost:	100%			$ 10,000	OAQPS
CEM Annual Costs					$ 26,000	EPA Model
Utility Costs:						
Additional Pressurre Drop		2.1	iwc			Specified
Perf. loss:	(%):	0.5	(0.25% per inch)			Estimate
Electricity cost	($/kwh):	0.1	Performance loss cost penalty:		$ 100,000	Estimate
Catalyst Costs						
Catalyst Life (yrs)	7					
Interest Rate (%)	7	8.654	Capital Recovery			
Annualized catalyst replace:assume 2.8 ft3 catalyst per MW, $2300/ft3					$ 16,000	vendor
Annualized catalyst dispose(included w/ catalyst cost)						
Annualized Precious Metal Credit					$ (9,114)	vendor
Total DAC:					**$ 162,886**	
Indirect Annual Costs (IAC):						
Overhead:	60% of O&M				18,000	OAQPS
Administrative:				0.02 TCI	9,000	OAQPS
Insurance:				0.01 TCI	5,000	OAQPS
Property tax:				0.01 TCI	5,000	OAQPS
Capital recovery:	interest rate (%):	7				
	period (years):	20		0.09 TCI	44,000	OAQPS
Total IAC:					**81,000**	
Total Annual Cost (DAC + IAC):					**$243,886**	

CO Exhaust Concentration	**2.5 ppmv**	
Turbine CO Emission Rate (tons/yr):		**50.3**
Duct Burner CO (tons/yr):		0.0
CO Removed (tons/yr):		45.3
Cost Effectiveness ($/ton):		$5,387
Electricity Cost Increment (¢/kwh):		0.128

Notes:

1) Basic Equipment includes: monolithic Pt Catalyst welded in SS frame and housing for simple cycle. Carbon steel used on low temp.

2) CEM Costs include: platform,analyzers and auxillary equipment,installation, initial performance test, and QA/QC plan.

3) Additional Ducting for Simple Cycle includes: transition piece and expansion joint each side of catalyst housing.

4) OAQPS data is for VOC reduction catalyst with supplemetal fuel.

5) Vendors Contacted: Prototech, Engelhard, Johnson Matthey. BASF does not sell monolithic, only pelletized.

6) Catalyst works best in the 500-1200 F range with max UHC removal at the higher temps. Exhaust stream must be cooled before contacting catalyst. Therefore, must install within boiler (I.e. split boiler) at substantial added cost.

7) Catalyst Performance (eff) strong function of temp and flow. Since Duct Burner adds little flow (1%), catalyst control efficiency is relatively unaffected by duct burner addition.

Titan 250 30000S - Oxidation Catalyst Add-On Control Cost Analysis (GT-02)

DATA INPUT

Turbine Configuration	Simple Cycle or unfired HRSG	
Turbine CO Conc.	25	(@ 15% O2)
Control Efficiency	90%	
Duct Burner Heat Input	0	MM BTU_{HHV}/hr
Ductburner Emission factor	0.1	lb/MM BTU_{HHV}
Annual Operating Hours	8760	
Include CEM ? (y/n)	y	

Description of Cost				Cost Factor	Cost ($)	Source
Direct Capital Costs (DC):						
Purchased Equip. Cost (PE):						
Basic Equipment (Framed Catalyst and Housing)(	21.7 MW				$ 251,550	Vendor
Transition ducting & expansion joints					$ 29,000	CS estimate
						CS estimate
Taxes and freight:				0.08 (A+B+CEM)	$ 20,000	OAQPS
PE Total:					**$ 300,550**	
Direct Installation Costs (DI):						
Foundation & supports:				0.08 PE	$ 25,000	OAQPS
Handling and erection:				0.14 PE	$ 42,000	OAQPS
Insulation(catalyst housing only):				0.01 A	$ 3,000	estimate
Painting:				0.01 PE	$ 4,000	OAQPS
Additional HRSG cost to "split" boiler.					$ -	CS estimate
CEM Installation					$ -	EPA Model
Site Preparation/Excavation					$ -	Site Specific
DI Total:					**$ 74,000**	
Installed CEM Costs					**$ -**	**Vendor**
DC Total (PE+DI):					**$ 374,550**	
Indirect Costs (IC):						
Engineering:				0.10 PE	$ 30,000	OAQPS
Construction and field expenses:				0.05 PE	$ 15,000	OAQPS
Contractor fees:				0.10 PE	$ 30,000	OAQPS
Start-up:				0.02 PE	$ 6,000	OAQPS
CEM: Startup Test, QA/QC Plan					$ -	EPA Model
Performance testing:				0.01 PE	$ 3,006	OAQPS
Contingencies:				0.03 PE	$ 9,000	OAQPS
IC Total:					**$ 93,006**	
Total Capital Investment (TCI = DC + IC):					**$ 467,556**	
Direct Annual Costs (DAC):						
Operating Costs (O):						
Operator:	hr/shift:	0.3	operator pay ($/hr):	30	$ 8,000	OAQPS
Supervisor:	15% of operator				$ 2,000	OAQPS
Maintenance Costs (M):						
Labor:	hr/shift:	0.3	labor pay ($/hr):	35	$ 10,000	OAQPS
Material:	% of labor cost:	100%			$ 10,000	OAQPS
CEM Annual Costs					$ 26,000	EPA Model
Utility Costs:						
Additional Pressurre Drop		2.1	iwc			Specified
Perf. loss:	(%):	0.5	(0.25% per inch)			Estimate
Electricity cost	($/kwh):	0.1	Performance loss cost penalty:		$ 100,000	Estimate
Catalyst Costs						
Catalyst Life (yrs)	7					
Interest Rate (%)	7	8.654	Capital Recovery			
Annualized catalyst replace:assume 2.8 ft3 catalyst per MW, $2300/ft3					$ 16,000	vendor
Annualized catalyst dispose(included w/ catalyst cost)						
Annualized Precious Metal Credit					$ (9,114)	vendor
Total DAC:					**$ 162,886**	
Indirect Annual Costs (IAC):						
Overhead:	60% of O&M				18,000	OAQPS
Administrative:				0.02 TCI	9,000	OAQPS
Insurance:				0.01 TCI	5,000	OAQPS
Property tax:				0.01 TCI	5,000	OAQPS
Capital recovery:	interest rate (%):	7				
	period (years):	20		0.09 TCI	44,000	OAQPS
Total IAC:					**81,000**	
Total Annual Cost (DAC + IAC):					**$243,886**	

CO Exhaust Concentration	**2.5 ppmv**	
Turbine CO Emission Rate (tons/yr):		**50.3**
Duct Burner CO (tons/yr):		0.0
CO Removed (tons/yr):		45.3
Cost Effectiveness ($/ton):		$5,387
Electricity Cost Increment (¢/kwh):		0.128

Notes:

1) Basic Equipment includes: monolithic Pt Catalyst welded in SS frame and housing for simple cycle. Carbon steel used on low temp.

2) CEM Costs include: platform,analyzers and auxillary equipment,installation, initial performance test, and QA/QC plan.

3) Additional Ducting for Simple Cycle includes: transition piece and expansion joint each side of catalyst housing.

4) OAQPS data is for VOC reduction catalyst with supplemetal fuel.

5) Vendors Contacted: Prototech, Engelhard, Johnson Matthey. BASF does not sell monolithic, only pelletized.

6) Catalyst works best in the 500-1200 F range with max UHC removal at the higher temps. Exhaust stream must be cooled before contacting catalyst. Therefore, must install within boiler (I.e. split boiler) at substantial added cost.

7) Catalyst Performance (eff) strong function of temp and flow. Since Duct Burner adds little flow (1%), catalyst control efficiency is relatively unaffected by duct burner addition.

DCL America Inc.

12620 FM 1960 W, Ste A4 Box # 560, Houston, TX 77065
Tel.: 877-897-9759 *Fax:* 281-605-5858 *E-mail:* info@dclamerica.com

GLOBAL LEADER IN EMISSION CONTROL SOLUTIONS

Quote: 21-212

July 17, 2012

Quotation by: Sam Kirk

DCL America Inc.
12620 FM 1960 W, Ste A4 Box # 560, Houston, TX 77065
Tel.: 877-897-9759 *Fax:* 281-605-5858 *E-mail:* info@dclamerica.com

July 17, 2012

Providence
11767 Katy Freeway Suite 430
Houston, TX 77079
Rance Jett

RE: Mercury 50 & Titan 250 Gas Turbine

Mr. Jett,

I am pleased to provide this quote based on the following information. This quotation is valid for a period of 90 days. If you have any questions or concerns please feel free to contact myself or any of my associates at DCL America.

Please note: Our prices are based on today's precious metal prices. DCL reserves the right to revise this quote should changes occur in the spot prices of the precious metals used in the above product(s).

Also, this quotation is subject to DCL's standard terms and conditions of sale attached. Copies of limited warranty statement are available from DCL upon request (DCL doc. No. X0010-0000-68).

Best Regards,

DCL America Inc.

Sam Kirk

Regional Sales Manager

281-253-3091

DCL America Inc.
12620 FM 1960 W, Ste A4 Box # 560, Houston, TX 77065
Tel.: 877-897-9759 Fax: 281-605-5858 E-mail: info@dclamerica.com

TURBINE DATA

Turbine Model	Mercury 50	Titan 250
Power	4620 kW	30000 hp
Fuel	Pipeline NG	Pipeline NG
Exhaust Flow	31514 acfm	279024 acfm
Exhaust Temperature	685˚F	700˚F

CATALYST SYSTEM DATA

Catalyst Model	RC5x6x1-30	Custom
Catalyst Type	Oxidation	Oxidation
Number of Elements	15	120
Number of Housings	1	1
Cell Density	200 cpsi	200 cpsi
Approx. Dimensions	Custom	Custom TBD
Approx Weight	7500 Lbs	TBD
Approx. Pressure Drop	1.8” w.c.	2.1” w.c.
Connection Size	Recommended 30”	Recommended 84”

EMISSION REQUIREMENTS

Exhaust Gas Component	% Reduction
CO	90

DCL America Inc.
12620 FM 1960 W, Ste A4 Box # 560, Houston, TX 77065
Tel.: 877-897-9759 *Fax:* 281-605-5858 *E-mail:* info@dclamerica.com

MODEL DESCRIPTION:

MERCURY 50

RC™ Model 5x6x1-30 catalytic silencer converter with (1) catalyst layer with room to expand up to 3 layers, side loading access door, S516 steel construction and ports per customer requirements. Standard high heat black paint, any special paint/coating requirements will be at additional charge.

- Element Dimensions: 24”x12”x3.7” (each full block)
- Cell density: 200 cpsi
- Catalyst Volume 14L (each)
- 15 Elements per layer

Unit Price:	$ 39,413.00 EA USD
Quantity:	1
Lead Time:	Ships ~ 8-10 weeks after receipt of order/approval of drawing
Delivery Terms:	FCA (Incoterms 2000)

TITAN 250

RC™ Custom Model catalytic silencer converter with (1) catalyst layer with room to expand up to 3 layers, side loading access door, S516 steel construction and ports per customer requirements. Standard high heat black paint, any special paint/coating requirements will be at additional charge.

- Element Dimensions: 24”x12”x3.7” (each full block)
- Cell density: 200 cpsi
- Catalyst Volume 14L (each)
- 120 Elements per layer

Unit Price:	$ 251,550.00 EA USD
Quantity:	1
Lead Time:	Ships ~ 12-14 weeks after receipt of order/approval of drawing
Delivery Terms:	FCA (Incoterms 2000)

Note
Payment Terms: Net 30
15% Down payment required if ordered

CARBON CAPTURE AND SEQUESTRATION ADD-ON CONTROL COST ANALYSIS

Carbon Capture, Storage and Sequestration Cost Analysis

Carbon Capture Cost Analysis					Source
Total Capital Investment (Assumes 80% of the Facility Capital Investment)				**$120,000,000**	Note 1
Direct Annual Costs					
	Operating Costs				
Operator:	8 hr/shift	30 $/hr	8760 hr/yr	$262,800	OAQPS
Supervisor:		15% of operator		$39,420	OAQPS
	Maintenace Costs				
Labor:	0.5 hr/shift	30 $/hr	8760 hr/yr	$16,425	OAQPS
Material:		100% of Labor Cost		$16,425	OAQPS
Utility Costs					
Electrical	0.1 $/kWh	8760 hr/yr	10 MW	$8,760,000	Estimate
Amine	1 gal/hr	1 $/gal	8760 hr/yr	$8,760	Estimate
			Total Direct Annual Costs	**$9,103,830**	
Indirect Annual Costs					
Overhead:			60% of O&M	$201,042	OAQPS
Administrative:			0.02 TCI	$2,400,000	OAQPS
Insurance:			0.01 TCI	$1,200,000	OAQPS
Property tax:			0.01 TCI	$1,200,000	OAQPS
Capital recovery:	(10 Years; 8.5%)		0.15 TCI	$18,288,925	OAQPS
			Total Indirect Annual Costs	**$23,289,967**	
			Total Annual Cost (DC + IC)	**$32,393,797**	

(1) Total Capital Investment is estimated as 80% of Facility Capital Investment based on the "Report of the Interagency Task Force on Carbon Capture and Storage" for a NGCC plant using post-combustion carbon capture.

Transport Cost Analysis			
Cost Type	**Units**	**Cost Formula**	**Cost[1]**
Pipeline Costs			
Materials	$ / Diameter (inches) / Length (miles)	$64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)	$11,195,986
Labor	$ / Diameter (inches) / Length (miles)	$341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$50,797,987
Miscellaneous	$ / Diameter (inches) / Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$12,921,369
Right-of-Way	$ / Diameter (inches) / Length (miles)	$48,037 + $1.20 x L x (577 x D + 29,788)	$5,634,037
Other Capital			
CO_2 Surge Tank	$	Fixed	$1,150,636
Pipeline Control System	$	Fixed	$110,632
O&M			
Fixed O&M	$/mile/year	Fixed	$8,632
Total Capital Investment (TCI)			**$81,810,647**
Capital Recovery (10 years; 8.5%)		0.15 TCI	$12,468,573
Annualized O&M Costs (Fixed O&M x Pileline Length x 10 years x 8.5%)			$1,027,208
Total Annual Pipeline Cost (O&M + Capital Recovery)			**$13,495,781**

(1) Costs based on pipeline distance of: 140 miles. This assumes the closest facility that accepts an anthropogenic CO_2 stream is the Enid-Purdy Pipeline, located in Central Oklahoma.

(2) As a conservative approach, the pipeline diameter was estimated as: 6 inches.

(3) Cost analysis methodology provided in NETL's "Quality Guidelines for Energy System Studies".

FACILITY-WIDE LEAKLESS COMPONENT COST ANALYSIS

Cost Analysis for Leakless Components for Process Fugitives

Component Type	Service Type	Number of Components	Source	Notes
Valves	All	265	NGP Estimate	Includes gas and light liquid service.
Pumps	All	7	NGP Estimate	Includes gas and light liquid service.
Compressors	All	5	NGP Estimate	Includes gas and light liquid service.
PRV	All	33	NGP Estimate	Includes gas and light liquid service.
Connectors	All	687	NGP Estimate	Includes gas and light liquid service.
Component Type	**Additional Cost per Component**	**Total Capital Cost ($/type)**	**Source**	**Notes**
Valves	$ 1,400.00	$ 371,000.00	Bonney Forge; FlowServe	See 1 (Conservatively assumes only carbon forged steel materials.)
Pumps	$ 12,000.00	$ 84,000.00	Klaus Union	See 2
Compressors	$ -	$ -		See 3
PRV	$ 275.00	$ 9,075.00	Petersen Product Co.	See 4
Connectors	N/A	$ -	EPA 453/R-95-017	Costs for welded connections conservatively assumed zero.
	Equipment Cost =	$ 464,100.00		
	Fright and Taxes =	$ 37,100.00	OAQPS	Assumes 3% and 5% of equipment cost for taxes and freight.
	Total Purchased Equipment Cost =	$ 501,200.00		
	Direct Installation and Handling Cost =	$ 125,300.00	OAQPS	Assumes 25% of equipment cost. Section 2 Chapter 1.
	Total Capital Investment =	$ 626,500.00		
	Capital Recovery Factor (Valves) =	0.110	OAQPS	Assumes 7% interest rate and 15 year equipment life.
	Capital Recovery Factor (Pumps/Comps./PRVs) =	0.244	OAQPS	Assumes 7% interest rate and 5 year equipment life.
	Annual Direct/Indirect Operating Costs =	$ -	OAQPS	Conservatively assumed zero.
	Total Annual Cost =	$ 84,400.00	OAQPS	Conservatively assumes no additional maintenance or operating costs.
	Total Tons of Methane Removed =	0.32	EPA 453/R-95-017	Assumes 100% reduction efficiency.
	Cost Effectiveness, $/ton CH_4 Removed	**$ 263,750.00**		

1) According to Flowserve's "Connection Bulletin for Bellows Seal Valves, CB 11", bellow seal valves have costs three to ten times higher than a standard equivalent valve. Costs are conservatively assumed three times higher. Baseline costs were determined from the average cost of Bonney Forge standard port Class 800 Series Globe valves (1/4 in to 2 in) and standard port Class 800 Series Gate valves (1/4 in to 2 in) priced in the May 2, 2011 FSV-831 Price Schedule. Price range for standard valves: $91 to $1,269.

2) Based on phone conversations with Klaus Union, sealless heat transfer and hot oil magentic drive pumps range in price from $22,000 to $165,000 depending on the size of the application. Cost analysis is conservatively assumed for the SLM-HVO hot oil magentic drive pump with 100 gpm flowrate capicity with 100 feet of head ($22,000) Actual facility flowrates may vary, and exceed 1,000 gpm. Base cost for a standard air-cooled hot oil centrifugal pump (horizontal mount), of equivalent size was set at $10,000.

3) Pricing excludes Solar Turbine, Inc. centrifugal compressors for inlet compression and recompression (3 units). These units come standard with tandem dry gas seals. Pricing excludes regeneration compressor (1 unit), unit comes standard with double mechanical seals. Assumes negligable methane content for refrigeration compressor unit (1 unit).

4) Additional costs are based on the addition of a rupture disc upstream of the pressure relief valve. Pricing based on Petersen 924 Series Rupture Disc online price schedule.