Statement of Basis

Permit to Construct No. P-2010.0076
Project No. 60948

New Energy One, LLC
Rock Creek Project
Filer, Idaho

Facility ID No. 083-00127

Facility Review

March 30, 2012
Ken Hanna
Permit Writer

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The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

ACRONYMS, UNITS, AND CHEMICAL NOMENCLATURE

AAC	acceptable ambient concentrations
AACC	acceptable ambient concentrations for carcinogens
acfm	actual cubic feet per minute
bhp	brake horsepower
Btu	British thermal units
CAM	Compliance Assurance Monitoring
CEMS	continuous emission monitoring systems
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CI	compression ignition
CMS	continuous monitoring systems
CO	carbon monoxide
COMS	continuous opacity monitoring systems
DEQ	Department of Environmental Quality
dscf	dry standard cubic feet
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
HAP	hazardous air pollutants
hp	horsepower
hr/yr	hours per year
ICE	internal combustion engines
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/hr	pounds per hour
MACT	Maximum Achievable Control Technology
mg/dscm	milligrams per dry standard cubic meter
MMBtu	million British thermal units
MMscf	million standard cubic feet
NAAQS	National Ambient Air Quality Standard
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operation and maintenance
PAH	polyaromatic hydrocarbons
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTE	potential to emit
Rules	Rules for the Control of Air Pollution in Idaho
scf	standard cubic feet
SM	synthetic minor
SO_2	sulfur dioxide
T/yr	tons per consecutive 12-calendar month period
T2	Tier II operating permit
TAP	toxic air pollutants
VOC	volatile organic compounds
$\mu g/m^3$	micrograms per cubic meter

FACILITY INFORMATION

Description

New Energy One, LLC has been issued a permit to operate an anaerobic digester renewable energy system on property leased from Rock Creek Dairy near Filer, Idaho. Manure from the dairy will be directed to an anaerobic digestion system. The digestion system will consist of a series of above ground completely mixed reactors that retain the manure as it is anaerobically processed. The biogas released through the facility will be collected and directed to combustion sources. The facility will have gensets powered with reciprocating internal combustion engines, one small boiler, and a flare that can accept the biogas produced by the digester system. The gensets will produce electricity that will be sold to the Idaho Power Company. The boiler will produce heat to maintain optimum conditions for the anaerobic process.

Permitting History

The following information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

April 3, 2012	P-2010.0076, Project 60948, Revised PTC was issued for the biogas power project to install different gensets than previously planned; Permit status (A)
March 30, 2011	P-2010.0076, Initial PTC issued for the biogas power project; Permit status (S)

Application Scope

The applicant has proposed to:

- install two CAT G3520C gensets instead of the one CAT G3520C genset and three CAT 3412 gensets initially permitted.
- add an iron sponge filter to reduce biogas hydrogen sulfide concentrations to 700 ppm prior to combustion.

Application Chronology

October 28, 2011	DEQ received an application and an application fee.
November 11 – 28, 2011	DEQ provided an opportunity to request a public comment period on the application and proposed permitting action.
November 15, 2011	DEQ issued 15-day pre-permit construction approval letter
November 28, 2011	DEQ determined that the application was complete.
February 3, 2012	DEQ made available the draft permit and statement of basis for peer and regional office review.
February 3, 2012	DEQ made available the draft permit and statement of basis for applicant review.
March 30, 2012	DEQ received the permit processing fee.

TECHNICAL ANALYSIS

Emissions Units and Control Devices

Table 1 EMISSIONS UNIT AND CONTROL DEVICE INFORMATION

Source Description	Control Equipment Description
Two Industrial Engines **Manufacturer : Caterpillar** **Model: G3520C** **Rated Power 2,233 bhp** **Fuel: biogas**	**Good combustion control**
Boiler **Manufacturer: Columbia Boilers** **Model: MPH-125** **Rated Input: 5.3 MMBtu/hr**	**Good combustion control**
Flare **Manufacturer: Shand&Jurs** **Model: 97300**	**Good combustion control**
Anaerobic Digesters (6) **Manufacturer: Northern Biogas** **Capacity: ~ 1,000,000 gallon**	**Biological Desulfurization (H_2S Control)** **Iron Sponge to reduce H2S, and Combustion (generator engine, flare, or boiler)**

Emissions Inventories

Potential to Emit

IDAPA 58.01.01 defines Potential to Emit as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable. Secondary emissions do not count in determining the potential to emit of a facility or stationary source.

Using this definition of Potential to Emit, an emission inventory was developed for the generator engines, a boiler and a flare at the facility (see Appendix A). Emissions estimates of criteria pollutants were based on emission factors from AP-42, vendor emissions data, and mass balance (for sulfur dioxide). Sulfur dioxide emissions were estimated by assuming that all of the hydrogen sulfide in the raw biogas is converted to sulfur dioxide. The anaerobic digesters are designed with a biological desulfurization system. Mirco-organisms consume hydrogen sulfide in the presence of oxygen. Hydrogen sulfide concentration data for raw biogas from a similar digester was provided in the application. Hydrogen sulfide in the raw biogas is 1,000 ppmv or less. To provide additional protection for the combustion equipment, an iron sponge filter will be used; this will reduce H_2S in biogas to 700 ppmv or less.

Toxic air pollutant emission estimates were based on emission factors from AP-42 and data from the Gas Technology Institute (Pipeline Quality Biomethane). The data from the Gas Technology Institute gives TAP concentrations in raw biogas from dairies. Average toxic air pollutant concentrations in raw biogas were used to estimate annual average emission rates to demonstrate compliance with carcinogenic toxic air pollutant increments. Maximum toxic air pollutant concentrations in raw biogas were used to estimate emission rates to demonstrate compliance with non-carcinogenic 24-hr average toxic air pollutant increments. Where raw data from the Gas Technology Institute was used to estimate TAP emissions it was assumed that 97.2% of the TAP was destroyed in the combustion process; 97.2% is listed as the VOC destruction in internal combustion engines (EPA AP-42, Section 2.4, Table 2.4-3, draft 2008).

Uncontrolled Potential to Emit

Using the definition of Potential to Emit, uncontrolled Potential to Emit is then defined as the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall **not** be treated as part of its design **since** the limitation or the effect it would have on emissions **is not** state or federally enforceable.

The uncontrolled Potential to Emit is used to determine if a facility is a "Synthetic Minor" source of emissions. Synthetic Minor sources are facilities that have an uncontrolled Potential to Emit for regulated air pollutants or HAP above the applicable Major Source threshold without permit limits

In the Statement of Basis for the existing permit, it was shown that this facility is classified as synthetic minor. For this modification of the existing permit, the uncontrolled PTE is not changed substantively, therefore, the synthetic minor facility classification remains unchanged.

Pre-Project Potential to Emit

Pre-project Potential to Emit is used to establish the change in emissions at a facility as a result of this project.

The following table presents the pre-project potential to emit for all criteria pollutants from all emissions units at the facility as submitted by the Applicant and verified by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 2 PRE-PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_x		CO		VOC	
	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]	lb/hr[a]	lb/hr[a]	lb/hr[a]	T/yr[b]	lb/hr[a]	T/yr[b]
Gen 1 (2233 bhp)	---	0.57	---	16.8	---	19.9	---	49.7	---	16.7
Gen 2 (503 bhp)	---	0.12	---	3.45	---	8.96	---	8.51	---	3.63
Gen 3 (503 bhp)	---	0.12	---	3.45	---	8.96	---	8.51	---	3.63
Gen 4 (503 bhp)	---	0.12	---	3.45	---	8.96	---	8.51	---	3.63
Boiler	---	0.9	---	6.24	---	3.75	---	3.15	---	0.21
Total, Point Sources	---	1.8	---	33.4	---	50.5	---	78.4	---	27.8
All biogas combusted in a flare instead of in the generators and boiler	---	1.5	---	33.4	---	7.7	---	42	---	15.9

1) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
2) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Post Project Potential to Emit

Post project Potential to Emit is used to establish the change in emissions at a facility and to determine the facility's classification as a result of this project. Post project Potential to Emit includes all permit limits resulting from this project.

The following table presents the post project Potential to Emit for criteria pollutants from all emissions units at the facility as determined by DEQ staff. See Appendix A for a detailed presentation of the calculations of these emissions for each emissions unit.

Table 3 POST PROJECT POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_x		CO		VOC	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	lb/hr[(a)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
Gen 1 (2233 bhp)	0.14	0.46	2.91	9.50	4.92	16.1	12.3	40.2	4.14	13.5
Gen 2 (2233 bhp)	0.14	0.46	2.91	9.50	4.92	16.1	12.3	40.2	4.14	13.5
Boiler	0.07	0.28	1.08	4.36	0.93	3.74	0.78	3.15	0.05	0.21
Total, Point Sources	0.35	1.20	6.90	23.4	10.8	35.9	25.4	83.6	8.33	27.2
All biogas combusted in a flare instead of in the generators and boiler	0.45	1.53	6.90	23.4	2.28	7.71	12.4	42.0	4.70	15.9

a) Controlled average emission rate in pounds per hour is a daily average, based on the proposed daily operating schedule and daily limits.
3) Controlled average emission rate in tons per year is an annual average, based on the proposed annual operating schedule and annual limits.

Change in Potential to Emit

The change in facility-wide potential to emit is used to determine if a public comment period may be required and to determine the processing fee per IDAPA 58.01.01.225. The following table presents the facility-wide change in the potential to emit for criteria pollutants.

Table 4 CHANGES IN POTENTIAL TO EMIT FOR REGULATED AIR POLLUTANTS

Source	$PM_{10}/PM_{2.5}$		SO_2		NO_x		CO		VOC	
	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	lb/hr[(a)]	lb/hr[(a)]	T/yr[(b)]	lb/hr[(a)]	T/yr[(b)]
Pre-Project Potential to Emit	---	1.8	---	33.4	---	50.5	---	78.4	---	27.8
Post Project Potential to Emit	---	1.53	---	23.4	---	35.9	---	83.6	---	27.2
Changes in Potential to Emit	0.0	-0.27	0.00	-10.0	0.00	-14.6	0.00	+5.2	0.00	-0.6

TAP Emissions

For this project to change engines, only one toxic air pollutant (TAP) was found to have an estimated increase in emissions that exceeds a screening emission level. It is acrolein. The change in emissions for all other TAPs are emitted at below screening emissions levels. See Appendix A for a detailed presentation of the calculations. Since acrolein emission rates greater than the screening emission rate, air dispersion modeling was conducted to determine if ambient impacts are below the allowable increments listed in IDAPA 58.01.01.585 & 586. All ambient impacts were determined to be below the allowable increments; see the Ambient Impact Assessment included in Appendix B.

HAP Emissions

HAP emissions are not substantively changed by this permit modification and the facility classification is not affected. The facility is a minor HAP source because no one HAP is emitted at a rate greater than 10 tons per year and all HAPs combined are emitted at rates less than 25 tons per year. See Appendix A for a detailed presentation of the calculations.

Ambient Air Quality Impact Analyses

The applicant has demonstrated pre-construction compliance to DEQ's satisfaction that emissions from this facility will not cause or significantly contribute to a violation of any ambient air quality standard. The applicant has also demonstrated pre-construction compliance to DEQ's satisfaction that the emissions increase due to this permitting action will not exceed any acceptable ambient concentration (AAC) or acceptable ambient concentration for carcinogens (AACC) for toxic air pollutants (TAP).

An ambient air quality impact analyses document has been crafted by DEQ based on a review of the modeling analysis submitted in the application. That document is part of the final permit package for this permitting action (see Appendix B).

REGULATORY ANALYSIS

Attainment Designation (40 CFR 81.313)

The facility is located in Twin Falls County, which is designated as attainment or unclassifiable for $PM_{2.5}$, PM_{10}, SO_2, NO_2, CO, and Ozone. Refer to 40 CFR 81.313 for additional information.

Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201 Permit to Construct Required

The permittee has requested that a PTC be issued to the facility to modify the existing PTC. Therefore, a permit to construct is required to be issued in accordance with IDAPA 58.01.01.220. This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.200-228.

Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.401 Tier II Operating Permit

The facility is not subject to IDAPA 58.01.01.300-399, and the applicant did not apply for a Tier II operating permit in accordance with IDAPA 58.01.01.401. The Tier II permit requirements do no apply.

Toxic Air Pollutants (IDAPA 58.01.01.210)

The acrolein emissions estimate exceed the screening emission level listed in IDAPA 58.01.01. All other TAPs are emitted at levels below the screening emissions levels. Emissions of acrolein was determined to result in ambient concentrations below the pollutants respective acceptable ambient concentration. See the modeling memorandum in Appendix B.

As in the previous permit, all toxic air pollutant emission rates are inherently limited by the biogas combustion rate limit without a need for specific emission rate limits.

Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.625 Visible Emissions

The sources of particulate matter emissions at this facility are subject to the State of Idaho visible emissions standard of 20% opacity.

Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

IDAPA 58.01.01.301 Requirement to Obtain Tier I Operating Permit

Post project facility-wide emissions from this facility don't have a potential to emit greater than 100 tons per year for PM_{10}, SO_2, NO_X, CO, VOC, or 10 tons per year for any one HAP or 25 tons per year for all HAPs combined as demonstrated in the Statement of basis for the previous permit. Therefore, the facility is not a Tier I source in accordance with IDAPA 58.01.01.006.113 and the requirements of IDAPA 58.01.01.301 do not apply.

PSD Classification (40 CFR 52.21)

40 CFR 52.21 Prevention of Significant Deterioration of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1). Therefore in accordance with 40 CFR 52.21(a)(2), PSD requirements are not applicable to this permitting action. The facility is not a designated facility as defined in 40 CFR 52.21(b)(1)(i)(a), and does not have facility-wide emissions of any criteria pollutant that exceed 250 T/yr.

NSPS Applicability (40 CFR 60)

The facility is subject to the requirements of 40 CFR 60 Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Engines. See Appendix C for the regulatory analysis. Note that this is an exact copy of the analysis that was prepared for the previous permit issued on March 30, 2011 - it has not been changed.

NESHAP Applicability (40 CFR 61)

The facility is not subject to any NESHAP requirements in 40 CFR 61.

MACT Applicability (40 CFR 63)

The facility is not subject to any MACT standards in 40 CFR Part 63.

EPA promulgated the area source boiler MACT (Subpart JJJJJJ) on February 21, 2011. The proposed gas fired boiler is not an affected emission unit because in accordance with 40 CFR 63.11195(e) gas fired boilers are not affected emission units.

Permit Conditions Review

This section describes the permit conditions for this initial permit.

Permit Conditions 1-3

Explains the purpose and scope of this PTC.

Permit Condition 4

Lists the permitted emission units and associated control devices.

Permit Condition 5 & 6

Provides a brief process description and lists the permitted emission units.

Revised Permit Condition 7

Lists the emission rate limits for sulfur dioxide and carbon monoxide. These pollutants have emission rate limits because potential uncontrolled emission rates would exceed major facility thresholds, and in case of sulfur dioxide, the air dispersion model predicts an exceedance of the ambient standards would occur. The limits in this modified permit were revised to correspond to the compliance demonstration provided for the two gensets used. Emission rate limits were not needed for VOC, NOx and PM_{10} because uncontrolled emission rates would not exceed major facility thresholds or cause exceedances of the ambient standards.

Compliance with the sulfur dioxide emission limits is assessed by requiring monitoring of sulfur dioxide emission rates in accordance with a DEQ approved monitoring protocol to assure compliance with the pound per hour emission limit for all emission units. If the facility complies with this pound per hour emission limit it is presumed that they are in compliance with the ton per year emission limits.. All of the hydrogen sulfide in the biogas is assumed to be converted to sulfur dioxide in the combustion processes.

The applicant estimated carbon monoxide emissions based on vender emissions data which is less than the NSPS standards. If the facility were to emit carbon monoxide at the NSPS standard the facility would be a major facility instead of a minor facility. Therefore, the permit includes carbon monoxide emission limits and source testing requirements to assure the facility remains a minor facility. If the facility complies with the pound per hour emission limits, it is presumed that they are in compliance with the ton per year emission limits.

Permit Condition 8

Includes the opacity standard of IDAPA 58.01.01.625.

Permit Condition 9

Includes the odor standard of IDAPA 58.01.01.776.

Permit Condition 10

Requires that all biogas be combusted in the engines, boiler or flare. The facility did not demonstrate compliance with the hydrogen sulfide toxic air pollutant increment under a scenario where the biogas was not combusted. Therefore, the permit requires all biogas to be combusted.

Permit Condition 11

Requires the flare be operated with a pilot flame at all times that biogas is vented to the flare, so that no gas is vented directly to the atmosphere without being combusted/controlled.

Permit Condition 12

Requires that the permittee develop an operations and maintenance (O&M) manual and submit that manual to DEQ. The manual is required to address operational procedures for the biogas flow rate monitor including the frequency of calibration, operational maintenance and procedures for upsets/breakdowns and for correcting malfunction conditions. The O&M manual also requires developing procedures to ensure that flare ignition system is operational, is maintained, and procedures for correcting upsets or breakdowns.

The O&M manual must be a permittee developed document but it may be based on manufacturer requirements.

Permit Condition 13

Requires installation and operation of a biogas flow rate monitor.

Permit Condition 14.1

Requires monitoring of sulfur dioxide emissions once each 3 hours unless 12 consecutive weeks of monitoring show that no one measured value exceeds 90% of the combined sulfur dioxide limit. If no one value of the 3-hour monitoring exceeds 90% of the combined sulfur dioxide limit during a 12 week period then the sulfur dioxide monitoring may occur once each day. If any daily value exceeds 90% then monitoring shall revert back to once each three hours.

Monitoring once each three hours is necessary because uncontrolled sulfur dioxide emissions, which occur from oxidization of hydrogen sulfide in the combustion processes, is predicted by the air dispersion model to exceed the 3- hour sulfur dioxide ambient air quality standard. Further, the hydrogen sulfide concentrations from the digesters can not be guaranteed by the manufacturers of the anaerobic digesters because as the applicant has said a "variety of environmental factors, some of which of which are not thoroughly understood" influence hydrogen sulfide emissions.

Permit Condition 14.2

Allows the permittee to use a hydrogen sulfide CEM, sulfur dioxide CEM, or a hand held hydrogen sulfide monitor to determine sulfur dioxide emission rates. Any one of these devices will give data that can be used in conjunction with the biogas flow rate to determine sulfur dioxide emission rates.

Permit Condition 14.3

If a hydrogen sulfide CEM or sulfur dioxide CEM is used to determine emissions the permittee is required to submit to DEQ, and receive approval for, a monitoring protocol. The monitoring protocol must address installation specifications, calibration requirements, and details of how sulfur dioxide emission rates will be calculated using the CEM data and the flow rate of biogas.

The sulfur dioxide monitoring requirements are intended to demonstrate compliance with the combined (generators, boiler, and flare) sulfur dioxide emission limit. The monitoring protocol must address how emissions from the flare will be determined using the CEM data and DEQ should not approve the monitoring protocol unless flare emissions are adequately addressed. Emissions data from a sulfur dioxide CEM on a generator or the boiler can be used to calculate the hydrogen sulfide concentration in the biogas which can in turn be used to calculate emissions of the combined system (generators, boiler and flare) if the total biogas flow is known.

Permit Condition 14.4

Includes provisions that apply if the permittee elects to monitor sulfur dioxide emissions using a hand held hydrogen sulfide monitor. These provisions include that the monitor must be accurate within plus or minus 3% as provided in the application. The permittee is required to submit to DEQ, and receive approval for, a monitoring protocol. The monitoring protocol must address monitoring procedures, calibration requirements, and details of how sulfur dioxide emission rates will be calculated using the hydrogen sulfide data and the flow rate of biogas.

Permit Condition 15

Requires the permittee to keep record of all order complaints received along with a record of any corrective action taken.

Permit Condition 16

Requires conducting a performance test to demonstrate compliance with the pound per hour carbon monoxide emission rate each time the generators must be tested in accordance with NSPS Subpart JJJJ.

The construction and operation notification provision requires that the permittee notify DEQ of the dates of construction and operation, in accordance with IDAPA 58.01.01.211.

Revised Permit Conditions 17 – 23

The permit conditions incorporate NSPS Subpart JJJJ requirements. Permit Condition 17 was revised to remove the CAT 3412 generator sets and to show that Gen 2 is in the greater than 500 horsepower category. Correspondence received from the permittee indicates that Gen 2 will have a 2011 model year engine similar to Gen 1 (i.e., it will not have a 2007 model year engine). Should there be a conflict between these permit conditions and the NSPS, the NSPS shall govern.

Permit Condition 24

The duty to comply general compliance provision requires that the permittee comply with all of the permit terms and conditions pursuant to Idaho Code §39-101.

Permit Condition 25

The maintenance and operation general compliance provision requires that the permittee maintain and operate all treatment and control facilities at the facility in accordance with IDAPA 58.01.01.211.

Permit Condition 26

The obligation to comply general compliance provision specifies that no permit condition is intended to relieve or exempt the permittee from compliance with applicable state and federal requirements, in accordance with IDAPA 58.01.01.212.01.

Permit Condition 27

The inspection and entry provision requires that the permittee allow DEQ inspection and entry pursuant to Idaho Code §39-108.

Permit Condition 28 & 29

The permit may expire if construction is not conducted within the allowable timeframe. The construction and operation notification provision requires that the permittee notify DEQ of the dates of construction and operation, in accordance with IDAPA 58.01.01.211.

Permit Condition 30

The performance testing notification of intent provision requires that the permittee notify DEQ at least 15 days prior to any performance test to provide DEQ the option to have an observer present, in accordance with IDAPA 58.01.01.157.03.

Permit Condition 31

The performance test protocol provision requires that any performance testing be conducted in accordance with the procedures of IDAPA 58.01.01.157, and encourages the permittee to submit a protocol to DEQ for approval prior to testing.

Permit Condition 32

The performance test report provision requires that the permittee report any performance test results to DEQ within 30 days of completion, in accordance with IDAPA 58.01.01.157.04-05.

Permit Condition 33

The monitoring and recordkeeping provision requires that the permittee maintain sufficient records to ensure compliance with permit conditions, in accordance with IDAPA 58.01.01.211.

Permit Condition 34

The excess emissions provision requires that the permittee follow the procedures required for excess emissions events, in accordance with IDAPA 58.01.01.130.

Permit Condition 35

The certification provision requires that a responsible official certify all documents submitted to DEQ, in accordance with IDAPA 58.01.01.123.

Permit Condition 36

The false statement provision requires that no person make false statements, representations, or certifications, in accordance with IDAPA 58.01.01.125.

Permit Condition 37

The tampering provision requires that no person render inaccurate any required monitoring device or method, in accordance with IDAPA 58.01.01.126.

Permit Condition 38

The transferability provision specifies that this permit to construct is transferable, in accordance with the procedures of IDAPA 58.01.01.209.06.

Permit Condition 39

The severability provision specifies that permit conditions are severable, in accordance with IDAPA 58.01.01.211.

PUBLIC REVIEW

Public Comment Opportunity

An opportunity for public comment period on the application was provided in accordance with IDAPA 58.01.01.209.01.c. During this time, there were no comments on the application and there was not a request for a public comment period on DEQ's proposed action. Refer to the chronology for public comment opportunity dates.

APPENDIX A – EMISSIONS INVENTORIES

Section 4 – Emission Estimates

will not operate at a peak hourly rate for the entire year and the overall operation will be limited due to the maximum expected biogas generated from the digesters. The annual anticipated operation will be impacted by maintenance downtime and fluctuations in biogas generation. We have estimated the genset's annual average consumption of biogas will be approximately 77% of their peak hourly consumption.

Each genset will have an individual stack extending 30 feet above the ground surface. The source parameters for the gensets vary based on their individual capacity. The exhaust from the gensets will pass through a heat exchanger prior to discharging to the atmosphere. The heat exchange process will reduce stack discharge temperatures and exhaust flow rates for the gensets. There are no emissions associated with the heat exchanger. Table 4-2 summarizes the source parameter for each of the emission units.

Table 4-2. Emission Unit Source Parameters

	Emission Units (EU)			
	1	2	3	4
Source type	Genset	Genset	Boiler	Flare
Model number	CAT 3520	CAT 3520	Columbia	Shand&Jurs 97300 (or equivalent)
End of Stack exhaust temperature (°F)	350	350	NA	NA
Stack Height (ft)	30	30.05	30	30
Stack Diameter (in)	14	14	14	24
Exhaust flow rate at capacity (cfm) w/o heat exchange	12,476	12,476	1,677	10,790
Exhaust flow rate at capacity (cfm) w/ heat exchange	7,440	7,440	NA	NA

Boiler

The boiler will also operate from biogas generated from the digesters. The purpose of the boiler is to provide heat energy to the digesters to optimize the digester operating conditions. The boiler is not anticipated to be used continuously, but on an as needed basis. During startup and emergency operation, it may be necessary to use No. 2 Diesel to power the boiler. This permit application requests the boiler be permitted as a permanent emission source at the facility.

Flare

The intent and objective of the facility is to minimize the volume of gas diverted to the flare. However, it will be necessary to use the flare to accommodate swings in biogas flow or to divert biogas if its deemed necessary to bring a generator offline. The flare is a candlestick type flare.

4.3 Emission Factors

The emission factors used to estimate emissions from the combustion equipment came from multiple sources including research conducted by The Gas Technology Institute on

Nitrogen Dioxide (NOx), Carbon Monoxide (CO) and Volatile Organic Compounds (VOCs)

Caterpillar provides an estimate of the emissions of NOx, CO and VOCs for each of its gensets. The data provided by Caterpillar is in terms of grams per hour of pollutant per break horsepower. The manufacturer technical data sheets are included in Appendix 1. The vendor indicates that the gensets will out-perform the federal NSPS standards (40 CFR Part 60 Subpart JJJJ). AP-42 emission factors for natural gas combustion were used to estimate emissions from the proposed boiler and flare. NO_2 emission rates were estimated assuming 75% of NOx emissions were NO_2.

Particulate Emissions

The PM_{10} and $PM_{2.5}$ emission factors for the gensets were selected from AP-42 Section 3.2, Table 3.2 – Uncontrolled Emission Factors for 4-stroke Lean–Burn Engines. The table presents D-Rated PM-10 (filterable) and PM condensable emission factors for natural gas lean burn reciprocating engines. The PM-10 emissions represent the sum of the PM-10 (filterable) and the PM condensable fractions, since the condensable fraction is likely less than 10 microns. The AP-42 emission factors were converted to lb/cf basis for purposes of maintaining consistency with other emission factors.

AP-42 emission factors (AP-42 Section 1.4) for natural gas combustion were used to estimate PM emissions from the boiler.

4.4 Emission Estimate

The hourly emission rates were calculated by multiplying the expected hourly peak biogas consumption rate for each emission unit by the pollutant emission factor. The peak hourly consumption rates were estimated based on the maximum anticipated hourly capacity for each unit.

The annual emissions from each emission unit were calculated by multiplying the expected annual peak biogas consumption for each unit by the pollutant emission factor. The expected peak annual biogas consumption is limited by the amount of biogas the digester system is capable of producing. Although hourly swings in each unit's gas consumption may reach its maximum hourly capacity. The units will not be capable of operating at its peak hourly capacity for the entire year.

The total potential facility emission calculations assumed two operating scenarios. The first scenario assumes that all biogas is combusted in the gensets and boiler and that no biogas is diverted to the flare. This provides a worst-case estimate of the emissions both for short-term hourly emission calculations and for the annual emission estimate. It is not likely the boiler will operate at capacity, or continuously, when the gensets are operating at capacity.

The second operating scenario considers all biogas is diverted to the flare. This mode of operation was included to demonstrate that modeled impacts to NAAQS and TAPs are within allowable limits when the flare is operating at capacity Long term operation of

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Table 4-4. Summary of TAPs Potential Emission Rates

	Pollutant	Genset and Boiler Emissions		Flare Emissions		TAP EL (lb/hr)	Exceed EL?
		(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)		
Section 585 TAP	Acrolein	1.45E-01	4.74E-01			1.70E-02	Yes
	Barium, soluble compounds, as Ba	4.09E-05	1.65E-04	2.61E-04	8.83E-04	3.30E-02	No
	Biphenyl	5.99E-03	1.96E-02			1.00E-01	No
	2-Chlorophenol (and all isomers) (ID)	6.07E-07	2.02E-06	5.41E-07	1.83E-06	3.30E-02	No
	Chromium metal - Including:	1.30E-05	5.24E-05	8.30E-05	2.81E-04	3.30E-02	No
	Cobalt metal, dust, and fume	7.81E-07	3.15E-06	4.98E-06	1.69E-05	3.30E-03	No
	Copper - Dusts & mists, as Cu	7.90E-06	3.18E-05	5.04E-05	1.71E-04	6.70E-02	No
	Cresols/Cresylic Acid (isomers and mixtures)	3.58E-05	1.19E-04	3.19E-05	1.08E-04	1.47E+00	No
	Cyclopentane	6.41E-03	2.09E-02			1.15E+02	No
	Dibutyl phthalate	1.19E-06	3.97E-06	1.06E-06	3.59E-06	3.33E-01	No
	Ethyl benzene	1.14E-03	3.71E-03	1.29E-05	4.37E-05	2.90E+01	No
	Manganese as Mn Dust & compounds	3.53E-06	1.42E-05	2.25E-05	7.63E-05	3.33E-01	No
	Mercury (vapors except Alkyl as Hg)	2.42E-06	9.74E-06	1.54E-05	5.22E-05	3.00E-03	No
	Molybdenum as Mo -Soluble compounds	1.02E-05	4.12E-05	6.52E-05	2.21E-04	3.33E-01	No
	Methanol	7.06E-02	2.31E-01			1.73E+01	No
	Hexane (n-Hexane)	3.14E-02	1.02E-01			1.20E+01	No
	Hydrogen sulfide	9.46E-02	3.15E-01	8.43E-02	2.85E-01	9.33E-01	No
	o-Methylcyclohexanone	3.47E-02	1.13E-01			1.53E+01	No
	Naphthalene	2.11E-03	6.89E-03	3.69E-05	1.25E-04	3.33E+00	No
	Nitrobenzene	2.83E-07	9.43E-07	2.52E-07	8.55E-07	3.33E-01	No
	Nonane	3.11E-03	1.01E-02			7.00E+01	No
	Octane	9.92E-03	3.24E-02			9.33E+01	No
	Pentane	9.76E-02	3.37E-01	1.54E-01	5.22E-01	1.18E+02	No
	Phenol	6.89E-04	2.25E-03	9.53E-06	3.23E-05	1.27E+00	No
	Pyridine	4.76E-07	1.58E-06	4.24E-07	1.44E-06	1.00E+00	No
	Selenium	2.23E-07	8.99E-07	1.42E-06	4.82E-06	1.30E-02	No
	Styrene monomer (ID)	5.38E-07	1.79E-06	4.80E-07	1.62E-06	6.67E+00	No
	Toluene (toluol)	1.16E-02	3.80E-02	2.50E-04	8.48E-04	2.50E+01	No
	Trimethyl benzene (mixed and individual	2.01E-03	6.56E-03			8.20E+00	No
	2,2,4-Trimethyl-pentane	7.06E-03	2.31E-02			2.33E+01	No
	Xylene (o-, m-, p-isomers)	5.23E-03	1.71E-02	1.72E-03	5.82E-03	2.90E+01	No
Section 586 TAP	Aniline	7.32E-06	3.21E-05	6.63E-06	2.90E-05	9.0E-04	No
	Arsenic compounds	1.71E-06	7.49E-06	9.17E-06	4.02E-05	1.5E-06	Yes
	Benzene	9.29E-03	4.07E-02	9.90E-05	4.34E-04	8.0E-04	Yes
	Bis (2-chloro-1-methyl- ethyl) ether	1.76E-06	7.71E-06	1.59E-06	6.98E-06	3.3E-04	No
	Bis (2-ethylhexyl) phthalate	4.56E-06	2.00E-05	4.13E-06	1.81E-05	2.8E-02	No
	Cadmium and compounds	9.40E-06	4.12E-05	5.04E-05	2.21E-04	3.7E-06	Yes
	Carbon tetrachloride	1.00E-06	4.39E-06	9.07E-07	3.97E-06	4.4E-04	No
	Formaldehyde	6.41E-04	2.81E-03	3.44E-03	1.51E-02	5.1E-04	Yes
	Nickel	1.80E-05	7.86E-05	9.63E-05	4.22E-04	2.7E-05	Yes
	Dichloromethane (Methylenechloride)	4.21E-04	1.85E-03			1.6E-03	No
	1,1,2,2,Tetrachloro-ethane	5.22E-05	2.29E-04			1.1E-05	Yes
	Tetrachloroethylene	8.30E-07	3.63E-06	7.52E-07	3.29E-06	1.3E-02	No
	1,1,2 - trichloroethane	2.03E-05	8.90E-05	1.84E-05	8.06E-05	4.2E-04	No
	Vinyl Chloride	3.14E-04	1.37E-03			1.2E-03	No

4.7 Limitations on Potential to Emit

In order to remain below the National Ambient Air Quality Standard (NAAQS) for SO_2, the facility agrees to a limit to maintain the SO_2 discharge rate below 6.9 lb/hr. Monitoring and recordkeeping of sulfur dioxide emissions will occur once every 3 hours for the first 12 weeks of operations. Daily monitoring will be used if the 12 week sulfur dioxide emission rate (measured every 3 hours) does not meet or exceed 90 percent of the pound per hour limit. If any measured sulfur dioxide emission rate during daily monitoring meets or exceeds 90 percent of the SO_2 pound per hour limit the monitoring frequency will revert to 3 hour intervals.

At full capacity, the digester is expected to produce 1.1 million cubic feet (cf)/day of biogas with maximum H_2S concentration of 700 ppm_v. At startup, biogas production will increase as each digester tank is brought on line until maximum production is reached. During startup the average H_2S concentration may exceed 700 ppm_v but the biogas flow rate will be below maximum capacity which will result in a mass discharge rate less than the requested lb/hr limit.

Combustion emission rates were determined based on equipment maximum rated firing rates for short-term averaging periods and the maximum potential biogas generation rate for annual averages. A permit limit of 402 million cf/year biogas is appropriate for demonstrating regulatory compliance.

New Energy One Biogas Project - Modification
Calculation Input Assumptions

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Digester

Peak daily gas generation from digester	1,100,000	cf/day
Peak annual gas production	402	MMcf/year
Biogas heat value	565	Btu/cf
Biogas heat content	431,597	Btu/min
Peak hourly heat energy in biogas	25.9	MMBtu/hr

Emission Sources

	Emission Units (EU)			
	1	2	3	4
Source type	Genset	Genset	Boiler	Flare
Model number	CAT 3520	CAT 3520	Columbia	Shand&Jurs 97300 (or equivalent)
Break Horsepower	2,233	2,233	125	
Hourly Equipment Peak Input Biogas Capacity (cf/hr)	25,000	25,000	9,292	59,292
Peak Biogas Heat Input Capacity (Btu/hr)	14.1	14.1	5.2	33.5
Daily Peak Biogas Capacity (cf/day)	600,000	600,000	223,008	1,423,008
Annual Equipment Biogas Capacity (Mcf/year)	219	219	81	519
Estimated Annual Capacity Factor	77%	77%	92%	77%
Annual Estimated Peak Biogas Capacity (Mcf/year)	163	163	75	402
End of Stack Temperature (°F) w/ heat exchange	350	350		
End of Stack Temperature (°F) w/o heat exchange	898	898	350	
Stack Height (ft)	30	30.05	30	30
Stack Diameter (in)	14	14	14	24
Exhaust Flow Rate at Capacity (cfm) w/o heat exchange	12,476	12,476	1,677	10,790
Exhaust Flow Rate at Capacity (cfm) w/ heat exchange	7,440	7,440		

Modeled Parameter

Stack height (m)	9.15	9.16	9.15	13.79[a]
Stack inside Diameter (m)	0.36	0.36	0.36	0.61
Stack exit velocity (m/s)	35.37	35.37	7.97	17.45
Stack gas temperature (°K)	450	450	450	1273.15[a]

Notes:

[a] Stack height for flare is effective release hight calculated by SCREEN3. The stack gas temperature is the default value listed in the SCREEN3 Model User'

New Energy One Biogas Project - Modification

Change in Emissions Associated with Proposed Modifications

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	Pollutant	Genset and Boiler Emissions				Flare Emissions			
		Change (lb/hr)	% Change	Change (T/yr)	% Change	Change (lb/hr)	% Change	Change (T/yr)	% Change
Primary Pollutants	PM10	0.1	18%	0.0	0%	0.1	19%	0	0%
Primary Pollutants	PM2.5	0.1	18%	0.0	0%	0.1	19%	0	0%
Primary Pollutants	SO_2	-1.4	-17%	-10.0	-30%	-1.4	-17%	-10	-30%
Primary Pollutants	NOx	-1.7	-14%	-14.6	-29%	0.4	19%	0	0%
Primary Pollutants	NO_2	-1.3	-14%	-10.9	-29%	0.3	19%	0	0%
Primary Pollutants	CO	6.0	31%	5.2	7%	2.0	19%	0	0%
Primary Pollutants	VOC	1.4	21%	-0.6	-2%	0.8	19%	0	0%
Primary Pollutants	Lead								
Section 585 TAP	Acrolein	2.8E-02	24%	0.0	0%				
Section 585 TAP	Barium, soluble compounds, as Ba	0.0E+00	0%	0.0	0%	4.2E-05	19%	0.0	0%
Section 585 TAP	Biphenyl	1.1E-03	24%	0.0	0%				
Section 585 TAP	2-Chlorophenol (and all isomers) (ID)	1.1E-07	21%	0.0	0%	8.7E-08	19%	0.0	0%
Section 585 TAP	Chromium metal - Including:	0.0E+00	0%	0.0	0%	1.3E-05	19%	0.0	0%
Section 585 TAP	Cobalt metal, dust, and fume	0.0E+00	0%	0.0	0%	8.0E-07	19%	0.0	0%
Section 585 TAP	Copper - Dusts & mists, as Cu	0.0E+00	0%	0.0	0%	8.1E-06	19%	0.0	0%
Section 585 TAP	Cresols/Cresylic Acid (isomers and mixtures)	6.3E-06	21%	0.0	0%	5.2E-06	19%	0.0	0%
Section 585 TAP	Cyclopentane	1.2E-03	24%	0.0	0%	0.0E+00			
Section 585 TAP	Dibutyl phthalate	2.1E-07	21%	0.0	0%	1.7E-07	19%	0.0	0%
Section 585 TAP	Ethyl benzene	2.2E-04	24%	0.0	0%	2.1E-06	19%	0.0	0%
Section 585 TAP	Manganese as Mn Dust & compounds	0.0E+00	0%	0.0	0%	3.6E-06	19%	0.0	0%
Section 585 TAP	Mercury (vapors except Alkyl as Hg)	0.0E+00	0%	0.0	0%	2.5E-06	19%	0.0	0%
Section 585 TAP	Molybdenum as Mo -Soluble compounds	0.0E+00	0%	0.0	0%	1.1E-05	19%	0.0	0%
Section 585 TAP	Methanol	1.4E-02	24%	0.0	0%				
Section 585 TAP	Hexane (n-Hexane)	6.0E-03	24%	0.0	0%				
Section 585 TAP	Hydrogen sulfide	-1.7E-02	-15%	-0.1	-30%	-1.7E-02	-17%	-0.1	-30%
Section 585 TAP	o-Methylcyclohexanone	6.7E-03	24%	0.0	0%				
Section 585 TAP	Naphthalene	4.0E-04	24%	0.0	0%	6.0E-06	19%	0.0	0%
Section 585 TAP	Nitrobenzene	5.0E-08	21%	0.0	0%	4.1E-08	19%	0.0	0%
Section 585 TAP	Nonane	6.0E-04	24%	0.0	0%				
Section 585 TAP	Octane	1.9E-03	24%	0.0	0%				
Section 585 TAP	Pentane	1.4E-02	17%	0.0	0%	2.5E-02	19%	0.0	0%
Section 585 TAP	Phenol	1.3E-04	24%	0.0	0%	1.5E-06	19%	0.0	0%
Section 585 TAP	Pyridine	8.3E-08	21%	0.0	0%	6.8E-08	19%	0.0	0%
Section 585 TAP	Selenium	0.0E+00	0%	0.0	0%	2.3E-07	19%	0.0	0%
Section 585 TAP	Styrene monomer (ID)	9.4E-08	21%	0.0	0%	7.7E-08	19%	0.0	0%
Section 585 TAP	Toluene (toluol)	2.2E-03	24%	0.0	0%	4.0E-05	19%	0.0	0%
Section 585 TAP	Trimethyl benzene (mixed and individual isomers)	3.8E-04	24%	0.0	0%				
Section 585 TAP	2,2,4-Trimethyl-pentane	1.4E-03	24%	0.0	0%				
Section 585 TAP	Xylene (o-, m-, p-isomers)	1.0E-03	24%	0.0	0%	2.8E-04	19%	0.0	0%
Section 586 TAP	Aniline	0.0	0%	0.0	0%	0.00	0%	0.0	0%
Section 586 TAP	Arsenic compounds	0.0	0%	0.0	0%	0.00	0%	0.0	0%
Section 586 TAP	Benzene	0.0	0%	0.0	0%	0.00	0%	0.0	0%
Section 586 TAP	Bis (2-chloro-1-methyl- ethyl) ether	0.0	0%	0.0	0%	0.00	0%	0.0	0%
Section 586 TAP	Bis (2-ethylhexyl) phthalate	0.0	0%	0.0	0%	0.00	0%	0.0	0%
Section 586 TAP	Cadmium and compounds	0.0	0%	0.0	0%	0.00	0%	0.0	0%
Section 586 TAP	Carbon tetrachloride	0.0	0%	0.0	0%	0.00	0%	0.0	0%
Section 586 TAP	Formaldehyde	0.0	0%	0.0	0%	0.00	0%	0.0	0%
Section 586 TAP	Nickel	0.0	0%	0.0	0%	0.00	0%	0.0	0%
Section 586 TAP	Dichloromethane (Methylenechloride)	0.0	0%	0.0	0%				
Section 586 TAP	1,1,2,2,Tetrachloro-ethane	0.0	0%	0.0	0%				
Section 586 TAP	Tetrachloroethylene	0.0	0%	0.0	0%	0.00	0%	0%	0%
Section 586 TAP	1,1,2 - trichloroethane	0.0	0%	0.0	0%	0.00	0%	0%	0%
Section 586 TAP	Vinyl Chloride	0.0	0%	0.0	0%				

New Energy One Biogas Project - Modification
Emission Unit Calculations - Genset EU2

Millennium Science & Engineering, Inc.

Emission unit number	2
Source type	Genset
Model number	CAT 3520
Break Horsepower	2,233 bHP

Hourly Peak Biogas capacity (scf/hr)	25,000 cf/hour
Daily peak biogas capacity (scf/day)	600,000 cf/day
Annual peak biogas capacity (Mcf/year)	219.00 MMcf/year
Annual Estimated peak biogas capacity (Mcf/year)	163.31 MMcf/year

	Pollutant	Raw Biogas (lb/cf)	Control Factor	EF Un-Combusted Biogas (lb/cf)	EF Combust Products (lb/cf)	Comments	Emissions lbs/hr	Emissions tons/yr
Primary Pollutants	PM10				5.64E-06	AP-42 Section 3.2, Table 3.2-2 (includes filterable and	0.14	0.46
	PM2.5				5.64E-06	condensible)	0.14	0.46
	SO2 (1 hour and 24 hour)				1.16E-04	Based on anticipated maximum H2S concentration	2.91	NA
	SO2 (annual)				1.16E-04	Based on anticipated average H2S concentration	NA	9.50
	NOx				1.97E-04	Vendor: NOx = 1 g/bhp-hour	4.92	16.08
	NO_2				1.48E-04	NO_2=75%NOx	3.69	12.06
	CO				4.92E-04	Vendor: CO = 2.5 g/bhp-hour	12.31	40.20
	VOC				1.65E-04	Vendor: VOC = 0.84 g/bhp-hour	4.14	13.51
	Lead				NA			
Section 585 TAP	Acrolein				2.90E-06	AP-42 Table 3.2-2	7.3E-02	2.37E-01
	Biphenyl				1.20E-07	AP-42 Table 3.2-2	3.0E-03	9.78E-03
	2-Chlorophenol (and all isomers) (ID)	3.97E-10	97.2%	1.11E-11		EF Uncombusted Biogas based on max concentration	2.8E-07	9.07E-07
	Cresols/Cresylic Acid (isomers and mixtures)	2.34E-08	97.2%	6.56E-10		EF Uncombusted Biogas based on max concentration	1.6E-05	5.35E-05
	Cyclopentane				1.28E-07	AP-42 Table 3.2-2	3.2E-03	1.05E-02
	Dibutyl phthalate	7.78E-10	97.2%	2.18E-11		EF Uncombusted Biogas based on max concentration	5.4E-07	1.78E-06
	Ethyl benzene	9.47E-09	97.2%	2.65E-10	2.24E-08	EF Uncombusted Biogas based on max concentration	5.7E-04	1.85E-03
	Methanol				1.41E-06	AP-42 Table 3.2-2	3.5E-02	1.15E-01
	Hexane (n-Hexane)				6.27E-07	AP-42 Table 3.2-2	1.6E-02	5.12E-02
	Hydrogen sulfide	6.18E-05	97.2%	1.73E-06		EF Uncombusted Biogas based on max concentration	4.3E-02	1.41E-01
	o-Methylcyclohexanone				6.95E-07	AP-42 Table 3.2-2	1.7E-02	5.67E-02
	Naphthalene	5.48E-10	97.2%	1.53E-11	4.20E-08	EF Uncombusted Biogas based on max concentration	1.1E-03	3.43E-03
	Nitrobenzene	1.85E-10	97.2%	5.18E-12		EF Uncombusted Biogas based on max concentration	1.3E-07	4.23E-07
	Nonane				6.22E-08	AP-42 Table 3.2-2	1.6E-03	5.07E-03
	Octane				1.98E-07	AP-42 Table 3.2-2	5.0E-03	1.62E-02
	Pentane				1.47E-06	AP-42 Table 3.2-2	3.7E-02	1.20E-01
	Phenol	6.99E-09	97.2%	1.96E-10	1.36E-08	EF Uncombusted Biogas based on max concentration	3.4E-04	1.12E-03
	Pyridine	3.11E-10	97.2%	8.71E-12		EF Uncombusted Biogas based on max concentration	2.2E-07	7.11E-07
	Styrene monomer (ID)	3.52E-10	97.2%	9.85E-12		EF Uncombusted Biogas based on max concentration	2.5E-07	8.04E-07
	Toluene (toluol)	3.58E-08	97.2%	1.00E-09	2.31E-07	EF Uncombusted Biogas based on max concentration	5.8E-03	1.89E-02
	Trimethyl benzene (mixed and individual				4.02E-08	AP-42 Table 3.2-2	1.0E-03	3.28E-03
	2,2,4-Trimethyl-pentane				1.41E-07	AP-42 Table 3.2-2	3.5E-03	1.15E-02
	Xylene (o-, m-, p-isomers)	2.21E-08	97.2%	6.19E-10	1.04E-07	EF Uncombusted Biogas based on max concentration	2.6E-03	8.54E-03
Section 586 TAP	Aniline	6.29E-09	97.2%	1.76E-10		EF Uncombusted Biogas based on average concen.	3.3E-06	1.44E-05
	Benzene	2.63E-09	97.2%	7.35E-11	2.49E-07	EF Uncombusted Biogas based on average concen.	4.6E-03	2.03E-02
	1,3-Butadiene				1.51E-07	AP-42 Table 3.2-2	2.8E-03	1.23E-02
	Bis (2-chloro-1-methyl- ethyl) ether	1.51E-09	97.2%	4.23E-11		EF Uncombusted Biogas based on average concen.	7.9E-07	3.46E-06
	Bis (2-ethylhexyl) phthalate	3.92E-09	97.2%	1.10E-10		EF Uncombusted Biogas based on average concen.	2.0E-06	8.95E-06
	Carbon tetrachloride	8.60E-10	97.2%	2.41E-11		EF Uncombusted Biogas based on average concen.	4.5E-07	1.97E-06
	Dichloromethane (Methylenechloride)				1.13E-08	AP-42 Table 3.2-2	2.1E-04	9.23E-04
	1,1,2,2,Tetrachloro-ethane				1.40E-09	EF Uncombusted Biogas based on average concen.	2.6E-05	1.14E-04
	Tetrachloroethylene	7.13E-10	97.2%	2.00E-11		EF Uncombusted Biogas based on average concen.	3.7E-07	1.63E-06
	1,1,2 - trichloroethane	1.75E-08	97.2%	4.89E-10		EF Uncombusted Biogas based on average concen.	9.1E-06	3.99E-05
	Vinyl Chloride				8.42E-09	EF Uncombusted Biogas based on average concen.	1.6E-04	6.87E-04

Notes:

EF Un-Combused Biogas = Raw Biogas x (1-Control Factor)
585 TAP Emissions (lb/hr) = Hourly Peak Biogas Capacity x (EF Non-Combustion Biogas + EF Combustion Products
585 TAP Emissions (ton/yr) = Annual Estimated Peak Biogas Capacity x (EF Non-Combustion Biogas + EF Combustion)Products) / 2000 lb/ton
586 TAP Emissions (ton/yr) = Annual Estimated Peak Biogas Capacity x (EF Non-Combustion Biogas + EF Combustion)Products) / 2000 lb/ton
586 TAP Emissions (lb/hr) = 586 TAP Emissions (ton/yr) / 8760 hr/yr x 2000 lb/ton
Control Efficiency (AP42 Table 2.4-3 (2008 draft) **97.2% (IC Engines)**
Grain Loading Calculation 8.03E-03 gr/dscf

New Energy One Biogas Project - Modification

Emission Unit Calculations - Flare EU4

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Emission unit number	4	**Hourly Peak Biogas capacity (scf/hr)**	59,292 cf/hour
Source type	Flare	**Daily peak biogas capacity (scf/day)**	1,423,008 cf/day
Model number	Shand&Jurs 97300 (or equivalent)	**Annual peak biogas capacity (Mcf/year)**	519.40 MMcf/year
Break Horsepower	- bHP	**Annual Estimated peak biogas capacity (Mcf/year)**	401.50 MMcf/year

	Pollutant	Raw Biogas (lb/cf)	Control Factor	EF Un-Combusted Biogas (lb/cf)	EF Combust Products (lb/cf)	Comments	Emissions lbs/hr	Emissions tons/yr
Primary Pollutants	PM10				7.60E-06	AP42 Table 1.4-2	0.45	1.53
	PM2.5				7.60E-06		0.45	1.53
	SO2 (1 hour and 24 hour)				1.16E-04	Based on anticipated maximum H2S concentration	6.90	NA
	SO2 (annual)				1.16E-04	Based on anticipated average H2S concentration	NA	23.36
	NOx				3.84E-05	AP42 Table 13.5-1	2.28	7.71
	NO_2				2.88E-05	NO_2=75%NOx	1.71	5.78
	CO				2.09E-04	AP42 Table 13.5-2	12.39	41.97
	VOC	1.70E-07	97.7%	1.66E-07	7.91E-05	Sum of nonmethane VOCS	4.70	15.91
	Lead				NA			
Section 585 TAP	Barium, soluble compounds, as Ba				4.40E-09	AP42 Table 1.4-4	2.6E-04	8.83E-04
	2-Chlorophenol (and all isomers) (ID)	3.97E-10	97.7%	9.13E-12		EF Uncombusted Biogas based on max concentration	5.4E-07	1.83E-06
	Chromium metal - Including:				1.40E-09	AP42 Table 1.4-4	8.3E-05	2.81E-04
	Cobalt metal, dust, and fume				8.40E-11	AP42 Table 1.4-4	5.0E-06	1.69E-05
	Copper - Dusts & mists, as Cu				8.50E-10	AP42 Table 1.4-4	5.0E-05	1.71E-04
	Cresols/Cresylic Acid (isomers and mixtures)	2.34E-08	97.7%	5.39E-10		EF Uncombusted Biogas based on max concentration	3.2E-05	1.08E-04
	Dibutyl phthalate	7.78E-10	97.7%	1.79E-11		EF Uncombusted Biogas based on max concentration	1.1E-06	3.59E-06
	Ethyl benzene	9.47E-09	97.7%	2.18E-10		EF Uncombusted Biogas based on max concentration	1.3E-05	4.37E-05
	Hydrogen sulfide	6.18E-05	97.7%	1.42E-06		EF Uncombusted Biogas based on max concentration	8.4E-02	2.85E-01
	Manganese as Mn Dust & compounds				3.80E-10	AP42 Table 1.4-4	2.3E-05	7.63E-05
	Mercury (vapors except Alkyl as Hg)				2.60E-10	AP42 Table 1.4-4	1.5E-05	5.22E-05
	Molybdenum as Mo -Soluble compounds				1.10E-09	AP42 Table 1.4-4	6.5E-05	2.21E-04
	Naphthalene	5.48E-10	97.7%	1.26E-11	6.10E-10	EF Uncombusted Biogas based on max concentration	3.7E-05	1.25E-04
	Nitrobenzene	1.85E-10	97.7%	4.26E-12		EF Uncombusted Biogas based on max concentration	2.5E-07	8.55E-07
	Pentane				2.60E-06	AP42 Table 1.4-4	1.5E-01	5.22E-01
	Phenol	6.99E-09	97.7%	1.61E-10		EF Uncombusted Biogas based on max concentration	9.5E-06	3.23E-05
	Pyridine	3.11E-10	97.7%	7.15E-12		EF Uncombusted Biogas based on max concentration	4.2E-07	1.44E-06
	Selenium				2.40E-11	AP42 Table 1.4-4	1.4E-06	4.82E-06
	Styrene monomer (ID)	3.52E-10	97.7%	8.09E-12		EF Uncombusted Biogas based on max concentration	4.8E-07	1.62E-06
	Toluene (toluol)	3.58E-08	97.7%	8.23E-10	3.40E-09	EF Uncombusted Biogas based on max concentration	2.5E-04	8.48E-04
	Xylene (o-, m-, p-isomers)	2.21E-08	97.7%	5.08E-10		EF Uncombusted Biogas based on max concentration	3.0E-05	1.02E-04
	Zinc oxide dust				2.90E-08	AP42 Table 1.4-4	1.7E-03	5.82E-03
Section 586 TAP	Aniline	6.29E-09	97.7%	1.45E-10		EF Uncombusted Biogas based on average concen.	6.6E-06	2.90E-05
	Arsenic compounds				2.00E-10	AP42 Table 1.4-4	9.2E-06	4.02E-05
	Benzene	2.63E-09	97.7%	6.04E-11	2.10E-09	EF Uncombusted Biogas based on average concen.	9.9E-05	4.34E-04
	Bis (2-chloro-1-methyl- ethyl) ether	1.51E-09	97.7%	3.48E-11		EF Uncombusted Biogas based on average concen.	1.6E-06	6.98E-06
	Bis (2-ethylhexyl) phthalate	3.92E-09	97.7%	9.01E-11		EF Uncombusted Biogas based on average concen.	4.1E-06	1.81E-05
	Cadmium and compounds				1.10E-09	AP42 Table 1.4-4	5.0E-05	2.21E-04
	Carbon tetrachloride	8.60E-10	97.7%	1.98E-11		EF Uncombusted Biogas based on average concen.	9.1E-07	3.97E-06
	Formaldehyde				7.50E-08	AP42 Table 1.4-3	3.4E-03	1.51E-02
	Nickel				2.10E-09	AP42 Table 1.4-4	9.6E-05	4.22E-04
	Tetrachloroethylene	7.13E-10	97.7%	1.64E-11		EF Uncombusted Biogas based on average concen.	7.5E-07	3.29E-06
	1,1,2 - trichloroethane	1.75E-08	97.7%	4.02E-10		EF Uncombusted Biogas based on average concen.	1.8E-05	8.06E-05

Notes:

EF Un-Combused Biogas = Raw Biogas x (1-Control Factor)

585 TAP Emissions (lb/hr) = Hourly Peak Biogas Capacity x (EF Non-Combustion Biogas + EF Combustion Products

585 TAP Emissions (ton/yr) = Annual Estimated Peak Biogas Capacity x (EF Non-Combustion Biogas + EF Combustion)Products) / 2000 lb/to

586 TAP Emissions (ton/yr) = Annual Estimated Peak Biogas Capacity x (EF Non-Combustion Biogas + EF Combustion)Products) / 2000 lb/to

586 TAP Emissions (lb/hr) = 586 TAP Emissions (ton/yr) / 8760 hr/yr x 2000 lb/to

Control Efficiency (AP42 Table 2.4-3 (2008 draf **97.7% (Flare)**

Grain Loading Calculation = 1.08E-02 gr/dscf

New Energy One Biogas Project - Modification

TAP EF Calculation

Compound	CAS	molecular wieght	Partially Clean Biogas Avg Conc (ppbv)*	Partially Clean Biogas Max Conc (ppbv)*	Raw Biogas Avg Conc (ppbv)*	Raw Biogas Max Conc (ppbv)*	Selected Biogas Concentration (ppbv)**	Biogas Compound Mass Flow Rate (lb/scf biogas)***	AP-42 (Boiler)		AP-42 (Engine)	
									(lb/10^6 scf NG)	lb/cf biogas	(lb/ MMBtu)	lb/cf biogas
Acrolein	107-02-8										5.14E-03	2.90E-06
Biphenyl	92-52-4										2.12E-04	1.20E-07
Chlorobenzene	108-90-7	112.56	1.48E+00				1.48E+00	4.40E-10				
2-Chlorophenol	95-57-8	128.56	1.05E+00		8.50E-01	1.17	1.17E+00	3.97E-10				
3,4-Methylphenol (o,p-cresol)	1319-77-3	108.14	7.45E+00		1.80E+01	82.07	8.21E+01	2.34E-08				
Cyclopentane	287-92-3						0.00E+00				2.27E-04	1.28E-07
Di-n-butyl phthalate	84-74-2	278.34	7.40E-01		7.50E-01	1.06	1.06E+00	7.78E-10	fna			
Ethylbenzene	100-41-4	106.167	9.75E+00		1.05E+01	33.81	3.38E+01	9.47E-09	fna		3.97E-05	2.24E-08
n-hexane	110-54-3						0.00E+00				1.11E-03	6.27E-07
Methanol	67-56-1						0.00E+00				2.50E-03	1.41E-06
Methylcyclohexane	583-60-8						0.00E+00				1.23E-03	6.95E-07
Naphthalene	91-20-3	128.17	9.00E-01		1.62E+00		1.62E+00	5.48E-10	6.10E-04	6.10E-10	7.44E-05	4.20E-08
Nitrobenzene	98-95-3	123.06			5.50E-01	0.57	5.70E-01	1.85E-10				
Nonane	111-84-2						0.00E+00				1.10E-04	6.22E-08
Octane	111-65-9						0.00E+00				3.51E-04	1.98E-07
Pentane	109-66-0						0.00E+00				2.60E-03	1.47E-06
Phenol	108-95-2	94.11	1.05E+01		9.68E+00	28.14	2.81E+01	6.99E-09	fna		2.40E-05	1.36E-08
Pyridine	110-86-1	79.1			1.49E+00	1.49	1.49E+00	3.11E-10				
Styrene	100-42-5	104.15	1.28E+00		4.50E-01	0.45	1.28E+00	3.52E-10				
Toluene	108-88-3	92.14	2.23E+01		4.33E+01	147.26	1.47E+02	3.58E-08	3.40E-03	3.40E-09	4.08E-04	2.31E-07
Trimethylbenzene	25551-13-7						0.00E+00				7.11E-05	4.02E-08
2,2,4-Trimethylpentane	540-84-1						0.00E+00				2.50E-04	1.41E-07
Xylenes (o,m,p isomers)	1330-20-7	106.167	5.22E+00		1.77E+01	78.89	7.89E+01	2.21E-08	fna		1.84E-04	1.04E-07
Aniline	62-53-3	93.13	1.29E+01	2.56E+01	2.13E+01		2.56E+01	6.29E-09	fna			
Benzene	71-43-2	78.11	5.85E+00	1.27E+01	4.20E+00		1.27E+01	2.63E-09	2.10E-03	2.10E-09	4.40E-04	2.49E-07
1,3-Butadiene	106-99-0						0.00E+00				2.67E-04	1.51E-07
Bis (2-chloro-1-methyl- ethyl) ether	108-60-1	171.06	3.15E+00	3.15E+00	3.35E+00		3.35E+00	1.51E-09	fna			
bis(2-Ethylhexyl)phthalate	117-81-7	390.56	8.30E-01	3.80E+00	3.90E-01		3.80E+00	3.92E-09	fna			
Carbon Tetrachloride	56-23-5	153.82	1.35E+00	2.12E+00	1.30E+00		2.12E+00	8.60E-10				
Methylene Chloride	75-09-2						0.00E+00				2.00E-05	1.13E-08
1,1,2,2-Tetracholoroethane	79-34-5	167.85	6.80E-01	6.80E-01			6.80E-01	3.01E-10			2.48E-06	1.40E-09
Tetrachloroethylene	127-18-4	167.85	1.61E+00	1.61E+00	1.26E+00		1.61E+00	7.13E-10				
1,1,2- Trichloroethane	79-00-5	133.4	2.42E+01	4.96E+01	3.16E+01		4.96E+01	1.75E-08				
Vinyl Chloride	75-01-4						0.00E+00				1.49E-05	8.42E-09
1,2,4-Trimethylbenzene	95-63-6	120.19	3.08E+00		1.20E+01		1.20E+01	3.81E-09				
1,3,5-Trimethylbenzene	108-67-8	120.19	1.61E+00		4.72E+00		4.72E+00	1.50E-09				
1-Methylnaphthalene	90-12-0	142.2			3.08E+00		3.08E+00	1.16E-09				
2-Methylnaphthalene	91-57-6	142.2			2.20E+00		2.20E+00	8.25E-10				
Benzyl Alcohol	100-51-6	108.14	4.63E+01		5.08E+00		4.63E+01	1.32E-08				
Diethylphthalate	84-66-2	222.24	2.30E-01		2.10E-01		2.30E-01	1.35E-10				
Fluoranthene	206-44-0	202.26			4.30E-01		4.30E-01	2.29E-10				
Isopropylbenzene (cumene)	98-82-8	120.19	1.11E+00		3.56E+00		3.56E+00	1.13E-09				
n-Butylbenzene	104-51-8	134.22	1.36E+00		3.55E+00		3.55E+00	1.26E-09				
N-nitroso-di-n-propylamine	621-64-7	130.19	6.40E-01		6.80E-01		6.80E-01	2.34E-10				
n-propylbenzene	103-65-1	120.19	1.42E+00		5.74E+00		5.74E+00	1.82E-09				
Phenanthrene	85-01-8	178.23			1.09E+00		1.09E+00	5.13E-10				
p-Isopropyltoluene	99-87-6	134.22	2.01E+01		3.26E+00		2.01E+01	7.13E-09				
sec-Butylbenzene	135-98-8	134.22	9.60E-01		3.83E+00		3.83E+00	1.36E-09				
tert-Butylbenzene	98-06-6	134.22	1.02E+00		3.26E+00		3.26E+00	1.15E-09				
Arsenic									2.00E-04	2.00E-10		
Barium									4.40E-03	4.40E-09		
Cadmium									1.10E-03	1.10E-09		
Chromium									1.40E-03	1.40E-09		
Cobalt									8.40E-05	8.40E-11		
Copper									8.50E-04	8.50E-10		
Formaldehyde									7.50E-02	7.50E-08		
Hexane									1.80E+00	1.80E-06		
Manganese									3.80E-04	3.80E-10		
Mercury									2.60E-04	2.60E-10		
Molybdenum									1.10E-03	1.10E-09		
Nickel									2.10E-03	2.10E-09		
Pentane									2.60E+00	2.60E-06		
Selenium									2.40E-05	2.40E-11		
Zinc									2.90E-02	2.90E-08		
							Sum	1.7E-07				

* Source: GTI Pipeline Quality Biomethane: North American Guidance Document for Introduction of Dairy Waste Derived Biomethane Into Existing Natural Gas Networks

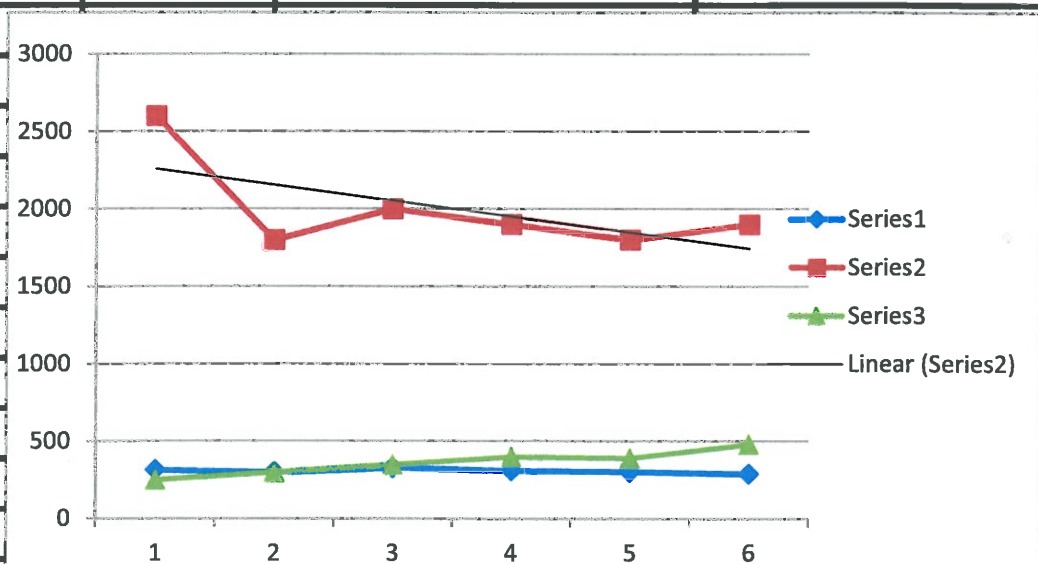
** Selected biogas concentration based on highest of either partially clean or raw biogas maximum concentrations for IDAPA 585 TAPs and the highest of either partially clean or raw biogas average concentrations for IDAPA 586 TAPs.

*** Biogas compound mass flow rate = (Selected biogas concentration (ppbv) / 1x10^9) x (1 lb-mole / 379 scf)

H2S SAMPLES

SITE: PAGELS PONDEROSA (4) IRON SPONGES

DATE	CFM	BEFORE IRON SPONGE	AFTER IRON SPONGE
6/17/11	315	2600	250
6/18/11	300	1800	300
6/19/11	331	2000	350
6/20/11	310	1900	400
6/21/11	303	1800	390
6/22/11	290	1900	480
6/23/11	260	1600	200
6/27/11	300	1650	200
7/1/11	300	1550	450
7/5/11	298	1400	400
7/8/11	276	1500	400
7/12/11	250	1600	400



APPENDIX B – AMBIENT AIR QUALITY IMPACT ANALYSES

MEMORANDUM

DATE: January 13, 2012

TO: Ken Hanna, Permit Writer, Air Program

FROM: Darrin Mehr, Air Quality Analyst, Air Program

PROJECT NUMBER: P-2010.0076 Project 60948

SUBJECT: Modeling Demonstration for a PTC Modification Application for an Anaerobic Digester Biogas System with Electrical Generation Units, a Boiler, and a Flare at the New Energy One's Rock Creek Biogas Project Facility near Filer, Idaho

1.0 Summary

New Energy One, LLC (NEO) submitted a 15-Day Pre-Permit Construction (15-Day PTC) application to modify the emissions units to be constructed at the facility on the Rock Creek Dairy south of Filer, Idaho. This facility was issued its initial PTC on March 30, 2011. The facility will process dairy manure and wastewater with anaerobic digesters to produce biogas. The biogas fuels internal combustion engines for generation of electricity. The NEO facility proposes to construct and operate the following emissions units:

- Two CAT 3520 generator engines rated at 2,233 brake horsepower fired on biogas,
- One boiler rated at 5.2 million British thermal units per hour (Btu/hr) fired on biogas,
- One elevated open flare (also referred to as a candlestick flare) for incinerating excess biogas, and,
- Six anaerobic digester tanks (85 feet diameter each).

Emission units that were permitted in the facility's initial PTC that will not be constructed include:

- Three CAT 3412 generator engines each rated at 503 brake horsepower fired on biogas.

An additional component of this project is a requested permit allowable increase in the short-term biogas usage on hourly and daily bases. There is no enforceable permit limitation on the daily biogas generation rate. The original PTC analyses evaluated operation at 1.1 million cubic feet of biogas per day (MM cu ft/day); whereas this project evaluated sources operating at a total of 1.423 MM cu ft/day. The annual facility-wide biogas production limit will remain unchanged. The permit limitation on hydrogen sulfide content in the biogas will be reduced from 1000 parts per million by volume (ppm_v) to 700 ppm_v.

The project timeline and associated submittals are listed below:

- March 30, 2011: DEQ issued NEO the initial PTC for the Rock Creek Project facility.
- May 20, 2011: DEQ received a modeling protocol via email from Millenium Science and Engineering (MSE) on behalf of NEO for a project to modify the facility's PTC.
- May 24, 2011: DEQ issued a conditional modeling protocol approval letter to NEO and MSE via email with clarifications provided by email concerning the preliminary analyses via email on May 26, 2011.

- October 28, 2011: DEQ received a 15-Day PTC application for the modification of PTC P-2010.0076, Project 60627, issued March 30, 2011.
- November 15, 2011: DEQ issued the pre-permit construction authorization to NEO via email.
- November 28, 2011: DEQ determined the application was complete and issued a completeness determination letter via email to NEO.

The facility is not a *designated facility*, as defined in IDAPA 58.01.01.006, Rules for the Control of Air Pollution in Idaho (Idaho Air Rules). The facility's potential to emit (PTE) of particulate matter with an aerodynamic diameter of ten microns or less (PM_{10}), sulfur dioxide (SO_2), carbon monoxide (CO), and nitrogen oxides (NO_x) each is less than 100 tons per year (T/yr). The facility is not a major facility under the New Source Review (NSR) PSD program.

The proposed project is subject to review under Section 200 of Idaho Air Rules. Idaho Air Rules Section 203.0, which requires that the facility demonstrates compliance with the National Ambient Air Quality Standards (NAAQS). Idaho Air Rules Section 210 requires the facility to demonstrate compliance with the toxic air pollutants (TAPs) increments, which are listed in Sections 585 and 586.

The submitted modeling analyses: 1) utilized appropriate methods and models; 2) were conducted using reasonably accurate or conservative model parameters and input data; 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed that predicted pollutant concentrations from emissions associated with the facility were below the applicable significant contribution levels for NO_2 and SO_2, 1-hour averaging period, and were below the applicable TAP increments at all ambient air locations.

The submitted modeling analyses were conducted by Millennium Science and Engineering, Inc. (MSE), on behalf of NEO. Key assumptions and results that should be considered in the development of the permit are shown in Table 1.

Air impact analyses are required by the Rules to be conducted according to methods outlined in 40 CFR 51, Appendix W (Guideline on Air Quality Models). Appendix W requires that facilities be modeled using emissions and operations representative of design capacity or as limited by a federally enforceable permit condition. The submitted information demonstrated to the satisfaction of the Department that operations of the proposed facility will not cause or significantly contribute to a violation of any ambient air quality standard, provided the key conditions in Table 1 are representative of facility design capacity or operations as limited by a federally enforceable permit condition.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES	
Criteria/Assumption/Result	**Explanation/Consideration**
The equipment listing for this facility has been altered as follows: • One additional CAT 3520 dairy waste anaerobic digester biogas-fired generator engine will be constructed in place of three CAT 3412 biogas-fired engines. • SO_2 potential emissions were limited by the application of the hydrogen sulfide (H_2S) control system consisting of an "iron sponge."	This project analyzed whether the operational change from three small generator engines permitted in the initial March 30, 2011 facility-wide PTC to a single larger generator engine would cause maximum ambient impacts to exceed the significant contribution level of any pollutant emitted at a rate that exceeded the modeling applicability thresholds due to emission rate increases and the changes in the release parameters (such as stack location, exit velocity, etc.).
<u>Sulfur Dioxide Emissions</u> Sulfur dioxide (SO_2) emissions resulting from the conversion (oxidation) of hydrogen sulfide (H_2S) during the combustion process were based on reductions in the biogas H_2S content using a system to maintain lower levels of H_2S in the biogas supplied to all emissions units. SO_2 emissions increase and decrease linearly with H_2S concentration in the biogas that is combusted in the facility's emissions units. The initial facility-wide PTC included anaerobic digesters designed with an air injection system in the gas collection portion of each digester tank. This system was expected to maintain H_2S levels below 1,000 parts per million on a volumetric basis (ppm_v) in the biogas during normal service. This project's emission rates are based on an additional H_2S control system—described as an "iron sponge filter." The maximum predicted H_2S concentration used to quantify the resulting SO_2 emissions was 700 ppm_v.	SO_2 emissions are directly related to the hydrogen sulfide (H_2S) concentration in the biogas combusted in the facility's emissions units (generator engines, boiler, and open flare). Generator Engines 1 and 2, the boiler, and the flare were assumed to combust biogas with an H_2S content of 700 ppm_v.
<u>Biogas Production and Assumptions</u> • Total requested permit limit capacity 402 million cubic feet (MM cu ft) per year. • The daily production rate of biogas for this project's emission estimates increased from the original 1.1 MM cu ft/day to a rate of 1.423 MM cu ft/day. • Biogas heat content of 565 British thermal units per cu ft biogas (Btu/cu ft).	Emission rates for two generator engines are based on the heat input capacity of the generator engines rather than the heat content of the biogas produced and combusted. The heat input capacity of the two generator engines exceeds the average hourly and the average daily biogas production capacity of the anaerobic digester system, as currently described. This should provide a conservative analysis of ambient impacts attributed to the equipment change. Capacity of equipment used in the analysis: • Generator 1: 25,000 cu ft gas/hr and 600,000 cu ft gas/day (unchanged); • Generator 2: 25,000 cu ft gas/hr and 600,000 cu ft gas/day; • Columbia Boiler: 9,292 cu ft gas/hr and 223,008 cu ft gas/day (unchanged); and, • Candlestick Flare: 59,292 cu ft gas/hr and 1.423 million cu ft gas/day.

2.0 Background Information

2.1 Applicable Air Quality Impact Limits and Modeling Requirements

This section identifies applicable ambient air quality limits and analyses used to demonstrate compliance.

2.1.1 Area Classification

The NEO facility is located in Twin Falls County, which is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), and particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers ($PM_{2.5}$).

There are no Class I areas within 10 kilometers of the facility.

2.1.2 Significant and Cumulative NAAQS Impact Analyses

If estimated maximum pollutant impacts to ambient air from the emissions sources associated with the existing unpermitted facility exceed the significant contribution levels (SCLs) of Section 006 of IDAPA 58.01.01, Rules for the Control of Air Pollution in Idaho (Idaho Air Rules), then a cumulative impact analysis is necessary to demonstrate compliance with National Ambient Air Quality Standards (NAAQS) and Idaho Air Rules Section 203.02 for Permits to Construct and Section 403.02 for Tier II Operating Permits. A cumulative NAAQS impact analysis for attainment area pollutants involves adding ambient impacts from facility-wide emissions, and emissions from any nearby co-contributing sources, to DEQ-approved background concentration values that are appropriate for the criteria pollutant/averaging-time at the facility location and the area of significant impact. The resulting maximum pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. The SCLs and the modeled value that must be used for comparison to the NAAQS are also listed in Table 2.

Table 2. APPLICABLE REGULATORY LIMITS				
Pollutant	Averaging Period	Significant Contribution Levels[c] ($\mu g/m^3$)[b]	Regulatory Limit[d] ($\mu g/m^3$)[b]	Modeled Value Used for NAAQS Analysis[g, h]
PM_{10}[a]	24-hour	5.0	150[f]	Maximum 6^{th} highest[i]
$PM_{2.5}$[a]	Annual	0.3[b]	15[e]	$PM_{2.5}$ –Maximum 1^{st} high[j]
	24-hour	1.2[b]	35	$PM_{2.5}$ –Maximum 1^{st} high[j]
Carbon monoxide (CO)	8-hour	500	10,000[f]	Maximum 2^{nd} highest
	1-hour	2,000	40,000[f]	Maximum 2^{nd} highest
Sulfur Dioxide (SO_2)	3-hour	25	1,300[f]	Maximum 2^{nd} highest
	1-hour	EPA Interim: 3 ppb[m] (~7.8 $\mu g/m^3$)	0.075 ppm[m,n] (196 $\mu g/m^3$)	Maximum 4^{th} highest[m]
Nitrogen Dioxide (NO_2)	Annual	1.0	100[f]	Maximum 1^{st} highest
	1-hour	EPA Interim: 4 ppb[l] (7.5 $\mu g/m^3$)	0.100 ppm[l, n] (188 $\mu g/m^3$)	Maximum 8^{th} highest[l]
Lead (Pb)	Rolling 3-month average	NA	0.15[f, k]	Maximum 1^{st} highest

[a] Particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) or 2.5 micrometers.
[b] Micrograms per cubic meter.
[c] SCLs are defined in Idaho Air Rules Section 006. $PM_{2.5}$ SCLs (75 FR 64864, October 20, 2010) were adopted as an Idaho temporary rule effective April 26, 2011. The pending rule will become final and effective upon adjournment of the 2012 legislative session if approved by the Idaho Legislature.
[d] Federal NAAQS (see 40 CFR 50) in effect as of July 1 of each year are incorporated by reference during the legislative session the following spring. See Idaho Air Rules Section 107 to review incorporations by reference.
[e] Never expected to be exceeded in any calendar year.
[f] Never expected to be exceeded more than once in any calendar year. The 3-hr and 24-hr SO_2 standards were revoked (see 75 FR 35520, June 22, 2010) but will remain in effect until one year after the effective date (~late 2012) of initial area designations for the new 1-hour SO_2 NAAQS (i.e., in effect until ~late 2013).
[g] Concentration at any modeled receptor.
[h] The maximum 1^{st} highest modeled value is always used for significant impact analyses.
[i] PM_{10} concentration at any modeled receptor when using five years of meteorological data. Use the maximum 2^{nd} highest value for analyses with less than five years of meteorological data or one year of site-specific met data.
[j] $PM_{2.5}$ concentration at any modeled receptor when using a single year of site-specific meteorological data or a concatenated file with five years of meteorological data. EPA recommends using the high 8^{th} high 3-year average monitored value for background, and using the highest 24-hr average and highest annual averages across five years of met data for the modeled result (Steven Page memo, Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS, March 23, 2010).
[k] Pb: The EPA's October 15, 2008 standard became effective in Idaho's NSR program when it was incorporated by reference into the Idaho Air Rules, i.e., when the Idaho Legislature adjourned *sine die* on March 29, 2010.
[l] NO_2 concentration at any modeled receptor when using complete year(s) of site-specific met data or five consecutive years of representative meteorological data. Compliance is based on the 3-year average of the 98^{th} percentile of the annual distribution of 1-hour average daily maximum concentrations. EPA Interim SIL, Page memo, dated June 29, 2010.
[m] SO_2 concentration at any modeled receptor when using complete year of site-specific met data or five consecutive years of representative meteorological data. Compliance is based on the 3-year average of the annual 99^{th} percentile of 1-hour daily maximum concentrations. EPA Interim SIL, Page memo, dated August 23, 2010.
[n] EPA's February 10, 2010 1-hour NO_2 standard (75 FR 6474) and June 22, 2010 1-hour SO_2 standard (75 FR 35520) became effective in Idaho on April 7, 2011.

2.1.3 TAPs Analyses

The increase in emissions from this project wererequired to demonstrate compliance with the toxic air pollutant (TAP) increments, with an ambient impact dispersion analysisrequired for any TAP having a requested potential emission rate that exceeds the screening emission rate limit (EL) specified by Idaho Air Rules Section 585 or 586.

This project includes switching a single larger capacity generator engine for three units with a lower heat input capacity. The overall biogas combustion capacity is greater than fo the proposed generator engine than was originally addressed in the initial PTC project and the applicant evaluated the increase in TAPs from the biogas-fired generator engine in accordance with Section 210 of the Idaho Air Rules.

2.2 Background Concentrations

No background concentrations were provided by DEQ for this project. The modeling demonstration for this project did not contain a full ambient impact analysis because the applicant's modeling demonstration predicted that the physical changes and emissions changes for the 1-hour averaging periods for NO_2 and SO_2 would not cause maximum ambient impacts that exceeded the applicable significant impact levels (or significant contribution levels).

3.0 Modeling Impact Assessment

3.1 Modeling Methodology

Table 3 provides a summary of the modeling parameters used in the submitted modeling analyses.

Table 3. MODELING PARAMETERS		
Parameter	**Description/ Values**	**Documentation/Additional Description**
Model	AERMOD	AERMOD, Version 11103.
Meteorological data	2000-2004	DEQ provided a pre-processed data set of individual year files of Twin Falls airport surface data and Boise airport upper air data covering the years 2000-2004.
Terrain	Considered	3-dimensional receptor coordinates were obtained by MSE from Digital Elevation Model (DEM) files for the surrounding area. The receptor grid was run through AERMAP Version 06341.
Building downwash	Downwash algorithm	AERMOD, Version 11103 uses BPIP-Prime and the PRIME algorithms to evaluate structure-induced downwash effects.
Receptor grid	Grid 1	25-meter spacing in roughly a 475-meter (X) by 475-meter (Y) grid off center of the facility's emissions units.
	Grid 2	100-meter spacing in a 2,000-meter (X) by 2,000-meter (Y) grid centered on Grid 1 and the facility.

3.1.1 Modeling Protocol

A modeling protocol addendum was submitted by MSE, on behalf of New Energy One, for the modification of the Rock Creek Biogas Project, on May 20, 2011. DEQ issued a conditional approval of the modeling protocol with comments on May 24, 2011.

Modeling was conducted using methods documented in the modeling protocol and the *State of Idaho Air Quality Modeling Guideline*.

3.1.2 Model Selection

AERMOD, Version 11103 was used to conduct the ambient air analyses for the criteria air pollutant significant contribution and TAPs compliance demonstrations

3.1.3 Meteorological Data

DEQ supplied MSE with an AERMOD-ready meteorological dataset that spans the years 2000 through 2004. Surface data were obtained from the Twin Falls Joslin Field airport. Upper air data were obtained for the corresponding years at theBoise airport site.

3.1.4 Terrain Effects

The modeling analysesconsidered elevated terrain. NEO's application included a site plot plan Building and source elevations appear to match the elevation data included on the plot plan. Receptor elevations were obtained from USGS DEM file. DEM files are based on the NAD27 coordinate system. AERMAP Version 11103 was used to process the receptor grid's elevations and hill height scale values. Theoutput files were based on the WGS84 system.

The modeling domain considered by NEO and MSE included the following boundaries:

Eastern Boundary: -114.593070 degrees longitude (deg LON)
Western Boundary: -114.640577 deg LON
Northern Boundary: 42.518179 degrees latitude (deg LAT)
Southern Boundary: 42.483025 deg LAT

3.1.5 Facility Layout

Google Earth imagery dates back toSeptember 21, 2011 for this site. The facility's location is entirely surrounded by property owned and controlled by the existing Rock Creek Dairy facility DEQ checked the site plan submitted with the permit applicationto verify the facility's layout. The final site plan provided by NEO was created independently of the modeling demonstration's input filesand matched the modeling files. The facility layoutand location of emission sources wereaccepted as submitted.

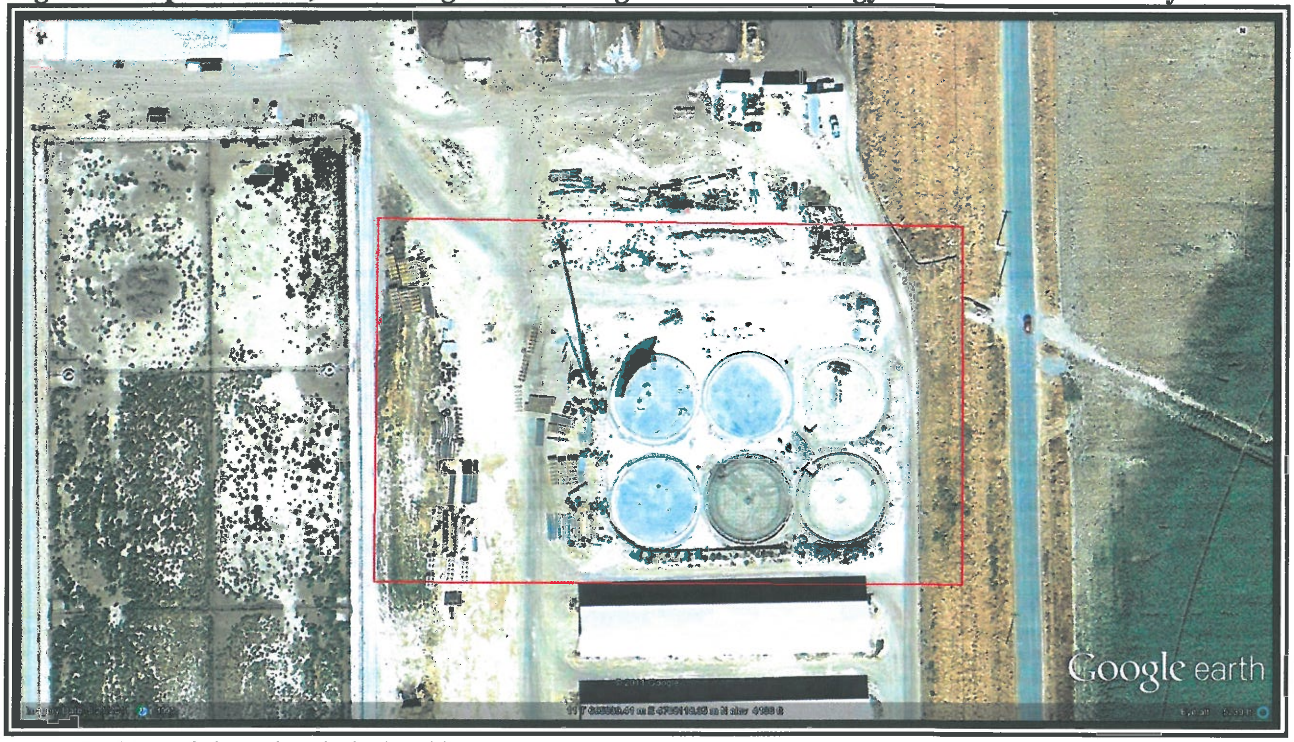
3.1.6 Building Downwash

Plume downwash effects caused by structures atthe facility were accounted for in the modeling analyses. The Building Profile Input Program-Plume Rise and Building Downwash Model(BPIP-PRIME) was used by the applicant to calculate direction-specific building dimensions and Good Engineering Practice (GEP) stack height information from building dimensions/configurations and emissions release parameters. The output from BPIP-PRIME was used as input to AERMOD, Version 11103, to account for building-induced downwash effects.

3.1.7 Ambient Air Boundary

The ambient air boundary employed by NEO for the PTC modification project is depicted in Figure 1 below. This is the boundary of the leased propertythat NEO will operate the biogas digesters, boiler, electricity generation engine sets, and flare. NEO's application states that the perimeter of the site will be controlled by NEO staff present on a daily basis and signs warning against entry. In addition it appears from the Google Earth imagery for the site that the eastern ambient air boundary follows a fence that would also prevent access from that area. This approach follows themethods of determining the ambient air boundary as specified in the *State of Idaho Air Quality Modeling Guideline*.

Figure 1. September 21, 2011 Google Earth Image of the New Energy One Rock Creek Dairy Site



Note: Ambient air boundary is depicted in red outline.

3.1.8 Receptor Network

The receptor grid used by NEO met the minimum recommendations specified in the *State of Idaho Air Quality Modeling Guideline*. DEQ determined the receptor grid was adequate to reasonably resolve the maximum modeled ambient impacts.

3.2 Emission Rates

3.2.1 Modeled Emission Rates

Emissions rates used in the dispersion modeling analyses submitted by the applicant were reviewed against those in the permit application. The following approach was used for NEO's modeling demonstration:

- All modeled criteria air pollutant and TAP emissions rates were equal to or greater than the facility's emission rates calculated in the PTC application.

  The significant contribution demonstration modeled the permit allowable emission rates for the existing ambient impact case and the future requested emission rates of the generator engines and the boiler for the future case. The increase in the TAP emission rate attributed to the change in equipment design was also evaluated.

- Table 4 lists the hourly emission rates that were modeled to demonstrate compliance with NAAQS for pollutants with short term averaging periods of one hour. The emission rates listed in Table 4 were modeled continuously for 24 hours per day. The NO_2 emission rates modeled by NEO accounted for a 75% NO_2 to NO_x formation ratio. The current EPA guidance[1] for NO_2 modeling provides an ambient ratio method (or ARM) value of 80% conversion of NO_2 to NO_x for the Tier II NO_2 compliance method.

Table 4. MODELED SHORT-TERM EMISSIONS RATES			
Source ID	Description	NO_2[b, c] 1-hour average (lb/hr)[a]	SO_2[d] 1-hour average (lb/hr)
Initial PTC Sources			
EU1	Generator #1 – CAT 3520	3.40 (3.63)	4.16
EU2	Generator #2 – CAT 3412	1.53 (1.63)	0.85
EU3	Generator #3 – CAT 3412	1.53 (1.63)	0.85
EU4	Generator #4 – CAT 3412	1.53 (1.63)	0.85
EU5	Columbia Boiler	0.65 (0.69)	1.54
Future Requested Sources			
EU1	Generator #1 – CAT 3520	3.69 (3.94)	2.91
EU2	Generator #2 – CAT 3520	3.69 (3.94)	2.91
EU3	Columbia Boiler	0.65 (0.69)	1.08

a. Pounds per hour.
b. Nitrogen dioxide (reflecting the application's assumed 75% NO_2 to NO_x ratio).
c. Values in parentheses reflect the default 80% value for the Tier II Ambient Ratio Method NO_2 to NO_x ratio.
d. Sulfur dioxide.

This facility will also install and operate an open flare for destruction of biogas. The open flare was not represented in this modeling demonstration for a significant contribution analysis. Normal operations are represented by full or partial load operation of the biogas-fired generator engines and the biogas-fired boiler. The modeling demonstration supporting the initial PTC indicated that the normal operating scenario with the generator engines and the boiler presented the project's worst-case ambient impacts. Flare operations are generally expected to be minimized in order to maximize electricity generation.

Annual operations were not modeled by NEO. Annual emission rates are not expected to increase as a result of this project, and the application requests a limit of 402 million cubic feet per year of biogas production. Based upon the results of the short term averaging period modeling demonstrations representing a small increase in short term emission rates and the change in impacts due to the different exhaust characteristics attributed to operating a single large generator engine instead of three smaller engines, DEQ agrees that no modeling would be required for pollutants with an annual averaging period.

Emissions of acrolein, a non-carcinogenic TAP, were expected to exceed the emissions screening level (EL), and modeling was required. The hourly emissions of the non-carcinogenic TAP listed in Table 5 were modeled for 24 hours per day to demonstrate compliance with the applicable acceptable ambient concentration for non-carcinogens (AAC). No emissions of any other non-carcinogenic TAP or any carcinogenic TAPs were predicted to exceed the screening emission rate limits specified in Idaho Air Rules Sections 585 and 586, and air impact analyses were not required.

1 *"Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard,"* Tyler Fox, Leader, Air Quality Modeling Group, EPA to Regional Air Division Directors, EPA, dated March 1, 2011.

Table 5. MODELED TOXIC AIR POLLUTANT EMISSIONS RATES				
Pollutant	**CAS No.[b]**	**Type**	**Emissions Units and Emission Rates**	
			Generator 1 (lb/hr)[a]	**Generator 2 (lb/hr)**
Acrolein	107-02-8	Non-carcinogenic	0.073	0.073

a. Pounds per hour
b. Chemical Abstract Service Number

3. 3 Emission Release Parameters

3.3.1 Point Sources

Table 6 provides emissions release parameters, including stack height, stack diameter, exhaust temperature, and exhaust velocityfor point sources. No area or volume sources were modeled.

The generator engines and the boiler were modeled as point sources each with a vertical uninterrupted release. Documentation was provided by the equipment vendor for the Cain heat exchanger units to support the exit temperature for the generator engine stacks. The heat exchangers transfer heat to the anaerobic digesters. The boiler also provides heat to the digester units. The reduction in exit temperature for the generator engine stacks due to the heat exchangers was also appropriately accounted for in the reduction in the volumetric flow rate of the exhaust stream on each generator engine. Manufacturer specification sheets were provided for the emissions units.

DEQ accepted the modeled exit temperatures, stack release heights, and diameters as submitted.

Table 6. POINT SOURCE STACK PARAMETERS						
Release Point	**Description**	**Release Orientation**	**Stack Height (m)[a]**	**Stack Gas Flow Temperature (K)[b]**	**Stack Gas Flow Velocity (m/sec)[c]**	**Stack Diameter (m)**
Modeled Existing (Originally-Permitted) Sources						
EU1	Generator #1 – CAT 3520	Vertical and uninterrupted	9.15	450	35.4	0.36
EU2	Generator #2 – CAT 3412	Vertical and uninterrupted	9.15	450	31.8	0.20
EU3	Generator #3 – CAT 3412	Vertical and uninterrupted	9.15	450	31.8	0.20
EU4	Generator #4 – CAT 3412	Vertical and uninterrupted	9.15	450	31.8	0.20
EU5	Columbia Boiler	Vertical and uninterrupted	9.15	450	8.0	0.36
Modeled Future Sources						
EU1	Generator #1 – CAT 3520	Vertical and Uninterrupted	9.14	450	35.4	0.36
EU2	Generator #2 – CAT 3520	Vertical and Uninterrupted	9.16	450	35.4	0.36
EU3	Columbia Boiler	Vertical and Uninterrupted	9.14	450	8.0	0.36

a. Meters
b. Kelvin
c. Meters per second

3.4 Results for Ambient Impact Analyses

3.4.1 Significant Impact Analyses

A significant impact analysis wasperformed for this project NEO's modeling demonstration presented ambient impacts for the facility's initiallypermitted operating scenario for one CAT3520 generator engine, three CAT 3412 generator engines, and one 5.2 million Btu/hr boiler, all operating at rated capacity. The requested modification scenario involved modeling two CAT 3520 generator engines and one 5.2 million Btu/hr boiler operating at rated capacity. Flaring was not accounted for in either existing or future requested scenarios. Flaring is not a desired operatingcase and is expected to be minimized. The worst case impacts are expected to occur for the normal operating scenarioTable 7 lists the project's maximum flare-only operating scenario emissions changes in comparison to the DEQ modeling thresholds presentd in the *State of Idaho Guideline for Performing Air QualityImpact Analyses*, Revison 2, July 2011.

Table 7. FLARE-ONLY SCENARIO MODELING APPLICABILITY				
Pollutant	Project Emissions Increase (lb/hr)[a]	Level I Modeling Threshold (lb/hr)	Level II Modeling Threshold (lb/hr)	Modeling Required
$PM_{2.5}$[b]	0.07	0.054	0.63	No—per DEQ discretion
PM_{10}[c]	0.07	0.22	2.6	No
SO_2[d]	-1.36	0.21	2.5	No
NO_x[e]	0.37	0.20	2.4	No—per DEQ discretion
CO[f]	2.0	15	175	No

a. Pounds per hour.
b. Particulate matter with a mean aerodynamic diameter of 2.5 microns or less.
c. Particulate matter with a mean aerodynamic diameter of 10 microns or less.
d. Sulfur dioxide.
e. Nitrogen oxides.
f. Carbon monoxide.

Table 8 presents the results of NEO's significant impact analysesThe predicted net ambient impacts were below the applicable levels, and the demonstration concluded this project will not cause an exceedence of a significant contribution level.

Table 8. RESULTS OF SIGNIFICANT IMPACT ANALYSES					
Pollutant	Averaging Period	Design Concentration ($\mu g/m^3$)[a]	Design Value	Significant Impact Level ($\mu g/m^3$)	Percent of Significant Impact Level
NO_2[c]	1-hour	3.15 (3.36)[b]	5-year average of the maximum daily 1-hour average impacts	7.5	42% (45%)
SO_2[d]	1-hour	3.75	5-year average of the maximum daily 1-hour average impacts	7.8	48%

a. Micrograms per cubic meter.
b. Values in parentheses applied the current Ambient Ratio Method value of 80% NO_2 to NO_x for the Tier II NO_x compliance method.
c. Nitrogen dioxide.
d. Sulfur dioxide.

3.4.2 Full Impact Analyses

Based on the results of the significant impact analyses a full impact analysis was not required, and a full impact analysis was not submitted, nor was required, for any criteria air pollutant and any averaging period for this project.

3.4.3 Toxic Air Pollutant Impact Analyses

Dispersion modeling for TAPs was required to demonstrate compliance with TAP increments specified by Idaho Air Rules Section 585 for non-carcinogenic TAPs. This project involves a modification to a facility that was issued a PTC in March 2011. The increase in TAPs emissions due to the increase in heat input capacity of the equipment was evaluated for compliance with allowable increments. The predicted ambient TAPs impacts are listed in Table 9 and were below allowable increments. Acrolein is a non-carcinogenic TAP.

Table 9. RESULTS OF TAPs ANALYSES				
Toxic Air Pollutant	**CAS[a]**	**Maximum Modeled Concentration ($\mu g/m^3$)[b]**	**AAC[c] ($\mu g/m^3$)**	**Percent of AAC**
Acrolein	107-02-8	1.71	12.5	13.7%

a. Chemical Abstract Service Number
b. Micrograms per cubic meter
c. Acceptable ambient concentration for non-carcinogens

4.0 Conclusions

The ambient air impact analysis submitted demonstrated to DEQ's satisfaction that emissions from the facility, as represented by the applicant in the permit application, will not cause or significantly contribute to a violation of any air quality standard.

APPENDIX C – NSPS SUBPART JJJJ

Note: The following applicability review utilizes colored highlighting to denote applicable and non-applicable portions of Subpart JJJJ as it relates to the proposed Rock Creek Biogas Project.

Subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
Source: 73 FR 3591, Jan. 18, 2008, unless otherwise noted.
What This Subpart Covers
§ 60.4230 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary spark ignition (SI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (5) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary SI ICE with a maximum engine power less than or equal to 19 kilowatt (KW) (25 horsepower (HP)) that are manufactured on or after July 1, 2008.

(2) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are gasoline fueled or that are rich burn engines fueled by liquefied petroleum gas (LPG), where the date of manufacture is:

(i) On or after July 1, 2008; or

(ii) On or after January 1, 2009, for emergency engines.

(3) Manufacturers of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are not gasoline fueled and are not rich burn engines fueled by LPG, where the manufacturer participates in the voluntary manufacturer certification program described in this subpart and where the date of manufacture is:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

(ii) On or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

(iii) On or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

(iv) On or after January 1, 2009, for emergency engines.

→ **Not applicable, applies to engine manufacturer, not owner/operator.**

(4) Owners and operators of stationary SI ICE that commence construction after June 12, 2006, where the stationary SI ICE are manufactured:

(i) On or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP);

→ **Not applicable since the CAT 3520 engine (2233 HP) was constructed before July 1, 2007 and the CAT 3412 engines (503 HP) are lean burn engines greater than 500 HP and less than 1,350 HP.**

(ii) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP;

→ **Applicable to CAT 3412 engines (503 HP) since these engines are lean burn engines with engine power greater than 500 HP and less than 1,350 HP.**

(iii) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or

→ **Not applicable since all proposed engines have power rating greater than 500 HP.**

(iv) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

→ **Not applicable since all proposed engines are not considered to be "emergency engines".**

(5) Owners and operators of stationary SI ICE that commence modification or reconstruction after June 12, 2006.

(b) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that use gasoline and that are manufactured on or after the applicable date in §60.4230(a)(2), or manufactured on or after the applicable date in §60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that are manufactured on or after the applicable date in §60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cubic centimeters (cc) to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(c) Stationary SI internal combustion engine manufacturers must certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) (except emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) that are rich burn engines that use LPG and that are manufactured on or after the applicable date in §60.4230(a)(2), or manufactured on or after the applicable date in §60.4230(a)(4) for emergency stationary ICE with a maximum engine power greater than or equal to 130 HP, to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers must certify their emergency stationary SI ICE with a maximum engine power greater than 25 HP and less than 130 HP that are manufactured on or after the applicable date in §60.4230(a)(4) to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, and other requirements for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate.

(d) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) under the voluntary manufacturer certification program described in this subpart must certify those engines to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. Stationary SI internal combustion engine manufacturers who choose to certify their emergency stationary SI ICE greater than 25 HP and less than 130 HP, must certify those engines to the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, for new nonroad SI engines in 40 CFR part 90. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards for new nonroad SI engines in 40 CFR part 90 or 1054, as appropriate. For stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) and less than 75 KW (100 HP) (except gasoline and rich burn engines that use LPG and emergency stationary ICE with a maximum engine power greater than 25 HP and less than 130 HP) manufactured prior to January 1, 2011, manufacturers may choose to certify these engines to the standards in Table 1 to this subpart applicable to engines with a maximum engine power greater than or equal to 100 HP and less than 500 HP.

(e) Stationary SI internal combustion engine manufacturers who choose to certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) (except gasoline and rich burn engines that use LPG) under the voluntary manufacturer certification program described in this subpart must certify those engines to the emission standards in Table 1 to this subpart. Stationary SI internal combustion engine manufacturers may certify their stationary SI ICE with a maximum engine power greater than or equal to 75 KW (100 HP) that are lean burn engines that use LPG to the certification emission standards for new nonroad SI engines in 40 CFR part 1048. For stationary SI ICE with a maximum engine power greater than or equal to 100 HP (75 KW) and less than 500 HP (373 KW) manufactured prior to January 1, 2011, and for stationary SI ICE with a maximum engine power greater than or equal to 500 HP (373 KW) manufactured prior to July 1, 2010, manufacturers may choose to certify these engines to the certification emission standards

(f) Owners and operators of any modified or reconstructed stationary SI ICE subject to this subpart must meet the requirements as specified in paragraphs (f)(1) through (5) of this section.
(1) Owners and operators of stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (a) of this section.
(2) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that use gasoline engines, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (b) of this section.
(3) Owners and operators of stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) that are rich burn engines that use LPG, that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (c) of this section.
(4) Owners and operators of stationary SI natural gas and lean burn LPG engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (d) or (e) of this section, except that such owners and operators of non-emergency engines and emergency engines greater than or equal to 130 HP must meet a nitrogen oxides (NO_x) emission standard of 3.0 grams per HP-hour (g/HP-hr), a CO emission standard of 4.0 g/HP-hr (5.0 g/HP-hr for non-emergency engines less than 100 HP), and a volatile organic compounds (VOC) emission standard of 1.0 g/HP-hr, or a NO_x emission standard of 250 ppmvd at 15 percent oxygen (O_2), a CO emission standard 540 ppmvd at 15 percent O_2 (675 ppmvd at 15 percent O_2 for non-emergency engines less than 100 HP), and a VOC emission standard of 86 ppmvd at 15 percent O_2, where the date of manufacture of the engine is:
(i) Prior to July 1, 2007, for non-emergency engines with a maximum engine power greater than or equal to 500 HP;
(ii) Prior to July 1, 2008, for non-emergency engines with a maximum engine power less than 500 HP;
(iii) Prior to January 1, 2009, for emergency engines.
(5) Owners and operators of stationary SI landfill/digester gas ICE engines with a maximum engine power greater than 19 KW (25 HP), that are modified or reconstructed after June 12, 2006, must comply with the same emission standards as those specified in paragraph (e) of this section for stationary landfill/digester gas engines.

→ **Not applicable, proposed sources not modified or reconstructed.**

(g) Owners and operators of stationary SI wellhead gas ICE engines may petition the Administrator for approval on a case-by-case basis to meet emission standards no less stringent than the emission standards that apply to stationary emergency SI engines greater than 25 HP and less than 130 HP due to the presence of high sulfur levels in the fuel, as specified in Table 1 to this subpart. The request must, at a minimum, demonstrate that the fuel has high sulfur levels that prevent the use of aftertreatment controls and also that the owner has reasonably made all attempts possible to obtain an engine that will meet the standards without the use of aftertreatment controls. The petition must request the most stringent standards reasonably applicable to the engine using the fuel.

→ **Not applicable, the owner or operator is not petitioning the Administrator for less stringent emission standards.**

(h) Owners and operators of stationary SI ICE that are required to meet standards that reference 40 CFR 1048.101 must, if testing their engines in use, meet the standards in that section applicable to field testing, except as indicated in paragraph (e) of this section.

→ **Not applicable, stationary engines are not classified as nonroad engines; therefore 40 CFR 1048.101 does not apply.**

§ 60.4234 How long must I meet the emission standards if I am an owner or operator of a stationary SI internal combustion engine?
Owners and operators of stationary SI ICE must operate and maintain stationary SI ICE that achieve the emission standards as required in §60.4233 over the entire life of the engine.

standards applicable to non-emergency engines, you must install a non-resettable hour meter upon startup of your emergency engine.

→ **Not applicable, engines are not for emergency purposes.**

Compliance Requirements for Manufacturers

§ 60.4238 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines •19 KW (25 HP) or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(a) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[73 FR 59176, Oct. 8, 2008]

→ **Not applicable, applies to manufacturer, not operator.**

§ 60.4239 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that use gasoline or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(b) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[73 FR 59176, Oct. 8, 2008]

→ **Not applicable, applies to manufacturer, not operator.**

§ 60.4240 What are my compliance requirements if I am a manufacturer of stationary SI internal combustion engines >19 KW (25 HP) that are rich burn engines that use LPG or a manufacturer of equipment containing such engines?

Stationary SI internal combustion engine manufacturers who are subject to the emission standards specified in §60.4231(c) must certify their stationary SI ICE using the certification procedures required in 40 CFR part 1048, subpart C, and must test their engines as specified in that part. Stationary SI internal combustion engine manufacturers who certify their stationary SI ICE with a maximum engine power less than or equal to 30 KW (40 HP) with a total displacement less than or equal to 1,000 cc to the certification emission standards and other requirements for new nonroad SI engines in 40 CFR part 90 or 40 CFR part 1054, and manufacturers of stationary SI emergency engines that are greater than 25 HP and less than 130 HP who meet the Phase 1 emission standards in 40 CFR 90.103, applicable to class II engines, must certify their stationary SI ICE using the certification procedures required in 40 CFR part 90, subpart B, or 40 CFR part 1054, subpart C, as applicable, and must test their engines as specified in those parts. Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, subpart C, to the extent they apply to equipment manufacturers.

[73 FR 59176, Oct. 8, 2008]

→ **Not applicable, applies to manufacturer, not operator.**

landfill/digester gas applications. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).
(h) For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.
(i) For engines being certified to the voluntary certification standards in Table 1 of this subpart, the VOC measurement shall be made by following the procedures in 40 CFR 1065.260 and 1065.265 in order to determine the total NMHC emissions by using a flame-ionization detector and non-methane cutter. As an alternative to the nonmethane cutter, manufacturers may use a gas chromatograph as allowed under 40 CFR 1065.267 and may measure ethane, as well as methane, for excluding such levels from the total VOC measurement.
[73 FR 3591, Jan. 18, 2008, as amended by 73 FR 59176, Oct. 8, 2008]

→ **Not applicable, applies to manufacturer, not operator.**

§ 60.4242 What other requirements must I meet if I am a manufacturer of stationary SI internal combustion engines or equipment containing stationary SI internal combustion engines or a manufacturer of equipment containing such engines?
(a) Stationary SI internal combustion engine manufacturers must meet the provisions of 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054, as applicable, as well as 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1048 or 1054, except that engines certified pursuant to the voluntary certification procedures in §60.4241 are subject only to the provisions indicated in §60.4247 and are permitted to provide instructions to owners and operators allowing for deviations from certified configurations, if such deviations are consistent with the provisions of paragraphs §60.4241(c) through (f). Manufacturers of equipment containing stationary SI internal combustion engines meeting the provisions of 40 CFR part 1054 must meet the provisions of 40 CFR part 1060, as applicable. Labels on engines certified to 40 CFR part 1048 must refer to stationary engines, rather than or in addition to nonroad engines, as appropriate.
(b) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054 for that model year may certify any such family that contains both nonroad and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts. This provision also applies to equipment or component manufacturers certifying to standards under 40 CFR part 1060.
(c) Manufacturers of engine families certified to 40 CFR part 1048 may meet the labeling requirements referred to in paragraph (a) of this section for stationary SI ICE by either adding a separate label containing the information required in paragraph (a) of this section or by adding the words "and stationary" after the word "nonroad" to the label.
(d) For all engines manufactured on or after January 1, 2011, and for all engines with a maximum engine power greater than 25 HP and less than 130 HP manufactured on or after July 1, 2008, a stationary SI engine manufacturer that certifies an engine family solely to the standards applicable to emergency engines must add a permanent label stating that the engines in that family are for emergency use only. The label must be added according to the labeling requirements specified in 40 CFR 1048.135(b).
(e) All stationary SI engines subject to mandatory certification that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230. Stationary SI engines subject to standards in 40 CFR part 90 may use the provisions in 40 CFR 90.909. Manufacturers of stationary engines with a maximum engine power greater than 25 HP that are not certified to standards and other requirements under 40 CFR part 1048 are subject to the labeling provisions of 40 CFR 1048.20 pertaining to excluded stationary engines.
(f) For manufacturers of gaseous-fueled stationary engines required to meet the warranty provisions in 40 CFR 90.1103 or 1054.120, we may establish an hour-based warranty period equal to at least the certified emissions life of the engines (in engine operating hours) if we determine that these engines are likely to operate for a number of hours greater than the applicable useful life within 24 months. We will not approve an alternate warranty under this paragraph (f) for nonroad engines. An alternate warranty period approved under this paragraph (f) will be the specified number of engine operating hours or two years, whichever comes first. The engine manufacturer shall request this alternate warranty period in its application for certification or in an earlier submission. We may approve an alternate warranty period for an engine family subject to the following conditions:

(i) If you are an owner or operator of a stationary SI internal combustion engine greater than 25 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance.

(ii) If you are an owner or operator of a stationary SI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance.

→ **Applicable, engines are subject to 60.4233(e) and will demonstrate compliance through procedures described in 60.4244 in an initial performance test followed by periodic testing every 8760 hours of operation.**

(c) If you are an owner or operator of a stationary SI internal combustion engine that must comply with the emission standards specified in §60.4233(f), you must demonstrate compliance according paragraph (b)(2)(i) or (ii) of this section, except that if you comply according to paragraph (b)(2)(i) of this section, you demonstrate that your non-certified engine complies with the emission standards specified in §60.4233(f).

→ **Not applicable, engine power ratings are greater than 19 kW; therefore not applicable.**

(d) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Emergency stationary ICE may operate up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity. For owners and operators of emergency engines, any operation other than emergency operation, maintenance and testing, and operation in non emergency situations for 50 hours per year, as permitted in this section, is prohibited.

→ **Not applicable, engines are not for emergency use.**

(e) Owners and operators of stationary SI natural gas fired engines may operate their engines using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations, but must keep records of such use. If propane is used for more than 100 hours per year in an engine that is not certified to the emission standards when using propane, the owners and operators are required to conduct a performance test to demonstrate compliance with the emission standards of §60.4233.

→ **Not applicable, fueling engines with propane is not planned.**

(f) If you are an owner or operator of a stationary SI internal combustion engine that is less than or equal to 500 HP and you purchase a non-certified engine or you do not operate and maintain your certified stationary SI internal combustion engine and control device according to the manufacturer's written emission-related instructions, you are required to perform initial performance testing as indicated in this section, but you are not required to conduct subsequent performance testing unless the stationary engine is rebuilt or undergoes major repair or maintenance. A rebuilt stationary SI ICE means an engine that has been rebuilt as that term is defined in 40 CFR 94.11(a).

Cd= Measured CO concentration in ppmv.

1.164×10^{-3} = Conversion constant for ppm CO to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(f) For purposes of this subpart, when calculating emissions of VOC, emissions of formaldehyde should not be included. To determine compliance with the VOC mass per unit output emission limitation, convert the concentration of VOC in the engine exhaust using Equation 3 of this section:

$$ER = \frac{C_d \times 1.833 \times 10^{-3} \times Q \times T}{HP - hr} \qquad \text{(Eq. 3)}$$

Where:

ER = Emission rate of VOC in g/HP-hr.

Cd= VOC concentration measured as propane in ppmv.

1.833×10^{-3} = Conversion constant for ppm VOC measured as propane, to grams per standard cubic meter at 20 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meters per hour, dry basis.

T = Time of test run, in hours.

HP-hr = Brake work of the engine, in HP-hr.

(g) If the owner/operator chooses to measure VOC emissions using either Method 18 of 40 CFR part 60, appendix A, or Method 320 of 40 CFR part 63, appendix A, then it has the option of correcting the measured VOC emissions to account for the potential differences in measured values between these methods and Method 25A. The results from Method 18 and Method 320 can be corrected for response factor differences using Equations 4 and 5 of this section. The corrected VOC concentration can then be placed on a propane basis using Equation 6 of this section.

$$RF_i = \frac{C_{Mi}}{C_{Ai}} \qquad \text{(Eq. 4)}$$

Where:

RFi= Response factor of compound i when measured with EPA Method 25A.

C_{Mi}= Measured concentration of compound i in ppmv as carbon.

C_{Ai}= True concentration of compound i in ppmv as carbon.

$$C_{icorr} = RF_i \times C_{imeas} \qquad \text{(Eq. 5)}$$

Where:

C_{icorr}= Concentration of compound i corrected to the value that would have been measured by EPA Method 25A, ppmv as carbon.

C_{imeas}= Concentration of compound i measured by EPA Method 320, ppmv as carbon.

$$C_{Peq} = 0.6098 \times C_{icorr} \qquad \text{(Eq. 6)}$$

Where:

CPeq= Concentration of compound i in mg of propane equivalent per DSCM.

→ **Applicable, performance testing of engines will meet the requirements described above.**

Notification, Reports, and Records for Owners and Operators

§ 60.4245 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary SI internal combustion engine?

Owners or operators of stationary SI ICE must meet the following notification, reporting and recordkeeping requirements.

(a) Owners and operators of all stationary SI ICE must keep records of the information in paragraphs (a)(1) through (4) of this section.

(1) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(2) Maintenance conducted on the engine.

(3) If the stationary SI internal combustion engine is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards and information as required in 40 CFR parts 90, 1048, 1054, and 1060, as applicable.

(4) If the stationary SI internal combustion engine is not a certified engine or is a certified engine operating in a non-certified manner and subject to §60.4243(a)(2), documentation that the engine meets the emission standards.

1, 2010. Prior to January 1, 2010, manufacturers of stationary internal combustion engines participating in the voluntary certification program have the option to develop their own deterioration factors based on an engineering analysis.
[73 FR 3591, Jan. 18, 2008, as amended by 73 FR 59177, Oct. 8, 2008]

→ Not applicable. Only applies to manufacturers.

Definitions

→ The definitions below were utilized in this applicability review.

§ 60.4248 What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the CAA and in subpart A of this part.

Certified emissions life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for certified emissions life for stationary SI ICE with a maximum engine power less than or equal to 19 KW (25 HP) are given in 40 CFR 90.105, 40 CFR 1054.107, and 40 CFR 1060.101, as appropriate. The values for certified emissions life for stationary SI ICE with a maximum engine power greater than 19 KW (25 HP) certified to 40 CFR part 1048 are given in 40 CFR 1048.101(g). The certified emissions life for stationary SI ICE with a maximum engine power greater than 75 KW (100 HP) certified under the voluntary manufacturer certification program of this subpart is 5,000 hours or 7 years, whichever comes first.

Certified stationary internal combustion engine means an engine that belongs to an engine family that has a certificate of conformity that complies with the emission standards and requirements in this part, or of 40 CFR part 90, 40 CFR part 1048, or 40 CFR part 1054, as appropriate.

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and carbon dioxide (CO_2).

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary SI ICE used for peak shaving are not considered emergency stationary ICE. Stationary ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

Volatile organic compounds means volatile organic compounds as defined in 40 CFR 51.100(s).

Voluntary certification program means an optional engine certification program that manufacturers of stationary SI internal combustion engines with a maximum engine power greater than 19 KW (25 HP) that do not use gasoline and are not rich burn engines that use LPG can choose to participate in to certify their engines to the emission standards in §60.4231(d) or (e), as applicable.

[73 FR 3591, Jan. 18, 2008, as amended by 73 FR 59177, Oct. 8, 2008]

Table 1 to Subpart JJJJ of Part 60—NO_x, CO, and VOC Emission Standards for Stationary Non-Emergency SI Engines ≥100 HP (Except Gasoline and Rich Burn LPG), Stationary SI Landfill/Digester Gas Engines, and Stationary Emergency Engines >25 HP

Engine type and fuel	Maximum engine power	Manufacture date	Emission standards[a]					
			g/HP-hr			ppmvd at 15% O_2		
			NO_x	CO	VOC[d]	NO_x	CO	VOC[d]
Non-Emergency SI Natural Gas[b] and Non-Emergency SI Lean Burn LPG[b]	100•HP<500	7/1/2008 1/1/2011	2.0 1.0	4.0 2.0	1.0 0.7	160 82	540 270	86 60
Non-Emergency SI Lean Burn Natural Gas and LPG	500•HP<1,350	1/1/2008 7/1/2010	2.0 1.0	4.0 2.0	1.0 0.7	160 82	540 270	86 60
Non-Emergency SI Natural Gas and Non-Emergency SI Lean Burn LPG (except lean burn 500=•HP<1,350)	HP•500 HP•500	7/1/2007 7/1/2010	2.0 1.0	4.0 2.0	1.0 0.7	160 82	540 270	86 60
Landfill/Digester Gas (except lean burn 500•HP<1,350)	HP<500	7/1/2008 1/1/2011	3.0 2.0	5.0 5.0	1.0 1.0	220 150	610 610	80 80
	HP•500	7/1/2007 7/1/2010	3.0 2.0	5.0 5.0	1.0 1.0	220 150	610 610	80 80
Landfill/Digester Gas Lean Burn	500•HP<1,350	1/1/2008 7/1/2010	3.0 2.0	5.0 5.0	1.0 1.0	220 150	610 610	80 80
Emergency	25>HP<130 HP•130	1/1/2009	[c]10 2.0	387 4.0	N/A 1.0	N/A 160	N/A 540	N/A 86

[a]Owners and operators of stationary non-certified SI engines may choose to comply with the emission standards in units of either g/HP-hr or ppmvd at 15 percent O2.

[b]Owners and operators of new or reconstructed non-emergency lean burn SI stationary engines with a site rating of greater than or equal to 250 brake HP located at a major source that are meeting the requirements of 40 CFR part 63, subpart ZZZZ, Table 2A do not have to comply with the CO emission standards of Table 1 of this subpart.

[c]The emission standards applicable to emergency engines between 25 HP and 130 HP are in terms of NO_x+HC.

[d]For purposes of this subpart, when calculating emissions of volatile organic compounds, emissions of formaldehyde should not be included.

Table 2 to Subpart JJJJ of Part 60—Requirements for Performance Tests

[As stated in §60.4244, you must comply with the following requirements for performance tests within 10 percent of 100 percent peak (or the highest achievable) load]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary	a. limit the	i. Select the	(1) Method 1 or 1A	(a) If using a

	iii. Determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.		
	iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for CO concentration.	
	v. Measure CO at the exhaust of the stationary internal combustion engine.	(5) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522-00(2005)[a], Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17).	(d) Results of this test consist of the average of the three 1-hour or longer runs.	
	c. limit the concentration of VOC in the stationary SI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A.	(a) If using a control device, the sampling site must be located at the outlet of the control device.
	ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B[b] of 40 CFR part 60, appendix A or ASTM Method D6522-00(2005)[a].	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for VOC concentration.	
	iii. Determine the exhaust flowrate of the stationary internal combustion engine exhaust;	(3) Method 2 or 19 of 40 CFR part 60.		
	iv. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(4) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D6348-03 (incorporated by reference, see §60.17).	(c) Measurements to determine moisture must be made at the same time as the measurement for VOC concentration.	

§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	No	
§60.14	Modification	Yes	
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Table 4 to Subpart JJJJ of Part 60—Applicability of Mobile Source Provisions for Manufacturers Participating in the Voluntary Certification Program and Certifying Stationary SI ICE to Emission Standards in Table 1 of Subpart JJJJ

[As stated in §60.4247, you must comply with the following applicable mobile source provisions if you are a manufacturer participating in the voluntary certification program and certifying stationary SI ICE to emission standards in Table 1 of subpart JJJJ]

Mobile source provisions citation	Subject of citation	Applies to subpart	Explanation
1048 subpart A	Overview and Applicability	Yes	
1048 subpart B	Emission Standards and Related Requirements	Yes	Except for the specific sections below.
1048.101	Exhaust Emission Standards	No	
1048.105	Evaporative Emission Standards	No	
1048.110	Diagnosing Malfunctions	No	
1048.140	Certifying Blue Sky Series Engines	No	
1048.145	Interim Provisions	No	
1048 subpart C	Certifying Engine Families	Yes	Except for the specific sections below.
1048.205(b)	AECD reporting	Yes	
1048.205(c)	OBD Requirements	No	
1048.205(n)	Deterioration Factors	Yes	Except as indicated in 60.4247(c).
1048.205(p)(1)	Deterioration Factor Discussion	Yes	
1048.205(p)(2)	Liquid Fuels as they require	No	
1048.240(b)(c)(d)	Deterioration Factors	Yes	
1048 subpart D	Testing Production-Line Engines	Yes	
1048 subpart E	Testing In-Use Engines	No	
1048 subpart F	Test Procedures	Yes	
1065.5(a)(4)	Raw sampling (refers reader back to	Yes	

APPENDIX D – PROCESSING FEE

PTC Fee Calculation

Instructions:
Fill in the following information and answer the following questions with a Y or N. Enter the emissions increases and decreases for each pollutant in the table.

Company:	**New Energy One, LLC**
Address:	**Rock Creek Biogas Project**
City:	**Filer**
State:	
Zip Code:	
Facility Contact:	**Jay Kesting**
Title:	
AIRS No.:	**083-00127**

N Does this facility qualify for a general permit (i.e. concrete batch plant, hot-mix asphalt plant)? Y/N

Y Did this permit require engineering analysis? Y/N

N Is this a PSD permit Y/N (IDAPA 58.01.01.205.04)

Emissions Inventory			
Pollutant	Annual Emissions Increase (T/yr)	Annual Emissions Reduction (T/yr)	Annual Emissions Change (T/yr)
NO_X	0.0	14.6	-14.6
SO_2	0.0	10	-10.0
CO	5.2	0	5.2
PM10	0.0	0.27	-0.3
VOC	0.0	0.6	-0.6
TAPS/HAPS	0.0	0	0.0
Total:	0.0	25.47	**-20.3**
Fee Due	**$ 1,000.00**		

Comments: Project is a PTC modification to change the installed generator sets.