Bay Area Air Quality Management District

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Permit Evaluation
and
Statement of Basis
for
Minor Revision of

MAJOR FACILITY REVIEW PERMIT

for

East Bay Municipal Utility District
Facility A0591

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Application 18480

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Title V Statement of Basis

A. Background

This facility is subject to the Operating Permit requirements of Title V of the federal Clean Air Act, Part 70 of Volume 40 of the Code of Federal Regulations (CFR), and BAAQMD Regulation 2, Rule 6, Major Facility Review because it is a major facility as defined by BAAQMD Regulation 2-6-212. It is a major facility because it has the "potential to emit," as defined by BAAQMD Regulation 2-6-218, of more than 100 tons per year of a regulated air pollutant, by virtue of the combustion processes.

Major Facility Operating permits (Title V permits) must meet specifications contained in 40 CFR Part 70 as contained in BAAQMD Regulation 2, Rule 6. The permits must contain all applicable requirements (as defined in BAAQMD Regulation 2-6-202), monitoring requirements, recordkeeping requirements, and reporting requirements. The permit holders must submit reports of all monitoring at least every six months and compliance certifications at least every year.

In the Bay Area, state and District requirements are also applicable requirements and are included in the permit. These requirements can be federally enforceable or non-federally enforceable. All applicable requirements are contained in Sections I through VI of the permit.

Each facility in the Bay Area is assigned a facility identifier that consists of a letter and a 4-digit number. This identifier is also considered to be the identifier for the permit. The identifier for this facility is A0591.

This facility received its initial Title V permit on July 1, 1997, which was renewed on July 26, 2005. This application is for a Minor Permit Revision. It includes modifications made to the facility under (4) BAAQMD Permit Applications as follows:

AN 13736: Added Diesel Fired Backup Generator, S-54

AN 14243: Replaced the existing Hot Water Boiler S-5 with a new Hot Water Boiler S-55. Modified permit conditions for the Sludge Handling Processes, S-170.

AN 17399: Modified the Sludge Handling Processes, S-170 to add (2) sludge dewatering centrifuges to the existing equipment.

AN 17749: Authority to Construct for Digester Gas Turbines #1 and #2 (S-56, S-57)

In addition to these additions and modifications, a number of other changes to the Title V permit will be proposed, including: changes to applicable requirements due to regulatory activity since the previous permit was issued, updates to standard permit text, and source grouping where applicable to standardize requirements within source categories and streamline the permit.

Although the current permit (which includes this revision) expired on June 30, 2010, it continues in force until the District takes final action on the renewal Title V permit. The proposed permit revision shows all changes to the permit in strikeout/underline format.

B. Facility Description

The East Bay Municipal Utility District (EBMUD) is a publicly owned treatment works (POTW) facility that provides wastewater collection, treatment and disposal services to the residents and businesses of parts of Alameda and Contra Costa County. The sources that are permitted include liquid and semi-liquid wastewater process sources, support systems such as a gasoline dispensing station, and a number of combustion sources to convert the plant produced digester gas into electricity and hot water to supply the plant energy needs. Liquid sources include preliminary treatment, primary treatment, secondary treatment, clarification, disinfection, sludge handling, and sludge digestion. Combustion operations include a hot water boiler, emergency standby diesel generator sets, digester gas emergency flares, and cogeneration engine generators.

Average dry weather wastewater flow capacity is approximately 120,000,000 gal/day. Average wet weather flow capacity is approximately 325,000,000 gal/day. The wastewater processes at EBMUD are similar to any other “traditional” municipal wastewater treatment facility. The wastewater plant receives flows from a number of satellite pump stations throughout the aforementioned service area. Plant processes render the influent homogeneous, allow for physical separation to occur and hasten the occurrence of normal biological processes. The liquid and semi-solid wastes are processed such that the process resulting sludge is converted into digester gas fuel with residual biomass for offsite disposal. Effluent water outflow meets regional water quality control board standards for discharge or reuse.

The criteria pollutant emissions from the combustion processes, specifically the NOx and CO have the potential to emit more than 100 tons per year, hence East Bay Municipal Utility District's requirement for a Federal Title V Major Facility Permit.

C. Permit Content

The legal and factual basis for the permit follows. The permit sections are described in the order that they are presented in the permit. Changes to the standard permit text have been made since the initial Title V Permit for this site was issued. These changes are reflected in the new proposed permit in strikeout/underline format.

I. Standard Conditions

This section contains administrative requirements and conditions that apply to all facilities. If the Title IV (Acid Rain) requirements for certain fossil-fuel fired electrical generating facilities or the accidental release (40 CFR § 68) programs apply, the section will contain a standard condition pertaining to these programs. Many of these conditions derive from 40 CFR § 70.6, Permit Content, which dictates certain standard conditions that must be placed in the permit. The language that the District has developed for many of these requirements has been adopted into the BAAQMD Manual of Procedures, Volume II, Part 3, Section 4, and therefore must appear in the permit.

The standard conditions also contain references to BAAQMD Regulation 1 and Regulation 2. These are the District’s General Provisions and Permitting rules.

<u>Changes to permit:</u>

- The dates of adoption and approval of rules in Standard Condition 1.A have been updated.
- BAAQMD Regulation 2, Rule 5 – New Source Review of Toxic Air Contaminants, SIP Regulation 2, Rule 6 - Permits, Major Facility Review and BAAQMD Regulation 2, Rule 9 – Interchangeable Emission Reduction Credits have been added to Standard Condition 1.A.
- The basis for Standard Condition I.B.11, which requires the responsible official to certify all documents submitted, was updated to conform to changes in Regulation 2, Rule 6.

II. Equipment

This section of the permit lists all permitted or significant sources. Each source is identified by an S and a number (e.g., S-24).

Permitted sources are those sources that require a BAAQMD operating permit pursuant to BAAQMD Rule 2-1-302.

Significant sources are those sources that have a potential to emit of more than 2 tons of a "regulated air pollutant," as defined in BAAQMD Rule 2-6-222, per year or 400 pounds of a "hazardous air pollutant," as defined in BAAQMD Rule 2-6-210, per year.

The District has reviewed the operations at the East Bay Municipal Utility District and concluded that there are no sources at this facility that are exempt and significant, as defined above.

All abatement (control) devices that control permitted or significant sources are listed. Each abatement device whose primary function is to reduce emissions is identified by an A and a number (e.g., A-24). If a source is also an abatement device, such as when an engine controls VOC emissions, it will be listed in the abatement device table but will have an "S" number. An abatement device may also be a source (such as a thermal oxidizer that burns fuel) of secondary emissions. If the primary function of a device is to control emissions, it is considered an abatement (or "A") device. If the primary function of a device is a non-control function, the device is considered to be a source (or "S").

The equipment section is considered to be part of the facility description. It contains information that is necessary for applicability determinations, such as fuel types, contents or sizes of tanks, etc. This information is part of the factual basis of the permit.

Each of the permitted sources has previously been issued an authority to construct and/or permit to operate pursuant to the requirements of BAAQMD Regulation 2, Permits. These permits are issued in accordance with state law and the District's regulations. The capacities in the permitted sources table are the maximum allowable capacities for each source, pursuant to Standard Condition I.J and Regulation 2-1-403.

Following are explanations of the differences in the equipment list between the current Title V permit and the proposed minor revision.

<u>Changes to permit: (Table II-A)</u>

- The Hot Water Boiler S-5 will be removed and replaced with the new Hot Water Boiler S-55.
- The description of the Diesel Backup Generator S-52 will be corrected to include the designation "Portable". There has been no change to the equipment or mode of operation.
- The Diesel Fired Backup Generator S-54 will be added.
- Digester Gas Fired Turbines #1 and #2 (S-56 and S-57) will be added. It should be noted that this equipment is currently authorized under an extension to Authority to Construct #17749, but has not been installed.
- The description of S-170, Sludge Handling, will be updated to change the number of Dewatering Centrifuges from 4 to 6.

III. Generally Applicable Requirements

This section of the permit lists requirements that generally apply to all sources at a facility including insignificant sources and portable equipment that may not require a District permit. If a generally applicable requirement applies specifically to a source that is permitted or significant, the standard will also appear in Section IV and the monitoring for that requirement will appear in Sections IV and VII of the permit. Parts of this section apply to all facilities (e.g., particulate, architectural coating, odorous substance, and sandblasting standards). In addition, standards that apply to insignificant or unpermitted sources at a facility (e.g., refrigeration units that use more than 50 pounds of an ozone-depleting compound) are placed in this section.

Unpermitted sources are exempt from normal District permits pursuant to an exemption in BAAQMD Regulation 2, Rule 1. They may, however, be specifically described in a Title V permit if they are considered *significant sources* pursuant to the definition in BAAQMD Rule 2-6-239. This facility has no unpermitted significant sources.

<u>Changes to permit:</u>

- Changes to this section of the permit will include an update of EPA Region 9's SIP website address and the addition of generally applicable requirements that are new since the permit was last issued (e.g. BAAQMD Regulation 2, Rule 5 "New Source Review of Toxic Air Contaminants", adopted 6/15/05). Updates will also be made to reflect the most recent versions of cited regulations.

IV. Source-Specific Applicable Requirements

This section of the permit lists the applicable requirements that apply to permitted or significant sources. These applicable requirements are contained in tables that pertain to one or more sources that have the same requirements. The order of the requirements is:

- District Rules
- SIP Rules (if any) are listed following the corresponding District rules. SIP rules are District rules that have been approved by EPA for inclusion in the California State Implementation Plan. SIP rules are "federally enforceable" and a "Y" (yes) indication will appear in the "Federally Enforceable" column. If the SIP rule is the current District rule, separate citation of the SIP rule is not necessary and the "Federally Enforceable" column will have a "Y" for "yes". If the SIP rule is not the current District rule, the SIP rule or the necessary portion of the SIP rule is cited separately after the District rule. The SIP portion will be federally

enforceable; the non-SIP version will not be federally enforceable, unless EPA has approved it through another program.

- Other District requirements, such as the Manual of Procedures, as appropriate.
- Federal requirements (other than SIP provisions)
- BAAQMD permit conditions. The text of BAAQMD permit conditions is found in Section VI of the permit.
- Federal permit conditions. The text of Federal permit conditions, if any, is found in Section VI of the permit.

Section IV of the permit contains citations to all of the applicable requirements. The text of the requirements is found in the regulations, which are readily available on the District's or EPA's websites, or in the permit conditions, which are found in Section VI of the permit. All monitoring requirements are cited in Section IV. Section VII is a cross-reference between the limits and monitoring requirements. A discussion of monitoring is included in Section C.VII of this permit evaluation/statement of basis.

Complex Applicability Determinations:

<u>Applicability of 40 CFR 72, Acid Rain Program</u>
The Digester Gas Turbines S-56 and S-57 will not be subject to 40 CFR Part 72 (Acid Rain Program). Specifically, they fall under the new units exemption of Section 72.7:

> <u>72.7 New Units Exemption.</u>
>
> (a) *Applicability.* This section applies to any new utility unit that has not previously lost an exemption under paragraph (f)(4) of this section and that, in each year starting with the first year for which the unit is to be exempt under this section:
>
> (1) Serves during the entire year (except for any period before the unit commenced commercial operation) one or more generators with total nameplate capacity of 25 MWe or less;
>
> (2) Burns fuel that does not include any coal or coal-derived fuel (except coal-derived gaseous fuel with a total sulfur content no greater than natural gas); and
>
> (3) Burns gaseous fuel with an annual average sulfur content of 0.05 percent or less by weight (as determined under paragraph (d) of this section) and nongaseous fuel with an annual average sulfur content of 0.05 percent or less by weight (as determined under paragraph (d) of this section).

S-56 and S-57 each have a nameplate capacity of 4.5 MWe ($\leq$ 25MWe), they do not burn coal derived fuel, and they burn gaseous fuel with a sulfur content less than 0.05 percent by weight (e.g. digester gas burned at this facility is limited to 340 ppmv; equivalent to 308 ppmw or 0.0308 percent by weight)*.

* ppmw = ppmv x M/28.8
for digester gas (64% methane, 36% CO_2); M = 26.1

Applicability of 40 CFR Part 63, Subpart VVV -POTW NESHAP

This NESHAP was evaluated to determine if East Bay Municipal Utility District was subject to the MACT emission control requirements. The NESHAP requires MACT controls at POTWS which are major sources for HAP which are defined thusly: …any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate 10 tons per year (tpy) or more of any HAP or 25 tpy or more of any combination of HAP.

The District has reviewed the wastewater borne emissions potential of the most frequently seen HAPs and concluded that East Bay Municipal Utility District is not a major source for HAP emissions or for combined HAP emissions. A conservative estimate of HAP emissions may be obtained by using the 80^{th} % factors as developed by the BAAT-AMSA – CWEA studies in the 1990s. This procedure is the most conservative of the 7 accepted procedures developed for calculating emissions from wastewater processes. Most conservatively, the total plant throughput would have to be over 177 million gallons per dry-weather day on an ongoing basis to be a major source for HAP, based on the 80^{th} percentile (most conservative) calculation basis. The East Bay Municipal Utility District maximum dry weather flow rate is 120 million gallons per day and the average daily flow rate (annualized) is 80 MM gpd. Therefore, we conclude the facility is not a major source for HAP.

In addition, this POTW is an existing POTW that has not been reconstructed (as defined by 40 CFR 63.1595). Furthermore, the East Bay Municipal Utility District is not an Industrial POTW as defined by 40 CFR 63.1595. East Bay Municipal Utility District processes strictly domestic wastewater streams.

Applicability of 40 CFR 63 Subpart YYYY, NESHAP for Combustion Turbines (MACT)

East Bay Municipal Utility District is not subject to MACT standards for Combustion Turbines because it is not a major source of Hazardous Air Pollutants (HAPs).

Applicability of CAA 112 (j), Equivalent Emission Limitation by Permit

This section ensures control of HAP emissions even if the EPA should miss a scheduled NESHAP promulgation date. If the EPA misses a scheduled promulgation date by 18 months, major sources in that category must submit to their respective State (or local) agencies a permit application proposing source-specific MACT. Conditions of the MACT determination must be incorporated into the Title V operating permit. Section 112(j) is commonly referred to as the "MACT hammer."

East Bay Municipal Utility District is not subject to CAA Section 112 (j) because it is not a major source of Hazardous Air Pollutants (HAPs).

Applicability of Regulation 8 Rules to Digester Gas Combustion

The anaerobic digesters S-180 produce digester gas, which is principally combusted in the digester gas engines or hot water boiler, and secondarily in the digester gas flares. The composition of the digester gas is roughly 64% methane, 36% carbon dioxide, with about 21 ppmv of non methane organic compounds as hexane. The District evaluated whether the digester S-180 as well as the associated digester gas energy recovery sources and digester gas flares were subject to Regulation 8-1-110.3 (exemption from Regulation 8 Rules) or to 8-2-301 (Organic Compounds – Miscellaneous Operations). This discussion of applicability follows.

Regulation 8-1-110.3 states

8-1-110 **Exemptions:** The following shall be exempted from the provisions of this regulation:

110.1 Any structure designed and used exclusively as a dwelling for not more than two families, provided that this exclusion does not apply to the application of an architectural coating.

110.2 Any internal combustion engine.

110.3 Any operation or group of operations which are related to each other by being a part of a continuous process, or a series of such operations on the same process material, which are subject to Regulation 8, Rule 2 or Rule 4, and for which emissions of organic compounds are reduced at least 85% on a mass basis. Where such reduction is achieved by incineration, at least 90% of the organic carbon shall be oxidized to carbon dioxide.

Regulation 8-2-301 states:

8-2-301 Miscellaneous Operations: A person shall not discharge into the atmosphere from any miscellaneous operation an emission containing more than 6.8 kg. (15 lbs.) per day and containing a concentration of more than 300 PPM total carbon on a dry basis.

Organic compounds are defined in 8-1-201 as "any compound of carbon excluding methane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates and ammonium carbonate". The District has performed a conservative calculation (see Appendix C) to estimate the NMOC emissions potential from digester gas. The use of NMOC emissions potential is conservative since this includes all compounds of carbon with the exception of methane and carbon dioxide. EBMUD has estimated a maximum daily digester gas production rate (highest month average) of 3,800,000 cu ft, with a conservative maximum concentration of 82 micro-grams NMOC per liter of digester gas (16 ppmv). While it is expected that the destruction efficiency of NMOC in the heat recovery sources would easily exceed 90% it cannot be assured in any of the digester gas combustion devices. This is due to the very low inlet concentration (16 ppmv) of NMOC that upon combustion at 90% efficiency would result in an outlet concentration less than 2 ppm NMOC. It is difficult to ensure outlet concentrations at such low levels and to source test for NMOC at concentration levels near the error limits of the test methods. Based on these findings the District concludes 8-1-110.3 is not applicable to digester gas sources and combustion (abatement) devices.

We conclude the 8-2-301 is applicable to the digester gas sources and combustion devices. Based on the aforementioned calculation presented in Appendix C, and assuming all digester gas is vented at the maximum NMOC concentration gives a daily uncontrolled emission rate of approximately 19 lb per day (controlled emissions estimated as 1.9 lb/day), at an maximum concentration of 16 ppmv. Since the controlled emission level of NMOC from digester gas is less than both the daily limit and the emission stream concentration limit (on both molar and mass basis) as specified in 8-2-301, we conclude that the digester S-180 and the respective digester gas fired engines, boiler and flares are subject to and will comply with Reg 8-2-301. Regulation 8-2-301 will be included Table IV, Applicable Requirements for S-180 Anaerobic Digester as well as all combustion devices burning or abating digester gas.

<u>Applicability of 40 CFR 64, Compliance Assurance Monitoring (CAM)</u>

The Compliance Assurance Monitoring (CAM) regulation in 40 CFR 64 was developed to provide assurance that facilities comply with applicable emissions limitations by adequately monitoring control devices. The CAM rule was effective on November 21, 1997. However, most facilities are not affected by CAM requirements until they submit applications for Title V permit renewal.

CAM applies to a source of criteria pollutant or hazardous air pollutant (HAP) emissions if all the following requirements are met:

- The source is located at a major source for which a Title V permit is required; and
- The source is subject to a federally enforceable emission limitation or standard for a criteria pollutant or HAP; and
- The source uses a control device to comply with the federally enforceable emission limitation or standard; and
- The source has potential pre-control emissions of the regulated pollutant that are equal to or greater than the major source threshold for the pollutant (in BAAQMD, the major source thresholds are 100 tons per year for each criteria pollutant, 10 tons per year for a single HAP, and 25 tons per year for two or more HAPs); and
- The source is not otherwise exempt from CAM.

The applicability of compliance assurance monitoring (CAM) must be considered at this facility because the facility uses emission control devices to achieve compliance with a federally enforceable emission limit.

The control devices in use are flares A-190, A-191, A-192 and A-193. In addition, the boiler (S-55), cogeneration engines (S-37, S-38, and S-39), and proposed gas turbines (S-56, S-57) burn digester gas to make power and heat and therefore control emissions of digester gas. The flares and other combustion devices control emissions from the anaerobic digesters S-180, and are subject to the requirements of SIP Regulation 8, Rule 2-301 (see discussion above) This section prohibits the discharge of an emission containing more than 15 lbs/day and a concentration of more than 300 ppm total carbon.

In the Statement of Basis for the 2005 Title V permit renewal, the District performed a conservative calculation to estimate the NMOC emissions potential from digester gas. The calculation includes all compounds of carbon with the exception of methane and carbon dioxide. EBMUD has a historical maximum daily digester gas production rate of 2,160,000 cu ft (theoretical maximum of 3,800,000 cu ft/day), with a maximum concentration of 82 micro-grams NMOC per liter (16 ppmv), of digester gas. Assuming all digester gas is vented at the maximum NMOC concentration gives a daily uncontrolled emission rate of approximately 19 lb per day. CAM only applies if the uncontrolled emissions are more than 100 tpy. Since the maximum potential annual uncontrolled emissions are 3.5 ton (6,935 lb/yr), CAM is not required.

<u>Changes to permit:</u>

1) Update EPA Region 9's SIP website address.
2) A new version of Regulation 6 "Particulate Matter and Visible Emissions" was adopted by the BAAQMD on 12/5/2007. The previous version adopted 12/19/1990 is the SIP approved

version (FR date 9/4/1998). The applicable requirements tables for each source subject to Regulation 6 will be updated accordingly.

3) A new version of Regulation 8, Rule 2 “Organic Compounds - Miscellaneous Operations” was adopted by the BAAQMD on 7/20/2005. The previous version of this rule adopted 6/15/1994 remains the SIP approved version (FR date 3/22/1995). The applicable requirements tables for each source subject to Regulation 8, Rule 2 will be updated accordingly.
4) A new version of Regulation 8, Rule 5 “Organic Compounds – Storage of Organic Liquids” was adopted by the BAAQMD on 10/18/2006. The previous version of this rule adopted 11/27/2002 remains the SIP approved version (FR date 6/5/2003). The applicable requirements tables for the Gasoline Dispensing Facility S-48 will be updated accordingly.
5) The SIP approved version of Regulation 9, Rule 1 “Inorganic Pollutants – Sulfur Dioxide” (FR date 6/8/1999) will be added to the applicable requirements for all combustion sources. The current version of the rule, adopted 3/15/1995, is not the SIP approved version. This is a correction to the current Title V permit.
6) A new version of Regulation 9, Rule 8 “Inorganic Organic Compounds – Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines” was adopted by the BAAQMD on 7/25/2007. The previous version of this rule adopted 1/20/1993 remains the SIP approved version (FR date 12/15/1997). The applicable requirements tables for all IC engines will be updated accordingly.
7) The Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition Engines, Title 17 California Code of Regulations Section 93115 was adopted on 2/26/2004 and amended on 10/18/2007. Each stationary diesel fired IC engine at the facility is now subject to the requirements of this ATCM. The applicable requirements tables for these engines will be updated accordingly.
8) The ATCM for Portable Diesel Engines, Title 17 California Code of Regulations Section 93116 was adopted on 2/26/2004. Each portable diesel fired IC engine at the facility is now subject to the requirements of this ATCM. The applicable requirements tables for these engines will be updated accordingly.
9) The Hot Water Boiler S-5 has been removed from the facility and replaced with a new Hot Water Boiler (S-55). The applicable requirements table for S-5 will be removed and a new table for S-55 will be added. A new version of Regulation 9, Rule 7 “Inorganic Gaseous Pollutants – Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters” was adopted by the BAAQMD on 7/30/2008. The previous version of this rule adopted 9/15/1993 remains the SIP approved version (FR date 12/15/1997). This change will be reflected in the new table for S-55.
10) The Digester Gas Turbines S-56 and S-57 were issued an Authority to Construct (AC) under permit application #17749. This AC was extended at the request of the facility on June 28, 2010 and has a new expiration date of July 23, 2012. Applicable requirements for this equipment will be added to the permit in anticipation that it will be installed in accordance with the AC.
11) Where possible (because of identical requirements) diesel IC engines used for backup power generation will be grouped together in an effort to streamline the permit. This will also require that the affected sources have a single set of permit conditions common to the group. Changes to permit conditions will be discussed in Section VI of this Statement of Basis.

12) Tables will be deleted, added, and relabeled as necessary to reflect the proposed changes to this section.

V. Schedule of Compliance

A schedule of compliance is required in all Title V permits pursuant to BAAQMD Regulation 2-6-409.10 which provides that a major facility review permit shall contain the following information and provisions:

"409.10 A schedule of compliance containing the following elements:

10.1 A statement that the facility shall continue to comply with all applicable requirements with which it is currently in compliance;

10.2 A statement that the facility shall meet all applicable requirements on a timely basis as requirements become effective during the permit term; and

10.3 If the facility is out of compliance with an applicable requirement at the time of issuance, revision, or reopening, the schedule of compliance shall contain a plan by which the facility will achieve compliance. The plan shall contain deadlines for each item in the plan. The schedule of compliance shall also contain a requirement for submission of progress reports by the facility at least every six months. The progress reports shall contain the dates by which each item in the plan was achieved and an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted."

Since the District has not determined that the facility is out of compliance with an applicable requirement, the schedule of compliance for this permit contains only sections 2-6-409.10.1 and 2-6-409.10.2.

Changes to permit:
None.

VI. Permit Conditions

The BAAQMD has reviewed the existing permit conditions, deleted the obsolete conditions, and, as appropriate, revised the conditions for clarity and enforceability. Each permit condition is identified with a unique numerical identifier, up to five digits.

When necessary to meet applicable requirements, additional monitoring, recordkeeping, or reporting will be added to the permit.

All changes to existing permit conditions are clearly shown in "strike-out/underline" format in the proposed permit. When the permit is issued, all 'strike-out" language will be deleted; all "underline" language will be retained, subject to consideration of comments received.

The existing permit conditions are derived from previously issued District Authorities to Construct (A/C) or Permits to Operate (P/O). Permit conditions may also be imposed or revised as part of the annual review of the facility by the District pursuant to California Health and Safety Code (H&SC) § 42301(e), through a variance pursuant to H&SC § 42350 et seq., an order of abatement pursuant to H&SC § 42450 et seq., or as an administrative revision initiated by District staff. After issuance of the Title V permit, permit conditions will be revised using the procedures in Regulation 2, Rule 6, Major Facility Review.

The regulatory basis is listed following each condition. The regulatory basis may be a rule or regulation. The District is also using the following terms for regulatory basis:

- BACT: This term is used for a condition imposed by the Air Pollution Control Officer (APCO) to ensure compliance with the Best Available Control Technology in Regulation 2-2-301.
- Cumulative Increase: This term is used for a condition imposed by the APCO which limits a source's operation to the operation described in the permit application pursuant to BAAQMD Regulation 2-1-403.
- Offsets: This term is used for a condition imposed by the APCO to ensure compliance with the use of offsets for the permitting of a source or with the banking of emissions from a source pursuant to Regulation 2, Rules 2 and 4.
- PSD: This term is used for a condition imposed by the APCO to ensure compliance with a Prevention of Significant Deterioration permit issued pursuant to Regulation 2, Rule 2.
- TRMP: This term is used for a condition imposed by the APCO to ensure compliance with limits that arise from the District's Toxic Risk Management Policy.

Changes to permit:

Summary of Changes to Operating Conditions

The following table lists the sources in order with their previous and future (final) condition status. The condition changes will be discussed in the numerical order of the conditions.

Source Number	Current Condition #	Proposed Permit Condition #(s)
37	20651	18860, 20651
38	20651	18860, 20651
39	20651	18860, 20651
43	2409	2409
45	2409	2409
47	2409	2409
48	16516	16516, 21663
49	19058	19058
50	19040	19040
51	21921	19040
52	19184	19058
53	21924	19040
54	N/A	22850
55	N/A	18860, 20651
56	N/A	18860, 24050
57	N/A	18860, 24050
100	21759	21759
110	17335	17335
170	18006	18006
180	18860	18860

A summary of the proposed changes to permit conditions in Section VI of the permit are given below in numerical order as they appear in the permit.

Condition #2409
S-43, Wet Weather Primary Sludge Thickeners
S-45, Aerated Grit Tanks
S-47, Scum Thickening Building

- There are no proposed changes to this condition.

Condition 16516
Source S-48 GDF G-9008

- This is a standard condition used for gasoline dispensing facilities. The condition text in the revised permit will be updated to the current standard text.

Condition #17335
S-110, Headworks: IPS, Barscreens, ducted to/abated by A-461 and/or A-462

- There are no proposed changes to this condition.

Condition 18006
S –170, Sludge Handling; 3 W.A.S. GBT's, 6 Dewatering Centrifuges, Abated by A-7 or A-8 Atomized Mist Scrubber

- Minor changes were made to the conditions for S-170, Sludge Handling as a result of modifications made under Application #17399.

Condition 18860
S-180, Anaerobic Digesters

- Part 1: The Anaerobic Digesters provide a waste gas fuel to several energy recovery sources at the facility: the Cogeneration Engines S-37, S-38, S-39, the Hot Water Boiler S-55, and the proposed Digester Gas Turbines S-56 and S-57. Reference to the new Boiler S-55 and the Digester Gas Turbines S-56 and S-57 will be made in part 1.
- Part 3:The allowable total sulfur content of digester gas in part 3 will be lowered from 1500 ppmv to 340 ppmv. This is the result of a BACT determination made in Application #17749.

Condition 19040
S-50, S-51, S-53 Emergency Backup Generators: Diesel Fired, Installed before May 17, 2000

- S-51 and S-53 will be added to the existing permit conditions for S-50 because all three diesel engines have the same applicable requirements.
- Part 1: Under the ATCM for stationary diesel engines, in-use emergency standby engines having a diesel PM emission rate >0.40 g/bhp-hr are limited to 20 hours of operation per year for maintenance and testing (Ref. CCR 93115.6(b)(3)(A)(1)(a)). Since these engines have not

been verified to have a lower PM emission rate, they are each subject to the 20 hour/yr maintenance and testing limit. Part 1 will be modified to account for the ATCM standard.

- Part 4: The ATCM for stationary diesel engines requires the use of CARB Diesel Fuel or approved alternative (Ref. CCR 93115.5 (b)). CARB Diesel Fuel must have a sulfur content not to exceed 15 ppm (0.0015%). This is in sharp contrast to the current part 4 limit of 0.5% (Basis: Regulation 9-1-304). Part 4 will be modified to require fuel that complies with the ATCM.
- Part 5: The monitoring requirements in part 5 will be updated to directly reflect the ATCM requirement for a totalizing meter to record hours of operation.
- Part 6: Minor changes will be made to the recordkeeping requirements of part 6 to account for the addition of S-51 and S-53, and the new ATCM standards.

Condition 19058
S-49, S-52 Portable Standby Generators: Diesel Fired, Installed before May 17, 2000

- S-52 will be added to the existing permit conditions for S-49 because the engines have the same applicable requirements.
- Part 4: The ATCM for portable diesel engines requires the use of CARB Diesel Fuel or approved alternative (Ref. CCR 93116.3(a)). CARB Diesel Fuel must have a sulfur content not to exceed 15 ppm (0.0015%). This is in sharp contrast to the current part 4 limit of 0.5% (Basis: Regulation 9-1-304). Part 4 will be modified to require fuel that complies with the ATCM.
- Parts 6, 7, 8: Minor wording changes will be made to account for multiple sources covered by the condition.

Condition 19184: Deleted, AN 18480

- Condition will be deleted to streamline requirements. The Portable Standby Generator S-52 will be added to Condition 19058.

Condition 20651
S-55, Hot Water Boiler
S-37, Multi-Fuel Cogeneration Engine #1
S-38, Multi-Fuel Cogeneration Engine #2
S-39, Multi-Fuel Cogeneration Engine #3

- The Hot Water Boiler S-5 will be replaced by Hot Water Boiler S-55 in the conditions.
- Part 1: The Low Fuel Usage exemption and demonstration requirements in SIP Regulation 9-7-304 are not applicable to the new Hot Water Boiler S-55. The basis for the condition will be changed to “Cumulative Increase” for the sake of SO2 inventory.
- Part 2: A minor wording change will be made to acknowledge the replacement of S-5 with S-55 and to add clarity.
- Part 3: Changes to the heat capacity limit will be made to accommodate the larger Boiler S-55 and to include changes made to the condition under AN 17749.

- Part 4: The Low Fuel Usage exemption and demonstration requirements in SIP Regulation 9-7-304 are not applicable to the new Hot Water Boiler S-55. Therefore, part 4 was deleted in conjunction with AN 17749 as part of a periodic condition review.
- Part 5: The boiler tune-up requirement associated with the Low Fuel Usage exemption applicable to the previous boiler (S-5) will be deleted. In its place the BACT emissions limits (NOx and CO) for the new boiler (S-55) will be added.
- Part 16: Part 16 was deleted as part of AN 17749. The requirements were redundant to Condition 18860 parts 3 and 4.
- Part 17: Part 17 was deleted 10/2006. It refers to diesel fuel sulfur content of the pilot fuel used for the Multi-Fuel Cogeneration Engines S-37, S-38, and S-39. This condition was out of date; the current CARB statewide total sulfur standard for diesel fuel being 0.0015%.
- Part 18: Part 18 will be updated to replace S-5 with S-55 as previously noted.
- Part 19: The Boiler S-55 has BACT emissions limits for NOx and CO (Ref. Condition #20651, part 5) that do not currently require monitoring. S-55 will be added to the annual performance test requirement in part 19 in order to comply with Regulation 2-6-409.2.2; Major Facility Review, additional requirements, addition of periodic monitoring.

Condition 21663
S-48, GDF G-9008

- There are no proposed changes to this condition.

Condition 21759
S-100, Municipal Wastewater Treatment Plant

- There are no proposed changes to this condition.

Condition 21921: Deleted, AN 18480

- Condition will be deleted to streamline requirements. The Emergency Backup Generator S-51 will be added to Condition 19040.

Condition 21924: Deleted, AN 18480

- Condition will be deleted to streamline requirements. The Emergency Backup Generator S-53 will be added to Condition 19040.

Condition 22850: Replaced with new permit condition, AN 18480
S-54 Emergency Backup Generator: Diesel Fired, Caterpillar 3412B, 1114 HP

- S-54 was issued a BAAQMD Permit to Operate under AN 13736 and was given permit conditions under Condition #22850. This condition is used as a standard permit condition for emergency backup generators. However, the bases for these conditions as they pertain to the ATCM for stationary diesel engines are out of date and should not be included in the Title V permit. It is recommended that Standard Condition 22850 be replaced with the following new conditions specific to S-54:

1. S-54 shall only be operated to mitigate emergency conditions or for reliability-related activities. Operation for reliability-related activities shall not exceed 50 hours in any calendar year. Operation while mitigating emergency conditions is unlimited. [Basis: CCR 93115.6(b)(3)(A)(2)(b)]

2. Emergency use is defined as the use of an emergency standby engine during any of the following: [Basis: Regulation 9-8-231]

   a. Loss of regular natural gas supply.
   b. Failure of regular electric power supply.
   c. Flood mitigation.
   d. Sewage overflow mitigation.
   e. Fire,
   f. Failure of a primary motor, but only for such time as needed to repair or replace the primary motor.

3. Reliability-related activities is defined as any of the following: [Basis: Regulation 9-8-232]

   a. Operation of an emergency standby engine to test its ability to perform for an emergency use, or
   b. Operation of an emergency standby engine during maintenance of a primary motor

4. Only CARB Diesel fuel or approved alternative shall be combusted at this source. The maximum sulfur content of the fuel shall be demonstrated by vendor certification. [Basis: CCR 93115.5(b), CCR 93115.10(g)(G)(1)]

5. Monitoring
   This engine shall be equipped with a non-resettable totalizing meter that measures and records the hours of operation for the engine. This meter shall have a minimum display capability of 9,999 hours. [Basis: CCR 93115.10(e)(1)]

6. Recordkeeping
   The Permit Holder shall maintain the following monthly records for S-54 in a District-approved log. Records shall be maintained for at least 5 years from the date of entry. The Permit Holder shall make the log available for District inspection upon request. [Basis: Regulations 1-441, 9-8-530, CCR 93115.10(g)]

   a. Hours of operation (total)
   b. Hours of operation (emergency).
   c. For each emergency, the nature of the emergency condition.
   d. Diesel sulfur records required in Part 4, above.
   e. Monitoring records as noted in Part 5, above.

Condition 24050

S-56 Digester Gas Turbine #1, Solar Mercury 50 ultra-lean premix, recuperative 4.5 MW, 44.5 MM BTU/hr HHV
S-57 Digester Gas Turbine #2, Solar Mercury 50 ultra-lean premix, recuperative 4.5 MW, 44.5 MM BTU/hr HHV

- Condition 24050 for the proposed Digester Gas Turbines S-56 and S-57 was approved under BAAQMD AN 17749. Condition 24050 will be added to the Title V permit in anticipation of the issuance of BAAQMD permits for S-56 and S-57.

VII. Applicable Limits and Compliance Monitoring Requirements

This section of the permit is a summary of numerical limits and related monitoring requirements for each source. The summary includes a citation for each monitoring requirement, frequency of monitoring, and type of monitoring. The applicable requirements for monitoring are completely contained in Sections IV, Source-Specific Applicable Requirements, and VI, Permit Conditions, of the permit.

The tables below contain only the limits for which there is no monitoring or inadequate monitoring in the applicable requirements. The District has examined the monitoring for other limits and has determined that monitoring is adequate to provide a reasonable assurance of compliance. Calculations for potential to emit will be provided in the discussion when no monitoring is proposed due to the size of a source.

Monitoring decisions are typically the result of a balancing of several different factors including: 1) the likelihood of a violation given the characteristics of normal operation, 2) degree of variability in the operation and in the control device, if there is one, 3) the potential severity of impact of an undetected violation, 4) the technical feasibility and probative value of indicator monitoring, 5) the economic feasibility of indicator monitoring, and 6) whether there is some other factor, such as a different regulatory restriction applicable to the same operation, that also provides some assurance of compliance with the limit in question.

These factors are the same as those historically applied by the District in developing monitoring for applicable requirements. It follows that, although Title V calls for a re-examination of all monitoring, there is a presumption that these factors have been appropriately balanced and incorporated in the District's prior rule development and/or permit issuance. It is possible that, where a rule or permit requirement has historically had no monitoring associated with it, no monitoring may still be appropriate in the Title V permit if, for instance, there is little likelihood of a violation. Compliance behavior and associated costs of compliance are determined in part by the frequency and nature of associated monitoring requirements. As a result, the District will generally revise the nature or frequency of monitoring only when it can support a conclusion that existing monitoring is inadequate.

A detailed evaluation of the monitoring for this facility was performed when the Title V permit was renewed in 2005. Therefore, this monitoring discussion will be limited to sources that have been added or modified since that time. Specifically:

New Sources
S-54: Diesel Fired Backup Generator
S-55: Hot Water Boiler
S-56: Digester Gas Turbine #1
S-57: Digester Gas Turbine #2

Modified Source
S-170: Sludge Handling Processes

The District has reviewed the monitoring for these sources and found it to be adequate with the following exceptions that need further review.

NOx Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Periodic Monitoring
S-55 Hot Water Boiler	SIP 9-7-301.1	30 ppm @3% O_2	None
	BAAQMD Condition 20651, part 5	30 ppm @3% O_2	**Annual Source Test Added** Condition 20651, part 19

NOx Monitoring Discussion
The Hot Water Boiler S-55 has a federally enforceable 30 ppm @3% O_2 NOx limit from 2 applicable requirements as noted above. However, there was previously no periodic monitoring required for this limit, only an initial source test under SIP Regulation 9-7-403. This was corrected by adding an annual source test for S-55 under Condition 20651, part 19.

CO Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
S-55 Hot Water Boiler	SIP 9-7-301.2	400 ppm @3% O_2	None
	BAAQMD Condition 20651, part 5	50 ppm @3% O_2	**Annual Source Test Added** Condition 20651, part 19

CO Monitoring Discussion
The Hot Water Boiler S-55 has federally enforceable CO limits of 400 ppm @3% O_2 and 50 ppm @3% O_2 as noted above. However, there was previously no periodic monitoring requirement for

either limit, only an initial source test under SIP Regulation 9-7-403. This was corrected by adding an annual source test for S-55 under Condition 20651, part 19.

SO_2 Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
S-54 Diesel Fired Backup Generator	BAAQMD 9-1-304	Fuel Sulfur Content: 0.5% sulfur by weight	N
S-55 Hot Water Boiler	SIP 9-1-302	300 ppm (dry)	Fuel Sulfur Content
S-56, S-57 Digester Gas Fired Turbines	SIP 9-1-302	300 ppm (dry)	Fuel Sulfur Content

SO2 Monitoring Discussion

S-54: Diesel Fired Backup Generator

BAAQMD Regulation 9-1-304 limits the sulfur content of liquid fuels to 0.5% by weight. Per the CAPCOA/ARB/EPA Agreement of 6/24/99 entitled "Periodic Monitoring Recommendations For Generally Applicable Requirements in SIP", vendor fuel sulfur content certifications for liquid fuels will provide sufficient assurances of compliance with SO2 emissions limits.

Monitoring for compliance with Diesel fuel sulfur limits in BAAQMD Regulation 9-1-304 will be achieved by the vender certification requirement for CARB Diesel Fuel in Condition 24733, part 4. The BAAQMD concludes that a demonstration of compliance with the much more stringent fuel sulfur requirement for CARB Diesel Fuel adequately demonstrates compliance with Regulation 9-1-304.

S-55: Hot Water Boiler; S-56, S-57: Digester Gas Fired Turbines

This digester gas fired equipment is subject to SIP Regulation 9-1-302, which limits exhaust SO2 emissions to 300 ppmv. Condition 18860 part 3 limits the total sulfur content of digester gas used as fuel to 340 ppmv. This limits SO2 emissions from the combustion equipment to 58.4 ppmv as follows:

For digester gas (64% methane, 36% CO_2); the stoichiometric combustion factor is 5.82 cu ft dry reactants per cu ft fuel (5.82 cu ft FG/cu ft DG).

$$
\begin{aligned}
SO_2 &= [(340\text{ E-6 cu ft S/cu ft DG})(\text{cu ft } SO_2/\text{cu ft S})]/(5.82\text{ cu ft FG/cu ft DG}) \\
&= 5.84\text{ E-5 cu ft } SO_2/\text{cu ft FG} \\
&= 58.4\text{ ppmv}
\end{aligned}
$$

The BAAQMD concludes that a demonstration of compliance with the digester gas fuel sulfur limit also demonstrates compliance with the SO2 limit of SIP Regulation 9-1-302.

PM Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
S-54 Diesel Fired Backup Generator	SIP 6-303	>Ringelmann 2.0 for no more than 3 min in any hour	N
	SIP 6-310	0.15 gr/dscf	N
S-55 Hot Water Boiler	SIP 6-301	> Ringelmann 1.0 for no more than 3 min in any hour	N
	SIP 6-310	0.15 gr/dscf at 6% Oxygen	N
S-56, S-57 Digester Gas Fired Turbines	SIP 6-301	> Ringelmann 1.0 for no more than 3 min in any hour	N
	SIP 6-310	0.15 gr/dscf at 6% Oxygen	N

PM Monitoring Discussion

Regulation 6-301 Visible Emissions – Digester Gas Combustion Sources
SIP Regulation 6-301 limits visible emissions to Ringelmann 1.0 for 3 minutes in any hour. Visible emissions from gaseous fuel combustion are not expected to exceed this limitation. This includes emissions from all sources burning digester gas. No monitoring for visible emissions from digester gas combustion is recommended.

Regulation 6-303 Visible Emissions
SIP Regulation 6-303 applies to the diesel fired emergency standby generators at the facility and limits visible emissions to Ringelmann 2.0 for 3 minutes in any hour. Although there may be a potential for some visible emissions from diesel engine operation, we do not expect the intermittent and brief operation of the diesel engines to necessarily exceed the Ringelmann 2.0 standard, particularly since the engines are all required to use ultra low sulfur fuel ($\leq$0.0015%). No monitoring for visible emissions from or diesel combustion sources is recommended.

Regulation 6-310 Particulate Weight Limitation
BAAQMD Regulation 6-310 limits filterable particulate (FP) emissions from any source to 0.15 grains per dry standard cubic foot (gr/dscf) of exhaust volume. Section 310.3 limits filterable particulate emissions from "heat transfer operations" to 0.15 gr/dscf at 6% O_2. These are the "grain loading" standards. There are no sources burning gaseous fuel (digester gas) that would ever be expected to have emissions near this limitation.

On a routine basis, there are no sources which could approach the limit of 6-310, since only gaseous fuels are typically combusted. The only new sources that could potentially exceed these limits is the diesel fired backup generator S-54.

For S-54, BAAQMD Regulation 6-310 limits PM emissions to 0.15 gr/dscf. If it is assumed that the diesel engine exhaust gases contain 15% excess oxygen under normal operating conditions, the Regulation 6-310 limit can be compared to the expected emissions from S-54 as follows:

From 40 CFR 60, Appendix A, Method 19, Table 19-1, a stoichiometric dry gas combustion factor of 9,190 dscf/MMBTU is given for distillate oil combustion. At 15% excess O_2 this factor becomes:

9,190 x [21%/(21% - 15%)] = 32,165 dscf (combustion products)/MMBTU

The conversion of 0.15 gr/dscf @ 15% O_2 to lb/MMBTU is then:

(32,165 dscf/MMBTU) x (0.15 gr/dscf) x (lb/7,000 gr) = 0.689 lb/MMBTU

The manufacturer's PM emission rate for S-54 (0.14 g/bhp-hr) is converted to lb/MMBTU as follows:

[(0.14 g/bhp-hr x 1114 bhp)/453.6 g/lb] / [(54.8 gal diesel/hr) x (0.137 MMBTU/gal diesel)]
= 0.046 lb/MMBTU

Since the manufacturer's PM emission factor for S-54 is less than the converted Regulation 6-310 limit, compliance is assumed. No monitoring is recommended.

POC Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
S-55 Hot Water Boiler	SIP 8-2-301	15 lb/day and greater than 300 ppm total carbon	N
S-56, S-57 Digester Gas Fired Turbines	SIP 8-2-301	15 lb/day and greater than 300 ppm total carbon	N
S-170 Sludge Handling Processes	SIP 8-2-301	15 lb/day and greater than 300 ppm total carbon	N

POC Monitoring Discussion:

S-55: Hot Water Boiler; S-56, S-57: Digester Gas Fired Turbines

Potential POC emission sources include the combustion sources as a result of incomplete combustion of any organics that may be in the digester gas (trace amounts) and the precursor organics that may result from the wastewater processes. Conservative digester gas sampling indicates the precursor organic levels are less than 82 microgram/liter (5.1 lb/MM cu ft). For the purposes of this PTE calculation, we will estimate uncontrolled emissions as well as worst case un-combusted organics assuming a conservative 90% destruction efficiency.

Digester Gas Combustion: The PTE is based on the estimated maximum digester gas production rate of 159,000 cu ft/hr (maximum digester production rate)

PTE, organics from digester gas, uncontrolled = (159,000 scf DG/hr) x (8760 hr/yr) x (5.1 lb/1E6 scf DG) = 7,103 lb/yr (19.5 lb/day)

PTE, organics from digester gas, after abatement = (7,103 lb/yr) x (0.1) = 710 lb/yr (1.9 lb/day)

Since the potential to emit POC from all digester gas combustion sources is less than 15 lb/day, S-55, S-56, and S-57 comply with SIP Regulation 8-2-301. No monitoring is recommended.

Wastewater POC Sources (Including S-170: Sludge Handling Processes)
The PTE for organics from the wastewater sources is based on emission factors developed from the AB-2588 programs for sewage treatment plants. The maximum plant liquid flow rate is 120 MM gpd with an uncontrolled POC emission factor of 243 lb/yr per million gallon per day (BAAT-AMSA 80% Conservative Emission Factor). The PTE for POCs from the wastewater processes is:

PTE = (120 E6 gpd) x (243 lb/yr-1E6 gpd) = 29,160 lb/yr (80 lb/day throughout wastewater sources, all locations combined)

The emissions of POCs occur at various locations, at numerous liquid sources throughput the wastewater processes and are typically represented in high volume, highly dilute vapor streams, spread out over many processes that are difficult to capture and control. Modern grassroots POTWs are increasingly designed to be covered and vented to high efficiency control systems, but the costs associated with such retroactive controls are not cost effective. There are no conditions to control and/or monitor POC emissions from any of the liquid wastewater sources. We do not expect any wastewater POC emission source to have a concentration approaching 300 ppmv, therefore no monitoring is recommended.

Changes to permit:

- Additional monitoring was added for the Hot Water Boiler S-55 to require an annual source test to demonstrate ongoing compliance with the BACT limits for NOx and CO. This monitoring requirement was added to Condition 20651, part 19.

VIII. Test Methods

This section of the permit lists test methods that are associated with standards in District or other rules. It is included only for reference. In most cases, the test methods in the rules are source test methods that can be used to determine compliance but are not required on an ongoing basis. They are not applicable requirements.

If a rule or permit condition requires ongoing testing, the requirement will also appear in Section IV of the permit.

Changes to permit

- Test methods will be added and deleted as shown in Table VIII of the proposed permit revision in accordance with the changes to other sections of the permit that have previously been discussed.

IX. Permit Shield

The District rules allow two types of permit shields. The permit shield types are defined as follows: (1) A provision in a major facility review permit explaining that specific federally enforceable regulations and standards do not apply to a source or group of sources, or (2) A provision in a major facility review permit explaining that specific federally enforceable applicable requirements for monitoring, recordkeeping and/or reporting are subsumed because other applicable requirements for monitoring, recordkeeping, and reporting in the permit will assure compliance with all emission limits.

The second type of permit shield is allowed by EPA's White Paper 2 for Improved Implementation of the Part 70 Operating Permits Program. The District uses the second type of permit shield for all streamlining of monitoring, recordkeeping, and reporting requirements in Title V permits. The District's program does not allow other types of streamlining in Title V permits.

This facility has no permit shields.

X. Revision History

Initial Issuance:	July 1, 1997
Minor Revision (AN 1209, 1068, 27693)	November 9, 2000
Minor Revision (AN 10353/10237):	July 14, 2004
Renewal (AN 3926):	July 26, 2005
Minor Revision (AN 18480):	2010

The minor modification of November 9, 2000 was based on applications 1068, 1209, and 27693. These applications as well as several others since that time have been addressed in detail in the Statement of Basis. The minor modification of July 14, 2004 was to convert the underground storage tanks into aboveground tankage.

D. Alternate Operating Scenarios:

No alternate operating scenario has been requested for this facility.

E. Compliance Status:

F. Differences between the Application and the Proposed Permit:

This application is for a Minor Permit Revision. It includes modifications made to the facility under (4) BAAQMD Permit Applications as follows:

AN 13736: Added Diesel Fired Backup Generator, S-54
AN 14243: Replaced the existing Hot Water Boiler S-5 with a new Hot Water Boiler S-55. Modified permit conditions for the Sludge Handling Processes, S-170.
AN 17399: Modified the Sludge Handling Processes, S-170 to add (2) sludge dewatering centrifuges to the existing equipment.
AN 17749: Authority to Construct for Digester Gas Turbines #1 and #2 (S-56, S-57)

The proposed Title V revision is being processed under AN 18480. The applications listed above are the basis for constructing the proposed permit. In addition, the BAAQMD is recommending other changes, as noted in this Statement of Basis, to update, streamline, and standardize the permit.

G. Permit Shield:

This facility has no permit shields.

H:\Engineering\TITLE V Permit Appls\1 ALL T5 Application Files here\A0591\M Revision - 18480\Working Documents\MREV-SOB

APPENDIX A

BAAQMD COMPLIANCE REPORT

APPENDIX B

GLOSSARY

ACT
Federal Clean Air Act

APCO
Air Pollution Control Officer

ARB
Air Resources Board

BAAQMD
Bay Area Air Quality Management District

BACT
Best Available Control Technology

Basis
The underlying authority that allows the District to impose requirements.

BHP (bhp)
Brake Horsepower, see Units of Measure

BTU
British Thermal Unit. See units of measure.

BUG
Backup Generator (Emergency)

CAA
The federal Clean Air Act

CAAQS
California Ambient Air Quality Standards

CAPCOA
California Air Pollution Control Officers Association

CEQA
California Environmental Quality Act

CFR
The Code of Federal Regulations. 40 CFR contains the implementing regulations for federal environmental statutes such as the Clean Air Act. Parts 50-99 of 40 CFR contain the requirements for air pollution programs.

CO
Carbon Monoxide

Cu Ft
Cubic foot = ft^3, see Units of Measure

Cu M
Cubic meter = m^3, see Units of Measure

Cumulative Increase
The sum of permitted emissions from each new or modified source since a specified date pursuant to BAAQMD Rule 2-1-403, Permit Conditions (as amended by the District Board on 7/17/91) and SIP Rule 2-1-403, Permit Conditions (as approved by EPA on 6/23/95). Cumulative increase is used to determine whether threshold-based requirements are triggered.

DG
Digester Gas

District
The Bay Area Air Quality Management District

DSCF (dscf)
Dry Standard Cubic Feet, see Units of Measure

EPA
The federal Environmental Protection Agency.

Excluded
Not subject to any District regulations.

Federally Enforceable, FE
All limitations and conditions which are enforceable by the Administrator of the EPA including those requirements developed pursuant to 40 CFR Part 51, subpart I (NSR), Part 52.21 (PSD), Part 60 (NSPS), Part 61 (NESHAPs), Part 63 (MACT), and Part 72 (Permits Regulation, Acid Rain), including limitations and conditions contained in operating permits issued under an EPA-approved program that has been incorporated into the SIP.

FP
Filterable Particulate as measured by BAAQMD Method ST-15, Particulate.

HAP
Hazardous Air Pollutant. Any pollutant listed pursuant to Section 112(b) of the Act. Also refers to the program mandated by Title I, Section 112, of the Act and implemented by 40 CFR Part 63.

HHV
Higher Heating Value: The heat extracted by a reaction assuming all water vapor is condensed within the process, and the resulting heat of condensation recovered for useful work.

LHV
Lower Heating Value: The heat extracted by a reaction assuming all water vapor goes out the

exhaust stack with none of the heat of condensation recovered for useful work.

Mole
Quantity of a compound. One mole of a compound is estimated to have 6.023×10^{23} molecules (6.023 E +23) of the respective compound.

Major Facility
A facility with potential emissions of: (1) at least 100 tons per year of regulated air pollutants, (2) at least 10 tons per year of any single hazardous air pollutant, and/or (3) at least 25 tons per year of any combination of hazardous air pollutants, or such lesser quantity of hazardous air pollutants as determined by the EPA administrator.

MFR
Major Facility Review. The District's term for the federal operating permit program mandated by Title V of the Federal Clean Air Act and implemented by District Regulation 2, Rule 6.

Microgram
Unit of weight. 1 microgram (µg) = 1/1,000,000th of a gram or 1 millionth of a gram.

MM Btu/hr
Million BTU per hour.

MW
Molecular Weight. The weight of one mole or 6.023 E23 molecules of a compound.

PPM
Unit of concentration. Part Per Million. For vapor ppm is equivalent to a molar or volumetric concentration. For liquids and solids ppm is essentially equivalent to a weight fraction. See Units of Measure.

MOP
The District's Manual of Procedures.

NAAQS
National Ambient Air Quality Standards

NESHAPS
National Emission Standards for Hazardous Air Pollutants. See in 40 CFR Parts 61 and 63.

NMHC
Non-methane Hydrocarbons (Same as NMOC)

NMOC
Non-methane Organic Compounds (Same as NMHC)

NOx
Oxides of nitrogen.

NOV
Notice of Violation

NSPS

Standards of Performance for New Stationary Sources. Federal standards for emissions from new stationary sources. Mandated by Title I, Section 111 of the Federal Clean Air Act, and implemented by 40 CFR Part 60 and District Regulation 10.

NSR
New Source Review. A federal program for pre-construction review and permitting of new and modified sources of pollutants for which criteria have been established in accordance with Section 108 of the Federal Clean Air Act. Mandated by Title I of the Federal Clean Air Act and implemented by 40 CFR Parts 51 and 52 and District Regulation 2, Rule 2. (Note: There are additional NSR requirements mandated by the California Clean Air Act.)

Offset Requirement
A New Source Review requirement to provide federally enforceable emission offsets for the emissions from a new or modified source. Applies to emissions of POC, NOx, PM10, and SO2.

Phase II Acid Rain Facility
A facility that generates electricity for sale through fossil-fuel combustion and is not exempted by 40 CFR 72 from Titles IV and V of the Clean Air Act.

POC
Precursor Organic Compounds

PM
Particulate Matter

PM10
Particulate matter with aerodynamic equivalent diameter of less than or equal to 10 microns

POTW
Publicly Owner Treatment Works. Also known as wastewater treatment plant (WWTP) or sewage treatment plant (STP)

PPMV
Parts Per Million, by Volume. See Units of Measure.

PSD
Prevention of Significant Deterioration. A federal program for permitting new and modified sources of those air pollutants for which the District is classified "attainment" of the National Air Ambient Quality Standards. Mandated by Title I of the Act and implemented by both 40 CFR Part 52 and District Regulation 2, Rule 2.

PTE
Potential to emit

SIP
State Implementation Plan. State and District programs and regulations approved by EPA and developed in order to attain the National Air Ambient Quality Standards. Mandated by Title I of the Act.

SO2
Sulfur dioxide

STP
Sewage Treatment Plant. Also known as a publicly owned treatment works (POTW) or wastewater treatment plant (WWTP).

THC
Total Hydrocarbons (NMHC + Methane)

Title V
Title V of the federal Clean Air Act. Requires a federally enforceable operating permit program for major and certain other facilities.

TOC
Total Organic Compounds (NMOC + Methane, Same as THC)

TPH
Total Petroleum Hydrocarbons

TRMP
Toxic Risk Management Plan

TSP
Total Suspended Particulate

VOC
Volatile Organic Compounds

Units of Measure:

bhp	=	brake-horsepower
btu	=	British Thermal Unit
cfm	=	cubic feet per minute
dscf	=	dry standard cubic feet
g	=	grams
gal	=	gallon
gpm	=	gallons per minute
hp	=	horsepower
hr	=	hour
lb	=	pound
in	=	inches
max	=	maximum
m^2	=	square meter
m^3	=	cubic meter
min	=	minute
mm	=	million
MMbtu	=	million btu
MMcf	=	million cubic feet
ppmv	=	parts per million, by volume
ppmw	=	parts per million, by weight
psia	=	pounds per square inch, absolute
psig	=	pounds per square inch, gauge
scfm	=	standard cubic feet per minute
yr	=	year

EBMUD

East Bay Municipal Utility District

WWTP

Wastewater Treatment Plant. Also known as publicly owned treatment works (POTW) or sewage treatment plant (STP).

APPENDIX C

PERMIT APPLICATION ENGINEERING EVALUATIONS

Engineering Evaluations for the following permit applications are attached to the Statement of Basis in this Appendix.

AN	TITLE
13736	New Source: S-54, Diesel Fired Backup Generator
14243	Boiler Replacement. New Source: S-55, Hot Water Boiler; Remove S-5, Hot Water Boiler
17399	Modified Source: S-170, Sludge Handling Processes
17749	Authority to Construct. New Sources: S-56, S-57 – Digester Gas Turbines

ENGINEERING EVALUATION REPORT

PLANT NAME	East Bay Municipal Utility District
APPLICATION NUMBER	13736
PLANT NUMBER	A0591
DATE	24 May 2006

1. BACKGROUND

This application is for a fixed-location diesel genset to supply power in emergency situations for the East Bayshore Recycled Water facility that is currently under construction. The engine will be physically located at East Bay Municipal Utility District's (EBMUD) main wastewater treatment plant (BAAQMD Plant A0591) located at 2020 Wake Avenue in Oakland. A description of the source is as follows:

S-54 Emergency Backup Generator, Diesel Fired, 750 KW, 1114 BHP, 1649 cu in, Caterpillar Model 3412B, 2005 Model Year

This engine generator set is a new unit and therefore is subject to NSR as well as the CARB Stationary Diesel ATCM. The engine will be subject to the more stringent of the limitations of BACT and the Diesel ATCM. The certified diesel PM emission factor is 0.14 g/bhp-hr. The toxic risk will be evaluated and managed based on the policies and requirements contained in BAAQMD Regulation 2-5, Toxic NSR. After concluding the toxic risk screen, the engine will be permitted to operate for maintenance and testing at the lesser of either of the following:

a) 50 hours per year, or
b) At the number of hours per year producing a maximum risk of 10 in a million.

The engine will be permitted to operate for an unlimited number of hours during emergency conditions. The engine is not located within 1000 ft of any schools, therefore a Waters Bill Public Notice is not required.

2. TOXIC EVALUATION

S-54 Backup Generator, Diesel Fired, 1114 BHP: Toxic emissions from this source is PM-10 which is used as a surrogate for all other emitted toxic air contaminants. The engine meets TBACT (0.15 g/bhp-hr) with an emission factor of 0.14 g/bhp-hr. Therefore the maximum allowable risk is 10 in a million. Carcinogenic risks were estimated for the maximally exposed residential and industrial receptors. The engine will be permitted for reliability and maintenance to the lesser of either 50 hours/year (as allowed by the CARB ATCM) or as allowed up to a risk of 10 in a million.

Our toxic analysis used the following parameters in the development of the risk estimates for this engine:

TABLE 1 RISK MODELING PARAMETERS

PARAMETER	S-54 GENSET
Met Data	OST03RA.asc
Land Use	Rural*
Exhaust Flow	6,459 cfm
Stack Height	10.5' (total height)
Operating Hours	50 hr/yr
Nearest Residence	See aerial layout
Distance to Prop Line	See aerial layout
PM10 Emission Factor (>TBACT)	0.14 g/hp-hr (TBACT is 0.15 g/bhp-hr)

*Both Urban and Rural land use cases were modeled. Rural was found to be more conservative in the residential area (9.04 vs 4.17). Urban was more conservative at the fenceline (39.2 vs 36.9), but there are no receptors expected at the site of maximum impact.

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TABLE 2 TOXIC RISK SUMMARY

RISK TYPE	RESIDENT	INDUSTRIAL	STUDENT
Cancer Risk	0.7 in a million	0.6 in a million	N/A
Non-Cancer HQ	0.0005	0.0005	N/A

The maximum residential and worker risks are estimated as less than 1 in a million-an insignificant risk level. The hazard quotients for both the maximally exposed resident and worker receptors is less than 0.1, which is also an insignificant non-cancer risk level. This engine will be permitted to operate for 50 hours/year for reliability related operation. This engine generator S-54 complies with Regulation 2 Rule 5, Toxic New Source Review.

3. EMISSION CALCULATIONS

The proposed engine is CARB Certified (Executive Order U-R-001-0278).

TABLE 3 DIESEL ENGINE EMISSION FACTORS

POLLUTANT	ENGINE, per CARB Exec U-R-001-0278 (g/bhp-hr)	EPA Tier I Standards (g/bhp-hr)	BACT Standards (g/bhp-hr)
Diesel PM	**0.14**	0.4	0.15 (TBACT)
CO	**0.9**	8.5	2.75 (BACT2)
NMHC	**0.1**	1.0	1.5 (BACT2)
NOx	**5.7**	6.9	6.9 (BACT2)

Note: Factors used shown in **bold**

S-54 Backup Generator, 1124 BHP: The following data was derived from the diesel exhaust emissions per ISO 8178 D-2 (five) Cycle testing.

Operating Hours: 50 hr/yr
Engine HP: 1124 bhp

PM-10 Emissions: [1124 bhp][50 hr/yr][0.14* g/bhp-hr][lb/454 g] = 17.2 lb/yr (0.047 lb/day annual average)
Highest day emissions = [[17.2 lb/yr]/[50 hr/yr]]*24 hr/day= 8.2 lb/day

NOx Emissions: [1124 bhp][50 hr/yr][5.7* g/bhp-hr][lb/454 g] = 699 lb/yr (1.9 lb/day annual average)
Highest day emissions = [[699 lb/yr]/[50 hr/yr]]*24 hr/day= 336.4lb/day

CO Emissions: [1124 bhp][50 hr/yr][0.9* g/bhp-hr][lb/454 g] = 110 lb/yr (0.30 lb/day annual average)
Highest day emissions = [[110 lb/yr]/[50 hr/yr]]*24 hr/day= 53 lb/day

TOC Emissions: [1124 bhp][50 hr/yr][0.1* g/bhp-hr][lb/454 g] = 12.3 lb/yr (0.034 lb/day annual average)
Highest day emissions = [[12.3 lb/yr]/[50 hr/yr]]*24 hr/day= 6 lb/day

SO_2 Emissions: Basis: Diesel S Content: 500 ppm S (wt)
Diesel Usage = [50 hr/yr][54.8 gal/hr] = 2740 gal/yr
Annual SO_2 = [2,740 gal/yr][6.11 lb/gal][500 # S/1E6 # diesel]
[mole S/32.06 # S][mole SO_2/mole S][64.1 lb SO_2/mole] = 16.7 lb/yr SO_2
Daily average: 0.0476 lb/day
Highest Day Emission: [[16.7 lb/yr]/[50 hr/yr]]*24 hr/day= 8 lb/day

*Factors taken from CARB Executive Order U-R-001-0278 Diesel Generator specifications.

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4. EMISSIONS SUMMARY

The emissions calculated in Section 3, above are tabulated as follows.

TABLE 4 ANNUAL EMISSIONS SUMMARY

POLLUTANT	Annual Emissions (lb/yr)	Annual Average (lb/day)	Tons/Yr	Highest Day (lb/day)
PM10	17.2	0.047	0.009	8.2
NOx	699	1.9	0.35	336
CO	110	0.3	0.055	53
TOC	12.3	0.03	0.006	6
SO_2	16.7	0.046	0.008	8

5. PERMIT REQUIREMENTS/DISCUSSION OF EXEMPTION <N/A>

6. DETERMINATION OF COMPLIANCE

A. Regulation 1 – General Provisions and Definitions
§1-301: Prohibits discharging emissions in quantities that cause injury, detriment, nuisance, or annoyance. The toxic evaluation addresses these issues.

B. Permits – General Requirements, Regulation 2 Rule 1
The source is not located within 1000 feet of any school, and is therefore not subject to the public notification requirements of 2-1-412.

C. Permits – New Source Review, Regulation 2 Rule 2 (dated 10/7/98)

1. **BACT:** BACT is required if the highest daily emissions (reliability related operations) exceeds 10 lb. The 10 lb/day threshold is exceeded for NOx, CO, and POC. The engine meets BACT2 for these pollutants. Hence the engine complies with BACT requirements for NOx and CO. A comparison of BACT against the certified emission factors is shown on Table 3, above. The engine meets BACT for NOx, CO, and NMHC.

   The engine meets TBACT for diesel particulate.

2. **Offset Requirements:** §2-2-303: Overall facility emissions for POC and NOx at the EBMUD wastewater treatment plant are each over 35 tpy, therefore offsets for emission increases resulting from the project must be provided at the ratio of 1.15 to 1.0. Additionally, offsets must be provided to the cumulative increase, if any, of the above pollutants. The applicant has obtained 1.074 tpy POC offsets from the Johns Manville Corporation, purchased through Evolution Markets, on April 14, 2006. Following provides the disposition of these offsets:

TABLE 5 OFFSET SUMMARY

Pollutant Explanation	Emissions (tpy)	Offsets Required (tpy)
NOx Emissions		
Cumulative Increase, 1-18-06	0.02	0.02
Project Emissions	0.35	0.4025
POC Emissions		
Cumulative Increase; 1-18-06	0.146	0.146
Project Emissions	0.006	0.0069
TOTAL POC OFFSETS REQUIRED		**0.575**
POC Offsets Provided		**1.074**

} 0.153 tpy

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OFFSET BANK ACCT BALANCE		0.5

3. **Prevention of Significant Deterioration:** §2-2-304: District PSD requirements apply to emissions of SO2, NO2, CO, and PM10. Since this facility is not a major facility and the facility's cumulative increase does not exceed 15 ton/yr, the PSD requirements do not apply.

D. Regulation 3 – Fees
EBMUD has complied with fee requirements for this project.

E. Particulate Matter and Visible Emissions, Regulation 6

1. Section 301 prohibits for more than 3 minutes per hour, visible emissions as dark or darker than Ringelmann 1 or equivalent opacity. S-54 is expected to comply with this requirement.

2. Section 305 prohibits emissions of visible particles from causing a nuisance on property other than the operators. S-54 is expected to easily comply with this standard.

3. Section 310 limits the particulate concentration in exhaust gases to 0.15 gr/dscf. At the exhaust rate of 6,459 cfm, on a highest day emissions basis, the resulting concentration in the exhaust would be 0.006 grain/scf. Hence this engine complies with this requirement.

F. NSPS/NESHAPS
At this time there is no New Source Performance Standard or NESHAP for stationary emergency backup diesel engines.

G. CEQA
This project is considered to be ministerial under the District's CEQA Regulation 2-1-311. The engineering review for this project requires only the application of standard permit conditions and standard emissions factors and therefore is not discretionary as defined by CEQA.

H. Statewide Stationary Diesel Engine ATCM
This engine complies with all applicable sections of the ATCM, including (e)(1) Fuel Requirements, (e)(2)(F) Emission Requirements, (e)(4) Recordkeeping, Reporting and Monitoring. The engine also complies with EPA Tier I requirements for engines over 750 hp of model year (MY) 2005. The applicable requirements will be written into the permit conditions.

I. WATERS BILL PUBLIC NOTICE

There are no schools within 1000 ft of the source.

7. CONDITIONS

Recommend the following conditions (Condition Template 22850) for Emergency Backup Generator, Diesel Fired, 750 KW, 1114 BHP, 1649 cu in, Caterpillar Model 3412B, 2005 Model Year

1. Operating for reliability-related activities is limited to 50 hours per year per engine.

   [Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3) or (e)(2)(B)(3)]

2. The owner or operator shall operate each emergency standby engine only for the following purposes: to

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mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits is not limited.

[Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(3) or (e)(2)(B)(3)]]

3. The owner/operator shall operate each emergency standby engine only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained.

   [Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(G)(1)]

4. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 36 months from the date of entry (60 months if the facility has been issued a Title V Major Facility Review Permit or a Synthetic Minor Operating Permit). Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request.
   a. Hours of operation for reliability-related activities (maintenance and testing).
   b. Hours of operation for emission testing to show compliance with emission limits.
   c. Hours of operation (emergency).
   d. For each emergency, the nature of the emergency condition.
   e. Fuel usage for each engine(s).

   [Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(4)(I), (or Regulation 2-6-501)]

5. At School and Near-School Operation:
   If the emergency standby engine is located on school grounds or within 500 feet of any school grounds, the following requirements shall apply:
   The owner or operator shall not operate each stationary emergency standby diesel-fueled engine for non-emergency use, including maintenance and testing, during the following periods:
   a. Whenever there is a school sponsored activity (if the engine is located on school grounds).
   b. Between 7:30 a.m. and 3:30 p.m. on days when school is in session "School" or "School Grounds" means any public or private school used for the purposes of the education of more than 12 children in kindergarten or any of grades 1 to 12, inclusive, but does not include any private school in which education is primarily conducted in a private home(s). "School" or "School Grounds" includes any building or structure, playground, athletic field, or other areas of school property but does not

include unimproved school property.

[Basis: "Stationary Diesel Engine ATCM" section 93115, title 17, CA Code of Regulations, subsection (e)(2)(A)(1)] or (e)(2)(B)(2)]

8. RECOMMENDATIONS

a) Issue permit to operate for S-54 subject to Condition # 22850

b) Zero cumulative increase balances for NOx and POC

c) Issue banking certificate for 0.5 tpy POC emission offsets held.

by: REF

Randy E. Frazier, P.E.
24 May 2006

ENGINEERING EVALUATION REPORT

PLANT NAME	**East Bay Municipal Utility District**
PLANT NUMBER	**A0591**
APPLICATION NUMBER	**14243**
PLANT/SITE ADDRESS	**2020 Wake Avenue Oakland, CA 94607**
DATE	**3 October 2006 (revised 3-15-07)**
ENGINEER	**R.E. Frazier**
PAGE	**1 of 5**

3-15-07 Revision: The applicant mistakenly entered an erroneous gross heat input rate of 16.74 MM Btu/hr when the correct number was 20.41 MM Btu/hr. This engineering evaluation has been revised accordingly. Although there is a slight increase in emissions, the conclusions are the same. No net increase, no offsets required, and no significant toxic risk (carcinogenic or acute or chronic). The condition (#20651) has been modified to reflect the correct heat input limit.

1. BACKGROUND

This application is a two-part permit application as follows.

a) The first part of the application is to install a new digester gas fired boiler to supply hot water to the anaerobic digester process. The boiler will be configured to burn digester gas principally but can also burn natural gas if necessary. The boiler will use a small pilot of natural gas. The source will be identified as:

S-55 Hot Water Boiler, Digester Gas or Natural Gas Fired, (with Natural Gas Pilot) 20.41 MM Btu/hr

The purpose of this boiler will be to operate in the event one of the cogeneration engines (S-37, S-38 or S-39) is out of service. The current condition which governs the operation of the above engines and the current hot water boiler S-5 allows the simultaneous operation of all three engines or any combination of 2 engines and boiler S-5. The new boiler S-55 would be operated instead of S-5, only when at least 1 of the engines is out of service in order to supply the necessary high temperature hot water to the digesters – to produce Class A biosolids. Class A biosolids contain no detectable levels of pathogens, have low metals content, and have few, if any, agricultural use restrictions.

The applicant has stated that the boiler will be configured with a low NOx burner and flue gas recirculation—which represents BACT for a boiler burning digester gas. The boiler will be permitted based on the firing of 100% digester gas. This boiler will be permitted as a new source and will therefore be subject to BACT if the emissions of any criteria pollutant are over 10 lb/highest day.

Based on a cursory review of the toxic air contaminant emissions from digester gas combustion, the toxic trigger is exceeded for formaldehyde, therefore a toxic risk screening assessment will be performed.

b) The second part of this application is to modify condition 18006 for source S-170 Sludge Handling Processes. Currently the condition states that the odorous emissions from S-170 shall be routed to the atomized mist scrubber A-7. EBMUD wishes to amend the condition to allow the emissions to be routed to either A-7 or A-8, identical atomized mist scrubbers. A-8 has been used to abate odors from an exempt odor sources in the dewatering building. There would be no emissions increases or changes resulting from this change. The revised condition will be shown in Section 8.

2. EMISSION CALCULATIONS

Calculations Basis:

Hours of Operation, Annual: 7796 hr per year (89% operating factor)
Heat Duty: 20.41 E6 Btu/hr (34,075 cf/hr)
(265.6 MM scf/yr digester gas)

The boiler will typically only be used to backup the cogeneration engines, but will be permitted based on 7796 hours per year maximum operation to backup engine S-38 as needed.

Exhaust flowrate calculation:

Digester gas heat of combustion: 600 BTU/scf
F, digester gas, 60% natural gas: 5.5279
Oxygen Correction Factor (3% O2): 1.167

Exhaust Flow = [20.41E6 Btu/hr][scf DG/600 Btu][5.5279 scf FG/scf DG][1.167 scf FG @ 3% O2/1 scf FG @ 0% O2] = 219,444 scf/hr FG @ 3% O2

NOx (as NO2) 30 ppm Conversion to lb/MM Btu:

[30 scf NOx/1E6 scf FG][219,444 scf FG/20.41 MM Btu DG][lb-mole NOx/386 scf NOx][46.01 lb/mole] = 0.0384 lb NOx (as NO2)/MM Btu

CO Conversion:

[50/1E6][219,444/20.41][1/386][28.01] = 0.0391 lb CO/MM Btu

Table 1, S-55 Boiler Criteria Pollutant Emission Factors

FACTORS	PM10	NOx	VOC	CO	SO2
Emission Factors, ppm @ 3% oxygen		30 ppm @3% O2	n/s	50 ppm @ 3% O2	Mass balance*
AP-42 (natural gas based)	1.9 lb/MM scf		5.5 lb/MM scf		
Factor Converted for DB Usage, lb/MM Btu	3.167E-3	0.0384	9.167E-3	0.0391	

PM-10 Emissions: [20.41 MMBtu/hr][7796 hr/yr][3.167E-03 lb/MM Btu] = 504 lb/yr (1.4 lb/day annual average)

Highest day emissions = [[504 lb/yr]/[7796 hr/yr]]*24hr/day] = 1.6 lb/day

NOx Emissions: [20.41 MMBtu/hr][7796 hr/yr][0.0384 lb/MM Btu] = 6,110 lb/yr (16.7 lb/day annual average)

Highest day emissions = [[6110 lb/yr]/[7796 hr/yr]]*24hr/day] = **18.8** lb/day

CO Emissions: [20.41 MMBtu/hr][7796 hr/yr][0.0391 lb/MM Btu] = 6,221 lb/yr (17 lb/day annual average)

Highest day emissions = [6221 lb/yr]/[7796 hr/yr]]*24hr/day] = **19.2** lb/day

VOC Emissions: [20.41 MMBtu/hr][7796 hr/yr][9.167E-03 lb/MM Btu] = 1,459 lb/yr (3.99 lb/day annual average)

Highest day emissions = [[1,459 lb/yr]/[7796 hr/yr]]*24hr/day] = 4.5 lb/day

SO2 Emissions: Basis: Digester Gas S Content: 1500 ppm S (wt, limited by S-180 condition 18860)
Digester Gas Usage = [7796 hr/yr][20.41E6 Btu/hr][scf/600 Btu] = 265.6 MM scf/yr

Annual SO2 = [1500 scf H2S/MMscf DG)(265.6 MM scf DG/yr][mole H2S/386 scf H2S][1 mole SO2/mole H2S][64.1 lb SO2/mole SO2] = 66,159 lb/yr
Daily average: 181.3 lb/day
Highest Day Emission: [[66159 lb/yr]/[7796 hr/yr]]*[24 hr/day] = 203.7 lb/day

Digester Gas SO2 Emissions, at 340 ppm H2S (BACT) = [340 scf H2S/MM scf DG][265.6 MM scf DG/yr][mole H2S/386 scf H2S][1 mole SO2/mole H2S][64.1 lb SO2/mole SO2] = 14,996 lb/yr
Daily average: 41.1 lb/day
Highest Day Emission: [[14996 lb/yr]/[7796 hr/yr]]*[24 hr/day] = **46.2** lb/day

Formaldehyde Emissions: [20.41 MM Btu/hr][7796 hr/yr][MM scf DG/600 MM Btu][5.1E-1 lb/MM scf DG] = 135.2 lb/yr (toxic trigger level is 33 lb/yr)

3. EMISSIONS SUMMARY

Table 2 S-55 Boiler Criteria and Toxic Emissions Summary

POLLUTANT	Toxic Trigger (lb/yr)	Annual Emissions (lb/yr)	Annual Average (Lb/day)	Tons/Yr	Highest Day (Lb/day)
Criteria Pollutants					
NOx	N/A	6110	16.7	3.1	**18.8**
CO	N/A	6221	17	3.1	**19.2**
POC	N/A	1459	4	0.7	4.5
SO_2	N/A	14996	41.1	7.5	**46.2**
PM10	N/A	504	1.4	0.25	1.6
Toxic Pollutants					
Formaldehyde*	33	135	n/a	n/a	n/a
Benzene*	6.7	2.3	n/a	n/a	n/a
Methylene Chloride*	190	22.9	n/a	n/a	n/a
Perc*	33	0.04	n/a	n/a	n/a
TCE*	97	0.01	n/a	n/a	n/a
Vinyl Chloride*	2.5	1.8	n/a	n/a	n/a

*Toxic air contaminant factors from San Diego APCD source tests on digester gas combustion equipment

4. CUMULATIVE INCREASE/OFFSETS DISCUSSION

The new boiler S-55 will be conditioned to operate only when at least one of the cogeneration engines is out of service, and then only for 7,796 hours/yr. All three cogeneration engines are the same size, although the maximum annual permitted emissions levels are not equivalent. Engine S-38 is conditioned to achieve BACT while engines S-37 and S-39 are conditioned to BARCT (higher) emission levels. Therefore, the annual emissions from the new boiler will be compared against the emissions of engine S-38, and are summarized in the following table.

Table 3 Comparison of S-55 Emissions with S-38 BACT Conditioned Cogeneration Engine

POLLUTANT (Lb/yr)	NOx	CO	POC	SO2	PM10
Boiler S-55	6,110	6,221	1,459	14,996	504
Boiler S-5	897	756	Negl	Negl	Negl
S-5 + S-55 Total	7,007	6,977	1,459+ negl	14,996+	504+negl
Engine S-38	63,965	153,516	30,703	15,352	4,350

Since the emissions from S-5 and S-55 combined are less than those of engine S-38 and since the sources will not be operated unless at least S-38 (lowest emitting engine) is shutdown, there is no cumulative increase resulting from this project, therefore offsets are not required.

5. STATEMENT OF COMPLIANCE

A. Toxic Evaluation: The following toxic evaluation is based on the boiler operating on 100% digester gas for 7,796 hr/yr.

Toxic emission factors for digester gas combustion come from source tests conducted at the San Diego Air Pollution Control District, and are listed on the emissions calculation spreadsheet. The emission calculation for formaldehyde is shown in this evaluation (above section 2), since formaldehyde emissions trigger the risk screening analysis.

Our toxic analysis used the following assumptions in the development of the risk estimates for this boiler:

Meteorological Data: OST met data
Exhaust flow: 6,800 cfm @ 24 in dia exhaust
Stack height: 26' (building ht = 11')
Operation: 7,796 hr/yr (38.8% operating factor)
Building Parameters/Footprint: See facility plan view
Nearest residence: >2,000 feet
Distance to Property Line: ~158 ft
Land Use: Rural (worst case)

There are no schools located within 1000 feet of the source. The toxic risk analysis was performed using BEEST (ISCST) software in conjunction with the OST met data. The ambient concentrations obtained from the BEEST modeling analysis were based on a unit emission rate from the source.

HEALTH RISK	MEI-RESIDENT	*(i) MEI-WORKER*
Cancer Risk	< 1 in a million	<<1 in a million
Chronic HQ	<<0.2	<<0.2
Acute HQ	<<1.0	<<1.0

<u>Carcinogenic Risk Evaluation</u>

The maximum fenceline carcinogenic risk is estimated at 0.18 in a million. The facility is located in an area largely with open spaces to the north and south and some light industry to the east, bordering on the bay to the west. The nearest industrial receptors are located east of the source and near the property line. The MEI is located at an industrial receptor site – directly downwind of the facility. The nearest residence is more than 400 meters east and therefore has minimal exposure to the toxic air contaminants from this boiler. All estimated risks are less than 1 in a million and are therefore insignificant.

<u>Non-Carcinogenic Chronic Risk Evaluation</u>

Non-carcinogenic chronic risks were estimated using the REL for chronic inhalation of toxic pollutants from digester gas combustion. The tabulation of the emissions is shown in a spreadsheet in this evaluation, as are the calculated hazard indices for the various pollutants. The total chronic hazard index for the maximally exposed residential, fenceline, and industrial receptors are all much less than 0.2. Since the hazard indexes are less than 0.2, we conclude the health impacts from chronic exposure to exhaust emissions from S-15 boiler are not significant.

Public Notification: There are no schools or other receptors requiring a public notice within 1000 feet of this source. ***Therefore public notification due to toxic air contaminants is not required.***

B. Regulation 1 – General Provisions and Definitions

§1-301: Prohibits discharging emissions in quantities that cause injury, detriment, nuisance, or annoyance. The toxic evaluation addresses these issues.

C. Permits – General Requirements, Regulation 2 Rule 1

The source is not located within 1000 feet of the nearest school, and therefore is not subject to the public notification requirements of 2-1-412.

D. Permits – New Source Review, Regulation 2 Rule 2 (dated 10/7/98)

1. **BACT:** The applicant has indicated that the boiler will be equipped with low NOx burner and flue gas recirculation, which represents BACT for a boiler burning digester gas.

POLLUTANT	BACT LEVEL (ppm @ 3% O2))	VENDOR FACTORS (ppm @ 3% O2)
NOx	30*	20
CO	50	50
PM10	n/s	n/s
POC	Auto air control	n/s
SO2	340 ppm H2S feed gas to boiler	n/s

*Based on a recent BACT determination for a digester gas fired boiler, memo included in application package.

BACT is triggered for NOx, CO and SO2. The vendor has suggested NOx and CO emission levels of 20 and 50 ppm, respectively at 3% oxygen. Our literature search has shown that although the vendor believes the boiler will achieve 20 ppm NOx, there is limited source test data to support this recommendation. In addition, the boiler manufacturer has indicated they will not guarantee 20 ppm. According to the BAAQMD BACT handbook, BACT2 (achieved in practice) for a boiler of this size burning digester gas using FGR and Low NOx burners is 40 ppm at 3% oxygen. There is however, sufficient data to suggest that 30 ppm @ 3% oxygen is achieved in practice. We recommend 30 ppm NOx at 3% oxygen as BACT2 (achieved in practice) for this boiler.

The BACT Handbook specified BACT1 as the use of selective non-catalytic reduction (SNCR). The planned operation of this boiler is as a backup for one of the cogeneration engines—and operation will therefore be on an intermittent basis. For this reason, SNCR, which involves ammonia injection, is not expected to be cost effective or operationally practical due to injection control issues. We recommend BACT2 – 30 ppm @ 3% oxygen as the appropriate BACT level for this boiler.

For CO, there is sufficient source test data suggesting that 50 ppm at 3% oxygen is achievable on a consistent basis for digester gas fired boiler such as this. Therefore, we recommend CO BACT of 50 ppm @ 3% oxygen.

BACT for digester gas fired engines is 0.3 g/bhp-hr which is equivalent to approximately 340 ppm H2S in the engine feed. This BACT level was written into the condition for engine S-38 and seems to be the appropriate level for the gaseous feed to the boiler as well. The applicant has agreed to operate the fuel gas feed to the boiler to a maximum level of 340 ppm H2S. These limitations will be written into the permit conditions.

2. **Offset Requirements:** §2-2-303: The boiler S-55 will operate in a similar fashion to the current boiler S-5---only when one of the cogeneration engines is out of service. Therefore there are no net emission increases and offsets are not required.

3. **Prevention of Significant Deterioration:** §2-2-304: PSD thresholds are not exceeded, therefore a PSD analysis is not required.

E. Regulation 3 – Fees

The East Bay Municipal Utility District has complied with fee requirements for this permit application.

F. Particulate Matter and Visible Emissions, Regulation 6

1. Section 301 prohibits for more than 3 minutes per hour, visible emissions as dark or darker than Ringelmann 1 or equivalent opacity. Source S-55 is expected to easily comply with this requirement.

2. Section 305 prohibits emissions of visible particles from causing a nuisance on property other than the operators. S-55 is expected to easily comply with this standard.

3. Section 310 limits the particulate concentration in exhaust gases to 0.15 gr/dscf. At the estimated 6,800 cfm from boiler S-55, on a highest day emissions basis, the resulting concentration in the exhaust would be 0.001 grain/dscf. Hence this source complies with this requirement.

G. Regulation 9 Rule 7, Inorganic Gaseous Pollutants

The boiler is subject to Reg 9 Rule 7 requirements for NOx (300 ppm at 3% oxygen) and CO (400 ppm @ 3% oxygen). The BACT limits for these pollutants (which S-55 must meet) are lower than the limits specified in 9-7. Therefore S-55 meets the requirements of Reg 9 Rule 7.

H. NSPS/NESHAPS

There is no New Source Performance Standard or National Emission Standards for Hazardous Air Pollutants that apply to this source.

I. CEQA

This project is considered to be ministerial under the District's CEQA Regulation 2-1-311. The engineering review for this project requires only the application of standard permit conditions and standard emissions factors and therefore is not discretionary as defined by CEQA.

8. CONDITIONS

Condition 20651

S-5, Hot Water Boiler
S-55, Hot Water Boiler, Digester Gas Fired
S-37, Multi-Fuel Cogeneration Engine #1
S-38, Multi-Fuel Cogeneration Engine #2
S-39, Multi-Fuel Cogeneration Engine #3

1. Boilers S-5 and S-55 shall be fired only on sewage sludge digester gas. (Basis: ~~Regulation 9-7-304~~ Cumulative Increase)

2. ~~EBMUD shall not operate~~ S-5 and/or S-55 hot water boilers shall not be operated ~~simultaneously with~~ when more than two of the three cogeneration engines S-37, S-38, or S-39 are operating. (Basis: Cumulative Increase)

3. Boiler Gross Heat Input ~~Gross thermal input to S-5 shall not exceed 9.87 million Btu/hr~~

a. S-5: Not to exceed 9.87 million Btu/hr. (Basis: Regulation 9-7-304)
b. S-55: Not to exceed 20.41 million Btu/hr (Basis: Cumulative Increase)

4. The owner or operator of the hot water boiler S-5 shall perform an inspection and tune up of the combustion section at least annually to ensure the proper air-to-fuel ratio is being used ~~which~~ to maximize~~s~~ efficiency and minimize~~s~~ the production of nitrogen oxides and carbon monoxide, following the procedure of Regulation 9, Rule 7, Section 604 (CARB BARCT tune up procedure). The time interval between boiler tune-ups shall not exceed 12 months. (Basis: Regulation 9-7-304)

   In order to demonstrate compliance with this part, the owner or operator of ~~the~~ hot water boiler S-5 shall document each tune up as follows: (Basis: Regulation 9-7-503.1)

   a. Time and date of the tune up and the identify of the qualified technician.
   b. Firing rate (MM Btu/hr), stack gas flow rate (scfm), and temperature (degrees F).
   c. Stack gas oxygen concentrations (ppm dry) before and after any adjustments are made.

5. ~~In order to demonstrate compliance with this part, the owner or operator of the hot water boiler S-5 shall document each turn up as follows: (Basis: Regulation 9-7-503.1)~~

   ~~a. Time and date of the tune up and the identify of the qualified technician.~~
   ~~b. Firing rate (MM Btu/hr), stack gas flow rate (scfm), and temperature (degrees F).~~
   c. ~~Stack gas oxygen concentrations (ppm dry) before and after any adjustments are made.~~

   Nox and CO emissions from boiler S-55 shall not exceed 30 and 50 ppm, respectively, at 3% oxygen, dry basis. (Basis: BACT)

~~Conditions~~Parts Specific to ~~Cogeneration~~ Engine S-38 (parts 6 through 9)

6. NOx emissions, calculated as NO2, shall not exceed 1.25 g/hp-hr, except during transient periods or in the event of catastrophic damage to the natural gas fuel supply, when the engine may be fired solely on diesel fuel.

   If a source test demonstrates nitrogen oxide emissions greater than 1.0 g/hp-hr, but less than 1.25 g/hp-hr, the owner or operator shall either conduct a second source test to verify the results of the first test, or shut down the engine for necessary maintenance. In the event the retest conforms an emission level greater than 1.0 g/hp-hr, the owner or operator shall immediately shut down the engine for maintenance. (Basis: BACT)

7. [no change]

8. [no change

9. [no change]

~~Conditions~~Parts Specific to Engines S-37 and S-39 (parts 10 through 11)

10. ~~The total nitrogen oxide~~ NOx emissions from each of the engines S-37 and S-39 shall not exceed 140 ppmvd @ 15% oxygen. (Basis: Regulation 9-8-302)

11. ~~The total carbon monoxide~~ CO emissions from each of the engines S-37 and S-39 shall not exceed 2000 ppmvd @ 15% oxygen. (Basis: Regulation 9-8-302)

~~Conditions~~ Parts Specific to Engines S-37, S-38, and S-39 (parts 12 through 15)

12. [no change]

13. [no change]

14. [no change]

15. [no change]

16. Total sulfur content of the gaseous feed to engine S-38 and boiler S-55 shall not exceed 340 ppmv @ 0% O2. (Basis: BACT)

    The owner or operator ~~Permit Holder~~ shall demonstrate compliance with the above limit by weekly sampling and testing of either the digester gas or gaseous feed to the engines and boiler S-55 (when operational), according to the following methodologies:

    a. [no change]
    b. Portable Instrument Method: A Draeger PAC-III (or equivalent) portable meter with a hydrogen sulfide sensor capable of measuring over 800 ppmv hydrogen sulfide. In the event that sulfide levels exceed 800 ppmv, the ~~Permit Holder~~ owner or operator shall commence to perform a source test using method c, as follows.
    c. Chromatographic Method: The ~~Permit Holder~~ owner or operator may sample and test for sulfides according to BAAQMD Lab Method 44A (Manual of Procedures, Volume III), or by ASTM Method 5504, or by any other equivalent method, approved in advance by the APCO.

    An application for a change of condition to allow an alternative method for sampling and testing of the fuel gas for sulfides shall be handled as a minor revision to the Title V Permit.

17. Deleted 10-2006 ~~The diesel fuel sulfur content shall not exceed 0.05% by weight. (Basis: Cumulative Increase, BACT)~~

    ~~To demonstrate compliance with the above sulfur limit, the Permit Holder shall maintain a written statement, as applicable, received from the diesel fuel supplier(s) certifying that the diesel fuel purchased from the supplier is less than 0.05% by weight or meets the sulfur limitations for CARB Vehicular Diesel Fuel as specified in 13 CCR Section 2281, California Code of Regulations. (Basis: Regulations 2-6-409.2, 2-6-501)~~

18. To determine compliance with the above conditions, the ~~Permit Holder~~ owner or operator shall maintain the following records and provide all of the data necessary to evaluate compliance with the above conditions, including the following information:

    a. Daily records of the hours of operation of engines S-37, S-38, S-39 and boilers S-5 and S-55.
    b. Total fuel consumption (digester gas, natural gas, and/or diesel ~~consumption~~ for the engines and digester gas for the boilers) for the engines and boilers S-5 and S-55,
    c. Records of hours of operation of the engines during transient periods with an explanation of the nature of the transient period.

19. The owner or operator shall ensure that an annual performance test is conducted on each engine and on boiler S-55, in accordance with the District test procedures to demonstrate compliance with the NOx, CO, POC, and particulate limits, where applicable, as required by parts ~~6~~5 –11, respectively. The owner or operator may submit an alternative monitoring plan to the District for approval. If the alternative monitoring plan is approved, the plan shall supersede the annual source test requirement. Approvals shall be processed using the permit modification procedure contained in Regulation 2, Rule 6. (Basis: Regulation 2-6-409.2)

20. [no change]

Condition 18006

S-170, Sludge Handling; 3 GBTs, 4 WAS Thickening Centrifuges, Abated by A-7 or A-8 Atomized Mist Scrubber.

1. Throughput

   ~~Throughput~~. EBMUD shall monitor and record on a daily basis the activated sewage sludge throughput ~~through~~ of S-170. (Basis: Cumulative Increase)

2. Abatement

   All vapor emissions from S-170 shall be routed under negative pressure to A-7 or A-8 Atomized Mist Scrubber. (Basis: Cumulative Increase)

3. A-7 and A-8 Atomized Mist Scrubbers shall be properly maintained and kept in good operating condition at all times. (Basis: Regulation 2-1-403)

4. Records

   To demonstrate compliance with the above conditions, EBMUD shall keep and maintain the following records in a District-approved log: (Basis: Regulation 2-6-409.2)

   a. Records of all inspections and all maintenance work on A-7 and A-8. Records of each inspection shall consist of a log containing the date of inspection and the initials of the personnel that inspected A-7 and/or A-8.
   b. Records noting the occurrence and duration of any malfunction of A-7 or A-8, including the date, the suspected cause of the malfunction, and any action taken to restore normal operation.
   c. All records shall be retained on-site for 5 years from the date of entry, and made available for inspection by District staff upon request. These recordkeeping requirements shall not replace the recordkeeping requirements contained in any applicable District Regulations.

9. RECOMMENDATIONS

Issue an Authority to Construct for source S-55 subject to Condition # 20651, as modified in Section 8, above.. Modify Condition 18006 according to the recommended language shown in Section 8, above.

by: ________________________

Randy E. Frazier, P.E.
15-March 2007

ENGINEERING EVALUATION REPORT

PLANT NAME	East Bay Municipal Utility District
APPLICATION NUMBER	17399
PLANT NUMBER	A0591
DATE	14 May 2008

TITLE: INSTALLATION OF TWO NEW SLUDGE DEWATERING CENTRIFUGES TO AUGMENT THE FOUR EXISTING CENTRIFUGES

1. BACKGROUND

EBMUD is seeking to improve the efficiency of the existing dewatering process by adding 2 additional sludge dewatering centrifuges to existing source S-170. These centrifuges will be added to source S-170, and the revised source description of S-170 will be:

S-170 Sludge Handling, 3 WAS GBTs, 6 Dewatering Centrifuges

These additional centrifuges are required to improve the efficiency of the solids handling processes, which includes solids from normal wastewater treatment liquids as well as the EBMUD resource recovery programs.

There is no expectation of any significant incremental emissions from these additional centrifuges. In order to maintain good odor control from these processes, the air in the general area of the centrifuges will be educted away from the process area and vented to the existing atomized mist scrubbers A-7 and A-8.

The purpose of the WAS GBTs and dewatering centrifuges is to thicken waste activated sludge prior to its addition to the anaerobic sludge digestion process (S180). WAS is sludge that has settled in the bottom of the secondary clarifiers. The thickening process produces thickened sludge that is sent to the digesters and liquid that is returned to the secondary treatment process. Sludge that is too watery is problematic for the digesters, while liquid with excessive solids can cause settling problems in the secondary clarifiers – leading to poor plant effluent quality and the potential for NPDES permit violations. The goal of the thickening process is to make the solids concentration of the sludge as high as possible and the solids concentration of the liquid as low as possible. This project will assist in attainment of these goals.

2. EMISSION CALCULATIONS

There is no increase in emissions. There is no increase in plant operational capacity as a result of this project. Hence there are no emissions associated with this project.

Additionally, all liquid process emissions are charged against S-100, a virtual source representing the overall liquid processes of the facility. Since there is no increase in throughput at S-100, there is no increase in emissions.

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3. PERMIT REQUIREMENTS/DISCUSSION OF EXEMPTION

There are no exemptions that apply to this source.

4. APPLICABLE REQUIREMENTS

A. Toxic Evaluation:

There is no increase in toxic emissions therefore no toxic risk evaluation is required.

B. Regulation 1 – General Provisions and Definitions

§1-301: Prohibits discharging emissions in quantities that cause injury, detriment, nuisance, or annoyance.

S-170: The additional centrifuges are expected to improve the efficiency of liquid/solids separation, resulting in a dryer biosolids cake. There is no reason to expect any public impact as the process has always been abated by A-7 and A-8 atomized mist scrubbers. A-7 and A-8 use an aqueous caustic/sodium hypochlorite mixture to remove any odorous compounds that may be present. Based on previous source testing for this abatement device, efficiencies ranged from 50 to 99%. For the purposes of this analysis, we will use an average abatement efficiency of 75%. Hence the abatement factor will be 0.25.

C. Permits – General Requirements, Regulation 2 Rule 1

There is no increase in any toxic emissions as a result of this project. There are no significant toxic emissions from these operations and the source is not located with 1000 feet of the nearest school, and is therefore not subject to the public notification requirements of 2-1-412.

D. Permits – New Source Review, Regulation 2 Rule 2 (dated 10/7/98)

1. **BACT:** A BACT review is required for any new or modified source *which results in an emission from a new source or an increase in emissions from a modified source of precursor organic compounds (POC), non-precursor organic compounds (NPOC), nitrogen oxides (NOx), sulfur dioxide (SO2), PM10 or carbon monoxide (CO), in excess of 10.0 pounds per highest day.*

   There is no emissions increase as a result of this project, therefore BACT is not required.

2. **Offset Requirements:** §2-2-303: Offsets are not required for this application.

3. **Prevention of Significant Deterioration:** §2-2-304: This facility is not a new major facility, nor is this application for a major modification. PSD requirements do not apply to this permit application.

E. Regulation 3 – Fees

East Bay Municipal Utility District has complied with this requirement – by paying their application fees for this project. It is further expected that EBMUD will continue to comply with permit fee requirements.

F. Particulate Matter and Visible Emissions, Regulation 6

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There are no particulate emissions from S-170, hence Regulation 6 is not applicable

G. NSPS/NESHAPS

There is no New Source Performance Standard or National Emission Standard for Hazardous Air Pollutants that applies to this source.

H. CEQA

This project is considered to be ministerial under the District's CEQA Regulation 2-1-311. The engineering review for this project requires only the application of standard permit conditions and standard emissions factors and therefore is not discretionary as defined by CEQA. Chapter 19 of the Permit Handbook deals with POTWs.

5. CONDITIONS

Recommend the following revised permit conditions for S-170

COND# 18006 -------------------------------------

S -170, Sludge Handling; 3 W.A.S. GBTs, 6 Dewatering Centrifuges, Abated by A-7 or A-8 Atomized Mist Scrubber

1. Throughput

   EBMUD shall monitor and record on a daily basis the activated sewage sludge throughput through S-170. (Basis: Cumulative Increase)

2. Abatement

   All vapor emissions from S-170 shall be routed under negative pressure to A-7 or A-8 Atomized Mist Scrubber. (Basis: Cumulative Increase)

3. A-7 and A-8 Atomized Mist Scrubbers shall be properly maintained and kept in good operating condition at all times. (Basis: Regulation 2-1-403)

4. Records

   To demonstrate compliance with the above parts, EBMUD shall keep and maintain the following records in a District approved log: (Basis: Regulation 2-6-409.2)

   a. Records or all inspections and all maintenance work on A-7 and A-8. Records of each inspection shall consist of a log containing the date of inspection and the initials of the personnel that inspected A-7 and/or A-8.

   b. Records noting the occurrence and duration of any

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malfunction of A-7 or A-8, including the date, the suspected cause of the malfunction, and any action taken to restore normal operation.

c. All records shall be retained on-site for 5 years from the date of entry, and made available for inspection by District staff upon request. These recordkeeping requirements shall not replace the recordkeeping requirements contained in any applicable District Regulations.

6. RECOMMENDATIONS

Recommend issuance of a conditional Authority to Construct and Permit to Operate for:

S-170 **Sludge Handling, 3 WAS GBTs, 6 Dewatering Centrifuges**

Condition # 18006 (S-170)

by: REF
Randy E. Frazier, P.E.

ENGINEERING EVALUATION REPORT

PLANT NAME	East Bay Municipal Utility District
APPLICATION NUMBER	17749
PLANT NUMBER	A0591
DATE	21 July 2008

1. BACKGROUND

This application is for the installation of two 4.5 Mw ultra-lean premix, recuperative digester gas fired cogeneration turbines at the main wastewater plant for the East Bay Municipal Utility District (EBMUD) in Oakland. Specifically, these gas turbines are identified as:

S-56 Digester Gas Turbine #1, Solar Mercury 50, 4.5 MW, 44.5 MM Btu/hr HHV
S-57 Digester Gas Turbine #2, Solar Mercury 50, 4.5 MW, 44.5 MM Btu/hr HHV

There will be no duct burners downstream of these turbines, though heat will be recovered both for combustor air preheat (recuperation) and to generate process hot water for the digesters. EBMUD plans to operate the turbines for base load at the facility and to use the cogeneration engines secondarily to handle the balance of digester gas production. Currently, excess digester gas is flared at abatement devices A-190, A-191, A-192, and A-193.

The proposed gas turbines are part of the new EBMUD Power Generation Station (PGS) Renewal Energy Expansion Project. This project is being installed to efficiently produce electricity from the incremental digester gas produced as a result of EBMUD's resource recovery program. This resource recovery program has been in place and growing since about 2004. A key element of this program has been the introduction of about 400 gallons/day of liquid waste and 1.8 ton of semi-solid organic waste into the anaerobic digester feed streams. These quantities are expected to increase over time and include winery wastes, domestic waste, portable toilet and septic tank waste, animal processing waste, rendering facility waste, municipal water and wastewater sludge, groundwater, stormwater and other miscellaneous organic solid waste. Presently, the digester gas produced from these processes is burned in the three 2-Mwe cogeneration engines or in the 20.4 MM Btu/hr hot water boiler, with the balance flared at the existing digester gas flares A-190, 191, 192, 193.

The current permit allows the simultaneous operation of 2 cogeneration engines + the boiler or 3 cogen engines (without the boiler) for up to 25,316 combined engine hours/year. Simultaneous operation of all three engines requires approximately 2,010 dscfm digester gas based on a digester gas higher heating value (HHV) of 646 BTU/scf (LHV = 582 Btu/dscf) and an engine efficiency of 30%.

With the installation of these gas turbines, EBMUD will have a total electrical generation capacity from their resource recovery section of 15 MWe (9 MW from the turbines, 6 MW from the engines).

The project will be permitted based on the turbines firing incremental digester gas produced as a result of the treatment of the above digester feed materials. Each turbine is rated at 40.77 MM Btu/hr LHV heat input (44.5 MM Btu/hr HHV). This equates to approximately 1,200 dscfm DG per turbine or 2,400 dscf incremental digester gas total. The current permitted combustion capacity (not including the flares) is approximately 2,010 scfm (670 scfm/engine).

<u>About the Solar Mercury 50 Turbines</u>: The Mercury 50 turbine was developed as a result of an Advanced Turbine Systems (ATS) program in the 1990s to develop low emitting, economical gas turbine technology. The Mercury 50 employs a 10-stage compressor with an ultra lean-premix (ULP) combustion burner design. The Mercury 50 also employs a heat recovery section called a primary surface recuperator (PSR) which increases the thermal efficiency by preheating the compressed combustor inlet air. According to the literature, the Mercury 50 appears to be the cleanest combustion technology available for digester gas combustion. Our estimates indicate a comparable lean burn internal combustion engine producing 4.5 MW would result in more than 3 times the NOx and CO emissions of the Mercury 50.

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Digester Gas Treatment Processes: In order to improve turbine reliability and reduce operating costs, EBMUD also plans to purchase and install a state of the art digester gas fuel conditioning system (DGFCS). The purpose of this equipment is to reduce the moisture and siloxane content of the digester gas prior to combustion in the gas turbine. Currently, EBMUD doses ferric chloride into the wastewater entering the plant to control H_2S in the digester gas to 100 ppm (enabling the plant to stay well below the IC engines limit of 340 ppm fuel H_2S content). The DGFCS will employ refrigeration and filtration to condense and coalesce water and a specialized carbon adsorption bed to remove siloxanes—thereby greatly improving the digester gas quality prior to firing in the turbines. This system will be designed to process from 1,200 to 6,000 scfm of digester gas reducing total siloxanes to below the detection level of GCMS (0.3 mg/cu m).

Engine S-37, S-38, and S-39 Thermal Throughput Correction: In addition to the aforementioned project scope, we will be correcting the throughput limits for the cogeneration engines S-37, S-38, and S-39. This change is not an emission increase as the capacity is not changing –the engines have been and will continue to be 2 MW (electric generation) engines. The throughput limit is based on heat input, and this limit will be corrected to 1) reflect actual fuel input required to produce 2 MW per engine and 2) to address apparent permit condition enforceability issues. It should be noted that the current throughput limits for these engines, assume approximately 38% thermal/mechanical efficiency. As per data seen with other engines in this size range, the corrected maximum heat input rate will be established at 25 MM Btu/hr, HHV.

2. EMISSION CALCULATIONS

Criteria Emissions

Emissions will be calculated by establishing the exhaust emission levels (based on BACT, where applicable) in conjunction with the flue gas rate. Following are the proposed emission levels as compared with current published BACT.

Table 1 Criteria Pollutant Emission Factors

Pollutant	Proposed Factors	Landfill Gas Turbine BAAQMD BACT[1]	Recommended BACT, DG Fired Turbine	AP-42 (Comparison)
NOx	23 ppm @ 15% O_2	25	**25 ppm @ 15% O_2**	
CO	100 ppm @ 15% O_2	200	**130 ppm @ 15% O_2**	
NMHC	0.007 lb/MM Btu 5 ppm @ 15% O_2	ns	n/a	0.002.1 lb/MM Btu
PM_{10}	0.0098 lb/MM Btu	LFG pretreatment	n/a	0.0066 lb/MM Btu
SO_2	-	150 ppmv	**340 ppm DG H_2S**	

[1]BACT: BACT1 is typically represented by downstream catalytic controls. Due to the level of contaminants in digester gas, currently there is no technologically feasible and cost effective technology identified as BACT1. BAAQMD BACT listed is achieved in practice and therefore BACT2.

Flue gas calculation basis:
1 mole Digester Gas (DG)
Turbine Basis: One turbine
Assume: DG Contains 64% methane, 36% CO_2
Digester Gas Feed rate; 1,200 dscfm DG per turbine
Turbine exhaust temperature: 330 F (790 R)
Operating Hour/Yr: 8760 total
Startup/Shutdown Time: 3 hours (12 cycles/yr)
Net steady state operating time: 8757 hr/yr
Heat Input: 41 MM Btu/hr-turbine LHV (44.5 MM Btu/hr HHV)

Combustion Reaction (main): $CH_4 + 2O_2 = 2H_2O + CO_2$

1) Flue gas Flowrate (per turbine):

CH_4 in = 0.64 mole
Flue Gas: CO_2 in, DG = 0.36 mole
CO_2 out, rxn = 0.64 mole

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O_2 out = 0 mole (stiochiometric)
N_2 in = N_2 out = (3.76)(2)(0.64) = 4.813 mole
H_2O out = 2(0.64) = 1.28 mole

Dry Basis: FG = 0.36 mole CO_2 in + 0.64 mole CO_2 produced + 4.813 mole N_2 = 5.813 mole FG(dry)/mole DG = 5.813 dscf FG/dscf DG

Wet Basis: FG = 0.36 + 0.64 + 4.813 + 1.28 = 7.1 mole FG/mole DG
= 7.1 scf FG/scf DG

Correction to 15% O_2 in exhaust gas: Factor = (20.95 – 0)/(20.95 – 15) = 3.521 scf FG at 15% O_2/scf FG at 0% O_2

Flue Gas @ 15% oxygen, dry = [5.813 scf FG (dry)/scf DG][3.521] = 20.467 dscf FG/dscf DG

Flue Gas @ 15% oxygen, wet = (7.1)(3.521) = 24.999 scf FG/dscf DG

FG, dry = [20.467 dscf FG/dscf DG][1,200 dscf DG] = **24,560 dscf FG/min-turbine**
FG, wet = (24.999)(1,200) = 29,999 scf FG/min-turbine

Actual FG Flow, wet, from heat exchanger = (29,999 scf/min)[(460+330)/(460+70)] = 44,715 acfm @330 F

Actual FG Flow, wet, from turbine outlet = (29,999)[(460+724)/(460+70)] = 67,017 acfm @ 724 F

2) Startup/Shutdown Emissions: EBMUD plans to base load these digester gas turbines, therefore the number of startups and shutdowns will be minimized. As a conservative estimate, we assume 1 startup and shutdown per month or 12 cycles per engine per year. Solar estimates the startup cycle for a Mercury 50 turbine to be less than 10 minutes for a hot, warm, or cold simple cycle turbine. Shutdown requires about 5 minutes. Startup emissions are estimated by Solar to be 0.8 lb NOx and 75 lb CO. Shutdown emissions are estimated to be 0.4 lb NOx, and 31.1. lb CO. Hence 1 startup and shutdown cycle is estimated to produce 1.2 lb NOx and 106.1 lb CO. Total time required is (15 min/cycle time)(12 cycles/yr) = 180 minutes (3 hours).
NOx emissions = (12 cycles)((1.2 lb NOx/cycle) = 14.4 lb NOx per engine-year
CO emissions = (12 cycles)(106.1 lb/cycle) = 1,273 lb CO per engine-year

3) NOx, CO, and POC Emission Estimates:

NOx: 23 ppm @ 15% oxygen in FG, dry
CO: 100 ppm @ 15% oxygen in FG, dry
VOC (assume = POC): 5 ppm as methane @ 15% oxygen in FG, dry

NOx = [(23 scf NO2/1E6 dscf FG)(24,560 dscf FG/min)(60 min/hr)(8757 hr/yr)(lb-mole NO_2/379 scf NO_2)(46.01 lb NO_2/lb-mole NO_2) + 14.4 lb NOx/turbine-yr](ton/2,000 lb) = 18.02 tpy NO_2 per turbine (98.7 lb/day or 4.11 lb/hr)

CO = [(100/1E6)(24,560)(60)(8757)(1/379)(28.01) + 1,273 lb CO/engine-year](1/2,000) = 48.3 tpy/turbine (265 lb/day or 11.0 lb/hr)

POC = (5/1E6)(24,560)(60)(8760)(1/379)(16.1)(1/2,000) = 1.4 tpy-turbine (7.5 lb/day or 0.3 lb/hr)

4) SO_2 Emission Estimate: The cogeneration engines are conditioned to 340 ppm maximum feed sulfur content. This feed is a combination of digester gas with a diesel pilot fuel and the balance natural gas. As per the calculation in AN 3926 (Title V Statement of Basis), 340 ppm fuel sulfur produces approximately 0.3 g SO2/bhp-hr that was deemed BACT for SO_2 emissions.

Reg 9-1-301 limits the exhaust gas maximum sulfur concentration to 300 ppm dry. This equates to approximately 1,700 ppm sulfur level in the digester gas (assuming 100% digester gas feed). EBMUD never approaches this level as they add ferric chloride to control H_2S level in the digester gas to maintain less than 340 ppm. Since the engines could (and often are) fired on mainly digester gas (with a small

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slipstream of diesel), the 340 ppm fuel limit is effectively the digester gas limit. Hence SO_2 emissions will be based on a maximum digester gas H_2S concentration of 340 ppm.

SO_2, per turbine = (340 scf/1E6 scf DG)(1,200 dscf DG/min)(lb-mole H_2S/379 dscf H_2S)(1 mole SO_2/mole H_2S)(64.05 lb SO_2/lb-mole SO_2)(60 min/hr)(8760 hr/yr)(1/2,000) =
18.1 tpy SO_2/yr-turbine (99.3 lb/day-turbine or 4.1 lb/hr-turbine)

5) PM Emission Estimate: The applicant supplied a total PM emission factor of 0.03 lb/MM Btu fuel input which includes all condensables including water in the factor.
Total PM = (0.03 lb/MM Btu)(44.5 MM Btu/hr)(24 hr/day)(365 day/yr) =
5.8 tpy-turbine

Based on AP-42, the water typically accounts for about 70% of the particulate on a weight basis. Therefore, non-condensables = (0.3)(5.8 tpy-turbine) = 1.7 tpy-turbine (9.5 lb/day or 0.4 lb/hr)
Factor = (0.4 lb/hr)/(44.5 MM Btu/hr-turbine) = 0.0090 lb/MM Btu

Total project criteria pollutant emissions are presented below in Table 2.

TABLE 2 Criteria Pollutant Emissions Summary

POLLUTANT	Annual Emissions (tpy-turbine)	Daily Emissions (lb/day-turbine)	Project Emissions, tpy (2 turbine basis)
NOx	18.02	98.7	36.04
CO	48.3	265	96.6
POC	1.4	7.5	2.8
SO2	18.1	99.3	36.2
PM	1.7	9.5	3.4

Toxic Emissions:
Toxic emission factors were developed from speciated source tests of the #2 digester fired turbine at the joint water pollution control plant total energy facility in Los Angeles, test date August 10, 2001. Average concentrations of the detected compounds are listed below. The source test protocol required an average of 3 sampling events. Where the sampling and testing results showed non-detects for all three samples, the compound was determined to be non-detect—and therefore not included in the risk evaluation. Detailed calculation data is included on the Toxic Emissions spreadsheet, included in this evaluation.

TABLE 3 Toxic Emissions

POLLUTANT	Concentration[1] (ppm @ 15% O_2)	Annual Emissions (lb/yr-turbine)	Project Emissions (lb/yr, 2 turbine basis)
Formaldehyde	0.053	51.7	103.4
Acetaldehyde	0.007	10.0	20.0
Dichloromethane	0.0273	84.2	168.4
Benzene	0.00102	2.6	5.2
Toluene	0.0012	3.6	7.2
Xylene	0.00103	3.6	7.2
Vinyl Chloride	Tested, not detected	-	-
Ethyl Chloride	Tested, not detected	-	-
1,2-Dichloroethane	Tested, not detected	-	-
1,1,1-Trichloroethane	Tested, not detected	-	-
Carbon Tetrachloride	Tested, not detected	-	-
Trichloroethene	Tested, not detected	-	-
1,2-Dibromoethane	Tested, not detected	-	-
Perchloroethene	Tested, not detected	-	-
Chlorobenzene	Tested, not detected	-	-
Styrene	Tested, not detected	-	-
Dichlorobenzenes	Tested, not detected	-	-
1,3-Butadiene	Tested, not detected	-	-
1,4-Dioxane	Tested, not detected	-	-

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PAH	Ng/dscm[1] @ 15% O_2	Annual Emissions (lb/yr-turbine)	MAX EMISSIONS (Lb/yr- 2 turbine basis)
Naphthlene	241	0.19	0.38
Benzo(b)fluoranthene	0.71	5.57E-04	1.11E-03
Chrysene	1.64	1.29E-03	2.58E-3

[1] County Sanitation Districts of LA County, Turbine #2 Testing, August 10, 2001

3. **DETERMINATION OF COMPLIANCE**

A. **Regulation 1 – General Provisions and Definitions** (7/19/2006)
§1-301: Prohibits discharging emissions in quantities that cause injury, detriment, nuisance, or annoyance. The toxic evaluation addresses these issues. None

B. **Permits – General Requirements, Regulation 2 Rule 1** (7/19/2006)
The source is not located within 1000 feet of the nearest school, and is therefore not subject to the public notification requirements of 2-1-412. There are no exemptions that apply to this application.

C. **Permits – New Source Review, Regulation 2 Rule 2** (6/15/2005)

1. **BACT:** On a per turbine basis, emissions of NOx, CO, and SO_2 are greater than 10 lb/day, therefore BACT is required for these pollutants. When this application was submitted, there was no specific BAAQMD BACT determination for digester gas fired turbines. There is, however, a BACT determination for landfill gas fired turbines, published 6-17-99, and this information will be considered in addition to the recommendations published in the ARB Document entitled *Guidance for the Permitting of Electrical Generation Technologies,* September 28, 2001, and other pre-construction permit conditions. The BACT discussion for each of the above pollutants follows:

General Discussion-BACT1: BACT1 has been defined as being the lowest emission level or pollution technology that has been shown to be technologically feasible and cost effective. Often BACT1 involves after exhaust emission controls, typically catalytically based. Recent cost effectiveness evaluations in the South Coast as well as practical experience show that even with digester gas that has been highly treated to remove contaminants there remains a high probably that such catalytic systems will be unable to perform reliably in such service-due to masking of the catalyst by siloxane deposits. Hence BACT1 is not determined for digester gas applications.

NOx: The currently published value for BACT that is achieved in practice (BACT2) for a landfill gas turbine is 25 ppmv corrected to 15% oxygen. This value is consistent with the published BACT guidelines for the SCAQMD and the source test data we have seen indicates 25 ppm is achieved in practice. The ARB Guidance Document also recommends 25 ppm @ 15% oxygen, but notes this is achieved by water injection (typically on turbines that are approximately 10 MW in size). The use of water injection for the Mercury 50 4.5 MW turbine burning digester gas is not recommended by Solar, due to the potential for flame instability problems with ultra-lean premix dry fuel injection turbine technology.

In the present case, the applicant has proposed 23 ppm @ 15% oxygen controlled by the Mercury 50 recuperator design coupled with the ultra-lean premix dry fuel injection system (a type of dry low-NOx burner technology). Discussions with Solar Turbines representative (D. Anthony Pocengal) indicates there is a significant body of data supporting 23 ppm NOx at 15% oxygen as achieved in practice for this application. Based on the certifications by Solar and their willingness to guarantee the emissions, we recommend establishing 23 ppm corrected to 15% oxygen as the permit limit for EBMUD. At present, we recommend establishing the achieved

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in practice (BACT2) level for NOx from digester gas fired turbines less than 5 MW as 25 ppmv, dry, corrected to 15% oxygen.

CO: BAAQMD published BACT2 for CO for landfill gas fired turbines is 200 ppmv corrected to 15% oxygen. An October 2000 SCAQMD BACT determination recommended 130 ppmv, dry, @ 15% oxygen for a pair of landfill gas-fired Mercury 50 turbines. A more recent determination for a combined-cycle water injection 9.9 MW diffusion flame burner design turbine feeding digester gas supplemented by 5% natural gas specified 60 ppm @ 15% oxygen. The ARB guidance document does not make a recommendation for CO or for any other criteria pollutant (other than NOx) for waste gas fired turbines.

EBMUD has proposed 100 ppm @ 15% oxygen, which represents the lowest CO level that Solar is willing to guarantee. This level is proposed by the applicant to minimize the CO cumulative increase. Similar to NOx, we accept this proposal for the purpose of establishing a permit condition. We recommend establishing BACT2 (achieved in practice) for CO from digester gas fired turbines less than 5 MW as 130 ppm corrected to 15% oxygen. Although not demonstrated in commercial application, the Mercury 50 is expected to achieve 23 ppm NOx and 100 ppm CO simultaneously due to the use of the SoLoNox technology to reduce the combustor primary zone temperature while minimizing CO to CO_2 quench by augmented backside cooling (ABC) technology and thermal barrier coatings (TBC).

Feasibility of 60 ppm CO: The following discussion is presented since SCAQMD recently conditioned a digester gas fired turbine to 60 ppm @ 15% O_2. Short of adding natural gas (to improve combustion stability) to the feed slate, the only other option for achieving 60 ppm CO would be to apply the use of catalytic oxidation. Due to the presence of H_2S and other impurities in digester gas, the use of a catalyst with 100% digester gas fuel would require extensive additional fuel conditioning—well beyond what is proposed in this application. EBMUD has estimated the cost of such a system to be approximately $3.5 MM providing a cost effectiveness of roughly $57,000/ton CO removed. The technological feasibility is questionable and at $57,000/ton this is not a cost effective option, therefore we do not recommend 60 ppm for BACT1. BACT1 for CO is not determined.

SO_2: Emissions of SO_2 are directly proportional to the content of sulfur compounds in the fuel-in this case digester gas. In the case of landfill gas fired turbine, BACT2 has been established as 150 ppmv as H_2S, with fuel selection listed as the typical technology. This engineering evaluation is not tasked with re-evaluating the landfill gas fired turbine BACT determination. The present application also will not use the landfill gas BACT2 recommendation since landfill gas applications and digester gas applications, though similar in some instances, often have significantly different emission characteristics.

For the purpose of developing a BACT recommendation for digester gas for a landfill gas the SO_2 emission level accepted as achieved in practice (BACT2) for lean burn digester gas engines is 0.3 g/bhp-hr. This is roughly equivalent to 340 ppm H_2S which may be controlled by appropriate dosing of ferric chloride into the wastewater entering the plant. This limit will be placed on the digester gas fuel to the turbines. This limit has been achieved by EBMUD since this is the fuel sulfur limit that was established in AN 3694 (23 January 2003). Therefore we will recommend that BACT2 for SO_2 is 340 ppm, as H_2S in digester gas fuel to the turbine. This limit will be written into the units that produce digester gas – the anaerobic digesters.

2. **Offset Requirements:** §2-2-302: Current NOx and POC emissions at EBMUD are both greater than 35 tpy, therefore as required by Regulation 2-2-302, emission increases for these pollutants must be offset at a ratio of 1.15:1. EBMUD is not a major facility for either PM_{10} or SO_2, therefore offsets are not required for these pollutants.

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Pre-project Cumulative Increase:	NOx:	0 tpy
	POC:	0.145 tpy

NOx offsets required:	[(18.02)(2)](1.15) = **41.5 tpy total NOx**
POC offsets required:	[(1.4)(2) + 0.145](1.15) = **3.4 tpy total POC**

This project is classified as a resource recovery project. Resource recovery projects are not required to provide offsets provided that certain criteria is satisfied. These requirements are specified in §42314 of the California Health & Safety Code and will be fully addressed in an addendum to this engineering evaluation.

3. **Prevention of Significant Deterioration:** According to §2-2-304.2 of BAAQMD Regulation 2 a PSD review is required when NOx emission increases exceed 40 tpy where the facility is a major source for NOx. Since wastewater treatment plants are not in any of the 28 major source categories, the criteria for being a major facility for NOX is 250 tpy. Total facility NOx emissions are approximately 160 tpy, therefore EBMUD is not a major facility for NOx. Also, since the NOx emission increases from the project are 36 tpy (PSD threshold is 100 tpy), a PSD review for NOx is not required.

In the matter of CO, according to §2-2-305.2 of BAAQMD Regulation 2 a PSD review is required when CO emission increases exceed 100 tpy where the facility is a major source for CO. Although current actual CO emissions are approximately 170 tpy, the facility is permitted for CO emissions greater than 250 tpy, therefore EBMUD is currently a major facility for CO. The proposed CO emissions increases do not exceed 100 tpy, therefore a PSD review is not triggered for CO.

PM_{10} emission increases are 3.2 tpy, well below the PSD trigger of 15 tpy, therefore a PSD review is not triggered for PM_{10}.

D. Regulation 3 – Fees

East Bay Municipal Utility District has complied with the permit fee requirements for this application. Fees for this project amounted to $8,964 (Invoice #1XQ07). These fees were paid on 4-11-08.

E. Permits – Toxic Risk Evaluation, Regulation 2 Rule 5 (6/15/2005)

The following toxic evaluation is based on the turbines operating on 100% digester gas for 8,760 hr/yr (base-load operation).

Toxic emission factors for digester gas combustion in the turbines are taken from Table 3, which are based on actual source tests of a similar Solar turbine firing digester gas in the Los Angeles basin. The risk screening analysis is triggered by the emissions of formaldehyde.

Our toxic analysis used the following assumptions in the development of the risk estimates for this boiler:

Meteorological Data: OST met data
Exhaust flow (per stack): 71,479 acfm @ 6' stack diameter (330 F)
Stack height: 62' (building ht = 11')
Operation: 8760 hr/yr
Building Parameters/Footprint: See facility plan view
Nearest residence: 1,200 feet
Distance to Property Line: ~158 ft
Land Use: Urban (worst case)

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There are no schools located within 1000 feet of the source. The toxic risk analysis was performed using BEEST (ISCST) software in conjunction with the OST met data. The ambient concentrations obtained from the BEEST modeling analysis were based on a unit emission rate from the source..

Table 4 Maximum Chi/Q Values (µg/cu m per g/s)

Averaging Period/ Receptor Location	Urban Dispersion Chi/Q (	Rural Dispersion
Annual Average		
MEI-Fenceline	**0.82448**	0.14468
MEI Residential	**0.65741**	0.22974
MEI Industrial	**0.73317**	0.21946
Highest 1-Hr Average		
MEI-Fenceline	**19.82**	13.66
MEI Residential	**12.70**	5.49
MEI Industrial	**12.70**	5.45

Table 5 Maximum Health Risk Values

Health Risk	Residential Receptor	Workplace Receptor
Maximum Cancer Risk	5 E –9	1 E –9
Maximum Chronic Non-Cancer Hazard Index	2 E –4	5 E-5
Maximum Acute Non-Cancer Hazard Index	1 E -4	2 E -4

<u>Carcinogenic Risk Evaluation</u>

Table 4 shows that the maximum exposures were higher for urban dispersion than for rural, hence urban dispersion was used for this screening health risk evaluation. As a first cut estimate of the industrial risk, the fenceline maximum chi/q was used. Table 5 presents the estimated maximum cancer, chronic non-cancer and acute non-cancer risk levels for residential and worker receptors. All cancer risks are less than 1 in a million, therefore the risk is below levels deemed significant as per Reg 2 Rule 5 §301.

<u>Non-Carcinogenic Chronic Risk Evaluation</u>

Non-carcinogenic chronic risks were estimated using the REL for chronic and acute inhalation of toxic pollutants from the gas turbine combustion of digester gas. Table 5, above tabulates the hazard indices for residential and worker exposure to emissions from the proposed gas turbines. The worker exposures were calculated assuming exposure at the location of the MEI. Since all of the hazard indices are less than 0.2, we conclude the health impacts from chronic exposure to exhaust emissions from S-15 boiler are not significant. This project complies with Reg 2 Rule 5 Toxic New Source Review. No further evaluation is necessary.

Public Notification: There are no schools or other receptors requiring a public notice within 1000 feet of this source. The nearest school is approximately 4,500 ft from the proposed sources. Therefore public notification due to toxic air contaminants is not required.

F. **Particulate Matter and Visible Emissions, Regulation 6**

1. Section 301 prohibits for more than 3 minutes per hour, visible emissions as dark or darker than Ringelmann 1 or equivalent opacity. S-56 and S-57 are expected to easily comply with this requirement.

2. Section 305 prohibits emissions of visible particles from causing a nuisance on property other than the operators. There is no reason to expect that this could be an issue for S-56 and S-57.

3. Section 310 limits the particulate concentration in exhaust gases to 0.15 gr/dscf. At the estimated 23,928 dscfm, on a highest day emissions basis, the resulting concentration in the exhaust would be 0.002 grain/dscf. Hence these sources will easily comply with this requirement.

G. Nitrogen Oxides from Stationary Gas Turbines, Regulation 9 Rule 9

§301.1: The proposed gas turbines are subject to the general emission limits for gas turbines rated between 0.3 to less than 10 MW, as per §301.1.1. The requirements of this section state that "gas turbines rated at 0.3 MW to less than 10.0 MW shall not exceed 42 ppmv [corrected to 15% O_2, dry basis]..."

Digester gas turbine sources S-56 and S-57 will be conditioned to not exceed the applicant-proposed limit for NOx of 23 ppmvd @ 15% oxygen, therefore these turbines will easily comply with Reg 9-9-301.1.

§504: (Annual compliance demonstration): This requirement will be written into the permit conditions, hence EBMUD will comply with this requirement,

H. NESHAPS

40 CFR Part 63 Subpart YYYY contains the National Emission Standard for Hazardous Air Pollutants (HAP) for Stationary Gas Turbines located at major sources for HAPs. A major source for HAPs is designated as a facility that emits at least 10 tpy of a single HAP or 25 TPY of any combination of HAPs. EBMUD is not a major facility for HAP, therefore this NESHAP is not applicable to the proposed turbines.

I. NSPS

40 CFR Part 60 Subpart GG contains the new source performance standard for stationary gas turbines. The standards in this section address NOx and SO_2 emissions, monitoring, testing and compliance. Since the proposed gas turbine is a recuperative cycle turbine with a heat input less than 100 MM Btu/hr, the turbines are exempt [per §60.332(k)(1)] from the NOx standards identified in 60.332(a).

§60.333 states that "no owner or operator subject to the provisions of this subpart shall cause to be discharged to the atmosphere from any stationary gas turbine any gas which contain sulfur dioxide in excess of 0.015 percent by volume at 15% oxygen on a dry basis." The equates to 150 ppmvd @ 15% oxygen. As is shown in a calculation in Appendix A, 300 ppm equates to a fuel H_2S level of approximately 1700 ppm. Therefore 150 ppm would be 850 ppm H2S in the digester gas. The anaerobic digesters S-180 will be conditioned to not exceed 340 ppm H_2S in the digester gas, therefore this limit will not be exceeded.

§60.333 also limits the sulfur content of turbine feed gas to 8000 ppm, wt basis (0.8% wt). The equivalent ppm on a weight basis to 340 ppmvd is 435 ppm, therefore this limit will not be exceeded.

Monitoring requirements will be written into the permit conditions with an annual source test (periodic monitoring) required to demonstrate compliance with all emission limitations.

J. CEQA

EBMUD has complied with CEQA requirements by preparing and approving a Mitigated Negative Declaration for the proposed Power Generation Station Renewable Energy Expansion Project. This Negative Declaration was certified/approved in April of 2008. The engineering review for this project requires the application of largely standard permit conditions and standard emissions factors and therefore is not discretionary as defined by CEQA.

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5. CONDITIONS

Discussion: The following discussion is offered to explain the types of conditions as well as the requirements that are necessary to achieve compliance with the specified limit.

NOx: Both turbine sources S-56 and S-57 are subject to the exhaust gas NOx emission limit of 23 ppm NOx (calculated as NO_2), corrected to 15% oxygen. This limit has been converted to a lb/yr limit requiring monthly monitoring and recording. Turbines typically operate in a fairly consistent, steady state configuration, hence we do not expect a significant amount of variation over the course of a typical operating month. A condition requiring monthly exhaust gas testing will be written into the permit conditions. The requirement will state that a source test is required within a window that runs from 25 to 35 operating days of the most recent stack test, with at least one test every calendar month of operation. A calendar month of operation is defined as a month when the turbine operates at least 15 days.

Since the BACT limit of 23 ppm is more stringent than the Reg 9-9 limit of 42 ppm, there is no need to add the 9-9 limit to the permit. This limit will be noted in the Title V permit, but will not be written into the conditions.

CO: Both turbine sources S-56 and S-57 are subject to the exhaust gas emission limit of 100 ppmv CO, dry, corrected to 15% oxygen. Like NOx, above, this limit has also been converted to a lb/yr limit requiring monthly monitoring and recording. For the same reasons as for NOx above, each turbine exhaust must be tested at least on a monthly basis—within the window from 25 to 35 operating days and at least one time per calendar month of operation

Maximum CO emissions based on the above applicant-proposed limit and 100% operating factor at maximum turbine operation are 96.6 tpy. Regular monthly monitoring of the exhaust concentration of CO and the heat input will be sufficient to ensure CO emissions do not approach the 100 tpy CO PSD threshold.

NMOC (poc): EBMUD digester gas analyses have shown a maximum NMOC concentration of 83 E-6 g/L of digester gas. On an uncontrolled basis, this concentration would result in emissions of approximately 9 lb/day-turbine. The destruction efficiency is expected to be over 98% - resulting in estimated controlled NMOC emissions of approximately 0.2 lb/day. Annual testing of controlled NMOC emissions will be required in the permit conditions.

SO_2: SO_2 limits will be ensured by establishing total sulfide levels in the digester gas via the conditions for the anaerobic digesters (digester gas production units). The 150 ppm exhaust gas SO_2 limit required by the NSPS will be written into the conditions for the turbines, but the compliance will be ensured by maintaining 340 ppm sulfide in digester gas. The 340 ppm H_2S limit will be written into the conditions for the anaerobic digesters.

Heat Input: Annual heat input limits (combined turbine sources basis) will be written into the conditions—with a basis of a rolling 12-month average. Both turbines must have fuel totalizing meters with digester gas throughput recorded and summed on a monthly basis.

Summary – Condition Changes:
Recommend instituting a new permit condition for S-56 and S-57.
Recommend modifying Condition 20651 to correct cogeneration engine heat input.
Recommend modifying Condition 18860 for S-180 Anaerobic Digesters to limit digester gas total reduced sulfur concentration.

Recommended conditions for Digester Gas Turbines:

S-56 Digester Gas Turbine #1, Solar Mercury 50 ultra-lean premix, recuperative 4.5 MW, 44.5 MM Btu/hr HHV
S-57 Digester Gas Turbine #2, Solar Mercury 50 ultra-lean premix, recuperative 4.5 MW, 44.5 MM Btu/hr HHV

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1. Gas turbines S-56 and S-57 shall be fired only on S-190 digester gas. (Basis: Cumulative Increase)

2. Total combined heat input to S-56 and S-57 gas turbines shall not exceed 389,820 MM Btu HHV during any consecutive 12-month period. Until 12-months of operation is reached, the turbines shall be limited to the above Btu limit prorated for the number of months of operation. (Basis: Cumulative Increase)

3. Nitrogen Oxide (NOx) emissions, calculated as NO2, from sources S-56 and S-57 shall not exceed 23 ppm (15-minute average), corrected to 15% oxygen and 34,400 lb per turbine during any consecutive 12-month period. Until 12 months of operation is reached, each turbine shall be limited to the above mass limit prorated for the number of months of operation. These limits are applicable during steady state turbine operation and are not applicable during normal transient periods of startup, shutdown, and turbine commissioning. (Basis: BACT, Offsets, Cumulative Increase)

4. Carbon Monoxide (CO) emissions during normal turbine operation, from sources S-56 and S-57 shall not exceed 100 ppm (15-minute average), corrected to 15% oxygen and 92,200 lb per turbine during any consecutive 12-month period. Until 12 months of operation is reached, each turbine shall be limited to the above mass limit prorated for the number of months of operation. These limits are applicable during steady state turbine operation and are not applicable during normal transient periods of startup, shutdown, and turbine commissioning. (Basis: BACT, Cumulative Increase)

5. Sulfur Dioxide (SO2) emissions from the gas turbines shall not exceed 150 ppmv, dry, corrected to 15% oxygen. The owner or operator may demonstrate compliance with this part by analyzing the exhaust gas of either turbine or by calculating the SO2 concentration by mass balance based on the digester gas TRS concentration. The owner or operator shall determine and record the turbine SO2 exhaust concentration at least one time every calendar month. (Basis: 40 CFR Part 60 Subpart GG Section 60.333)

6. The owner or operator shall install and maintain District-approved totalizing digester gas fuel meters on each turbine. (Basis: Cumulative Increase)

7. To demonstrate initial compliance with parts 3, 4, and 5, above, the owner or operator shall, within 60 days of initial startup and annually thereafter perform a District-approved compliance source test at multiple loads as specified in 40 CFR 60.335, as applicable. The sample port design and locations shall be approved by the District Source Test Section prior to installation. The annual test shall be performed at a frequency of no sooner than 9 months and no later than 12 months after the previous source test. The annual source test shall be used to determine the following:

    a. Digester gas flow rate to each turbine (dry basis).
    b. Digester gas concentrations (dry basis) of carbon dioxide (CO2), methane, total non-methane organic compounds (NMOC).
    c. Exhaust gas flow rate from each gas turbine (dry basis).
    d. Exhaust gas concentrations (dry basis) of NOx, CO, NMOC, and O2 in the stack gas.

    The source test report shall provide the emissions results for NOx, CO and NMOC in the following units: ppmv, dry, corrected to 15% oxygen, lb/hour, lb/MM Btu heat input (HHV basis), lb/yr (prorated with actual fuel usage).

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The source test protocol shall be provided for [Source Test Section] review at least 14 days in advance of the source test date. The Source Test Section shall be notified of the scheduled test date at least 7 days in advance of each source test. The source test report shall be submitted to the Compliance and Enforcement Division and the Source Test Section within 60 days of the test date. (Basis: Cumulative Increase, BACT, Regulation 9-9-301.1, and 40 CFR 60.332(a))

8. To demonstrate ongoing compliance with parts 3 and 4, above, the owner or operator shall measure and record the 15 minute average concentrations of NOx and CO, corrected to 15% oxygen, dry, from each operating turbine by testing the flue gas with a District-approved hand-held analyzer. This testing shall be performed at a frequency of at least one time per calendar month. When the owner or operator is conducting a single analytic event in a calendar month, the interval between subsequent tests shall be at least 25 days and not more than 35 days. The emissions of NOx and CO shall be determined by mass balance using the analytic test results in conjunction with the turbine flue gas flow rate. When actual flue gas rate measurements are not available, the owner or operator shall assume 19.94 dscf flue gas per dscf digester gas, corrected to 15% oxygen, dry basis. (Basis: Cumulative Increase)

   When the owner or operator is conducting multiple tests of NOx, CO and O2 emissions, the monthly (15 minute average) concentrations of NOx and CO shall be determined by averaging the results of the test measurements taken during the course of the month. When actual flue gas flow measurements are not available, the owner or operator shall assume 19.94 dscf flue gas per dscf digester gas, corrected to 15% oxygen, dry basis. (Basis: Cumulative Increase)

8. The owner or operator shall sample, test, and record the digester gas Btu content at least one time per calendar week during turbine operation. If 6 months of data testing indicates digester gas Btu content is within plus or minus 5% of the average, the sampling/testing frequency may be decreased to one time per calendar month, with successive monthly sample dates at least 2 weeks apart. (Basis: Cumulative Increase)

9. The owner or operator shall maintain records and provide all the data necessary to demonstrate compliance with the above parts, including the following information. (Basis: Regulation 1-441)

   a. Monthly records of the quantity of digester gas (thousand scf) burned at each turbine.

   b. Monthly records of the total thermal input in BTU.

   c. Records of all NOx and CO measurements (ppmvd, at 15% oxygen, and calculated lb/yr, as applicable) as well as all annual source test results.

   d. All records shall be retained onsite for five years from the date of entry, and made available for inspection by District staff upon request.

   These recordkeeping requirements do not replace the recordkeeping requirements contained in any applicable District Regulations.

Condition 20651 Recommended Changes
(For sources S-5, S-55, S-37, S-38, and S-39)

1. Boiler ~~S-5 and~~ S-55 shall be fired only on sewage sludge digester gas.
   Comment: Boiler S-5 has been removed and the source archived.

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2. ~~S-5 and/or~~ S-55 hot water boiler~~s~~ shall not be operated when more than two of the three cogeneration engines S-37, S-38, or S-39 are operating.
Comment: S-5 has been removed from service.

3. Boiler Gross Heat Input:

a. ~~S-5: Not to exceed 9.87 MM Btu/hr.~~
~~b~~. S-55: Not to exceed 20.41 MM Btu/hr.

4. ~~The owner or operator of hot water boiler S-5 shall perform an inspection and tune up of the combustion section at least annually to ensure the proper air-to-fuel ratio is being used to maximize efficiency and minimize the production of nitrogen oxides and carbon monoxide, following the procedure of Regulation 9, Rule 7, Section 604 (CARB BARCT tune up procedure). The time interval between boiler tune-ups shall not exceed 12 months.~~
Comment: Part 4 to be deleted, since it deals entirely with S-5 which has been removed from service.

13. Total thermal throughput shall not exceed ~~19.8~~ 25 MM Btu/hr (gross basis) per engine.
Comment: 25 MM Btu/hr corresponds to an engine efficiency of approximately 30 percent—a much more realistic efficiency compared with the previous 38%. It should be noted that the original permit basis was calculated based on emissions per horsepower-hr basis. This has not changes, the engines are rated at 2980 hp, and since this was the basis for the original permitting of the engines, there is no change to permitted emissions. The throughput limits were established in the mid-90's and were incorrectly estimated.

16. ~~Total sulfur content of the gaseous feed to engine S-38 and boiler S-55 shall not exceed 340 ppmvd at 0% O2.~~
Comment: Since the digester gas (S-180) condition sulfide limit is being lowered from 1500 ppm to 340 ppm, there is no need for this additional testing requirement. This part will be deleted.
All other references to recordkeeping at source S-5 will also be removed from Condition 20651.

Condition 18860-Recommended Changes
(For anaerobic digester system S-190)

1. Emissions from S-180 shall be abated at all times by combustion at any or all of the following sources: S-56, S-57, S-37, S-38, S-39, and ~~S-5~~ S-55, except as specified in part 2.
Comment: S-5 has been removed from service, and S-55 should have been previously included in this part.

3. Digester gas total sulfur content shall not exceed ~~1500~~ 340 ppmv, dry.

6. RECOMMENDATIONS

Conditionally approve engineering evaluation, subject to final disposition of offset requirements.

Upon final resolution of the NOx and POC offsets issue, recommend issuance of Authority to Construct for new sources S-56 and S-57 subject to new Condition # 24050. Also recommend approval of revised condition numbers 20651 and 18860, above.

By: REF

Randy E. Frazier, P.E.
21 July 2008

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APPENDIX A

CALCULATIONS

1. Incremental Digester Gas Production (per turbine basis)
Basis: 40.77 MM Btu/hr per turbine, LHV

Digester gas composition: 64% methane, 35+% CO_2, <1% NMOC
DG Heating Value: (0.64)(913 Btu/dscf) = 584 Btu/dscf LHV (636 Btu/dscf HHV)

DG Required = (40.77E6 Btu/hr)(scf DG/584 Btu)(hr/60 min) = 1,164 dscf DG/min-turbine
(round up to 1,200 dscf DG/min-turbine)

Gross Heat Input = (1,200 dscfm)(60 min/hr)(636 Btu/dscf) = 44.5 MM Btu/hr (HHV)

2. Digester Gas Maximum Sulfur Concentration to comply with Reg 9-1-301 (SO_2 limit: 300 ppmvd)

<u>Stoichiometric FG Rate</u>:
CH_4 in = 0.62 mole
Flue Gas: CO_2 in, DG = 0.38 mole
CO_2 out, rxn = 0.62 mole
O_2 out = 0 mole (stiochiometric)
N_2 in = N_2 out = (3.76)(2)(0.62) = 4.662 mole
H_2O out = 2(0.62) = 1.24 mole

Dry Basis: FG = 0.38 mole CO_2 in + 0.62 mole CO_2 produced + 4.662 mole N_2 = 5.662 mole FG (dry)/mole DG = 5.662 dscf FG/dscf DG

H_2S in digester gas = (300E-6 cu ft SO_2/cu ft flue gas)(1 cu ft S/cu ft SO_2)(5.662 dscf FG/dscf DG)(1E6) = 1,699 ppm H_2S in digester gas

3. Water produced from combustion of digester gas:

Water produced = (1.24 mole H2O/mole DG feed)(1,200 dscf DG/min)(mole DG/387 scf)(18.02 lb H2O/lb-mole H2O)(60 min/hr)(8760 hr/yr) = 18,208 tpy water

4. Conversion of 0.3 g/hp-hr SO2 (BACT) to ppm H2S in Digester Gas (from SOB AN 3926)

Basis:
1 Hour operation
19.8E6 Btu/hr (Cogeneration Engine S-38)
2980 BHP
Diesel Usage: 2% (ht value) = 396,000 Btu/hr (2.8 gph)
Digester Gas (98%, conservative) = 19.404E6 Btu/hr (34,695 scf/hr @ 560 Btu/scf)

<u>Total</u> Sulfur Out = (0.3 g/hp-hr) = (0.3 g SO2/bhp-hr)(2980)(1/454) = 1.97 lb/hr SO2
= 0.031 mole/hr SO2
= 11.9 scf/hr SO2

SO2 from Diesel: (2.8 gal/hr)(6.11 lb diesel/gal)(500 lb S/MM lb diesel)(mole S/32.1 lb)(386 cu ft/mole SO2) = 0.103 scf SO2/hr

SO2 from Fuel Gas: 11.9 scf/hr – 0.103 scf/hr = 11.797 scf/hr
(11.797 scf SO2/hr)(mole SO2/386 scf)(mole H2S/mole SO2) = 3.056E-2 mole H2S/hr

Fuel Gas Rate = 34,695 scf/hr
Ppm H2S in Digester Gas = 3.056E-02 mole/[(34,695 scf)(mole/386 scf)/1E6] = 340 ppm

5. Conversion of 340 ppmv H2S to ppm weight basis:

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Average MW of Digester Gas: Basis: 1 mole

MW = ([0.62)(16 lb/mole CH_4) + (0.38)(44.01 lb/mole CO_2)] = 26.6 lb/mole

Ppm, wt = [340 scf H_2S)(34.1 lb/mole)]/[(26.6)(1E6)] = 435 ppm, wt

ENGINEERING EVALUATION REPORT

PLANT NAME	East Bay Municipal Utility District
APPLICATION NUMBER	17749
PLANT NUMBER	A591
DATE	21 July 2008

OFFSET ADDENDUM

1. BACKGROUND

This addendum addresses offset requirements for the installation of two 4.5 Mw ultra-lean premix, recuperative digester gas fired cogeneration turbines at the main wastewater plant for the East Bay Municipal Utility District (EBMUD) in Oakland. Specifically, these gas turbines are identified as:

S-56 Digester Gas Turbine #1, Solar Mercury 50, 4.5 MW, 44.5 MM Btu/hr HHV
S-57 Digester Gas Turbine #2, Solar Mercury 50, 4.5 MW, 44.5 MM Btu/hr HHV

2. EMISSION CALCULATIONS

<u>**Criteria Emissions**</u>

Emissions have been established by estimating the exhaust emission levels in conjunction with the flue gas rate. Following are emission levels used in this analysis.

Table 1 Criteria Pollutant Emission Factors

Pollutant	Proposed Factors
NOx	23 ppm @ 15% O_2
CO	100 ppm @ 15% O_2
NMHC	0.007 lb/MM Btu (~5 ppm @ 15% O_2)
PM_{10}	0.0098 lb/MM Btu
SO_2	(mass balance)

Total project criteria pollutant emissions are presented below in Table 2.

TABLE 2 Criteria Pollutant Emissions Summary

POLLUTANT	Annual Emissions (tpy-turbine)	Daily Emissions (lb/day-turbine)	Project Emissions, tpy (2 turbine basis)
NOx	18.02	**98.7**	36.04
CO	48.3	**265**	96.6
POC	1.4	7.5	2.8
SO2	18.1	**99.3**	36.2
PM	1.7	9.5	3.4

3. OFFSETS DISCUSSION

Offset Requirements: §2-2-302: Current NOx and POC emissions at EBMUD are both greater than 35 tpy, therefore as required by Regulation 2-2-302, emission increases for these pollutants must be offset at a ratio of 1.15:1. EBMUD is not a major facility for either PM_{10} or SO_2, therefore offsets are not required for these pollutants.

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Offset Quantities Required:

Pre-project Cumulative Increase:	NOx:	0 tpy
	POC:	0.145 tpy

NOx Offsets required:	[(18.02 tpy)(2)](1.15) = 41.4
POC Offsets required:	[(1.4 tpy)(2) + 0.145 tpy](1.15) = 3.4

EBMUD has petitioned the District to provide the needed NOx and POC offsets. Since this project meets the definition of a resource recovery project this is allowed, as long as the applicant satisfies certain requirements specified in the Health & Safety Code.

§39050.5 of the Health & Safety Code defines a resource recovery project as follows:

"Resource recovery project" *means a project that converts municipal wastes, agricultural wastes, forest wastes, landfill gas, or digester gas in a manner so as to produce energy as a byproduct in the air basin in which they are produced.*

Since the proposed project is to use digester gas ~~digester gas~~ to make heat and power, the project satisfies the definition of a resource recovery project.

Section 42314 from the California Health & Safety Code provides the following provision regarding offset requirements for resource recovery projects.

42314. (a) Notwithstanding any other provision of any district permit system, and except as provided in this section, no district shall require emissions offsets for any cogeneration technology project or resource recovery project that satisfies all of the following requirements:

...

(b) This section applies to any project for which an application for an authority to construct is deemed complete by the district after January 1, 1986, only if the project's net emissions, combined with the net emissions from projects previously permitted under this section, are less than the amount provided for in the applicable growth allowance established by the district pursuant to Section 41600. If a district has not yet provided a growth allowance pursuant to Section 41600, the growth allowance is zero. For purposes of this subdivision, "net emissions" means the project's emissions, less any offsets provided by the applicant and less utility displacement credits granted pursuant to Section 41605.

(c) This section does not relieve a project from satisfying all applicable requirements of Part C (Prevention of Significant Deterioration) of the Clean Air Act, as amended in 1977 (42 U.S.C.Sec. 7401 et seq.), or any rules or regulations adopted pursuant to Part C.

The specific requirements related to the proposed project as enumerated in §42314 are addressed as follows:

(1) The project satisfies one of the following size criteria:

(A) The project produces 50 megawatts or less of electricity. In the case of a combined cycle project, the electrical capacity of the steam turbine may be excluded from the total electrical capacity of the project for purposes of this paragraph if no supplemental firing is used for the steam portion and the combustion turbine has a minimum efficiency of 25 percent.

(B) The project processes municipal wastes and produces more than 50 megawatts, but less than 80 megawatts, of electricity.

Comment: The proposed project produces 9 MW of total power, hence the project size criteria identified in (1)(A), above, is satisfied.

(2) The project will use the appropriate degree of pollution control technology (BACT or LAER) as defined and to the extent required by the district permit system.

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Comment: BACT requirements have been satisfied for all applicable pollutants; hence this criteria requirement is satisfied.

(3) Existing permits for any item of equipment to be replaced by the project, whether the equipment is owned by the applicant or a thermal beneficiary of the project, are surrendered to the district or modified to prohibit operation simultaneously with the project to the extent necessary to satisfy district offset requirements. The emissions reductions associated with the shutdown of existing equipment shall be credited to the project as emissions offsets in accordance with district rules.

Comment: This section is not applicable, as the cogeneration engines will maintain their existing permits to operate. There is no permitted equipment that is being replaced, hence there is no surrender of permits.

(4) The applicant has provided offsets to the extent they are reasonably available from facilities it owns or operates in the air basin and that mitigate the remaining impacts of the project.

Comment: There are no available offsets from other EBMUD facilities in the air basin, hence EBMUD is unable to provide offsets from these facilities.

(5) For new projects that burn municipal waste, landfill gas, or digester gas, the applicant has, in the judgment of the district, made a good faith effort to secure all reasonably available emissions offsets to mitigate the remaining impact of the project, and has secured all reasonably available offsets.

Comment: Good Faith Effort to secure all reasonably available emission offsets: We have determined that a good faith effort means the applicant has obtained verifiable market-rate offset cost estimates. In obtaining offset cost estimates, the applicant contacted two offset brokers that do business in the Bay Area: Evolution Markets and Element Markets.

Reasonably Available Emission Offsets: There is no definition provided for the term *reasonably available emissions offsets*. Reasonably Available Control Technology (RACT), however, is defined in Regulation 2-1-109 and is a federal Clean Air Act (CAA) term that represents a basic level of emission control that should be included in State Implementation Plans (SIPs) for areas that are deemed non-attainment (in the present case, for the ozone precursors NOx and VOC). Specifically, CAA Section 172(c)(1) provides that SIPs for nonattainment areas must include reasonably available control measures, including RACT, for sources of emissions.

The EPA definition of RACT is very similar to the District definition, and includes an economic component: "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility." (EPA 453-R-07-003). EPA provides guidance to the states in making RACT determinations through a series of Control Techniques Guidelines (CTGs). The CTG documents typically provide the cost effectiveness of the EPA-recommended RACT controls in terms of "dollars per ton reduced".

Cost effectiveness figures for reasonably available control technologies for NOx are also summarized in an EPA Memo from D. Kent Berry, (Acting Director) to the regional EPA (Air) Directors entitled *Cost-Effective Nitrogen Oxides (NOx) Reasonably Available Control Technology*, March 16, 1994.

> *The cost-effectiveness figures in the report are based on data from different geographic regions and represent a variety of averaging times. As described in tables 1-4 and 1-5 of the EPA/NESCAUM report, the combustion-modification technologies available to meet EPA's presumptive NOx RACT levels show a range of cost effectiveness or about $160 to $5100 per ton; and the post-combustion technologies, excluding selective catalytic reduction, show a range of $320 to $5200 per ton. These are national estimates based on 1991 dollars. Some states may need to make regional adjustments to this range to reflect prevailing installation and operating labor costs which are higher or lower than the national average.*

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The District believes that the cost effectiveness of EPA-recommended RACT measures can be used to determine a reasonable price for banked emission reduction credits (ERCs). ERCs that are valued above the upper-bound of the "dollars per ton reduced" cost effectiveness of EPA recommended RACT measures would not be considered to be "reasonably available" in the context of Health and Safety Code Section 42314

<u>EBMUD Project Cost of Offsets</u>: In the case of the present application for an Authority to Construct, Evolution Markets provided two verbal quotations for the current cost of NOx and POC offsets: $15,750/ton and $16,000/ton. Additionally, Element Markets has indicated that NOx offsets in the Bay Area are currently selling somewhere in the range of $12,000 – $15,000 per ton. District records also indicate the lowest cost for offsets (in quantities around 40 tons) from 2006 and 2007 transactions were $12,500/ton. These figures are significantly higher than the upper bound of cost effectiveness of RACT measures recommended by EPA in guidance documents (even in these figures were inflation adjusted). Hence we conclude that these offsets are not reasonably available.

<u>Project Cost of Offsets</u>: The applicant has indicated in a memo dated July 3, 2008 that due to the expected "partial utilization of the 2nd turbine, the project is just on the cusp of being financially feasible. At the current market prices, if the cost of offsets is factored into the project, the 2nd turbine would go from a marginal payback time to a long payback time, and it is likely we [EBMUD] will cancel the 2nd turbine. (If we [EBMUD] delete the 2nd turbine, we would then normally run one turbine and 2 engines, using the 3rd engine for peaking and maintenance redundancy, instead of running 2 turbines and using the engines for peaking/redundancy)".

Due to the fact that the emissions from a comparable engine are more than double those of a turbine, as well as the goals of the District's Climate Protection Program, it is the District's position to encourage clean resource recovery projects such as the proposed project. Therefore, on a 2-turbine basis, the District accepts the applicant's contention that any additional costs could threaten the project as proposed.

The District therefore finds that the applicant has made a good faith effort to secure all reasonably available emissions offsets, and that offsets are not reasonably available.

4. RECOMMENDATIONS

Transfer of 44.9 tpy of POC emission reductions credits from the small facilities bank account into the growth allowance to fund the offset requirements for the proposed EBMUD resource recovery project, AN 17749.

By: REF

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21 July 2008

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