Bay Area Air Quality Management District
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Permit Evaluation
and
Statement of Basis
for
RENEWAL of

MAJOR FACILITY REVIEW PERMIT

for

Shell Martinez Refinery, Shell Oil Products US
Facility #A0011

Facility Address:
3485 Pacheco Blvd.
Martinez, CA 94553

Mailing Address:
PO Box 711
Martinez, CA 94553

Site Engineer: Anne Werth

Application: 27866

June 2018

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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 Title 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) more than 100 tons per year of a regulated air pollutant.

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 A0011.

This facility received its initial Title V permit under Application 16467 on December 1, 2003. The initial permit was administratively amended on May 27, 2004 and July 28, 2004. The permit was reopened under Application's 9293 and 12430 and was re-issued on December 16, 2004 and May 17, 2007, respectively. The version of the permit reopened under Application 12430 included Authorities to Construct issued under applications 3930, 4106, 4192, 4688, 4695, 6745, 9504, 10053, 11157, 12473, 12732, 13078, 13086, 13410, and 14224. In addition to the above, the permit also included the final action taken on the following Title V applications: 9699, 11158, 12731, and 13085. The permit re-issued on May 17, 2007 was amended the following year to incorporate changes stemming from a minor revision to the permit under Application 15599. The amended permit was later re-issued on April 4, 2008. Section X of the permit, Revision History, has a list of these revisions in chronological order.

The 1st renewal Title V permit was issued September 30, 2011 under Application 18239. It incorporated the following Authorities to Construct and/or Permits to Operate that were issued to Shell following the issuance of the April 4, 2008 permit: 14497, 15482, 15574, 16726, 17633, 18034, 18062, 19373, 19465, 20070, and 20868.

The proposed 2016 application is for the 2nd renewal of the Title V permit. Table 1 below incorporates the following recent Authorities to Construct and/or Permits to Operate that were issued to Shell following the issuance of the September 30, 2011 permit. In addition, there is one permit application issued in July 2001 that was inadvertently not incorporated in the previous two Title V permit renewals.

Table 1	
Application #	**Application Summary**
2736	**S1070:** Project to convert a fixed roof tank to an internal floating roof tank. Permitted in 2001 but inadvertently not included in previous Title V permit renewals.
19872	**Catalytic Cracking Unit (CCU):** The District authorized Shell for improvements of the Catalytic Cracking Unit (CCU), Reactor, Stripper, and the Catalytic Gas Plant (CGP), Rectified Adsorber and Debutanized Columns. These improvements included replacing the CCU Reactor and Stripper vessel internals, replacing the CGP column exchanger and Debutanizer internals, and installation of 180 new valves and 150 flanges/connectors in VOC service. (Condition 25345)
TV 21375 NSR 21359	**Construct Aeration Tank** The District authorized Shell to construct an Aeration Tank and Clarifier for Effluent Treatment Plant #3, custom made, with a wastewater feed rate of 2250 gpm. (Condition 24975)
TV 22046 NSR 22045	**Crude Tank Replacement Project (CTRP):** The District authorized Shell to increase the on-site crude oil storage capacity by replacing three existing crude oil storage tanks (S-541, S-544, and S-545) with three new, larger crude oil storage tanks (S-6069, S-6070, and S-6071), the construction of a new crude oil mix tank (S-6072), a refurbishment of an existing storage tank for crude oil service (S-1128), a refurbishment of an existing storage tank for jet fuel from a fixed roof tank to an internal floating roof tank for project offsets (S-967), increase the volume of crude oil shipments, and the implementation of emission reduction projects. The project status is as follows: • Replacement of two existing crude oil storage tanks (S-541 and S-544) with two new crude oil storage tanks (S-6069 and S-6070) has been

Table 1	
Application #	**Application Summary**
	completed. • Construction of the new crude oil mix tank (S-6072) has been completed. • Refurbishments to S-1128 have been completed. • Roof retrofits S-967 have been completed. • Replacement of the remaining crude oil storage tank (S-545) with the third new crude oil storage tank (S-6071) has not yet started. Therefore, S-545 is still shown in the Title V permit. (Condition 25134)
TV 22288 NSR 22287	**CO Boilers** This application incorporated the SO2 and NOx emission limits for the CO boilers abating CCU flue gas for the Equilon Consent Decree. (Condition 25247)
TV 24543 NSR 24479	**Crude Unit Feed Furnace S-1763** This application authorized Shell to replace an air preheater at S-1763 to improve energy efficiency and reduce GHG emissions. (Condition 25366)
TV 25811 NSR 25810	**S-6073 Portable Diesel Firewater Pump** The District authorized Shell to install and operate an On-Site Portable Emergency Standby Diesel Fire Pump Engine. (Condition 22850)
NSR 27434	**S-1487 and S1488:** The District authorized Shell to implement a heater tube replacement project for F41A/B. (no Condition)
TV 28653 NSR 28652	**S-1427 and S-1429** The District authorized Shell to make changes that will decrease energy consumption and greenhouse gases as well as increase gasoline quality at S-427. These improvements include Install 77 new and replaced valves, 225 new and replaced flanges, and 2 new pumps At S-1427: • Replace Main Fractionator trays with beds of structured packing. • Add a new HCCG side draw off the Main Fractionator. • Relocate the Upper Circulating Reflux (UCR) and Intermediate Circulating Reflux

Table 1	
Application #	**Application Summary**
	(ICR) pump-around draws and Catalytic Cracked Light Gas Oil (CCLGO) draw in the Main Fractionator. • Add a new Boiler Feed Water (BFW) Economizer to the UCR loop of the Main Fractionator. • Install line to bypass LCCG around the CGH, and connect the bypass line to the CGH product rundown line. • Install a new line to route Gasoline Splitter Column (C-128) bottoms product (MCCG) to the CGH. At S-1429: • Install new internals in the CGH (Condition 26555)
TV 29044 NSR 29043	**S-6049** The District authorized Shell to install and operate an On-Site Portable Emergency Standby Diesel Engine. (Condition 22850)

In addition to incorporating recent District permit actions, this application updates the standard sections of the permit to include new permit effective dates. Also, as discussed in the following sections, various other corrections have been made to the permit. This statement of basis will include all proposed changes that are shown in the permit markup in ~~strikeout~~/underline format.

B. Facility Description

The Shell Martinez Refinery (Shell) consists of a petroleum refinery and chemical manufacturing complex. The crude unit at the refinery is permitted to process approximately 178,800 barrels of crude oil per day into many finished products, including liquefied petroleum gas, automotive gasoline, jet fuel, diesel, industrial fuel oils and petroleum coke. The chemical plant manufactures several different specialty chemicals.

Shell has been in operation since 1915. The light oil processing (LOP) units were added in the mid 1970's, and the Flexicoker and associated units were added in the mid 1980's. Several new "clean fuels" units were added in 1995, including the Delayed Coker unit.

Finished products from the refinery include Liquefied Petroleum gas (LPG), which is sold as propane and used for home heating, cooking, recreational vehicles, etc. Automotive gasoline and diesel are marketed throughout California and Nevada and used to power cars, trucks, busses, boats and farm equipment. Heavier fuel oils are used for heating, in industrial steam boilers and utilities.

Through a variety of chemical reactions and physical changes, Shell manufactures finished petroleum products from crude oil. Oil Refining includes four basic processes, described below:

SEPARATION	Liquid hydrocarbons are separated into common boiling point fractions by distillation. The distillation process makes a "rough cut" of the crude oil, producing gases, light, medium and heavy boiling-range materials, and residuals. These cuts, or intermediate streams are then further processed by more sophisticated means.
CONVERSION	Cracking - This process breaks or cracks large hydrocarbon molecules into smaller ones. This is done by thermal or catalytic cracking. Reforming - This process uses high temperatures and catalysts to rearrange the chemical structure of a particular hydrocarbon stream to improve its quality. Combining - This process chemically combines two or more hydrocarbon streams to produce a higher-grade product. Liquefied petroleum gas streams are combined in this manner to produce gasoline.
PURIFICATION	This process converts contaminants into an easily removable or acceptable form.
BLENDING	This process mixes combinations of hydrocarbon liquids to produce a final product.

A more detailed description of petroleum refinery processes and the resulting air emissions may be found in Chapter 5 "Petroleum Industry" of EPA's publication AP-42, Compilation of Air Pollutant Emission Factors. This document may be found at:

http://www.epa.gov/ttn/chief/ap42/ch05/index.html

The principal sources of air emissions from refineries are:

- Combustion units (furnaces, boilers, and cogeneration facilities)
- Fluidized Catalytic Cracking (FCCUs)
- Storage tanks
- Fugitive emissions from pipe fittings, pumps, and compressors
- Sulfur plants
- Wastewater treatment facilities

Combustion unit emissions are generally controlled through the use of burner technology, steam injection, or selective catalytic reduction. Emissions from the FCCUs are controlled through the use of improved catalyst regeneration, CO boilers, electrostatic precipitators, selective non-catalytic reduction, hydrotreating the feed, and use of catalysts to remove impurities. Storage tank emissions are controlled through the use of add-on controls and or fitting-loss controls. Fugitive emissions have been controlled through the use of frequent inspections and maintenance checks. Sulfur plants are equipped with tail gas units to reduce emissions. Wastewater treatment facilities are controlled by covering units, gasketing covers, and add-on controls, such as carbon canisters.

Equilon Enterprises LLC, a bulk storage and loading terminal located adjacent to the refinery, submitted an application to obtain an initial Title V permit from the District on February 17, 2010 (AN 28067). Equilon Enterprises LLC is the smaller of the two facilities and operates under a different facility identifier number, B1956.

Although Equilon Enterprises LLC and the refinery are co-located, Equilon Enterprises LLC has received a separate Title V permit. Equilon has a different responsible official and the facility has asked for a separate permit. The definition of permit in the federal Title V regulations at 40 CFR 70.1, below, allows agencies to issue more than one permit to a facility and the District has issued more than one Title V permit to several facilities.

> "Part 70 permit or permit (unless the context suggests otherwise) means any permit or *group of permits* covering a part 70 source that is issued, renewed, amended, or revised pursuant to this part."

Therefore, the refinery permit and the Equilon permit can be proposed and issued separately.

The District has determined that sources at the refinery will not be subject to additional applicable requirements due to the refinery's association with Equilon Enterprises LLC.

C. Permit Content

The legal and factual basis for the permit follows. The permit sections are described in the order presented in the permit.

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.

Changes to permit

- The adoption and amendment dates of the rules in Standard Condition I.A have been updated.
- Condition I.G – In basis, removed MOP Volume II, Part 3 Section 4.15 because it does not exist.

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., S24).

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 per year of a "regulated air pollutant", as defined in BAAQMD Rule 2-6-222, or 400 pounds per year of a "hazardous air pollutant," as defined in BAAQMD Rule 2-6-210.

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 a 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.

Changes to Table II A "Permitted Sources":

- Deleted description wording related to the CO Boilers and Part B RCRA Hazardous Waste Permit
- Removed 'Asphalt Storage' from the description of tanks, loading racks, and blending and shipping operations that will no longer be in asphalt service because Shell has ceased asphalt production (S21, S23, S24, S26, S497, S552, S553, S554, S555, S556, S557, S558, S559, S560, S561 S567, S571, S572, S573, S598, S815, S867, S868, S876, S961, S985, S1017, S1018, S1041, S1043, S1044, S1045, S1048, S1075, S1160, S1408, S1523, S1524, S1525, and S6068.
- Deleted S541 and S544 per A/N 22045
- Deleted demolished sources S2992 and S1186
- Added S601, S602, and S603, flares that have been re-designated from abatement devices to emission sources
- Changed description and capacity of S967 per A/N 22045
- Revised description of S1070 per A/N 2736
- Added S1128 per A/N 22045
- Updated description of S1141 for clarification
- Changed capacity for S1426 per A/N 19872
- Added S6069, S6070, S6071, and S6072 per A/N 22045
- Added S6073 per A/N 25810
- Added S7000 per A/N 21359
- In capacity column, replaced 'NA' with 'See Condition # 18618, Part 1' where this statement was missing for sources listed in Condition #18618.

Changes to Table II B "Abatement Devices":

- Row for A1 abatement for S24: Removed Reg 6-1-301 applicability because the tanks are no longer used for asphalt storage, revised that row to indicate that the mist eliminators are still in place, but that they are not required by a BAAQMD or federal regulation;
- Row for A3 abatement for S552, S553, S554, S555, S556, S557, S558, S559: Removed Reg 6-1-301 applicability because the tanks are no longer used for asphalt storage, revised that row to indicate that the mist eliminators are still in place, but that they are not required by a BAAQMD or federal regulation;
- Row for A3 abatement for S1523: added new row for mist eliminator requirement for BAAQMD Condition 4101, Part 1;
- Row for A4 abatement for S560, S561, S815, S985: Removed Reg 6-1-301 applicability because the tanks are no longer used for asphalt storage, revised the row to indicate that the mist eliminators are still in place, but not required by a BAAQMD or federal regulation;

- Row for A5 abatement for S567: Removed Reg 6-1-301 applicability because the tanks are no longer used for asphalt storage, revised the row to indicate that the mist eliminators are still in place, but not required by a BAAQMD or federal regulation;
- Row for A6 abatement for S1043, S1044, S1045: Removed Reg 6-1-301 applicability because the tanks are no longer used for asphalt storage, revised the row to indicate that the mist eliminators are still in place, but not required by a BAAQMD or federal regulation
- Row for A7 abatement for S1048, S1525: Removed Reg 6-1-301 applicability because the tanks are no longer used for asphalt storage, revised the row to indicate that the mist eliminators are still in place, but not required by a BAAQMD or federal regulation;
- Row for A26 abatement for multiple tanks: Removed S1070 as an abated source. S1070 was retrofited from a fixed roof tank to an internal floating roof tank and abatement is no longer needed.
- Row for A53 abatement for S571, S572, S573, S1524: Removed Reg 6-1-301 applicability because the tanks are no longer used for asphalt storage; revised the row to indicate that the mist eliminators are still in place, but not required by a BAAQMD or federal regulation;
- Row for A54 abatement for S867, S868: Removed Reg 6-1-301 applicability because the tanks are no longer used for asphalt storage; revised the row to indicate that the mist eliminators are still in place, but not required by a BAAQMD or federal regulation;
- Row for A57 abatement for S23, S26, and S497: Removed Reg 6-1-301 applicability because the tanks are no longer used for asphalt storage; revised the row to indicate that the mist eliminators are still in place, but not required by a BAAQMD or federal regulation;
- Rows for A57 abatement for S6068; Added statement that mist eliminator requirement applies only when the tank is in asphalt storage service;
- Row for A100, amended “Applicable Requirements” based on revised Regulation 8, Rule 44;
- Rows for A101, A102, and A103, flares that are redesignated from abatement devices to emission sources S601, S602, and S603;
- Row for A1765 abatement for sulfur plant loading rack: Removed S4347 because the Sulfur Pit for Sulfur Plant 4 is not abated by the loading rack scrubber;
- Rows for A2023 abatement for Sulfur Plant 3: Added S1766 (Sulfur Pit for Sulfur Plant 4) as an applicable source abated by this device; and
- Row for A4181 abatement for Sulfur Plant 3: Removed S1765 and S1766 as applicable sources abated by this device, because S1765 and S1766 are abated by A2023.

Changes to Table II C – Exempt Sources

- Deleted S1128 per A/N 22045
- Deleted 12 demolished sources: S28, S33, S346, S418, S814, S928, S1040, S1061, S1074, S1165, and S1173

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" as defined in BAAQMD Rule 2-6-239.

<u>Changes to permit</u>

The dates of adoption or approval of the rules in Table III have been updated:

- BAAQMD Regulation 1
- BAAQMD Regulation 2, Rule 1 (revised for 8/31/2016 SIP adoption)
- SIP Regulation 2, Rule 1, removed due to SIP approval
- BAAQMD Regulation 2, Rule 2, removed due to redundancy with Standard Condition I.A
- SIP Regulation 2, Rule 2, removed due to SIP approval
- BAAQMD Regulation 2, Rule 4, removed due to redundancy with Standard Condition I.A
- SIP Regulation 2, Rule 4, removed due to redundancy with Standard Condition I.A
- BAAQMD Regulation 2, Rule 6, removed due to redundancy with Standard Condition I.A
- SIP Regulation 2, Rule 6, removed due to redundancy with Standard Condition I.A
- BAAQMD Regulation 2, Rule 9, removed due to redundancy with Section IV
- BAAQMD Regulation 3, removed due to redundancy with Standard Condition I.C
- BAAQMD Regulation 5
- BAAQMD Regulation 8, Rule 10, removed due to redundancy with Section IV
- SIP Regulation 8, Rule 10, removed due to redundancy with Section IV
- SIP Regulation 8, Rule 47, added for completeness
- BAAQMD Regulation 11, Rule 10 (added)
- BAAQMD Regulation 11, Rule 18 (added)
- BAAQMD Regulation 12, Rule 15 (added)
- CCR, Title 17, Section 93115
- CCR, Title 17, Section 93116
- 40 CFR Part 82, Subpart F
- 40 CFR Part 82, Subpart H
- 40 CFR Part 82, Subpart H 82.270(b)

BAAQMD Regulation 8, Rule 15 for Emulsified and Liquid Asphalts has been removed because asphalt is no longer produced at Facility A0011

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 or EPA 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.

<u>Changes to the proposed renewal permit:</u>

As shown in the table below, the tables in Section IV have been re-sequenced to accommodate table deletions and consolidations. In the following section, all changes are described using the old table numbers.

Old Lettering	New Lettering	Description
A	A	--
B	B	--
C	C	--

D	D	--
E	E	--
F	F	--
G	G	--
H	H	--
I	I	--
J	J	--
K	K	--
L	L	--
M	M	--
N	N	--
O	O	--
P	P	--
Q	Q	--
R	R	--
S	S	--
T	T	--
U	U	--
V	V	--
W	W	--
X	X	--
Y	Y	--
Z	Z	Incorporated S4180 (SRU4) from deleted AA, QQQ and S1765 (SRU3) from deleted BB--
AA	Deleted	For S4180 (SRU4), combined with Z
BB	Deleted	For S1765 (SRU3), combined with Z
CC	AA	Incorporated S4210 (CWT-13278) from deleted LLL--
DD	BB	--
EE	CC	--
FF	DD	Incorporated S601 (A101) and S602 (A102) from deleted VVV
GG	EE	Incorporated S603 (A103) from deleted VVV
HH	FF	--
II	GG	--
JJ	HH	--
KK	II	--
LL	JJ	--
MM	KK	--
NN	LL	--
OO	MM	--

PP	NN	--
QQ	OO	--
RR	PP	--
SS	QQ	--
TT	RR	--
UU	SS	--
VV	TT	--
WW	UU	--
XX	VV	--
YY	WW	--
ZZ	XX	--
AAA	YY	--
BBB	ZZ	--
CCC	AAA	--
DDD	BBB	--
EEE	CCC	--
FFF	DDD	--
GGG	EEE	--
HHH	FFF	--
III	GGG	--
JJJ	HHH	--
KKK	III	--
LLL	Deleted	For S4210 (CWT-13278), combined with CC
MMM	JJJ	--
NNN	KKK	--
OOO	LLL	--
DE	MMM	--
QQQ	Deleted	For S4180 (SRU4), combined with Z
RRR	NNN	--
SSS	OOO	--
TTT	PPP	--
UUU	QQQ	--
VVV	Deleted	For A101, A102, and A103, combined with FF and GG
WWW	RRR	--
XXX	SSS	--
YYY	Deleted	40 CFR 63 Subpart CC MPVs Removed
ZZZ	TTT	--
AAAA	UUU	--
BBBB	VVV	--
CCCC	WWW	--
DDDD	XXX	--

EEEE	YYY	--
FFFF	ZZZ	--
GGGG	AAAA	--
HHHH	BBBB	--
IIII	CCCC	--
JJJJ	DDDD	--

Regulatory names to BAAQMD, SIP, NSPS, and NESHAP regulations were updated for consistency throughput the permit.

Missing or incorrect federal enforceability status (Y or N) was updated in multiple tables.

The dates of adoption or approval of the rules and their “federal enforceability” status in Section IV have been updated for the following regulations:

- BAAQMD Regulation 1
- BAAQMD Regulation 2, Rule 1
- BAAQMD Regulation 8, Rule 1
- BAAQMD Regulation 8, Rule 9
- SIP Regulation 8, Rule 10
- BAAQMD Regulation 8, Rule 18
- BAAQMD Regulation 8, Rule 32
- BAAQMD & SIP Regulation 8, Rule 44
- BAAQMD Regulation 9, Rule 10
- SIP Regulation 9, Rule 10
- CCR, Title 17, Section 93115
- 40 CFR 60 Subpart A; BAAQMD Regulation 10-1
- 40 CFR 60 Subpart Db; BAAQMD Regulation 10-4
- 40 CFR 60 Subpart J
- 40 CFR 60 Subpart Ka; BAAQMD Regulation 10-16
- 40 CFR 60 Subpart Kb
- 40 CFR 60 Subpart GG; BAAQMD Regulation 10-40
- 40 CFR 60 Subpart GGG; BAAQMD Regulation 10-59
- 40 CFR 60 Subpart QQQ; BAAQMD Regulation 10-69
- 40 CFR 60 Subpart VV; BAAQMD Regulation 10-52
- 40 CFR 61 Subpart A
- 40 CFR 61 Subpart FF; BAAQMD Regulation 11, Rule 12
- 40 CFR 61 Subpart M
- 40 CFR 63 Subpart A
- 40 CFR 63 Subpart Y
- 40 CFR 63 Subpart J
- 40 CFR 63 Subpart CC

- 40 CFR 63 Subpart UUU

Inconsistencies in the formatting of BAAQMD incorporation by reference of federal rules have corrected for consistency throughout the permit for the following:

- BAAQMD Regulation 10-1 and 40 CFR 60 Subpart A
- BAAQMD Regulation 10-4 and 40 CFR 60 Subpart Db
- BAAQMD Regulation 10-16 and 40 CFR 60 Subpart Ka
- BAAQMD Regulation 10-40 and 40 CFR 60 Subpart GG
- BAAQMD Regulation 10-52 and 40 CFR 60 Subpart VV
- BAAQMD Regulation 10-59 and 40 CFR 60 Subpart GGG
- BAAQMD Regulation 10-69 and 40 CFR 60 Subpart QQQ
- BAAQMD Regulation 11, Rule 12 and 40 CFR 61 Subpart FF

Source-specific applicability has been updated based on recent changes to, or adoption of, BAAQMD and federal regulations. The following sections summarize the applicability changes for the following new and revised BAAQMD and federal regulations:

BAAQMD

- Regulation 6, Rule 5
- Regulation 8, Rule 53
- Regulation 8, Rule 18
- Regulation 8, Rule 32
- Regulation 8, Rule 44
- Regulation 9, Rule 10
- Regulation 11, Rule 10

Federal

- 40 CFR 60 Subpart Ja for flares
- 40 CFR 63 Subpart CC for heat exchange systems
- 40 CFR 63 Subpart Y for marine terminals
- 40 CFR 63 Subpart EEE for CO Boilers
- 40 CFR 63 Subpart DDDDD, Boiler MACT

Applicability of BAAQMD Regulation 6, Rule 5: "Particulate Emissions from Refinery Fluidized Catalytic Cracking Units"

This rule was adopted on December 16, 2015. The purpose of this rule is to limit emissions of condensable particulate matter and precursors of secondary particulate matter from refinery FCCUs. For this rule, commingled ammonia, condensable particulate matter, and sulfur dioxide emissions from an FCCU and one or more other downstream sources from a single exhaust point must all be considered to be FCCU emissions.

In Shell's case, the emissions train relating to the FCCU, CO boilers, and ESPs is as follows:
FCCU (S-1426) → CO Boilers (S-1507, S-1509, & S-1512) → ESPs (A-12, A-13, & A-14) → Emission Points (P-26, P-27, & P-28) → atmosphere. Thus, emissions from Emission

Points P-26, P-27, and P-28 shall be considered to be FCCU emissions and are subject to the requirements of Rule 6-5.

Section 6-5-301 establishes an ammonia emission limit for an FCCU of 10 ppmvd at 3% O2 as a daily average, effective January 1, 2018. Applicable administrative requirements are discussed in Sections 6-5-401, 6-5-402, 6-5-501, and 6-5-502.

In lieu of complying with the ammonia emission limit in Section 6-5-301, a refinery may seek a limited exemption from the ammonia emission limit under Section 6-5-115 by establishing an enforceable ammonia emission limit by optimization of ammonia and/or urea injection pursuant to a District-approved Optimization and Demonstration Protocol, in accordance with Section 6-5-403. Section 6-5-403 requires a refinery to submit an Optimization and Demonstration Protocol by March 1, 2016, commence and complete an approved Optimization and Demonstration Protocol by June 30, 2017, and report the results of the Optimization and Demonstration Protocol and the proposed Optimized Ammonia Emissions Concentration by August 31, 2017.

Shell has elected to optimize urea injection in accordance with Section 6-5-403 and seek a limited ammonia emission limit exemption under 6-5-115. Shell submitted its proposed Protocol March 2016 and the District approved that Protocol. Shell submitted an Optimization Report on August 31, 2018. The District will establish an enforceable emission limit pursuant to Section 6-5-403. Thus, the refinery is not subject to the ammonia emission limit in Section 6-5-301.

Applicability of BAAQMD Regulation 8, Rule 53: "Vacuum Truck Operations"

This rule was adopted on April 18, 2012. The purpose of this rule is to limit emissions of organic compounds from the use of vacuum trucks to move materials at petroleum refineries, bulk plants, bulk terminals, marine terminals, and organic liquid pipeline facilities.

Specifically, the rule includes an emission limit for any loading event (Section 8-53-301), limits for liquid and vapor leaks (Sections 8-53-302 and 303, respectively), and requirements for unloading of regulated material (Section 8-53-304). Reporting, monitoring, and recordkeeping requirements are addressed in Sections 8-53-400 and 500. Shell shall comply with the requirements for vacuum truck operations at its facility, as indicated in Table IV – CCCC of the permit.

Applicable definitions are included in Section 8-53-200. Some key definitions are specified below.

Per Section 8-53-211, a loading event is defined as "the loading at a single location within an affected facility of regulated material into a vacuum truck or other container through a vacuum truck operation. The resumption of loading at the same location after an interruption shall not be considered a separate loading event."

Per Section 8-53-218, regulated materials under this rule include:

218.1 "Gasoline, aviation gasoline, gasoline blending stock, naphtha;

218.2 Transmix, slop, or any other hydrocarbon mixture that includes a material listed in Section 8-53-218.1 if

2.1 For a mixture without significant water content, the true vapor pressure of the mixture is greater than 25.8 mmHg (0.5 psia) as determined pursuant to Section 8-53-602, or

2.2 For a mixture with significant water content, the water content is less than 98% as determined pursuant to Section 8-53-603.

Crude oil is not a regulated material."

Per Section 8-53-222, vacuum truck is defined as "portable equipment with an affixed barrel or tank that relies on the creation of a pressure differential, typically through use of a pump or blower, to pneumatically load materials into the barrel or tank of the equipment."

Per Section 8-53-223, vacuum truck operation is defined as "the movement of regulated material into a vacuum truck or into any other container through the use of a vacuum truck. For purposes of this rule, the use of other means, typically gravity feed or an auxiliary pump, to push or pull materials into a vacuum truck shall be considered a vacuum truck operation.

Applicability of BAAQMD Regulation 11, Rule 10: "Hexavalent Chromium Emissions from All Cooling Towers and Total Hydrocarbon Emissions from Petroleum Refinery Cooling Towers"

This rule was adopted on November 15, 1989 and was most recently amended on December 16, 2015. The rule's original scope was to limit hexavalent chromium emissions from all cooling towers. The recent amendment expanded the scope of the rule so that its purpose also includes limiting total hydrocarbon emissions from cooling towers at petroleum refineries.

Effective July 1, 2016 total hydrocarbon leak monitoring for petroleum refinery cooling towers must be initiated using one of the options in Section 11-10-304. Should monitoring results indicate that the applicable leak action level has been exceeded, the leak action requirements of Section 11-10-305 shall be followed. Section 11-10-402 outlines best modern practices that shall be used to minimize total hydrocarbon emissions. Reporting and recordkeeping requirements are described in Sections 11-10-401 and 504.

At the Shell Martinez refinery, this rule applies to sources S-1457, S-1778, and S-4210.

Applicability of 40 CFR 60, Subpart Ja

The Shell Martinez refinery owns and operates flares subject to the requirements of 40 CFR 60, Subpart Ja. The finalized rule for NSPS Subpart Ja was published in the Federal Register on September 12, 2012. The portions of the rule that were stayed in 2008 became effective on November 13, 2012. As documented in Shell's Notification of New Affected Sources submitted to the BAAQMD on December 12, 2012, there are three Shell emission sources affected by the rule. The sources, applicable standards, and monitoring provisions are summarized in the table shown below.

Unit Name	Source Number	Applicable Standards		Applicable Monitoring Provisions
Flare, Modified				
LOP Flare	S1471	60.103a(h)	Fuel gas H2S limited to 162 ppmv, 3-hour rolling average basis (combustion in a flare of process upset gas or fuel gas that is released as a result of relief valve leakage or other emergency malfunctions is exempt from this limit)	H2S monitoring under 60.107a(a)(2) is not required per 60.107a(a)(3) if the flare only combusts exempt streams under 60.103a(h) (process upset gases or emergency malfunctions). The LOP flare is an emergency use only flare, so H2S monitoring is not required.
OPCEN HC Flare	S1772	60.103a(h)	Fuel gas H2S limited to 162 ppmv, 3-hour rolling average basis (combustion in a flare of process upset gas or fuel gas that is released as a result of relief valve leakage or other emergency malfunctions is exempt from this limit)	H2S monitoring under 60.107a(a)(2) is not required per 60.107a(a)(3) if the flare only combusts exempt streams under 60.103a(h) (process upset gases or emergency malfunctions). The OPCEN HC flare is an emergency use only flare, so H2S monitoring is not required.
DCU Flare	S4201	60.103a(h)	Fuel gas H2S limited to 162 ppmv, 3-hour rolling average basis (combustion in a flare of process upset gas or fuel gas that is released as a result of relief valve leakage or other emergency malfunctions is exempt from this limit)	H2S monitoring under 60.107a(a)(2) is not required per 60.107a(a)(3) if the flare only combusts exempt streams under 60.103a(h) (process upset gases or emergency malfunctions). The DCU flare is an emergency use only flare, so H2S monitoring is not required.

Other Refinery sources potentially subject to 40 CFR 60, Subpart Ja are listed in the table below. However, because they have not been constructed, reconstructed, or modified after the relevant applicability date, these sources are not subject to 40 CFR 60, Subpart Ja.

Unit Name	Source Number	Applicability Date
Flares: FXG, LPG Loading Rack, VRS 1, 2, and 3 flares	1771, 1470, A101, A102, A103	6/24/08
FCCU	1426	5/14/07
DCU	4001	5/14/07

SRU1, SRU2, SRU3, SRU4	1431, 1432, 1765, 4180	5/14/07
Fuel Gas Combustion Devices (process heaters)	See Title V PC 16688	5/14/07

Applicability of 40 CFR 63 CC for Heat Exchange Systems, S-1457, S-1778, and S-4210 Cooling Towers

The Shell Martinez refinery owns and operates three heat exchange systems associated with a petroleum refining process unit meeting the criteria in 40 CFR 63.640(a) and which are in organic hazardous air pollutants (HAP) service, as defined in 40 CFR 63.641. The heat exchange systems are closed-loop systems that provide cooling water for the following Refinery's process units:

- S-1457 for heat exchange systems LOP-1 and LOP-2 (CWT-32) provides cooling water to the LOP processing units,
- S-1778 for heat exchange system OPCEN (CWT-50) provides cooling water to the OPCEN processing units, and
- S-4210 for heat exchange system DCU (CWT-13278) provides cooling water to the DCU processing units.

Consistent with the requirements of 40 CFR 63.655(f)(1), Shell submitted a Notice of Compliance Status (NOCS) report for these three heat exchange systems in a letter to the US EPA and BAAQMD on March 26, 2013. As specified in 40 CFR 63.655(f)(1)(vi), the NOCS report identified each heat exchange system subject to the requirements of Subpart CC. This application for the Title V permit renewal requests that S-1457, S-1778, and S-4210 be revised to include the applicable citations for 40 CFR 63 Subpart CC to identify these sources as affected units subject to the VOC emission and monitoring requirements for heat exchange systems. In addition, this application proposes the consolidation of Tables IV-CC (S-1457, S-1778) and IV-LLL (S-4210) for consistency with Table VII-Z (which addresses all three heat exchange systems).

Applicability of NESHAP 40 CFR 63 Subpart EEE for S1507, S1509, and S1512 UTIL CO Boilers

As stated in a letter to the US EPA and APCO BAAQMD dated December 22, 2014, the Shell Martinez Refinery is no longer an affected source of Subpart EEE. As required by 40 CFR 63.1200(b)(1):

1. Shell ceased combustion of the hazardous K048 Dissolved Air Floatation (DAF) Float waste in the CO Boilers #1, 2, and 3 in 2013.
2. Closure proceedings for the CO Boilers commenced with CO Boiler #2 in September 2014, and will be completed for CO Boilers #1 and #3 in 2016. In addition, Shell completed closure of the associated hazardous waste storage tank in 2014.

The CO Boilers (and associated Electrostatic Precipitators) serve as the control device for the refinery Catalytic Cracking Unit, and as such are subject to Subpart UUU (Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Unit). Per 40 CFR 63.7491(h), the CO Boilers are not subject to Subpart DDDDD (Industrial, Commercial, and Institutional Boilers and Process Heaters). Shell is complying with the requirements of Subpart UUU.

Applicability of NESHAP 40 CFR 63, Subpart ZZZZ, Internal Combustion Engines

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

Under 40 CFR 63 Subpart ZZZZ (National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines) new emergency stationary engines with a site rating of more than 500 horsepower located at a major source of hazardous air pollutants (HAP) are only subject to the initial notification requirements specified under Section 63.6645(f) (per Section 63.6590(b)(1)(i)). In January 2014, Shell submitted an Initial Notification statement certifying that Subpart ZZZZ applies to S6703 – Diesel Engine as a new affected source with a compliance effective date of January 15, 2014 because it has a power rating of > 500 brake horsepower.

Applicability of NESHAP 40 CFR 63, Subpart DDDDD, Boiler MACT Requirements

The Shell Martinez refinery owns and operates boilers and process heaters subject to the requirements of 40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, known as the Boiler MACT. The finalized rule for 40 CFR 63, Subpart DDDDD was published in the Federal Register on January 31, 2013. As documented in Shell's Initial Notification for affected Sources submitted to the EPA Region IX and BAAQMD January 11, 2012, there are industrial boilers and process heaters at the Martinez refinery that will become subject to the periodic tune-up and initial energy assessment requirements.

The sources and applicable standards are summarized below, including identification of other combustion devices that are not subject to the requirements because they are specifically excluded or do not meet the definition of a boiler or process heater:

Unit Name/Source Number	Applicable Standards
Boilers and Process Heaters with Heat Input > 10 MMBtu/Hr	

DH CU F40/S1486 DH CU F126/S1763 DH VFU F41A/S1488 DH VFU F41B/S1487 DH SRHT F43/S1490 DH SRHT F44/S1491 DH SRHT F45/S1492 DH SRHT F46/S1493 DH SRHT F47/S1494 DH CRU F49/S1495 DH CRU F50/S1496 DH CRU F51/S1497 DH CRU F128/S1762 DH CRU F52/S1498 DH CRU F53/S1499 DH HP1 F60/S1505 DH SGP F55/S1500 DH HCU F57/S1502	DH HCU F58/S1503 DH HCU F59/S1504 DH HCU F71/S1515 DCD DCU F13425A/S4002 DCU F13425B/S4003 DCD DHT F13909/S4021 DCD HGHT F14011/S4141 DCD HGHT F14012S/4031 HP3 HP3 H101/S4161 UTL CGH F61/S1506 CP CFH F63/S1508 CP CCU F66/S1510 CP CCU F67/S1511 OPCEN FXU F102/S1760 OPCEN DSU F30/S1481 OPCEN HP2 F104/S1761 UTL Boiler 4 F70/S1514	63.5715	Tune-ups and one-time energy assessment
Fuel Gas Combustion Devices That Are Not Subject to 40 CFR 63, Subpart DDDDD			
SRU1/S1431 SRU2/S1432 SRU3/S1765 SRU4/S4180 UTIL Boiler 6 Turbine/S4190 UTIL Boiler 6 Turbine /S4192		63.7575	Do not meet the definition of boilers or process heaters
UTIL Boiler 6 HRSG/S4191 UTIL Boiler 6 HRSG/S4913		63.7575	Waste heat boilers
UTIL CO Boiler 1/S1507 UTIL CO Boiler 2/S1509 UTIL CO Boiler 3/S1512		63.7491(l)	Listed as an affected source in a standard established under Section 129 of the Clean Air Act

Applicability of Refinery Sector Rule (RSR) Revisions to NESHAP 40 CFR 63, Subpart CC and Subpart UUU, Refinery MACT Requirements

The Shell Martinez refinery owns and operates sources affected by the Refinery Sector Rule revisions to 40CFR63 Subparts CC and UUU. The finalized rule for 40 CFR 63, Subpart CC (Refinery MACT 1) was published in the Federal Register on July 13 2016. The finalized rule for 40 CFR Subpart UUU (Refinery MACT 2) was published in the Federal Register on December 1, 2015. Changes to incorporate the revised regulatory requirements have been added to the following sources, including future applicable dates, where applicable. For some sources, the detailed regulatory applicability has been rolled up in the Title V Permit pending EPA revisions to the regulations, expected in early 2018. Affected sources and Title V Permit changes for the RSR revisions include:

Source #	**Description**	**Regulation(s)**	**Table(s)**
S601	Flare for VRS #2	Added Subpart CC, 63.670 and 671	IV-DD
S602	Flare for VRS #3	Added Subpart CC, 63.670 and 671	IV-DD
S603	Flare for VRS #1	Added Subpart CC, 63.670 and 671	IV-EE
S1471	LOP Auxiliary Flare	Added Subpart CC, 63.670 and 671	IV-FF

Source #	Description	Regulation(s)	Table(s)
S1472	LOP Main Flare	Added Subpart CC, 63.670 and 671	IV-FF
S1771	OPCEN Flexigas Flare	Added Subpart CC, 63.670 and 671 and added Subpart A 63.6(i) for request for extension	IV-QQ
S1772	OPCEN HC Flare	Added Subpart CC, 63.670 and 671	IV-RR
S4201	DC Clean Fuels Flare	Added Subpart CC, 63.670 and 671	IV-III
NA	Equipment Leaks - PRDs	Added Subpart CC, 63.648(j)	IV-TTT
Multiple	Multiple	Removed 63.655(h)(1) SSM reporting	Multiple
Multiple	General provisions	Updated 63.642	Multiple
Facility-Wide	MPV-Maintenance Vents	Added Subpart CC, 63.640(c)(1), 643	IV-WWW
Facility-Wide	Fenceline Monitoring	Added Subpart CC, 63.658	IV-WWW
Facility-Wide	Wastewater Provisions	Updated 63.647(c) to (d)	IV-VVV, IV-WWW
S1425	Catalytic Reformer Unit	Removed SSM and revised general duty for 63.1570, 1571,1572, 1575	IV-X
S1426	Catalytic Cracking Unit	Added 63.1564, 1565 startup, shutdown, hot standby compliance options	IV-Y
S1426	Catalytic Cracking Unit	Removed SSM and revised general duty for 63.1570, 1571,1572, 1575	IV-Y
S1426	Catalytic Cracking Unit	Added 63.1571 performance testing for PM/Ni and HCN	IV-Y
S1431, S1432, S1765, S4180	SRU1, SRU2, SRU3, SRU4	Added 63.1568 startup, shutdown compliance options	IV-Z
S1431, S1432, S1765, S4180	SRU1, SRU2, SRU3, SRU4	Removed SSM and revised general duty for 63.1570, 1571,1572, 1575	IV-Z
Multiple	Tanks	Added 63.640(n) Subpart CC overlap for NSPS Subpart Ka tanks	IV-K
Multiple	Tanks	Updated 63.640(n) Subpart CC overlap for NSPS Subpart Kb tanks	IV-N, IV-M, IV-Q
Multiple	Tanks, Group 1	Added statement for applicability to 63.646/Subpart G until 63.660/Subpart WW compliance based on 63.640(h) compliance date	IV-I, IV-K, IV-BB VII-F, VII-H
Multiple	Tanks, Group 1	Updated 63.646 and added 63.660	IV-I, IV-K, IV-BB
Multiple	Tanks, Group 1	Renumbered 63.655(g)(4) to (g)(3)	Multiple
Multiple	Tanks, Group 1	Removed 63.655(g)(3) subsections	Multiple
Multiple	Tanks, Group 1	Updated 63.655 recordkeeping requirements	IV-BB, IV-K

Source #	Description	Regulation(s)	Table(s)
Multiple	Tanks, Group 1	Added 63.640(n)(8) requirements for Kb storage vessels	IV-N, IV-M
Multiple	Tanks, Group 2	Added statement for applicability to 63.646/Subpart G until 63.660/Subpart WW compliance based on 63.640(h) compliance date	IV-A, IV-C, IV-F, IV-H, IV-J, IV-XXX, IV-ZZZ
Multiple	Tanks, Group 2	Added 63.655(i)(1)(vi) recordkeeping requirements	IV-A, IV-C, IV-F, IV-H, IV-J, IV-XXX, IV-ZZZ
Multiple	Tanks	Renumbered 63.655(i)(5) to (i)(6)	Multiple
Multiple	Tanks	For wastewater sources with closed vent systems, added 63.647(c) flare control requirements	IV-L, IV-R, IV-JJJ, IV-NNN

<u>Changes to permit:</u>

- Table IV – A
  - BAAQMD Condition # 25134 added per A/N 22045
- Table IV – D
  - S1070 deleted per A/N 2736
  - BAAQMD Condition # 18153, S1070 no longer in table per A/N 2736
  - BAAQMD Condition #18618, added S19 and S1139
- Table IV – E
  - Added monitoring exemption for NSPS 40 CFR 60 Ka for storage vessels equipped with a closed vent system and control device.
- Table IV – F
  - BAAQMD & SIP Regulation 6-1-301, -305, -311, and -401, removed applicability because the tanks are no longer used to store asphalt since asphalt is no longer produced at Facility A0011
  - BAAQMD & SIP 8-5-117, limited exemption added to allow owner/operator to use the tank in exempt material service
- Table IV – G
  - S1408, S1523, S1524, and S1525, deleted asphalt from the source description consistent with the changes in Section II
  - BAAQMD & SIP Regulation 6-1-301, -305, -311, and -401, removed applicability because the tanks are no longer used to store asphalt since asphalt is no longer produced at Facility A0011
- Table IV – H
  - BAAQMD & SIP 8-5-117 limited exemption added to allow owner/operator to use the tank in exempt material service
- Table IV – I

- S541 and S544 deleted per A/N 22045
    - BAAQMD Condition # 11850 deleted per A/N 22045
    - BAAQMD Condition # 18618 description updated per A/N 22045
    - BAAQMD Condition # 18618, added S540 per A/N 14163
- Table IV – J
    - Deleted S992 from the source description – a demolished source
- Table IV – M
    - S1070 added per A/N 2736
    - S1128 added per A/N 22045
    - BAAQMD Condition # 18153 added per A/N 2736
    - BAAQMD Condition # 18618 added for S1070 and S1128 per A/N 2736 and A/N 22045
    - BAAQMD Condition # 18618, added S2445 and S2446
    - BAAQMD Condition # 18618, added S6062 per A/N 14224
    - BAAQMD Condition # 23003 add because it was missing
    - BAAQMD Condition # 25134 added per A/N 22045
- Table IV – N
    - S6069, S6070, S6071, S6072 added per A/N 22045
    - BAAQMD Condition #18618, added S6069, S6070, S6071, and S6072 per A/N 22045
    - BAAQMD Condition #25134 added per A/N 22045
    - BAAQMD Condition # 18618, added S2013 per A/N 1583
    - BAAQMD Condition # 18618, added S17095 per A/N 5700
- Table IV – Q
    - BAAQMD Condition #7215, Parts 4, 5, and 6 added because they were missing
    - BAAQMD Condition # 18618, added S1114 and S1115 per A/N 12025
    - Added requirement to operate in compliance with the monitoring plan required by NSPS 40 CFR 60 Kb 60.113b(c)(1) for storage vessels equipped with a closed vent system and control device.
    - Expanded NSPS 40 CFR 60 Kb applicability for consistency with other similar storage vessels
- Table IV – R
    - BAAQMD Condition # 18618, added S1805 per A/N 2365
- Table IV–-S
    - Added requirement to operate in compliance with control requirements of NSPS40 CFR 60.18 because this tank is subject to NSPS Kb 60.113b(c)(1)
- Table IV – U
    - Deleted S1186 from the source description – a demolished source
- Table IV – W
    - BAAQMD Regulation 8, Rule 18, updated applicability
    - SIP Regulation 8, Rule 18, updated applicability

- BAAQMD Condition # 18618, added S1424
    - BAAQMD Condition # 21896, Part 1 amended to allow for five-year source testing
    - BAAQMD Condition # 25345 added per A/N 19872
    - BAAQMD Condition #26555 added per A/N 28652
- Table IV – X
    - BAAQMD Regulation 8, Rule 18, updated applicability
    - SIP Regulation 8, Rule 18, updated applicability
- Table IV – Y
    - BAAQMD Regulation 6, Rule 5, new regulation added
    - BAAQMD Regulation 8, Rule 18, updated applicability
    - SIP Regulation 8, Rule 18, updated applicability
    - BAAQMD Condition # 25345 added per A/N 19872
- Table IV – Z
    - BAAQMD Regulation 11, Rule 10, added applicability
    - Table has been merged with former Tables IV – AA, BB, and QQQ
- Table IV – AA
    - Table has been deleted and combined with Table IV – Z
- Table IV – BB
    - Table has been deleted and combined with Table IV – Z
- Table IV – CC (resequenced to AA)
    - S4210 – Cooling Water Tower (CWT-13278) added
    - BAAQMD Regulation 1, added applicability
    - SIP Regulation 1, added applicability
    - BAAQMD Regulation 11, Rule 10, added applicability
    - NESHAP 40 CFR 63 Subpart A, added applicability
    - NESHAP 40 CFR 63 Subpart CC, added applicability
- Table IV – DD (resequenced to BB)
    - BAAQMD Regulation 8, Rule 8 updated regulation description
- Table IV – EE (resequenced to CC)
    - NSPS 40 CFR 60 Subpart A, applicability updated for consistency for other flares subject to NSPS Subpart J
    - NSPS 40 CFR 60 Subpart J, updated applicability
- Table IV – FF (resequenced to DD)
    - NSPS 40 CFR 60 Subpart A, applicability updated for consistency for other flares subject to NSPS Subpart J or Subpart Ja
    - NSPS 40 CFR 60 Subpart J, updated applicability
    - NSPS 40 CFR 60 Subpart Kb, updated applicability for flare as control device
    - BAAQMD Condition # 7761, Parts 6 and 11, updated for re-designation of A101 and 102 to S601 and S602
    - Table has been merged with former Table IV – VVV
- Table IV – GG (resequenced to EE)

- Description updated to indicate re-designation of A103 abatement device to emission source S603
    - NSPS 40 CFR 60 Subpart A, applicability updated for consistency for other flares subject to NSPS Subpart J or Subpart Ja
    - NSPS 40 CFR 60 Subpart J, updated applicability
    - BAAQMD Condition # 7761, Part 1, updated for re-designation of A103 to S603
    - Table has been merged with former Table IV – VVV
- Table IV – HH (resequenced to FF)
    - BAAQMD Regulation 12, Rule 12, added applicability
    - NSPS 40 CFR 60 Subpart A, applicability updated for consistency for other flares subject to NSPS Subpart J or Subpart Ja
    - NSPS 40 CFR 60 Subpart J deleted
    - NSPS 40 CFR 60 Subpart Ja, added applicability
- Table IV – II (resequenced to GG)
    - BAAQMD Regulation 9, Rule 10, updated applicability
    - NESHAP 40 CFR 63 Subpart A, added applicability
    - NESHAP 40 CFR 63 Subpart DDDDD, new regulation added
    - BAAQMD Condition # 18265, Part 9 deleted since it does not apply as the heaters have a firing rate of < 25 MMBTU/hr
- Table IV – JJ (resequenced to HH)
    - BAAQMD Regulation 9, Rule 10, updated applicability
    - NESHAP 40 CFR 63 Subpart A, added applicability
    - NESHAP 40 CFR 63 Subpart DDDDD, new regulation added
- Table IV – KK (resequenced to II)
    - BAAQMD Regulation 9, Rule 10, modified to reflect regulation amendment
    - NESHAP 40 CFR 63 Subpart A, added applicability
    - NESHAP 40 CFR 63 Subpart DDDDD, new regulation added
    - BAAQMD Condition #25134 added per A/N 22045
- Table IV – LL (resequenced to JJ)
    - BAAQMD Regulation 9, Rule 10, modified to reflect regulation amendment
    - NESHAP 40 CFR 63 Subpart A, added applicability
    - NESHAP 40 CFR 63 Subpart DDDDD, new regulation added
- Table IV – MM (resequenced to KK)
    - BAAQMD Regulation 9, Rule 10, modified to reflect regulation amendment
    - NESHAP 40 CFR 63 Subpart A, added applicability
    - NESHAP 40 CFR 63 Subpart DDDDD, new regulation added
    - BAAQMD Condition #16688 deleted, already listed in the table
    - BAAQMD Condition #18618, Part 2 removed because Part 2 applies only if the source(s) are listed in Condition 18618, Part 1
- Table IV – NN (resequenced to LL)
    - BAAQMD Regulation 9, Rule 10, modified to reflect regulation amendment

    - NESHAP 40 CFR 63 Subpart A removed
    - NESHAP 40 CFR 63 Subpart EEE removed
    - NESHAP 40 CFR 63 Subpart DDDDD exemption added
    - BAAQMD Condition # 17533 revised per A/N 28866 and Regulation 6-5
    - BAAQMD Condition # 25134 added per A/N 22045
    - BAAQMD Condition # 25247 added per A/N 22287
- Table IV – OO (resequenced to MM)
    - BAAQMD Regulation 9, Rule 10, modified to reflect regulation amendment
    - NESHAP 40 CFR 63 Subpart A, added applicability
    - NESHAP 40 CFR 63 Subpart DDDDD, new regulation added
- Table IV – PP resequenced to NN)
    - BAAQMD Condition #24298, added federal enforceability, erroneously omitted
- Table IV – SS (resequenced to QQ)
    - BAAQMD Regulation 12, Rule 12, added applicability
    - BAAQMD Condition #7618, resequenced for alphanumeric order
    - NSPS 40 CFR 60 Subpart A, applicability updated for consistency for other flares subject to NSPS Subpart J or Subpart Ja
    - NSPS 40 CFR 60 Subpart J, updated applicability
- Table IV – TT (resequenced to RR)
    - BAAQMD Regulation 12, Rule 12, added applicability
    - NSPS 40 CFR 60 Subpart A, applicability updated for consistency for other flares subject to NSPS Subpart J or Subpart Ja
    - NSPS 40 CFR 60 Subpart J deleted
    - NSPS 40 CFR 60 Subpart Ja, added applicability
- Table IV – UU (resequenced to SS)
    - BAAQMD Regulation 9, Rule 10, modified to reflect regulation amendment
- Table IV – WW (resequenced to UU)
    - BAAQMD Regulation 8, Rule 32, modified to reflect regulation amendment
    - SIP Regulation 8, Rule 32, regulation added
- Table IV – ZZ (resequenced to XX)
    - BAAQMD Regulation 8, Rule 44, modified to reflect regulation amendment
    - BAAQMD Regulation 8, Rule 44, removed sections applicable to marine vessel owners only
    - SIP Regulation 8, Rule 44, regulation added
    - NESHAP 40 CFR 63 Subpart A, regulation added
    - NESHAP 40 CFR 63 Subpart CC, regulation added
    - NESHAP 40 CFR 63 Subpart Y, modified to reflect regulation amendment
- Table IV – AAA (resequenced to YY)
    - BAAQMD Regulation 8, Rule 8 changed regulation description

    - Deleted incorrect monitoring requirement 61.354(c)(8) for carbon adsorption with regeneration because source is subject to 61.354(d) for monitoring carbon adsorption systems without regeneration
- Table IV – BBB (resequenced to ZZ)
    - BAAQMD Regulation 8, Rule 8 changed regulation description
- Table IV – CCC (resequenced to AAA)
    - BAAQMD Regulation 8, Rule 8 changed regulation description
- Table IV – GGG (resequenced to EEE)
    - BAAQMD Regulation 9, Rule 10, modified to reflect regulation amendment
    - NESHAP 40 CFR 63 Subpart A, added applicability
    - NESHAP 40 CFR 63 Subpart DDDDD, new regulation added
    - BAAQMD Condition #25134 added per A/N 22045
- Table IV – HHH (resequenced to FFF)
    - BAAQMD Regulation 9, Rule 10, modified to reflect regulation amendment
    - NESHAP 40 CFR 63 Subpart A, added applicability
    - NESHAP 40 CFR 63 Subpart DDDDD, new regulation added
- Table IV – KKK (resequenced to III)
    - BAAQMD Regulation 12, Rule 12, added applicability
    - NSPS 40 CFR 60 Subpart A, applicability updated for consistency for other flares subject to NSPS Subpart J or Subpart Ja
    - NSPS 40 CFR 60 Subpart J deleted
    - NSPS 40 CFR 60 Subpart Ja, added applicability
    - BAAQMD Condition #18618, Part 19 deleted for consistency
- Table IV – LLL
    - Table has been deleted and combined with Table IV – CC
- Table IV – DE (resequenced to MMM)
    - SIP Regulation 6, added applicability (was missing)
- Table IV – QQQ
    - Table has been deleted and combined with Table IV – Z
- Table IV – SSS (resequenced to OOO)
    - BAAQMD & SIP Regulation 8, Rule 5 updated applicability
- Table IV – TTT (resequenced to PPP)
    - BAAQMD Regulation 8, Rule 8 changed regulation description
- Table IV – UUU (resequenced to QQQ)
    - S6073 – Diesel Engine added with CARB ATCM and MACT ZZZZ applicability per A/N 25810
    - BAAQMD 9-8-110 and 9-8-110.5 added for the emergency standby engine exemption
    - BAAQMD 9-8-330.2 removed, no longer applies, superceded by 9-8-330.3
    - CCR Title 17 Section 93115.10, citation numbering updated
    - CCR Title 17 Section 93115.11 and 93115.11(a) deleted because it is a past-due requirement

- BAAQMD Condition # 22820 changed to reflect it is only applicable to S6051 through S6057, S6059, and S6060
  - BAAQMD Condition # 22820, citation numbering updated
  - BAAQMD Condition # 22820, Part 5 removed from Table, part does not exist in permit condition
  - BAAQMD Condition # 22850 added per A/N 25810 and 29043
  - BAAQMD Condition # 22850, citation numbering updated
- Table IV – VVV
  - Table has been deleted and combined with Tables IV – FF and GG
- Table IV – YYY
  - Table has been deleted because there are no longer any 40 CFR 63, Subpart CC Group 1 Miscellaneous Process Vents.
- Table IV – CCCC (resequenced to WWW)
  - BAAQMD Regulation 8, Rule 15, deleted as the plant no longer produces asphalt
  - BAAQMD Regulation 8, Rule 53, new regulation added
  - NESHAP 40 CFR 63 Subpart DDDDD, new regulation added
- Table IV – DDDD (resequenced to XXX)
  - Deleted 12 demolished sources from the source description: S28, S33, S346, S418, S814, S928, S1040, S1061, S1074, S1165, and S1173
  - S1128 deleted per A/N 22045
  - Added 40 CFR 63 Subpart CC requirements for Group 2 Storage Vessels
- Table IV – FFFF (resequenced to ZZZ)
  - Deleted asphalt from the source description consistent with the changes in Section II
  - BAAQMD & SIP Regulation 6-1-301, -305, -311, and -401, removed applicability because the tanks are no longer used to store asphalt since asphalt is no longer produced at Facility A0011
- Table IV – GGGG (resequenced to AAAA)
  - S7000 added per A/N 21359
  - BAAQMD Condition # 24795 added per A/N 21359
- Table IV – IIII (resequenced to CCCC)
  - S1426 and S1427 added per A/N 19872
- Table IV – JJJJ (resequenced to DDDD)
  - Changed order of regulations for consistency throughout the permit
  - BAAQMD Regulation 8, Rule 18, updated applicability
  - SIP Regulation 8, Rule 18, updated applicability

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.

The BAAQMD Compliance and Enforcement Division has conducted a review of compliance over the past year and has no records of compliance problems at this facility during the past year. The compliance report is contained in Appendix A of this permit evaluation and statement of basis.

VI. Permit Conditions

During the Title V permit development, the District 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 Title V requirements, additional monitoring, recordkeeping, or reporting requirements have been 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 and 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 <u>et seq</u>., an order of abatement pursuant to H&SC § 42450 <u>et seq</u>., 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 District has reviewed and, where appropriate, revised or added new annual and daily throughput limits on sources so as to help ensure compliance with District rules addressing preconstruction review. The applicability of preconstruction review depends on whether a source has been "modified" as defined in District Rule 2-1-234. Whether there is a modified source depends in part on whether there has been an "increase" in the potential to emit of a source. Regulation 2-1-234 defines what is considered an increase in the potential to emit of a source.

Sources that were modified or constructed since the District began issuing new source review permits will have permits that contain throughput limits, and these limits are reflected in the Title V permit. Each limit has previously undergone District review, and is the legally binding "potential to emit" of the source for purposes of 2-1-234.1.1. By contrast, for older sources that have never been through preconstruction review (commonly referred to as "grandfathered" sources), an "increase" in "potential to emit" is addressed in 2-1-234.1.2. A grandfathered source is not subject to preconstruction review unless it undergoes a change that results in an increase in its potential to emit as defined in 2-1-234.1.2. The emissions increase shall be calculated as the difference between (i) the source's potential to emit after the change, and (ii) the soruces's adjusted baseline emissions before the change, calculated in accordance with Section 2-2-603. However, if the throughput capacity of a grandfathered source is limited by upstream or downstream equipment (i.e., is "bottlenecked"), or for any source that cannot physically operate to the full extent of the source's potential to emit, then the relaxing of that limitation ("debottlenecking") is considered a modification as defined in 2-1-234.1.2. In the case of a source that has undergone New Source Review and is subject to a limit on its potential to emit that it cannot physically attain, then any physical change, change in method of operation, change in throughput or production, or other similar change at the source that allows it to increase its potential to emit beyond this physical limit is also considered a modification.

The District has added throughput limits to the Title V permit for grandfathered sources. As discussed above, these limits were added so that the District could determine whether an increase in emission levels has occurred. The purpose of these limits is to facilitate implementation of the District's preconstruction review program. If these limits are exceeded, the facility would be expected to report the exceedance, and the District would treat the reported exceedance as presumptively establishing the occurrence of a modification. The facility would then be expected to apply for a preconstruction permit addressing the modification and the District would consider whether an enforcement action was appropriate.

It is important to note the presumptive nature of throughput limits for grandfathered sources that are created in the Title V permit. These limits are generally based upon the District's review of information provided by the facility regarding the design capacity or highest documented capacity of the grandfathered source. To verify whether these limits reflect the true design, documented, or "bottlenecked" capacity (pursuant to 2-1-234.1.2) of each source is beyond the resource abilities of the District in this Title V process. Moreover, the District cannot be completely confident that the facility has had time or resources necessary to provide the most accurate information available in this regard. Creating throughput limits in the Title V permit for grandfathered sources is not required by either Part 70 or the District's Major Facility Review rules. Despite the lack of such a requirement, and despite the resource and information challenges presented in the Title V process, the District believes that writing presumptive limits for grandfathered sources into the Title V permit will provide a measure of predictability regarding the future applicability of the preconstruction review program, and that this increased predictability is universally beneficial.

It follows from the presumptive nature of these throughput limits for grandfathered sources that exceedance of these limits is not per se a violation of the permit. *Failure to report an exceedance would be a permit violation.* In this sense, the throughput limits function as monitoring levels, and are imposed pursuant to the District's authority to required monitoring that provide a reasonable assurance of compliance. If an exceedance occurs, the facility would have an opportunity to demonstrate that the throughput limit in fact did not reflect the appropriate limit for purposes of 2-1-234.1.2. If the facility can demonstrate this, no enforcement action would follow, and the permit would be revised at the next opportunity. It also follows that compliance with these limits is not a "safe harbor" for the facility. If evidence clearly shows that a source has undergone a "modification" as defined in 2-1-234.1.2, the District would consider that a preconstruction review-triggering event, notwithstanding compliance with the throughput limit in the Title V permit. In other words, the protection afforded the facility by complying with the throughput limit in the Title V permit is only as strong as the information on which it was based. There is no Title V "permit shield" associated with throughput limits for grandfathered sources, as they are being proposed. A shield may be provided if the District determines with certainty that a particular limit is appropriate with respect to 2-1-234.1.2.

Conditions that are obsolete or that have no regulatory basis have been deleted from the permit.

Conditions have also been deleted due to the following:

- Redundancy in recordkeeping requirements.
- Redundancy in other conditions, regulations and rules.
- The condition has been superseded by other regulations and rules.
- The equipment has been taken out of service or is exempt.
- The event has already occurred (i.e. initial or start-up source tests).

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 that 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 the proposed renewal permit stemming from changes to existing permit conditions and/or from incorporating new permit conditions:

BAAQMD Permit Condition 4101
Deleted 'asphalt' from the description of S1523 since asphalt is no longer produced at Facility A0011.

BAAQMD Permit Condition 7215
Corrected numbering of parts 4, 5, and 6

BAAQMD Permit Condition 7618
Tables II, III, IV, and V revised to adjust for CARB marine fuel sulfur standards per A/N 22045. Table II revised to adjust for BAAQMD Regulation 9-10-307 limit for partial-burn CO boilers per A/N 27866.

BAAQMD Permit Condition 7761
Revised description and parts 1, 6, and 11 for re-designation of flares A101, A102, and A103 as abatement devices to emission sources

BAAQMD Permit Condition 11850
This permit condition has been deleted per A/N 22045.

BAAQMD Permit condition 12271, Part 69
The revision to this permit condition incorporates language to provide for an allowance to decrease source test frequency based on results that are less than 50% of the applicable emission standard. This is for consistency with other source test permit conditions where this allowance is already included.

BAAQMD Permit condition 12271, Part 85
Nitrogen oxides limit revised to account for BAAQMD Regulation 9-10-307 limit. Reduced by 996 lbs/day.

BAAQMD Permit condition 12271, Part 86
Nitrogen oxides limit revised to account for BAAQMD Regulation 9-10-307 limit. Reduced by 996 lbs/day.

BAAQMD Permit Condition 18618, Part 1
This part has been separated into two subparts, Part 1a and Part 1b. Consistent with Standard Condition J – Miscellaneous Conditions, Part 2, sources listed in Condition 18618, Part 1a are 'grandfathered' sources whose throughput limits were based on District records at the time of MRF permit issuance. Exceedance of those limits are not a violation of the permit if it can be demonstrated within 60 days that the throughput limit should be higher as established in accordance with Regulation 2-1-234.3, and the excess throughput complies with the new limit. Sources which have undergone New Source Review (NSR) have been moved from Part 1a to Part 1b. These 'NSR' sources have throughput limits that are based on other permit conditions or NSR application information. Exceedance of the throughput limits in Part 1b is a violation of Regulation 2-1-307 immediately upon exceedance of the limit.

This part has also been updated to account for the new sources and throughput limits per A/N 22045.

S549 and S6068 were added to Part 1 because these tanks are shown as being applicable to Condition #18618 in Sections IV and VII, and they are included in a group throughput limit for other tanks listed in Condition #18618.

For the following sources, 'asphalt storage' was removed from the description because the tanks will no longer be used for asphalt service since asphalt is no longer produced at Facility A0011: S21, S23, S24, S26, S497, S552, S553, S554, S555, S556, S557, S558, S559, S560, S561, S567, S572, S573, S598, S815, S985, S1043, S1044, S1045, S1160

BAAQMD Permit Condition 18618, Part 19
This part has been updated to remove the future effective date and deleted S4201

BAAQMD Permit Condition 19748, Part 7
The revision to this permit condition corrects the SO2 emission limit averaging period from 24 to 12-hoursfor consistency with the NSPS J limit. This error was noted during EPA review of the Title V permit during termination of the EPA Consent Decree.

BAAQMD Permit Condition 19748, Part 14
The revision to this permit condition incorporates language to provide for an allowance to decrease source test frequency based on results that are less than 50% of the

applicable emission standard. This is for consistency with other source test permit conditions where this allowance is already included.

BAAQMD Permit Condition 21896
The revision to this permit condition incorporates language to provide for an allowance to decrease source test frequency based on results that are less than 50% of the applicable emission standard. This is for consistency with other source test permit conditions where this allowance is already included.

BAAQMD Condition 22165
Deleted Parts 2 through 5 based on notations in Table IV – NN for COBs.

BAAQMD Condition 22820
Regulatory basis for citations have been updated.

BAAQMD Condition 22850
This permit condition has been added per NSR A/N 25810 and 29043.
Regulatory basis for citations have been updated.

BAAQMD AMP Condition 24337
This permit condition has been deleted [Basis: Fuel gas streams inherently low in sulfur content are exempt from monitoring per 40 CFR 60.105(a)(4)(iv)].

BAAQMD Permit Condition 24795
This permit condition has been added per A/N 21359.

BAAQMD Permit Condition 25134
This permit condition has been added per A/N 22045.

BAAQMD Permit Condition 25247
This permit condition has been added per A/N 22287

BAAQMD Permit Condition 25345
This permit condition has been added per A/N 19872

BAAQMD Permit Condition 25366
This permit condition has been added per A/N 24479

BAAQMD Permit Condition 26555
This permit condition has been added per A/N 26555

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.

<u>Changes to permit</u>

As shown in the table below, the tables in Section VII have been re-sequenced to accommodate table deletions and consolidations. In the following section, all changes are described using the old table numbers.

Old Lettering	New Lettering	Description
A	A	
B	B	--
C	C	--
D	D	--
E	E	--
F	F	--
G	G	--
H	H	--
I	I	--
J	J	--
K	K	--
L	L	--
M	M	--
N	N	--
O	O	--
P	P	--
Q	Q	--
R	R	--
S	S	--
T	T	--
U	U	--
V	V	--
W	W	Incorporated S4180 (SRU4) from deleted X, FFF and S1765 (SRU3) from deleted X and Y
X	Deleted	For S4180 (SRU4), combined with W
Y	Deleted	For S1765 (SRU3), combined with W
Z	X	--
AA	Y	--
BB	Z	--

CC	AA	--
DD	BB	--
EE	CC	--
FF	DD	--
GG	EE	--
HH	FF	--
II	GG	--
JJ	HH	--
KK	II	--
LL	JJ	--
MM	KK	--
NN	LL	--
OO	MM	--
PP	NN	--
QQ	OO	--
RR	PP	--
SS	QQ	--
TT	RR	--
UU	SS	--
VV	TT	--
WW	UU	--
XX	VV	--
YYY(#1)	WW	--
ZZ	XX	--
AAA	YY	--
BBB	ZZ	--
CCC	AAA	--
DDD	BBB	--
EEE	CCC	--
FFF	Deleted	For S4180 (SRU4), combined with W
GGG	DDD	--
HHH	EEE	--
III	FFF	--
JJJ	GGG	--
KKK	HHH	--
LLL	III	--
MMM	JJJ	--
NNN	KKK	--
OOO	LLL	--
PPP	MMM	--
QQQ	Deleted	40 CFR 63 Subpart CC MPVs Removed
RRR	NNN	--

SSS	OOO	--
TTT	PPP	--
UUU	QQQ	--
VVV	RRR	--
WWW	SSS	--
XXX	Deleted	For S568 (TK-568), combined with A
YYY (#2)	TTT	--
ZZZ	UUU	--
AAAA	VVV	--
--	WWW	For S63, S355, S432, and S568

Regulatory names for the NSPS and NESHAP regulations were updated for consistency throughput the permit.

- Table VII –A
  - Modified per A/N 22045 for S967
  - Merged with Table VII - XXX
- Table VII – C
  - S1070 deleted per A/N 2736
  - Added applicability for BAAQMD & SIP 8-5-303.1 & 303.2 with monitoring for 8-5-403 because the monitoring requirement had been inadvertently omitted.
  - Added applicability for BAAQMD 8-5-306.2 with monitoring for 8-5-403 because the monitoring requirement had been inadvertently omitted (the 8-5-118 limited exemption does not apply for tank appurtenances per 8-18-115)
  - Modified text of limit for BAAQMD Regulation 8-5-328.1 citation
  - Added S19 and S1139 to BAAQMD Condition # 18618
  - Deleted BAAQMD Condition # 18153 for S1070 per A/N 2736
- Table VII – D
  - Added applicability for BAAQMD & SIP 8-5-303.1 & 303.2 with monitoring for 8-5-403 because the monitoring requirement had been inadvertently omitted.
  - Added applicability for BAAQMD 8-5-306.2 with monitoring for 8-5-403because the monitoring requirement had been inadvertently omitted (the 8-5-118 limited exemption does not apply for tank appurtenances per 8-18-115)
  - For VOC row, added monitoring exemption for NSPS 40 CFR 60 Subpart Ka for storage vessels equipped with a closed vent system and control device.
  - For VOC row, removed incorrect 40 CFR 63 Subpart CC 63.640(d)(5) exemption because sources are not subject to this regulation so the exemption is not applicable.
- Table VII – E

    - S1160, S1408, S1523, S1524, and S1525, deleted asphalt from the source description consistent with the changes in Section II
    - BAAQMD & SIP Regulation 6-1-301, removed applicability because the tanks are no longer used to store asphalt since asphalt is no longer produced at Facility A0011
    - Added S24 to Condition #18618 Part 1, erroneously omitted
- Table VII – F
    - Deleted S541 and S544 and BAAQMD Condition # 11850 per A/N 22045
    - Added BAAQMD Condition # 12174 for S545 because it had been inadvertently omitted
    - Added S540 to BAAQMD Condition # 18618 per A/N 14163
- Table VII – G
    - Modified per A/N 22045 for S967
    - Deleted S992 and associated content because source has been demolished
- Table VII – I
    - Added applicability for BAAQMD & SIP 8-5-303.1 & 303.2 with monitoring for 8-5-403 because the monitoring requirement had been inadvertently omitted.
    - For HAP rows, added monitoring exemption for NESHAP 40 CFR 61 Subpart FF for gaseous streams routed to a fuel gas system.
    - For VOC row, removed incorrect 40 CFR 63 Subpart CC 63.640(d)(5) exemption because this does not provide a monitoring exemption for 40 CFR 61 Subpart FF.
- Table VII –K
    - Added S1070 per A/N 2736
    - Added S1128 and BAAQMD Condition # 25134 per A/N 22045
    - Added BAAQMD Condition #18618 per A/N 2736 and A/N 22045
    - Added S2445 and S2446 to BAAQMD Condition # 18618
    - Added BAAQMD Condition #18153 per A/N 2736
    - Add row for BAAQMD Condition #23003 throughput limit for S6062 because it was missing
- Table VII – L (S1006, S2013, S4310, S17095)
    - Updated rim-seal gap limits under 40 CFR 60 Subpart Kb
    - Added S6069, S6070, S6071, S6072, and BAAQMD Conditions #18618 and #25134 per A/N 22045
    - Added S2013 to BAAQMD Condition # 18618 per A/N 1583
    - Added S17095 to BAAQMD Condition # 18618 per A/N 5700
- Table VII – O
    - Added applicability for BAAQMD & SIP 8-5-303.1 & 303.2 with monitoring for 8-5-403 because the monitoring requirement had been inadvertently omitted.

- For VOC rows, added requirement to operate in compliance with the monitoring plan required by NSPS 40 CFR 60 Kb 60.113b(c)(1) for storage vessels equipped with a closed vent system and control device.
- For VOC rows, removed incorrect 40 CFR 63 Subpart CC 63.640(d)(5) exemption because sources are not subject to this regulation so the exemption is not applicable.
- Added S1114 and S1115 to BAAQMD Condition # 18618 per A/N 12025

- Table VII – P
    - Added applicability for BAAQMD & SIP 8-5-303.1 & 303.2 with monitoring for 8-5-403 because the monitoring requirement had been inadvertently omitted.
    - Added applicability for BAAQMD 8-5-306.2 with monitoring for 8-5-403because the monitoring requirement had been inadvertently omitted (the 8-5-118 limited exemption does not apply for tank appurtenances per 8-18-115) For HAP row, added monitoring exemption for NESHAP 40 CFR 61 Subpart FF for gaseous streams routed to a fuel gas system.
    - Added BAAQMD Condition # 18618 for S1805 per A/N 2365
- Table VII – R
    - Added applicability for BAAQMD & SIP 8-5-303.1 & 303.2 with monitoring for 8-5-403 because the monitoring requirement had been inadvertently omitted.
- Table VII – T
    - Updated to allow for source test frequency reduction allowance
    - Added monitoring requirement citation of BAAQMD Condition #18618 Part 2 to Condition #18618 Part 1 limit, erroneously omitted
    - Added S1424 to BAAQMD Condition # 18618
    - Corrected the throughput limits for S4001 and S4020 to reflect the correct unit capacity; the correction was inadvertently omitted when Condition # 12771 was updated for as constructed conditions
    - Updated applicability for BAAQMD & SIP Regulation 8 Rule 18
- Table VII – U
    - Updated applicability for BAAQMD & SIP Regulation 8 Rule 18
    - BAAQMD Condition # 18618 Part 1 added for throughput limit, erroneously omitted
- Table VII – V
    - Added BAAQMD Condition # 25345 per A/N 19872
    - Updated applicability for BAAQMD & SIP Regulation 8 Rule 18
- Table VII – W
    - Updated to allow for source test frequency reduction allowance
    - Merged with Tables VII – X, Y, and FFF
    - For BAAQMD and SIP Regulation 6 rows, add annual source test required by Condition 18618, Part 8 as compliance demonstration consistent with

monitoring documented in Statement of Basis for Title V Permit, Rev 0 for Facility ID A0011

- For NH_3/H_2S row, added archived permit conditions that required initial source test for 9-1-313.2 as compliance demonstration for destruction efficiency requirement
- Row for SO2, BAAQMD Condition # 19748, Part 7 revised averaging period from 24 to 12 hours for consistency with NSPS Subpart J. This permit condition is for incorporation of Consent Decree limits. The error was noted during EPA review of the Title V permit for termination of the Consent Decree

- Table VII – X
  - Deleted and merged with Table VII – W
- Table VII – Y
  - Updated to allow for source test frequency reduction allowance
  - Deleted and merged with Table VII – W
- Table VII – Z (S1457, S1778, S4210)
  - Added applicability for Regulation 11-10
- Table VII – BB
  - Updated to delete BAAQMD Condition # 24337 and update NSPS Subpart J
  - Row for VOC, removed because BAAQMD Condition 12271, Part 74 is an abatement requirement, not a monitoring requirement
- Table VII – CC
  - Revised description for re-designation of flares A101 and A102 as abatement devices to emission sources S601 and S602
  - Added applicability for BAAQMD 8-5-306.2 with monitoring for 8-5-403 because the monitoring requirement had been inadvertently omitted (the 8-5-118 limited exemption does not apply for tank appurtenances per 8-18-115)
  - Updated monitoring frequency and type for NSPS 40 CFR 60 Subpart J
  - Row for VOC, clarified that monitoring is not required per 8-5-502.1 for Approved Emission Control Systems with combustion
  - Row for SO2, clarified that monitoring is not required per 60.105(a)(4)(iv)
- Table VII – DD
  - Revised description for re-designation of flare A103 as an abatement device to emission source S603
  - Updated to delete monitoring requirements for NSPS 40 CFR 60 Subpart J and added monitoring requirements for BAAQMD Regulation 12, Rule 12 and NSPS 40 CFR 60 Subpart Ja
  - Added applicability for BAAQMD 8-5-306.2 with monitoring for 8-5-403because the monitoring requirement had been inadvertently omitted (the 8-5-118 limited exemption does not apply for tank appurtenances per 8-18-115)

    - Row for VOC, clarified that monitoring is not required per 8-5-502.1 for Approved Emission Control Systems with combustion
    - Row for SO2, clarified that monitoring is not required per 60.105(a)(4)(iv)
- Table VII – FF
    - Added row to BAAQMD Condition #18265 monitoring requirement citation for clarification
- Table VII – HH
    - Added BAAQMD Condition # 25134 per A/N 22045
- Table VII – II
    - Added BAAQMD Condition #25366 for S1763 per A/N 24479
- Table VII – JJ
    - Updated to allow for source test frequency reduction allowance
- Table VII – KK
    - Updated to allow for source test frequency reduction allowance
- Table VII – LL (S1507, S1509, S1512)
    - Added applicability for Regulation 6-5
    - Added applicability for Regulation 9-10-307
    - Removed NESHAP 40 CFR 63 Subpart EEE
    - Revised NOx emission limit for BAAQMD Condition #12271 Part 85 per A/N 27866.
    - Added BAAQMD Condition # 25134 per A/N 22045
    - Added BAAQMD Condition # 25247 per A/N 22287
    - Pollutants reorganized by BAAQMD rule, then PC, then federal rule
- Table VII – QQ
    - BAAQMD Condition # 18618 Parts 16 and 17 deleted as these two parts do not apply to this source
- Table VII – RR
    - Updated to delete monitoring requirements for NSPS 40 CFR 60 Subpart J and added monitoring requirements for BAAQMD Regulation 12, Rule 12 and NSPS 40 CFR 60 Subpart Ja
- Table VII – XX
    - Deleted and merged with Table VII - A
    - Updated "Citation of Limit" column for Regulation 8-44 VOC limit
    - Corrected the monitoring frequency of monitoring requirement BAAQMD 8-4-501 and Condition #4288 Part 3a
- Table VII – DDD
    - Updated to allow for source test frequency reduction allowance
    - Revised BAAQMD Condition #18265 for clarification
    - Added BAAQMD Condition #25134 per A/N 22045
- Table VII – EEE
    - Updated to allow for source test frequency reduction allowance
- Table VII – FFF

  - Deleted and merged with Table VII - W
- Table VII – GGG
  - Updated to allow for source test frequency reduction allowance
  - Added 40 CFR 61 Subpart FF and 40 CFR 63 Subpart CC gas tight monitoring requirements for compliance demonstration method for BAAQMD Condition #12271, Part 52
- Table VII – HHH
  - Updated to allow for source test frequency reduction allowance
- Table VII – III
  - Updated to delete monitoring requirements for NSPS 40 CFR 60 Subpart J and added monitoring requirements for BAAQMD Regulation 12, Rule 12 and NSPS 40 CFR 60 Subpart Ja
- Table VII – LLL
  - Added applicability for BAAQMD & SIP 8-5-303.1 & 303.2 &8-5-307.3 with monitoring for 8-5-403 because the monitoring requirement had been inadvertently omitted.
  - For VOC rows, added requirement to operate in compliance with the monitoring plan required by NSPS 40 CFR 60 Kb 60.113b(c)(1) for storage vessels equipped with a closed vent system and control device.
  - For VOC rows, removed incorrect 40 CFR 63 Subpart CC 63.640(d)(5) exemption because sources are not subject to this regulation so the exemption is not applicable.
  - For HAP rows, added monitoring exemption for NESHAP 40 CFR 61 Subpart FF for gaseous streams routed to a fuel gas system.
  - For VOC row, removed incorrect 40 CFR 63 Subpart CC 63.640(d)(5) exemption because this does not provide a monitoring exemption for 40 CFR 61 Subpart FF.
- Table VII – MMM
  - Row for VOC, removed because BAAQMD Condition 12271, Part 74 is an abatement requirement, not a monitoring requirement
- Table VII – NNN
  - Added applicability for BAAQMD & SIP 8-5-303.1 & 303.2
  - Added applicability for BAAQMD 8-5-307.3,
  - Added applicability for SIP 8-5-307
- Table VII – OOO
  - Added S6073 per A/N 25810
  - Added applicability for S6073
  - Updated applicability to reflect it is only applicable to S6051 through S6057, S6059, and S6060
  - Updated citations for BAAQMD Regulation 9 Rule 8
- Table VII – QQQ
  - Table has been deleted because there are no longer any 40 CFR 63, Subpart CC Group 1 Miscellaneous Process Vents.

- Table VII – TTT
  - Deleted applicability for Regulation 8-15, asphalt is no longer produced at Facility A0011
  - Added applicability for Regulation 8-53
- Table VII – WWW
  - BAAQMD & SIP Regulation 6-1-301, removed applicability because the tank is no longer used to store asphalt since asphalt is no longer produced at Facility A0011
- Table VII – YYY
  - Added monitoring requirement for daily hydrocarbon inspections per BAAQMD Condition #11313, Part 6.b and 61.354(d)
- Table VII – ZZZ
  - Added S7000 per A/N 21359
  - Added BAAQMD Condition #24795 per A/N 21359
- Table VII – XXX (New)
  - Added new table for S63, S355, S432, and S568 which had BAAQMD 8-5-403 monitoring requirements but no table in Section VII

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" as defined by Regulation 2-6-202.

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

<u>Changes to permit:</u>

Regulatory names and dates of adoption for the NSPS and NESHAP regulations were updated for consistency throughput the permit.

Revisions to make method citations and references consistent throughout the section, and updates to add new/updated regulations to Section VIII, including:

a. BAAQMD Regulation 6 Rule 5
b. BAAQMD Regulation 8 Rule 18
c. BAAQMD Regulation 8 Rule 44
d. BAAQMD Regulation 8 Rule 53
e. BAAQMD Regulation 11 Rule 10
f. NESHAP 40 CFR 63 Subpart CC Heat Exchange requirements

Removed NESHAP 40 CFR 63, Subpart VV standards for oil-water separators and organic-water separators because this regulation is not shown elsewhere as applicable in the permit

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 the first and second types of permit shield.

<u>Changes to permit:</u>

- Table IX A – 1
    - Added permit shield for 40 CFR 63, Subpart DDDDD
- Table IX A – 2
    - Revised description for re-designation of flares A101,A102, and A103 as abatement devices to emission sources S601, S602, and S603
    - Shields for BAAQMD 12-11 and 12-12, changed A101, A102, and A103 to S601, S602, and S603
- Table IX A – 3
    - Added permit shield for BAAQMD Regulation 12 Rule 12 for S1470
- Table IX A - 4
    - Removed permit shield because it is not applicable per EPA review of Title V permit for termination of the EPA Consent Decree
- Table IX A – 6
    - Deleted, BAAQMD Regulation 8-46 deleted December 7, 2005
- Table IX A – 15
    - Added permit shield for 40 CFR 63, Subpart DDDDD for all sources except S1514
- Table IV B – 1
    - Deleted S541 and S544 per A/N 22045

    - Deleted S992 and associated content because source has been demolished
- Table IV B – 2
    - Added S1128 per A/N 22045
- Table IV B – 3
    - Added S6069, S6070, S6071, and S6072 per A/N 22045

X. Glossary

Changes to permit:

- Added DPM: Diesel Particulate Matter

D. Alternate Operating Scenarios:

No alternate operating scenario has been requested for this facility.

E. Compliance Status:

The responsible official for Shell Martinez Refinery submitted a signed Certification Statement form dated March, 2017. On this form, the responsible official certified that the following four statements are true:

Based on information and belief formed after reasonable inquiry, the source(s) identified in the Applicable Requirements and Compliance Summary form that is(are) in compliance will continue to comply with the applicable requirement(s);

Based on information and belief formed after reasonable inquiry, the source(s) identified in the Applicable Requirements and Compliance Summary form will comply with future-effective applicable requirement(s), on a timely basis;

Based on information and belief formed after reasonable inquiry, information on application forms, all accompanying reports, and other required certifications is true, accurate, and complete;

All fees required by Regulation 3, including Schedule P have been paid.

APPENDIX A
ENGINEERING EVALUATION REPORTS

For

- A/N 2736 – S1070 Fixed Roof to IFR Retrofit (7/2001) –Engineering Evaluation Report not available
- A/N 19872 – Catalytic Cracking Unit (CCU)
- A/N 21359 – Construct Aeration Tank
- A/N 22045 – Crude Tank Replacement Project (CTRP)
- A/N 22287 – CO Boilers
- A/N 25810 – Portable Diesel Firewater Pump
- A/N 27434 – F41A/B Heater Tube Replacement –Engineering Evaluation Report not available

ENGINEERING EVALUATION
SHELL MARTINEZ REFINERY; PLANT 11
CCU REACTOR REVAMP PROJECT

APPLICATION NO. 19872

BACKGROUND

The Shell Martinez Refinery (Shell) submitted this application for an Authority to Construct/Permit to Operate for alterations to the following equipment:

S1426 Catalytic Cracking Unit (CCU), Reactor (V-595) and Stripper (V-594)
S1427 Catalytic Gas Plant (CGP), Rectified Absorber and Debutanizer Columns

The CCU converts (cracks) heavy oils into gasoline and other feedstocks by contacting feed with hot circulating catalyst in a reactor. The CGP separates the overhead stream of the CCU main fractionator into dry gas, liquefied petroleum gas (LPG), and gasoline.

The purpose of the CCU Reactor Revamp Project is to replace the existing CCU reactor and stripper vessel internals. This equipment has reached end-of-life conditions and needs to be replaced. The project which will be undertaken during a regular CCU maintenance turnaround will replace the existing reactor cyclones and stripper internals with current best practice technology.

The CCU Reactor Revamp Project includes the following changes:

S1426 CCU Reactor (V-595) and Stripper (V-594)

a. Replacement of the CCU reactor cyclones and plenum with a close-coupled cyclone system. The close-coupled design directly connects the outlet of the new riser to new first stage cyclones.
b. Replacement of CCU Reactor steam stripping internals. The bottom of the reactor will now have disc and donut baffles.
c. Replacement of the CCU reactor spent catalyst transfer pipe connecting the CCU reactor to the stripper.
d. Replacement of the steam stripping internals in the CCU stripping vessel. The bottom of the stripper will now have one disk baffle followed by three stages of pentaflow baffles.

S1427 CGP Rectified Absorber (RA) Column and Debutanizer Columns

a. Replacement of the RA Column feed exchanger.
b. Replacement of the Debutanizer column feed tray with a chimney tray.
c. Minor Debutanizer column internal tray and piping modifications.
d. Replacement of the Debutanizer reboiler vapor and liquid return nozzles, and internal and liquid return piping.

In addition, the project includes replacement of turboexpander components with previously reconditioned components as part of the facility’s routine maintenance repair and replacement (RMRR) and the plugging of the nozzles in the regenerator air grid dome to improve air grid distribution at lower air flow rates. See attached October 10, 2010 report by RTP Environmental Associates, Inc. (RTP Report).

The changes to the CCU equipment have the potential to result in a slight yield shift in CCU fractionation products. Potentially slightly more gasoline range material (<1 percent of overall current gasoline production) may occur, with a corresponding decrease in dry gas and heavier components. The overall amount of CCU products will not change. The anticipated slight potential increase in gasoline production and corresponding decreases in dry gas and heavier components is insignificant, and cannot be accurately predicted or quantified.

As noted above, the project will result in physical changes of the CCU. The CCU is a grandfathered source, which has never undergone a formal New Source Review (NSR), nor does it have conditions limiting daily or annual emissions. Shell asserts that the CCU reactor and stripper and CGP changes will not increase daily or annual emission level of any regulated air pollutant, nor will it increase the throughput or production rates at the CCU that are used to estimate emissions levels. Also, Shell asserts that emissions from the CCU for all pollutants are expected to stay at current levels or decrease as a result of this project. The CCU's highest attainable design capacity was previously determined to be 79,515 barrels/day (bbl/day). See Regulation 2-1-234.3. For the above reasons, the physical changes to the CCU are not deemed a modification, but an alteration of the CCU.

This project does not change the crude processing capacity of the refinery. Except for a potential slight increase in gasoline production, which will be stored in fixed roof tankage abated by vapor recovery and the corresponding decrease in heavier components that are stored in fixed roof tankage, no significant or quantifiable changes in utilization of any upstream or downstream process units, support units, or heaters/boilers will result from this project. Therefore, Shell is not requesting any changes to Title V permit conditions for any upstream or downstream process units, support units, or heaters and boilers.

As part of this application, Shell submitted its PSD/NSPS applicability review. See RTP Report. RTP's analysis determined that PSD Pre-Project Recordkeeping is required and that PSD Post-Project Recordkeeping was recommended as well. The PSD Pre-Project Reporting Requirements were fulfilled by RTP's October 2010 report. The District is imposing conditions that require Post-Project Recordkeeping and Reporting to ensure that the applicable permit limits are not exceeded. However, at the time of this evaluation, the Post-Project Recordkeeping and Reporting requirements are not in effect, pending EPA review. If EPA removes the requirements for PSD Post-Project Recordkeeping and Reporting, this permit requirement will not take effect.

As explained below, the NOx and SO2 emissions from the CCU are limited by existing, enforceable permit condition limits.

<u>EMISSIONS SUMMARY</u>

<u>Project Emissions Excluding Fugitives</u>
The purpose of the CCU Reactor Revamp Project is to replace the existing CCU Reactor and Stripper internals. These components have reached end-of-life conditions and will be replaced with current best practice technology during a regular maintenance turnaround.

Shell asserts that based on anticipated improvements in stripping oil from the catalyst in the reactor and stripper, CCU emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2) may decrease slightly. Carbon monoxide (CO), particulate matter (PM), and precursor organic compounds (POC) are anticipated to stay at current levels. Also, toxic air contaminants (TAC) are expected to stay at current levels.

Emissions from the CCU are exhausted to three CO Boilers. Each of these CO Boilers has a dedicated exhaust stack, which are equipped with CEMs. The CO Boilers have NOx and SO2 emissions limits in Permit Condition No. 12271, Parts 85 and 90. This project is being treated as an alteration because while there is a physical change, the project is not expected to result in increased emissions.

NOx, CO, SO2, and PM emissions are limited by the REFEMS Bubble Permit Condition No. 7618. Shell asserts that the NOx, CO, SO2, and PM emissions from S1426 and S1427 are limited by this bubble permit condition.

<u>Fugitive Emissions</u>
The project will install new fugitive emission components. To calculate fugitive emissions for the Project, the total number of valves required is estimated to be 180 and the total number of flanges is estimated to be 150.

Fugitive emission estimates are calculated using United States Environmental Protection Agency (EPA) Correlation Equations, with the TAC speciation based on Shell's characterization of the materials being processed. For the purposes of this application, screening values for the new valves and flanges are assumed to be at the maximum leak rate of 100 ppm as allowed by BAAQMD Regulation 8 Rule 18. However, this calculation assumed no pegged leakers, which is allowed per Regulation 8, Rule 18. Total fugitive emissions are estimated by multiplying the emission factor at the maximum leak rate for each component type by the estimated count of each component type. For the proposed project, total emissions from the additional fugitive components are estimated to be approximately 1.63 lbs/day (0.30 tons per year [tpy]), as shown in **Table 1**.

Table 1 Total Fugitive Component Potential Emissions

Type/Service	Number of Components[1]	Emission Factor lbs/hr/component[2]	Potential Emissions lbs/day	Potential Emissions tpy
Valves/Gas/Light Liquid	180	0.00016	0.69	0.13
Flanges/All[3]	150	0.00026	0.94	0.17
Total	**330**	---	**1.63**	**0.30**

1) To ensure that emissions are not under-estimated, the number of valves and flanges used in the emission calculations is 20% higher than predicted for the project.
2) Source: California Implementation Guidelines for Estimating Mass Emissions from Fugitive Hydrocarbon Leaks at Petroleum Facilities, February 1999. Screening values are assumed to be maximum leak rate allowed by BAAQMD, Regulation 8-18.
3) Flange counts include connectors; the higher emission factor was selected.

Shell estimates that 70 percent of the new valves and flanges will be in CCU reactor product service and 30 percent in natural gas service, as shown in **Table 2**.

Table 2 Component Count by Type of Service

Material	Valves	Flanges
CCU Reactor Product	126	105
Natural Gas	54	45

Speciated fugitive emissions are determined by multiplying the concentration of the TAC species by the total fugitive emissions, as presented in **Table 3** and **Table 4**. TAC speciation is based on Shell's characterization of the materials processed. Chemicals that are hazardous air pollutants (HAP) and/or toxic air contaminants (TAC) are identified in the tables.

Table 3 Speciated Fugitive Emissions for CCU Reactor Product Components

Chemical Name	CAS Number	Conc. wt. %	Potential Emissions lbs/hr	Potential Emissions lbs/yr	TAC	HAP
2,2,4-Trimethylpentane	540-84-1	1.54	7.2E-04	6.30E+00	✓	✓
Benzene	71-43-2	0.48	2.2E-04	1.9E+00	✓	✓
Cumene	98-82-8	0.04	2.0E-05	1.7E-01	✓	✓
Ethylbenzene	100-41-4	0.49	2.3E-04	2.0E+00	✓	✓
Hexane, (-n)	110-54-3	0.32	1.5E-04	1.3E+00	✓	✓
Hydrogen Sulfide	7783-06-4	0.24	1.1E-04	9.8E-01	✓	
Naphthalene	91-20-3	0.01	2.7E-06	2.4E-02	✓	✓
Propylene	115-07-1	0.11	5.3E-05	4.6E-01	✓	
Toluene	108-88-3	1.88	8.8E-04	7.7E+00	✓	✓
Xylene (Mixed Isomers)	1330-20-7	2.30	1.1E-03	9.4E+00	✓	✓

Table 4 Speciated Fugitive Emissions for Natural Gas Components

Chemical Name	CAS Number	Conc. wt. %	Potential Emissions lbs/hr	Potential Emissions lbs/yr	TAC	HAP
Hydrogen Sulfide	7783-06-4	0.003	6.6E-07	5.8E-03	✓	

<u>TOXICS</u>

Table 5 compares the estimated TAC emissions from the new fugitive components to the Acute and Chronic TAC Trigger Levels (TTLs) listed in Table 2-5-1 of Regulation 2, Rule 5 "New Source Review of Toxic Air Contaminants," to determine if a Toxic Health Risk Screening Analysis (HRSA) is required.

Table 5 Toxic Air Contaminant Trigger Level Evaluation[1]

Chemical Name	Potential TAC Emissions lbs/hr	Acute Trigger Level lbs/hr	Exceeds Trigger Level? Yes/No	Potential TAC Emissions lbs/yr	Chronic Trigger Level lbs/yr	Exceeds Trigger Level? Yes/No
Benzene	2.2E-04	2.9E+00	No	1.9E+00	3.8E+00	No
Ethylbenzene	2.3E-04	---	N/A	2.0E+00	4.3E+01	No
Hexane, (-n)	1.5E-04	---	N/A	1.3E+00	2.7E+05	No
Hydrogen Sulfide	1.1E-04	9.3E-02	No	9.8E-01	3.9E+02	No
Naphthalene	2.7E-06	---	N/A	2.4E-02	3.2E+00	No
Propylene	5.3E-05	---	N/A	4.6E-01	1.2E+05	No
Toluene	8.8E-04	8.2E+01	No	7.7E+00	1.2E+04	No
Xylene (Mixed Isomers)	1.1E-03	4.9E+01	No	9.4E+00	2.7E+04	No

[1] Note: Although TACs, cumene and 2,2,4-trimethylpentane do not have California AB 2588 risk assessment health values or BAAQMD chronic or acute TTLs.

As shown in **Table 5**, no TAC emissions will exceed a chronic or acute TTL. Therefore, this application does not require a Toxics HRSA.

BEST AVAILABLE CONTROL TECHNOLOGY

Per Regulation 2-2-301, BACT shall be applied to a new or modified source which results in an emission from a new source or an increase in emissions from a modified source, and which has the potential to emit 10 pounds or more per highest day of emissions. The proposed changes to the CCU do not constitute a modification of the process unit, and the fugitive components summarized in *Table 1* ***will not exceed 10 lb/highest day for this project (see discussions on Regulations 2-1-301 and 2-1-128.21, respectively, in the "Statement of Compliance" section). Therefore, BACT is not triggered for this project. However, Shell agrees to install only BACT components for this project and has agreed to only offset the increase in POC.***

CUMULATIVE INCREASE AND OFFSETS

Shell is an existing facility. The increase in POC emissions from the additional fugitive components are summarized in *Table 1.* ***Shell surrenders offsets on an annual basis to pay for fugitive component increases (as allowed under the Offset Deferral provisions in District Regulation 2). The proposed changes to the CCU will not result in a cumulative increase in criteria pollutant emissions other than fugitives. Therefore, offsets are required for only the fugitive component emissions of this application.***

STATEMENT OF COMPLIANCE

BAAQMD REGULATIONS

REGULATION 1 – GENERAL PROVISIONS

Regulation 1-301 prohibits discharge from any source such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public; or which endangers the comfort, repose, health or safety of any such person or the public; or which causes or has a natural tendency to cause injury or damage to business or property. The CCU Reactor Revamp Project will be operated in accordance with all federal and BAAQMD rules and regulations, and is not expected to cause a public nuisance.

REGULATION 2 RULE 1 - PERMITS, GENERAL REQUIREMENTS

Regulation 2-1-301 states the following:

"2-1-301 Authority to Construct: Any person who, after July, 1972, puts in place, builds, erects, installs, modifies, modernizes, alters or replaces any article, machine, equipment or other contrivance, the use of which may cause, reduce, or control the emission of air contaminants, shall first secure written authorization from the APCO in the form of an authority to construct."

The applicant is seeking an Authority to Construct.

As described in the Background section above, this project is an alteration, which is defined in BAAQMD 2-1-233 as follows:
"2-1-233 Alter: To make any physical change to, or change in the method of operation of, a source which may affect emissions. Such changes require a permit to operate, and may require permit conditions, whether or not the alteration results in an emission increase."

REGULATION 2-1-128.21 - EXEMPTION, MISCELLANEOUS EQUIPMENT

Regulation 2-1-128.21 states the following:

"2-1-128 Exemption, Miscellaneous Equipment: The following equipment is exempt from the requirements of Sections 2-1-301 and 302, provided that the source does not require permitting pursuant to Section 2-1-319.

128.21 Modification, replacement, or addition of fugitive components (e.g. valves, flanges, pumps, compressors, relief valves, process drains) at existing permitted process units at petroleum refineries, chemical plants, bulk terminals or bulk plants, provided that the cumulative emissions from all additional components installed at a given process unit during any consecutive twelve month period do not exceed 10 lb/day, and that the components meet applicable requirements of Regulation 8 rules."

The intent of this exemption is to be used for projects that involve only fugitive components and are not related to other activities that require a permit to operate such as this application. Shell will provide offsets and has further agreed to install only BACT components for this project.

As shown in the emission calculations summarized in** Table 1, **the cumulative emissions from the estimated 330 new fugitive components for the Project are less than 10 lbs/day (i.e, 1.63 lb/day). However, no pegged leakers were included in the calculation and are allowed per Regulation 8, Rule 18, unless the facility accepts a Permit to Operate condition limiting pegged leaker emissions. In addition, the new fugitive components summarized in** Table 1 **will meet the requirements of Regulation 8 "Organic Compounds", Rule 18 "Equipment Leaks," and be incorporated into Shell's Leak Detection and Repair (LDAR) program.

The proposed alteration to the CCU is also not subject to permitting per Regulations 2-1-316 through 319 as follows:

- ***<u>Regulation 2-1-316:</u>***
  As shown in** Table 5**, toxic air contaminants (TAC) from the 330 new fugitive components will not exceed the TAC trigger levels in Table 2-5-1 of Regulation 2-5; and hazardous air pollutants (HAP) from the new components will not exceed 2.5 tpy for a single HAP (0.005 tpy), or 6.5 tpy for a combination of HAPs (0.01 tpy).
- ***<u>Regulation 2-1-317:</u>***
  The CCU is not a source of a public nuisance.
- ***<u>Regulation 2-1-318:</u>***
  As shown in** Tables 3 and 4**, the CCU does not emit any of the compounds in Sections 318.1 through 318.8 of the above regulation, except for sulfuric acid mist and reduced sulfur compounds including hydrogen sulfide. Emissions of these compounds are not expected to increase from current levels as a result of the project.
- ***<u>Regulation 2-1-319:</u>***
  As shown in** Table 1, **POC emissions from the 330 new fugitive components are below 5 tpy (0.30 tpy) after abatement, and the project is not subject to the requirements in Regulation 2-1-316 through 2-1-318.

<u>REGULATION 2-1-412 - PUBLIC NOTICE, SCHOOLS</u>

Regulation 2-1-412 requires public notice if the new or modified source is located within 1,000 feet of the outer boundary of any K-12 school. The CCU is not located within 1,000 feet of any school.

<u>REGULATION 8 RULE 18 - ORGANIC COMPOUNDS, EQUIPMENT LEAKS</u>

Regulation 8, Rule 18 limits emissions of organic compounds and methane from leaking equipment at petroleum refineries including, but not limited to: valves, connectors, pumps, compressors, pressure relief devices, diaphragms, hatches, sight-glasses, fittings, sampling ports, meters, pipes, and vessels. The rule requires regular inspections, prompt repairs and recordkeeping and reporting. The fugitive components summarized in** Table 2 **will be subject to this rule.

<u>REGULATION 8 RULE 28 – EPISODIC RELEASES FROM PRESSURE RELIEF DEVICES AT PETROLEUM REFINERIES AND CHEMICAL PLANTS</u>

Regulation 8 Rule 28 requires that any person installing a new refinery source or modifying an existing refinery source, that is equipped with at least one pressure relief device in organic compound service, shall meet all applicable requirements of BAAQMD Regulation 2-2,

including BACT. Since no pressure relief valves will be removed, replaced, or added as a result of the proposed project, this regulation does not apply.

REGULATION 11 RULE 7 – HAZARDOUS POLLUTANTS, BENZENE

Regulation 11 Rule 7 limits benzene emissions from fugitive emission sources such as pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flanges and other product accumulator vessels, and control devices intended to operate in benzene service. Regulation 11-7-207 defines "In Benzene Service" to be any equipment which either contains or contacts a fluid (liquid or gas) that is at least 10 percent benzene by weight. The proposed project will not include process streams which will either contain or contact a fluid that is at least 10 percent benzene by weight. Therefore, Regulation 11 Rule 7 does not apply.

PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

RTP Environmental Associates, Inc. (RTP) submitted an NSPS and PSD Applicability Review of this project (see attached RTP report dated October 10, 2010).

RTP's report asserts that the project related emissions increase is less than the significance threshold for each pollutant. As a result, the requirements for PSD permitting are not triggered. RTP's analysis also determined the need for Pre-Project Recordkeeping in accordance with the requirements of 40 CFR 52.21(r)(6) for SO2, NOx, CO, and PM species. RTP's report fulfills the Pre-Project Recordkeeping requirements at 40 CFR 52.21(r)(6)(i). RTP also notes that in light of the EPA reconsideration of the Reasonable Possibility Rule, they recommend that all post-project emissions be tracked in order to guard against the potential that the reasonable possibility thresholds change and retroactively require the 5-year Post – Project Recordkeeping and Reporting requirements after the project is implemented.

The PSD Post-Project Recordkeeping and Reporting requirements are currently not applicable, but could become applicable depending on the outcome of the EPA's reconsideration of the Reasonable Possibility Rule.

Permit conditions have been proposed that will help ensure compliance with the federal reporting and recordkeeping requirements.

NEW SOURCE PERFORMANCE STANDARDS (NSPS)

40 CFR 60 Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions of Subpart A. Subpart A requires various notification and recordkeeping for sources subject to any of the Part 60 NSPS. As described in the following sections, the CCU is subject to several NSPS standards.

40 CFR 60 Subpart J – Standards of Performance for Petroleum Refineries

Currently, the CCU is subject to the New Source Performance Standard (NSPS) in 40 CFR Part 60 Subpart J (Standards for Performance for Petroleum Refineries). The CCU Reactor Revamp Project will not change the applicability of the CCU to this subpart, and the CCU will continue to comply with the requirements of NSPS Subpart J.

40 CFR 60 Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

The standards in 40 CFR 60 Subpart Ja affect fluid catalytic cracking units, coking units, sulfur recovery plants, and fuel gas combustion devices. The proposed project will not be subject to the requirement of 40 CFR Subpart Ja. This project does not constitute a modification under Subpart Ja, because there is no emission increase for any pollutant to which a standard applies under Subpart Ja for fluid catalytic cracking units.

In addition, the project does not constitute a reconstruction under NSPS because the fixed capital cost of the new components for the CCU Reactor Revamp Project will not exceed 50 percent of the fixed capital cost that would be required to construct a comparable entirely new CCU facility. Under Subpart Ja, the definition of a fluid catalytic cracking unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

Shell has provided the District "Trade Secret" cost information demonstrating that the estimated project cost was well below the 50% reconstruction threshold set forth in 40 CFR Subpart 60.15. Shell's estimated percent of CCU replacement cost for the project is conservative as it does not include the cost to replace the three CO boilers and the electrostatic precipitators, and did not reflect the recent sharp increase in construction materials such as steel since the cost estimate to replace the CCU was developed in 2005.

40 CFR 60 Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

The CCU Reactor Revamp Project includes replacement or addition of fugitive components (valves and flanges or other connectors) to the CCU Reactor and Stripper, and the CGP. Fugitive components subject to 40 CFR 60 Subpart GGG (NSPS for Equipment Leaks of Volatile Organic Compound [VOC] in Petroleum Refineries) must comply with 40 CFR 60 Subpart VV (Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry). The CCU and CGP are currently subject to and will continue to comply with the requirements of NSPS GGG and VV.

40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006

The CCU Reactor Revamp Project includes replacement or addition of fugitive components (valves and flanges or other connectors) to the CCU Reactor and Stripper, and the CGP. Since the CCU and CGP are currently subject to NSPS GGG/VV, the facilities are excluded from the requirements of NSPS Subpart GGGa.

MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY (MACT)

Maximum Achievable Control Technology (MACT) standards in 40 CFR Part 63 are applicable to specific source categories at facilities that are major sources of HAPs. The MACT standards that are applicable to the CCU include 40 CFR Part 63, Subpart CC "NESHAP for Petroleum Refineries", and 40 CFR Part 63, Subpart UUU "NESHAP for Petroleum Refineries: Sulfur Recovery Units, Catalytic Cracking Units, and Catalytic Reforming Units."
40 CFR 63 Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 63 is also subject to the general provisions of Subpart A. Subpart A requires various notification and recordkeeping for sources subject to any of the Part 63 MACT standards. As described in the following sections, the CCU is subject to several MACT standards.

40 CFR 63 Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

Subpart CC establishes standards for miscellaneous process vents, storage vessels, wastewater streams and treatment operations, equipment leaks, gasoline loading racks, and marine vessel loading operations. The new fugitive components that are subject to Subpart CC will be regulated in accordance with the equipment leak provisions of Subpart CC. Shell is currently in compliance with this rule, and the proposed changes in this application will not impact compliance.

40 CFR 63 Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

Subpart UUU regulates HAP emissions from catalytic cracking units, catalytic reforming units, and sulfur recovery units at petroleum refineries. These units at the Shell Martinez Refinery are subject to this subpart. Shell's CCU is in compliance with this rule, and the physical changes proposed in this application for the CCU will not impact compliance.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

Per Regulation 2-1-311, a permit application for a proposed new or modified source will be classified as ministerial and will accordingly be exempt from the CEQA requirement of Section 2-1-310, if the District's engineering evaluation and basis for approval of the permit application for the project is limited to the criteria set forth in Section 2-1-428, and to the procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook. The method for determining whether a given permit application will be classified as ministerial is set forth in Section 2-1-427.

Per Section 2-1-427, if the District determines that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook, the District's evaluation of the permit application will be classified as ministerial and the engineering evaluation of the permit application by the District will be limited to the use of said specific procedures, fixed standards and objective measurements. For such projects, the District will merely apply the law to the facts as presented in the permit application, and the District's decision regarding whether to issue the permit will be based only on the criteria set forth in Section 2-1-428 and in the District's Permit Handbook and BACT/TBACT Workbook.

For this permit application, the District determined that its evaluation of the permit application is covered by the specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook Chapter 3.4 “Petroleum Refinery Fugitive Emissions”. Since the District classified this permit application as ministerial pursuant to Section 2-1-427, and as a result of its evaluation of the permit application, the District determined that all of the criteria for approval of ministerial permit applications pursuant to Section 2-1-428 were met, the issuance by the District of a Authority to Construct for the proposed project is a mandatory ministerial duty and is accordingly exempt from the CEQA review requirement of Section 2-1-310.

In addition to the ministerial exemption determination above, the District has also determined that the CEQA categorical exemptions of Section 2-1-312 of the District Rules and Regulations and the CEQA "Common Sense Exemption" apply.

<u>CEQA Categorical Exemptions, and CEQA "Common Sense Exemption"</u>
Section 2-1-312 of the District Rules and Regulations sets forth specific categories of projects, which have been determined by the District to be categorically exempt from CEQA.

Per Section 2-1-312.6, permit applications relating exclusively to the repair, maintenance or minor alteration of existing facilities, equipment or sources involving negligible or no expansion of use beyond that previously existing, are exempt from CEQA review.

A permit applicant wishing to qualify under any of the specific exemptions set forth in Section 2-1-312 must also provide in its permit application CEQA-related information in accordance with Section 2-1-426.1. This Section sets forth the requirements for a preliminary environmental study which shall describe the proposed project and discuss any potential significant adverse environmental impacts, alternatives to the project, and any necessary mitigation measures to minimize adverse impacts. Furthermore, the preliminary study shall include all activities involved in the project and shall not be limited to those activities just affecting air quality.

In accordance with Section 2-1-426.1, Shell completed and submitted to the District CEQA Appendix H, Environmental Information Form, for the project. Shell provided a “No” response to all of the questions in Appendix H. Shell also provided supplemental information on non-air impacts and construction related activities to further assist the District’s evaluation of the project's possible significant effects.

Per CEQA Guidelines in Title 14, California Code of Regulations, Chapter 3, Article 5, Section 15061(b)(3), a project is exempt from CEQA if the activity is covered by the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment. This is commonly known as the "Common Sense Exemption". Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to CEQA review.

The new fugitive components that will be added as part of the proposed CCU Reactor Revamp Project are exempt from Regulation 2-1-301 per Regulation 2-1-128.21. As a result, the 0.30 tpy increase in POC emissions summarized in *Table 1* ***will not be counted toward the cumulative increase in emissions at Shell, since the emissions are considered deminimus.***

The District finds these assertions and arguments to be credible. Thus, the District concludes that the permit application is exempt from CEQA review because it is ministerial, it is categorically exempt from CEQA, and the project qualifies for the "Common Sense Exemption" of Subsection (b)(3) of the State CEQA Guidelines.

Based on all of the information before the District and the District's review of the information submitted, the District has determined that there is no possibility that the project may have any significant environmental effect.

The District has considered whether the proposed CCU Reactor Revamp Project is part of a larger project for CEQA purposes, and has concluded that it is not. The purpose of the proposed CCU Reactor Revamp Project is to replace the existing CCU reactor and stripper vessel internals that have reached end-of-life conditions, as part of periodic preventative maintenance necessary to ensure safe and reliable operations. This purpose does not imply any relationship to other projects, such as a prerequisite for other projects or a foreseeable consequence of them.

Permit Conditions

1. The owner/operator of S-1426 and S-1427 shall not exceed a Fluid Catalytic Cracking Unit feed throughput of 79,500 barrels during any day.
   (Basis: Alteration 2-1-233)

2. The owner/operator of S-1426 and S-1427 shall comply with all applicable PSD Post-Project Recordkeeping and Reporting requirements in 40 CFR 52.21(r)(6) for a period of 5 years after project implementation.
   (Basis: 40 CFR 52.21)

3. In order to demonstrate compliance with parts 1 and 2 above, the owner/operator of S-1426 and S-1427 shall report and maintain records to comply with the above condition parts 1 and 2. All records shall be recorded in a District-approved log. All records shall be retained on-site for five 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.
   (Basis: Alteration 2-1-233, 40 CFR 52.21)

FUGITIVE COMPONENTS

4. The owner/operator shall submit a count of installed pumps, valves and flanges/connectors and provide each component’s unique permanent identification code in this project every 6 months after startup until completion of the FCCU Revamp Project. Upon project completion, the owner/operator shall

provide the District's Engineering Division with a final count of all fugitive components. The owner/operator has been permitted to install the following fugitive components:

180 valves in hydrocarbon service;

150 flanges/connectors in hydrocarbon service;

[Basis: Cumulative Increase, offsets, Regulation 2-5]

5. If any of the fugitive component counts exceed the count stated in Part 3, the plant's cumulative emissions for the project shall be adjusted, subject to APCO approval, to reflect the difference between emissions based on predicted versus actual component counts. The owner/operator shall provide to the District all additional required offsets at an offset ratio of 1.15:1 no later than 21 days after submittal of the final POC fugitive count. If the component count increase triggers any additional regulatory review, the owner/operator shall submit an application to address the increased emissions. The owner/operator submitted 0.345 tons per year of POC offset credits corresponding to the fugitive component counts in Part 3. If the actual component count is less than the predicted, the total emissions in Part 8 may be adjusted accordingly, subject to APCO approval, and all emission offsets applied by the owner/operator in excess of the fully offset permitted total POC emissions may be credited back to the owner/operator upon approval by the APCO.
[Basis: offsets, Cumulative Increase]

6. The Owner/Operator of S-1426 and S-1427 shall install only the following types of fugitive components:

    a. For valves in hydrocarbon service: (1) bellows sealed, (2) live loaded, (3) graphitic packed, (4) quarter-turn (e.g., ball valves or plug valves), or equivalent technology to comply with provisions in Regulation 8, Rule 18 as determined by the APCO.
    b. For flanges in hydrocarbon service: graphitic-based gaskets, metal ring joints, or equivalent technology to comply with provisions in Regulation 8, Rule 18 as determined by the APCO.
    c. For pumps in hydrocarbon service: double mechanical seal with barrier fluid, or equivalent technology to comply with provisions in Regulation 8, Rule 18 as determined by the APCO.

    [Basis: Cumulative increase, Regulation 8, Rule 18]

7. The Owner/Operator shall comply with a leak standard of 100 ppm of TOC (measured as C1) at valves and flanges and 500 ppm at any pumps installed as part of the application19872 in hydrocarbon service, unless the owner/operator complies with the applicable minimization and repair provisions contained in Regulation 8-18.
[Basis: Cumulative Increase, Regulation 8 Rule 18]

8. The Owner/Operator shall conduct inspections of fugitive components installed as part of application 19872 in hydrocarbon service in accordance with the frequency below:
Valves: Quarterly
Flanges: Annual
[Basis: Cumulative Increase, Regulations 8 Rule 18]

9. The Owner/Operator shall not exceed 0.30 tons of POC emissions per consecutive 365-day period measured as C1 from for all fugitive components installed as part of application 19872 in hydrocarbon service. Reporting for this provision shall be performed quarterly and results shall be submitted to the District's Engineering Division on a quarterly basis for two years commencing with the completion of the FCCU Revamp Project. The quarterly reports are due within 30 days of the close of each calendar quarter after the District's issuance of the Permit to Operate for application 19872.
   [Basis: Cumulative Increase, offsets]

10. The Owner/Operator shall keep a District-approved log of fugitive component counts installed as part of application 19872, each component's unique permanent identification codes, monitoring results, and any annual emissions estimates required per part 8 for at least five years from date of entry. The log shall be retained on site and made available to district staff upon request.
    [Basis: offsets, recordkeeping]

RECOMMENDATION

The District recommends the following:

Waive the Authority to Construct and issue a Permit to Operate to Shell for the alteration of the following sources:

S1426 **Catalytic Cracking Unit (CCU), Reactor (V-595) and Stripper (V-594)**
S1427 **Catalytic Gas Plant (CGP), Rectified Absorber and Debutanizer Columns**

Improvements to the CCU and CGP include:

- Replace CCU Reactor and Stripper vessel internals.
- Replace CGP RA Column exchanger and Debutanizer internals and other minor changes
- Install 180 new valves and 150 new flanges/connectors in VOC service

By: ____________________
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____
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ENGINEERING EVALUATION
SHELL MARTINEZ REFINERY; PLANT 11
APPLICATION 21359

1.0 BACKGROUND

The Shell Martinez Refinery (Shell) submitted this application for an Authority to Construct and/or Permit to Operate the following new equipment:

S7000 Effluent Treatment Plant # 3 (ETP-3): Aeration Tank (Custom made, maximum wastewater feed rate of 2,250 gpm) and Gravity Clarifier

Shell currently operates two wastewater Effluent Treatment Plants, ETP-1 and ETP-2, which comprise all the secondary wastewater treatment capability in the refinery. ETP-1 is an older, in-ground biotreater (built in 1970). ETP-2 is an above ground coated steel tank built in 1995. Both ETPs are required to treat Shell's full wastewater volume generated by the refinery.

The ETP-2 biotreater will be due for a mandatory internal inspection under the American Petroleum Institute (API) Standard 653. An outage for the biotreater will require some means for continued wastewater treatment during this maintenance period. Thus, Shell proposes to construct a new treatment plant, ETP-3, which will replace ETP-2 during its turnaround. ETP-3 will be similar in design to ETP-2, and will consist of a new aeration tank and a new clarifier, along with miscellaneous support equipment. ETP-3 will continue to operate after ETP-2 is brought back online. There will be no change in refinery throughput or wastewater flowrate.

ETP-3 will consist of the following facilities or wastewater processing units:

- One aeration tank with air supply and distribution system – The aeration tank will be an above-ground open top circular tank. The tank will be constructed of coated carbon steel. It will provide aerobic biological treatment of wastewater using an activated sludge process. The tank will have a diameter of 130 feet and a side water depth of 25 feet.
- One clarifier – The clarifier will be an above-ground, circular, open top steel tank where biosolids (sludge) from the aeration tank will be separated from the treated wastewater. The tank will have a diameter of 75 feet, and a side water depth of 19 feet. Since this unit receives biologically-treated wastewater with low volatile organic compound (VOC) content, emissions are negligible. The clarifier is proposed to be an exempt source since it is functionally equivalent to a tank or vessel containing an aqueous solution with a VOC content less than 1 percent by weight (a Rule 2-1-128.19 equivalent to a Rule 2-1-123.2 exemption).

In addition, except for administrative requirements under Rule 8-8 (see Section 4.8), this source is not subject to any Regulation 8 standards, and thus, would be equivalent to a source complying with a Rule 2-1-103 exemption.

Additional support equipment will be included, such as piping components, instrumentation and chemical feed pumps.

While the aeration tank and the clarifiers at ETP-2 are out of service for inspection and maintenance work, the effluent from the primary treatment units, including the ETP-2 diversion tanks and dissolved nitrogen floatation (DNF) units will be diverted to the ETP-3 aeration tank for secondary treatment. When ETP-2 returns to service, ETP-3 will continue to treat a portion of this influent stream, and may also treat a portion of the wastewater feed currently being fed to ETP-1. During the wet weather season, a portion of the ETP-3 feed may also include rainwater.

Contaminants in the wastewater will undergo biological oxidation in the aeration tank. Microorganisms in the tank will metabolize carbonaceous and nitrogenous compounds in the wastewater. Dissolved oxygen required by the microorganisms will be supplied by a submerged air dispersion system consisting of jet aerators or diffusers.

Effluent from the ETP-3 aeration tank (mixture of treated wastewater and microorganisms) will flow into the ETP-3 clarifier. Treated wastewater will flow over a weir around the clarifier tank perimeter and will be directed to the existing downstream equalization ponds. Biosolids (sludge) will be separated from the treated wastewater in the clarifier by gravity. Most of the settled sludge will be returned to the aeration tank to maintain the desired biomass concentration. In accordance with normal municipal and industrial wastewater treatment standards, the clarifier will have an open roof. It will receive essentially oil-free and odorless treated wastewater from the aeration tank, so precursor organic compound (POC) emissions and odor are expected to be negligible.

2.0 EMISSIONS SUMMARY

For the purpose of calculating annual emissions for this application an operating schedule of 8,760 hours per year was assumed. The system will have a maximum hydraulic capacity of 2,250 gallons per minute (gpm) of wastewater feed.

The two existing ETP-2 air blowers each have a capacity of 4,600 cubic feet per minute (cfm) of air, for a total of 9,200 cfm. When both ETP-2 and ETP-3 are operating, each plant will utilize one of the blowers. The maximum air rate for ETP-3 will be 9,200 cfm using two blowers.

Estimated POC emissions and toxic air contaminant (TAC) emissions from the proposed project are described in this section. Emissions are based on the project description and anticipated operating levels. The summary sheets from the TOXCHEM+ model runs are located in **Appendix A** of this application.

Calculation Approach:

The emission estimation method was based upon the techniques used by BAAQMD staff in its Further Study Measure 9: Refinery Wastewater Treatment Systems. A copy of the staff report for this study is included in **Appendix B**. Emissions from the proposed project were estimated using a modeling approach, adjusted for actual measured emissions at a similar source.

In this study, BAAQMD used the state of the art TOXCHEM+ empirical model to estimate emissions of POC from refinery wastewater treatment systems. TOXCHEM+ is an EPA-approved model designed to quantify emissions from wastewater treatment systems. This model provides a means to comprehensively evaluate the fate and transport of organic compounds in wastewater treatment systems.

The TOXCHEM+ model estimates emissions from specific chemical species. The POCs present in the influent constitute a wide and unpredictable range of hydrocarbons. To calibrate the model to the actual mix of materials in the wastewater, BAAQMD compared emissions predicted using a surrogate analyte against limited flux chamber test results from refinery wastewater treatment plants, as described below.

The District sampled refinery treatment plant influent for Total Petroleum Hydrocarbons in the gasoline range (TPHg), and used TPHg concentration as a surrogate for all POC present in the wastewater. BAAQMD ran the TOXCHEM+ model with the TPHg concentrations as input, using the physical property information for toluene, since toluene is present at relatively high concentrations in the wastewater streams.

BAAQMD then calibrated the model using limited real-world emissions sampling data. Vapor measurements were collected from the treatment plants at two refineries (Valero and ConocoPhilips) using EPA's surface isolation emission flux chamber technology. During the flux chamber test, BAAQMD simultaneously collected wastewater samples, which were analyzed for TPHg. The measured emissions were lower than predicted by the model. The model was calibrated to be consistent with the emission test by modifying the biodegradation rate constant used by the model to a value that caused the model to predict the actual emissions.

Shell used the same approach described above to estimate POC emissions from ETP-3. The TOXCHEM+ model was used to estimate emissions from the unit at its maximum hydraulic and air operating rate (2,250 gpm and 9,200 cfm, respectively) assuming an inlet TPHg concentration at a conservatively high level (30 milligrams per liter [mg/L]). Toluene was used to represent TPHg, with its biodegradation rate constant adjusted to match the BAAQMD study as described above. The resulting emission rate represents POC emissions from the aerator.

For TACs, the adjustment described above was not necessary, as the emissions predicted by TOXCHEM+ are assumed to be accurate since each TAC is an individual chemical species. TAC emissions were estimated using historic analytical data from ETP-2. The inlet concentration of each TAC in the ETP-3 feed was assumed to be equal to the historic average ETP-2 concentration.

TOXCHEM+ predicts emissions from both the aerator and the clarifier. However, as previously noted, the clarifier receives water that is essentially free of oils and odors, and emissions are expected to be negligible. This is reflected in the model results, in which the clarifier emissions represent only about 0.5% of the total. For completeness, the small quantity of emissions predicted for the clarifier has conservatively been included in the aerator emissions.

POC Emissions:

POC emissions were estimated using the approach outlined above. The aerator was assumed to be operating at full air and water flow capacity. **Table 1** summarizes the modeled inputs and the expected project emissions. Summary sheets generated by the model are included in **Appendix A**.

Table 1 POC Emissions from ETP-3

Parameter	Unit	Value
Air Rate	cfm	9,200
Inlet Flow Rate	gpm	2,250
TPHg Concentration (as Toluene)	mg/L	30
Biodegradation Rate Constant	L/(mg-hr)	0.01
Emissions	Lb/Hr	0.41
	Lb/Day	9.94
	Tons/Year	1.814

2.1 CUMULATIVE INCREASE AND OFFSETS

Shell is an existing facility. Table 2 summarizes the cumulative increase in criteria pollutant emissions that will result at Plant 11 from the operation of S7000.

Table 2 Cumulative Increase				
Pollutant	**Increase in plant emissions prior to April 5, 1991 (TPY)**	**Increase in plant emissions since April 5, 1991 (TPY)**	**Increase in plant emissions associated with this application (TPY)**	**Cumulative increase in emissions (Post 4/5/91 + Current application increase) (TPY)**
NOx	0	8.100	0	8.100
POC	26.09	0.249	1.814	2.063
CO	0	335.250	0	335.250
PM_{10}	0.11	0.240	0	0.240
SO_2	0	0	0	0
NPOC	11.00	14.700	0	14.700

Post April 5, 1991 POC emissions of 0.249 tpy are secondary emissions attributed to operation of Thermal Oxidizer, A2023 that was permitted under Application 18034. Section 42301.2 in the California Health and Safety Code states the following and would have prevented the District from requiring Shell to provide the required offsets:

"A district shall not require emission offsets for any emission increase at a source that results from the installation, operation, or other implementation of any emission control device or technique used to comply with a district, state, or federal emission control requirement, including, but not limited to, requirements for the use of reasonably available control technology or best available retrofit control technology, unless there is a modification that results in an increase in capacity of the unit being controlled."

Following is an excerpt from a June 19, 2008 District Policy memo from Carol Allen – Senior Air Quality Engineer, Toxics Evaluation Section to the Engineering Division staff: "Although H&S Code 42301.2 states: "A district shall not require emission offsets..." for qualifying control device projects, the District is concerned that eliminating the offset requirement for secondary NO_x and POC emissions from new/modified abatement devices would be in conflict with the District's no net increase provisions and could potentially compromise the District's ozone related air quality improvement goals. To alleviate these concerns while still providing the state required offset relief for industry, the District shall continue to require offsets for any qualifying control device project (as stated in current District regulations), but the District will provide any necessary offsets, on behalf of the facility from the small facility banking account, for each qualifying abatement device project, even if that project is located at a facility that does not qualify for the small facility banking account. The District has adopted a similar policy for resource recovery projects that comply with H&S Code Section 42314 and that are located at sites that do not qualify for the small facility banking account.

Hence, 0.249 tpy secondary POC emissions are not required to be offset.

Table 3 Offsets					
Pollutant	**Permitted plant emissions (TPY) Pre-April 5, 1991 + Post-April 5, 1991**	**Actual plant emissions[1] (TPY)**	**Increase in plant emissions associated with this application (TPY)**	**Total emissions (Higher of Permitted/Actual Emissions + Emissions associated with this application) (TPY)**	**Regulation 2-2-302 and 2-2-303 Offset Triggers (TPY)**
NOx	8.100	1080.76	0	1080.76	> 35
POC	26.339	1386.00	1.814	1387.81	> 35
CO	335.250	1308.80	0	1308.80	NA
PM_{10}	0.350	346.86	0	346.86	> 1
SO_2	0	1222.51	0	1222.51	> 1
NPOC	25.70	0	0	25.70	NA

[1] Db → q2 →p → all

It can be seen from Table 3 above that offsets are warranted for POC, since the emissions of the above pollutant are greater than the 35 tons per year offset trigger. It can also be seen that the actual emissions of NOx, POC, CO, PM_{10}, and SO_2 are above the permitted emissions for the above pollutants. This is so because most sources at refineries are grand fathered (i.e., Pre-1971 sources). Therefore, Shell will have to surrender to the District 2.090 TPY of POC Emission Reduction Credits (ERCs) at an offset ratio of 1.15:1[2]. Shell currently owns 18.921 tons of POC ERCs in Certificate #993 that was issued by the District on September 6, 2006. Shell has surrendered above certificate to the District, and will receive a new certificate in the amount of 16.831 (18.921 – 2.090) tons per year with a new issuance date.

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2 Per Regulation 2-2-302, 1.814 x 1.15 = 2.090 TPY.

2.2 BEST AVAILABLE CONTROL TECHNOLOGY

In accordance with BAAQMD Regulation 2, Rule 2, Section 301, a source with the potential to emit 10 pounds or more per highest day of POC, NPOC, NOx, CO, SO_2 or PM_{10} must use BACT. For this application, BACT is not triggered because POC emissions from the proposed ETP-3 aeration tank will be 9.94 pounds per highest day (i.e., below 10 pounds per highest day), assuming a very conservative high-end estimate for POC mass emissions. The emission rate is based on an inlet POC concentration of 30 parts per million (ppm), maximum air rate of 9,200 scfm, and the maximum design inlet water flow rate of 2,250 gallons per minute (gpm). Under certain unusual operating scenarios, the POC concentration may be closer to 50 ppm. However, these scenarios would not occur during maximum flow periods, as the maximum flow rate only occurs during rain events, and rainwater does not contribute POC to the aerator feed. Therefore, in a high-flow scenario, the concentration of POC would be well below 50 ppm, and would likely be substantially lower than 30 ppm as well. Therefore, the emission estimates in the application are conservatively high.

Nevertheless, in order to ensure that all contingencies have been addressed, a BACT analysis has been performed for this project.

The BAAQMD's BACT/TBACT Workbook does not have any BACT guidance for secondary wastewater treatment aerators at petroleum refineries.

Technologies Considered

To evaluate BACT, Shell investigated the following technologies:

1. Constructing the aerator with a dome or roof and venting the emissions to a regenerative thermal oxidizer (RTO);

2. Installing a steam stripper to remove the POC from the wastewater prior to the inlet to the aerator; and

3. Installation of a granular activated carbon (GAC) system to remove the POC from the wastewater before it enters the inlet to the aerator.

These technologies were included in the BAAQMD's evaluation of emissions from refinery wastewater treatment systems in its study, *Further Study Measures 9 – Refinery Wastewater Treatment Systems Report, November 2005* (Further Study Measures).

Technical Feasibility

The BAAQMD is not aware of any enclosed secondary wastewater treatment aerators at petroleum refineries with external control devices, nor of any systems for which is the POC removed prior to the aerator via steam stripping or carbon adsorption. A review of regulatory BACT databases did not identify any existing BACT determinations for either configuration. This database review included the following:

• US Environmental Protection Agency (USEPA) BACT/LAER Clearinghouse:

http://www.epa.gov/ttn/catc/rblc/htm/welcome.html

• California Air Resources Board (CARB) BACT Clearinghouse:

http://www.arb.ca.gov/bact/bact.htm

• South Coast Air Quality Management District (SCAQMD) BACT Determinations:

http://www.aqmd.gov/bact/AQMDBactDeterminations.htm

• San Joaquin Valley Air Pollution Control District (SJAPCD) BACT Clearinghouse:

http://www.valleyair.org/busind/pto/bact/bactchidx.htm

Accordingly, the BAAQMD concludes that neither of these control methodologies has been achieved in practice. Nevertheless, the BAAQMD assumes for the purpose of this evaluation only that any of these technologies would be technically feasible.

Cost Effectiveness

A cost effectiveness analysis was conducted using the "levelized cash flow" methodology, commonly referred to as the annualized cost method, presented in the BAAQMD's BACT/TBACT Workbook guidance. For POC, the BAAQMD considers a cost below $17,500 per ton to be cost effective.

Emission Reduction

As noted previously, the estimated uncontrolled POC emission rate from the ETP-3 aerator would be 1.81 TPY. For the purpose of this cost effectiveness analysis, a conservatively high estimate of 2.0 TPY emission reductions is assumed.

Project Capital Cost

Shell estimated the total installed capital cost of the roof/RTO and the steam stripping options. These estimated costs are listed below:

1. Enclosed Aerator and RTO: **$6,502,000**
2. Steam Stripping: **$97,878,000**

The Further Study Measures concluded that the cost of the carbon system was similar to the cost of steam stripping; therefore Shell has not explicitly conducted a cost analysis for this technology, but has assumed that the cost effectiveness would be the comparable to that of steam stripping.

Annualized Capital Cost

In order to calculate the cost effectiveness of this project, the final installed cost must be amortized to an annual cost using a Capital Recovery Factor (CRF), which converts the up-front capital cost (the installed equipment cost) to an annualized cost. Shell assumed an annual cost of money of 6 percent, which results in a CRF of 0.136.

Total Annual Cost

In addition to the installed capital cost, the total cost of the project includes recurring annual costs, such as maintenance, labor, utilities, and taxes. Since the details of operating and maintenance (O&M) costs have not been developed, Shell used several cost factors benchmarked to the capital cost as recommended by the District. These cost factors are the Tax Factor (T = 0.01), Insurance Factor (I = 0.01), General and Administrative Cost Factor (G&A = 0.02), and the O&M Cost Factor (O&M = 0.05). For this initial estimate, the total annualized cost (TAC) is calculated according to the following formula:

TAC = Total Installed Cost X [CRF + T + I + G&A + O + M]

Thus, TAC = Total Installed Cost x 0.226. Using this simplified approach, the total annual cost is estimated as follows:

1. Enclosure/RTO: **$1,469,452/year**
2. Steam Stripper: **$22,120,425/year**

<u>Cost Effectiveness</u>

As stated previously, the cost effectiveness for an abatement project is calculated by dividing the total annualized cost by the annual emission reduction. The cost effectiveness of the two technologies is estimated below:

1. Enclosure/RTO: **$724,726/ton**
2. Steam Stripper: **$11,060,214/ton**

Each of these technologies is well beyond the cost effectiveness threshold of $17,500/ton, and therefore neither technology is cost effective.

Emission Rate at Which Control would be Cost Effective

To provide another perspective on the cost effectiveness of these technologies, this section considers the emission rate at which the considered technologies would be cost effective. At some annual POC emission rate above the rate that was actually estimated for the project, a control option would be cost effective.

The project POC emission rate at for which each considered technology would be cost effective is shown below:

1. Enclosure/RTO: 83.9 TPY
2. Steam Stripper: 1,264 TPY

In each case, the emission rate at which the technology becomes cost effective is significantly greater than any reasonable estimate of project emissions.

Conclusion

Based upon the results of this analysis, none of the abatement technologies reviewed above is technologically feasible and cost effective for the ETP-3 project.

Please refer to **Appendix C** for complete cost effectiveness report.

2.3 TOXICS

The influent water to ETP-3 will contain TACs that may be emitted to the atmosphere from the aerator. The emissions were estimated using the TOXCHEM+ data assuming that the influent water contained the historical average concentration of each pollutant in the ETP-2 feed.

TAC concentrations in the feed water may vary, because the water may come from various sources, including the existing ETP-2 feed, rainwater, and when ETP-2 is returned to service after maintenance work, wastewater feed that would otherwise be directed to ETP-1. The worst-case emissions scenario would occur when the feed to ETP-3 consists entirely of the current feed to ETP-2, since this has the highest TAC concentrations of the various feed sources. Thus, Shell used historic average ETP-2 feed concentration to calculate ETP-3 TAC emissions.

Shell routinely samples the ETP-2 influent for benzene, toluene, ethylbenzene, and xylenes (BTEX), so substantial data were available for these compounds. Summaries of the recent BTEX sampling data for ETP-2 and the sampling data for all TACs listed in BAAQMD Table 2-5-1 are included in the application folder.

TAC emissions from ETP-3, S7000, are shown in Table 4 below:

Table 4

TAC	Influent concentration (ug/L)	Daily emissions (lbs/day)	Hourly emissions (lbs/hr)	Acute TAC trigger level (lbs/hr)	Exceeds Acute TTL?	Annual emissions (lbs/yr)	Chronic TAC trigger level (lbs/yr)	Exceeds Chronic TTL?
Benzene	2,065	0.85	0.035	2.9	No	310.25	3.8	Yes
Bromomethane	260	2.07	0.086	8.6	No	755.55	190	Yes
Ethylbenzene	447	0.3	0.013	NA	No	109.50	43	Yes
Hexane	49	0.35	0.015	NA	No	127.75	270,000	No
Naphthalene	157	0.01	0.000	NA	No	3.65	3.2	Yes
Tetrachloroethylene	180	2.75	0.115	44	No	1,003.75	18	Yes
Toluene	30,000	9.94	0.414	82	No	3,628.10	12,000	No
	5,925	1.96	0.082		No	715.40		No
Xylene	2,900	0.46	0.019	49	No	167.90	27,000	No

Note:

1. Hourly & annual TAC emissions summarized in Table 4 are based on daily emissions estimated by the TOXCHEM+ model

based on TAC data collected at ETP #2's influent.

2. ETP #3 is assumed to operate for 24 hrs/day; 7 days/wk; and 365 days/yr.

3. In the case of Toluene, the average concentration of the above TAC measured in ETP #2's influent was 5.925 ppmv. However, using Toluene as a surrogate for TPHg a concentration of 30 ppmv was assumed for the purposes of BACT, offsets, etc.

It can be seen from Table 4 that a Health Risk Screening Analysis (HRSA) is warranted because the estimated annual emissions of benzene, bromomethane, ethylbenzene, naphthalene, and tetrachloroethylene are above their corresponding chronic trigger levels in Table 2-5-1 of the District Regulation 2, Rule 5.

Per June 26, 2010 memo from Ted Hull, Senior Air Quality Engineer (Toxics Section), the maximum cancer risk is 0.7 in a million, the chronic hazard index is 0.005, and the acute hazard index is 0.010. In accordance with Regulations 2-5-301 and 302 these are acceptable risks. The memo and HRSA report have been included in the application folder for future reference.

The ISCST3 air dispersion computer model was used to estimate annual average and maximum 1-hour ambient air concentrations based on a unit emission rate. Model runs were made with Shell West meteorological data using a 5-year period from 2001-2005. Elevated terrain was considered using input from the USGS Benicia and Vine Hill 10m digital elevation maps. Model runs were made with rural dispersion coefficients to best represent the land use in the area.

S7000, ETP-3, was modeled as a continuously emitting area source with a radius of 65 feet and a release height of 28 feet.

3.0 STATEMENT OF COMPLIANCE

(i)

(ii) REGULATION 1 – GENERAL PROVISIONS

Section 1-301 of Regulation 1 prohibits discharge from any source such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public; or which endangers the comfort, repose, health or safety of any such person or the public; or which causes or has a natural tendency to cause injury or damage to business or property. S7000 (ETP-3) is not expected to cause a public nuisance.

(iii) REGULATION 2-1-412 PUBLIC NOTICE, SCHOOLS

Section 2-1-412 requires public notice if the new or modified source is located within 1,000 feet of the outer boundary of any K-12 school. The proposed project will be located farther than 1,000 feet from the outer boundary of any school. Therefore, public notice is not required.

REGULATION 2-2-114.1 EXEMPTION, MACT REQUIREMENT

Under BAAQMD Section 2-2-114, The Maximum Achievable Control Technology (MACT) requirement of Section 2-2-317 does not apply to any source where the combined increase in potential to emit from all related sources in a proposed construction or modification is less than 10 tons per year of any HAP and less than 25 tons per year of any combination of HAPs. The TACs presented in **Table 4** are also HAPs. As shown in that table, emissions of any individual HAP and total HAPs from S7000 will be well below the respective 10 and 25 tons/year thresholds. Thus, Section 2-2-317 does not apply.

(iv) REGULATION 2-2-304 THROUGH 2-2-306 PSD REQUIREMENT

The project is exempt from PSD requirements since the project emissions will not exceed any of the thresholds listed in Regulations 2-2-304 through 2-2-306 or 40 CFR 52.21.

(V) REGULATION 2-6 – PERMITS – MAJOR FACILITY REVIEW

BAAQMD Rule 2-6, Major Facility Review, applies to major facilities, Phase II acid rain facilities, and any facility in a source category designated by the Administrator of the U.S. Environmental Protection Agency (EPA) in a rulemaking as requiring a Title V permit. The Refinery is a major facility and currently holds a Major Facility Review (MFR) operating permit, also referred to as a Title V operating permit. This project meets the definition of a Minor Permit Revision in accordance with Section 2-6-215, as follows:

- The project is not a major modification of a stationary source pursuant to 40 Code of Federal Regulations (CFR) Parts 51 (NSR) or 52 (PSD);
- The project is not a modification as defined in the New Source Performance Standards (NSPS) (40 CFR Part 60), National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 CFR Part 61), or Section 112 of the Clean Air Act;
- The project does not change or relax any applicable monitoring, reporting or recordkeeping condition in the MFR;
- The project does not avoid any applicable requirements;
- The project does not establish any case-by-case determinations;

- The project equipment is not a portable source; and
- The project does not modify any permit condition to incorporate new EPA requirements.

(VI) REGULATION 7 ODOROUS SUBSTANCES

BAAQMD Regulation 7 places general limitations on odorous substances and specific emission limitations on certain odorous compounds. This rule only becomes applicable if the BAAQMD receives odor complaints from ten or more complainants within a 90-day period. Shell has not triggered this requirement, and the proposed project is not expected to cause or contribute to any violations in the future.

REGULATION 8-8 ORGANIC COMPOUNDS – WASTEWATER COLLECTION AND SEPARATION SYSTEMS

The purpose of this Rule is to limit the emissions of organic compounds from wastewater collection and separation systems that handle liquid organic compounds from industrial processes. As defined in Section 8-8-208, the proposed ETP-3 processes are secondary treatment processes; therefore, per Section 8-8-113, these processes are exempt from the requirements of Sections 8-8-301, 8-8-302, 8-8-306, and 8-8-308. Sections 8-8-303, 8-8-304, 8-8-305 and 8-8-307 are also not applicable to S7000.

Regulation 8-8 specifies standards for wastewater collection and treatment systems. It also specifies administrative requirements for inspection and maintenance plan, compliance schedule, monitoring and recordkeeping requirements. The proposed ETP-3 processes will be included in Shell's current inspection and maintenance plan and Shell will be required to ensure that the proposed processes comply with all the applicable requirements of this regulation.

(vii) REGULATION 8-18 ORGANIC COMPOUNDS- EQUIPMENT LEAKS

Rule 8-18 limits emissions of organic compounds and methane from leaking equipment at petroleum refineries including, but not limited to: valves, connectors, pumps, compressors, pressure relief devices, diaphragms, hatches, sight-glasses, fittings, sampling ports, meters, pipes, and vessels. The rule requires regular inspections, prompt repairs and recordkeeping and reporting. ETP-3 will handle only wastewater with low concentrations of organics. Therefore, no components of the proposed project are in organic liquid service, and Rule 8-18 does not apply.

NSPS

40 CFR 60 Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions of Subpart A. Subpart A requires various notification and recordkeeping for sources subject to any of the Part 60 NSPS. As described in the following sections, S7000 is not subject to any NSPS. Therefore, Subpart A also does not apply.

40 CFR 60 Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

The provisions of this subpart apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices, including flares and process heaters, and sulfur recovery plants.

The proposed project is not a part of any of the above processes or affected facilities; therefore, the project is not subject to the requirements of this subpart.

40 CFR 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984

The provisions of this subpart apply to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. The ETP-3 aerator and clarifier will be processing units, and will not be used for storage. Additionally, ETP-3 will not involve the handling of VOL, as the material handled and treated will be aqueous, with low levels of organics. Therefore, this subpart will not apply.

40 CFR 60 Subpart GGG/GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

The provisions of these subparts apply to affected facilities in petroleum refineries. According to this standard an affected facility includes a group of all the equipment within a process unit in VOC service. Because no components of ETP-3 will be in VOC service (defined as any liquid containing greater than 10 percent VOC), this subpart will not apply.

40 CFR 60 Subpart QQQ—Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems

The provisions of this subpart apply to affected facilities located in petroleum refineries for which construction, modification, or reconstruction is commenced after May 4, 1987. Under this standard an affected facility includes an individual drain system, an oil-water separator and an aggregate facility. An aggregate facility is defined as the drain system together with downstream sewer lines and oil-water separators, down to and including the secondary oil-water separator. ETP-3 is not a drain system and is not an oil-water separator. The ETP-3 equipment will be downstream of the oil-water separator, and thus is not a part of an aggregate facility. Thus, this subpart does not apply.

NESHAPS

40 CFR 61 Subpart FF - Subpart FF – National Emission Standard for Benzene Waste Operations

40 CFR Part 61 Subpart FF – National Emission Standard for Benzene Waste Operations applies to owner and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries and hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any of these facilities.

The proposed project will be a waste treatment operation that will receive materials that may contain benzene. The aerator meets the definition of a tank in Subpart FF. However, the benzene concentration in the inlet water contains less than 10 parts per million of benzene on an annual flow-weighted basis. Therefore, per 40 CFR 61.342(c)(2), the proposed project is exempt from the tank management requirements of 40 CFR 61.343.

Shell is currently subject to Subpart FF, and will continue to comply with all applicable requirements. As appropriate, ETP-3 will be incorporated into the refinery's compliance management plans for this regulation.

40 CFR 63 Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 63 is also subject to the general provisions of Subpart A. Subpart A requires various notification and recordkeeping for sources subject to any of the Part 63 MACT standards. As discussed below although ETP-3 will be part of an affected facility (the refinery) subject to Subpart CC, the proposed project is not a new affected facility, and will not represent reconstruction of an affected facility. Thus, no requirements under Subpart A apply to the proposed project.

40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

This subpart applies to petroleum refining process units and to related emission points at petroleum refineries. The affected source for this subpart includes all emission points from process units, storage vessels, waste treatment facilities, etc., at the refinery. Since the proposed ETP-3 equipment will be part of a waste treatment facility and will emit HAPs, it is part of the affected facility regulated by Subpart CC.

The ETP-3 inlet stream is classified as a Group 2 wastewater stream because it has an annual average benzene concentration less than 10 parts per million. Therefore, ETP-3 will not be subject to the control requirements of 40 CFR 63.647.

The refinery currently complies with Subpart CC, and ETP-3 will be incorporated into Shell's compliance management plans for this regulation.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

CEQA is a state law intended to inform government decision makers and the public of any potential adverse environmental effects of proposed discretionary projects. For ETP-3, the only regulatory agency that needs to grant authority for the proposed project is the BAAQMD.

Per BAAQMD Rule 2-1-311, an application for a ministerial project is exempt from CEQA review. In accordance with Rule 2-1-427, permit applications covered by specific procedures, fixed standards and objective measurements set forth in the BAAQMD's Permit Handbook and BACT/TBACT Workbook are classified as ministerial. BAAQMD regulations require ministerial projects to meet specific criteria for approval of the application. Rule 2-1-311 requires the BAAQMD's approval to be based on criteria set forth in Rule 2-1-428, as paraphrased below.

1. The proposed new or modified source will comply with all applicable BAAQMD, Federal, and State Rules and Regulations.
2. The emissions can be calculated using standardized emissions factors from published governmental sources, District source test results, engineering and scientific handbooks, and other similar published literature.
3. BACT for the new and proposed source can be determined based on the latest edition of the CARB's BACT/LAER Clearinghouse or on the BAAQMD's own compilations as set forth in the Permit Handbook and BACT/TBACT Workbook.
4. If the modification of the source involves the shutdown of an existing source, Reasonably Available Control Technology applicable to the source shut down can be determined from existing provisions of the BAAQMD's rules or as set forth in the Permit Handbook and BACT/TBACT Workbook.

5. Project risk will not exceed a cancer risk of 10 in one million; a chronic hazard index of 1.0; and an acute hazard index of 1.0.
6. If Toxic Best Available Control Technology (TBACT) is required, TBACT can be determined as set forth in the Permit Handbook and BACT/TBACT Workbook.

The proposed project meets the above listed criteria as shown below:

1. S7000 complies with all applicable BAAQMD, Federal, and State Rules and Regulations.
2. The emission estimates for the proposed project were calculated using a standard, EPA-approved biodegradation model, TOXCHEM+.
3. The proposed project will not trigger BACT.
4. The proposed project does not involve the (permanent) shutdown of an existing source.
5. As mentioned in **Section 2.3** of the evaluation, the maximum cancer risk is 0.7 in a million, the chronic hazard index is 0.005, and the acute hazard index is 0.010. Hence, the project complies with Reg. 2-1-428.5.
6. This application does not trigger TBACT.

As a result, this application is for a ministerial project.

Notwithstanding ministerial classification, Rule 2-1-312 provides eleven types of categorically exempt permits. Category 11 (Rule 2-1-312.11) states:

> *Permit applications for a new or modified source or sources or for process changes which will satisfy the "No Net Increase" provisions of District Regulation 2, Rule 2, and for which there is no possibility that the project may have any significant environmental effect in connection with any environmental media or resources other than on air quality.*

The project is not expected to result in significant impacts on non-air environmental media. The BAAQMD form "Appendix H" and supplemental project information provided by Shell, demonstrates that the proposed ETP-3 meets the criteria for exemption under 2-1-312.11.

4.0 PERMIT CONDITIONS

<u>Permit Condition for S7000 (ETP-3 Aeration Tank)</u>

1. The owner/operator shall ensure that total POC emissions from S7000 aeration tank at ETP-3 do not exceed 1.814 tons in any consecutive twelve-month period. [Basis: Cumulative Increase, Offsets]

2. The owner/operator shall use the following schedule to sample influent POC concentration:

Upon initial startup of S7000, the owner/operator shall sample influent POC concentration monthly for 12 months, and calculate POC emissions from S7000. Upon APCO approval, the sample frequency will be reduced from monthly to quarterly after the initial 12 consecutive months of testing.
[Basis: Offsets, Cumulative Increase]

3. In order to demonstrate compliance with Part 1, the owner/operator of S7000 aeration tank shall use the following calculation methodology:

   POC emissions from S7000 shall be calculated on a consecutive 12-month period, using POC emission results from TOXCHEM+ (or any other District-approved methodology), calculated monthly or quarterly based on the prior 12-month period, as provided in part 2. Input data for TOXCHEM+ shall include:

   a. Average air rate to S7000 – measured by an inline flow meter, cfm
   b. Average inlet effluent rate to S7000 – measured by an inline flow meter, gpm
   c. Influent POC concentration to S7000 – analyzed for Total Petroleum Hydrocarbons- Gasoline Range (TPHg) ppm expressed as toluene.

   Within 30 days of sampling influent POC concentration, the owner/operator shall demonstrate compliance with Part 1 by calculating POC emissions from S7000 using the above calculation methodology. Any instance of non-compliance with Part 1 shall be reported in accordance with Major Facility Review (Title V) reporting requirements set forth in Regulation 2-6-502.
   [Basis: Cumulative Increase, Recordkeeping, Regulation 2-6-502]

4. The owner/operator shall maintain monthly records for each operating day of the following:

   a. Air rate to S7000 measured in cfm
   b. Inlet effluent rate to S7000 measured in gpm
   c. Sample results of influent POC concentration
   d. POC emissions from S7000 calculated by TOXCHEM+ (or other District-approved methodology)
   e. POC consecutive twelve-month emissions

   The records shall be kept on site and made available for District inspection for a period of five years from the date that the record was made. [Basis: Cumulative Increase, Recordkeeping]

5.0 RECOMMENDATION

Staff recommends the following:

Issue an authority to construct to Shell for the following source:

S7000 **Effluent Treatment Plant # 3 (ETP-3): Aeration Tank (Custom made, maximum wastewater feed rate of 2,250 gpm) and Gravity Clarifier**

By: ____

Sanjeev Kamboj Date
Senior Air Quality Engineer

ENGINEERING EVALUATION
SHELL MARTINEZ REFINERY; PLANT 11
APPLICATION 22045

2.0 BACKGROUND

Shell Martinez Refinery (Shell) has submitted an application titled "Crude Tank Replacement Project" (CTRP).

Shell's long-term prospect of providing the necessary fuels to the California market is dependent upon the ability to supplement diminishing San Joaquin Valley (SJV) crude oil feedstock. Because SJV crude oil has been delivered by pipeline, crude oil supply has been steady and predictable, and Shell has been able to operate with its existing on-site crude oil storage capacity. An increase in on-site crude oil storage capacity is necessary to accommodate economically the future variability and the intermittent nature of crude oil marine shipments/volumes to provide for the steady operation of the facility.

The purpose of the CTRP is to allow Shell to continue to supply local markets with California Air Resources Board (CARB) cleaner-burning gasoline and ultra-low sulfur diesel (ULSD) fuels, as well as other products, by greater receipt of crude oil by vessel to offset the continuing decrease in the supply of SJV crude oil. Shell is proposing to increase crude oil storage capacity to approximately 800,000 barrels in order to maintain current production levels as crude oil delivered by vessel replaces SJV crude oil as a feedstock. The CTRP will not increase the crude oil throughput of the refinery or result in an increase in the production of existing products or byproducts. No modifications will be made to the refinery process equipment, other than energy recovery projects to be implemented as greenhouse gas emission mitigation measures for California Environmental Quality Act (CEQA). No modifications will be made at the marine terminal.

The proposed CTRP consists of the following components:

- Crude Oil Storage Tanks
    - Replacement of two existing crude oil storage tanks and an existing crude oil mix tank with three new, larger external floating roof crude oil storage tanks.
    - Construction of a new external floating roof crude oil mix tank.
    - Retrofit of an existing fixed roof crude oil storage tank to an internal floating roof storage tank.
- Fugitive Components

- Fugitive components associated with the replacement and new crude oil storage tanks.

- Marine Terminal
  - Increase in the number of crude oil vessel calls above recent levels by approximately 57 vessel calls per year. Although emissions from increased shipping activity will rise as compared to recent operations, vessel emissions will not exceed applicable refinery BAAQMD permit conditions that limit emissions from the refinery, including the marine terminal.
- Mitigation/Emission Reduction Projects
  - Emission reduction projects will be implemented prior to emission increasing activities to contemporaneously reduce project emissions to or below applicable BAAQMD and CEQA thresholds. Such projects include:
    - Retrofit of an existing fixed roof Jet A storage tank to an internal floating roof storage tank to provide contemporaneous emission reduction credits necessary to offset storage tank and fugitive emission increases of POCs. (BAAQMD/CEQA)
    - Operational changes of the existing Catalytic Cracking Unit to generate contemporaneous emission reduction credits to offset NOx emission increases from increased crude oil shipping activity. (CEQA)
    - Energy recovery projects to reduce fuel consumption, resulting in reductions in greenhouse gas (GHG) emissions that will be implemented to mitigate CO_2e emissions resulting from increased crude oil shipping activity. (CEQA)

The list of new equipment is shown below:

S6069	**Crude Oil Storage Tank, External Floating Roof, 300,000 Barrel Capacity (TK-17596) – Replacement for S541**
S6070	**Crude Oil Storage Tank, External Floating Roof, 300,000 Barrel Capacity (TK-17597) – Replacement for S544**
S6071	**Crude Oil Storage Tank, External Floating Roof, 300,000 Barrel Capacity (TK-17598) – Replacement for S545**
S6072	**Crude Oil Mix Tank, External Floating Roof, 55,000 Barrel Capacity (TK-17595) – Replacement for S1127**

Modified sources are as follows:

S967	**Jet Fuel Storage Tank, Internal Floating Roof, 69,000 Barrel Capacity (TK-967)**
S1128	**Crude Oil Storage Tank, Internal Floating Roof, 55,000 Barrel Capacity (TK-1128)**

The following sources will be altered to reduce GHG emissions:

S1486 **DH F-40 Crude Unit Furnace [Installation of Air Preheater]**
S1495 **DH F-49 CRU Preheat Furnace [Installation of Heat Exchanger]**
S4021 **DHT Recycle Process Heater [Installation of Heat Exchanger]**

Shell has requested to archive the following sources:

S541 **Crude Oil Storage Tank, External Floating Roof (TK-541)**
S544 **Crude Oil Storage Tank, External Floating Roof (TK-544)**
S545 **Crude Oil Storage Tank, External Floating Roof (TK-545)**

3.0 EMISSIONS SUMMARY

Annual mass emissions are calculated based on 24-hour-per-day and 365-day-per-year operation. Net emissions are presented as the increase associated with the CTRP based on post-project emissions minus baseline emissions. A baseline of the last 3 years (2007 through 2009) represents recent emissions at the refinery pursuant to BAAQMD Regulation 2-2-605.

The emissions are calculated to determine applicability of various requirements. The emission calculations will be presented in this order:

Tank emissions
Crude oil shipping emissions
Mitigation/Emission reduction projects

2.1 Tanks emissions

Table 1 below shows the baseline, post-project and net POC emissions:

TABLE 1

Source No.	Description	Roof Type	Baseline (tpy)	Post-Project (tpy)	Net Emissions (tpy)
6069	Storage Tank	External Floating	0.4	2.6	2.2
6070	Storage Tank	External Floating	0.6	2.6	2.0
6071	Storage Tank	External Floating	0.7	2.6	1.9
6072	Mix Tank	External Floating	--	1.8	1.8

1128	Storage Tank	Internal Floating	0.0	1.5	1.5
Total			1.7	11.1	9.4

Estimated net POC emissions from the tanks are presented in Table 2.

Table 2 Net POC Emissions from CTRP	
Source	**Tons/Year**
Emission Increases	
Replacement Crude Oil Storage Tanks (S6069, S6070, S6071))	6.1
Refurbished Crude Oil Storage Tank (S1128)	1.5
New Crude Oil Mix Tank (S6072)	1.8
Fugitive Components (Pumps, Valves, Flanges)	1.4
Emission Decreases	
Retrofitted Jet A Storage Tank (S967)	-7.4
Total	**3.4**

Emissions for crude oil tanks represent the net increase for the new and refurbished crude oil storage tanks and include the emissions reductions associated with removal of the existing tanks to be replaced. Fugitive emissions from components reflect the net increased number of components associated with the CTRP crude oil storage tanks, associated piping, and new electric transfer pumps.

Calculation Approach

CTRP tank POC emissions are calculated using the United States Environmental Protection Agency (USEPA) TANKS 4.0.9d software. Crude oil storage tank emissions for the CTRP are calculated for baseline, post-project, and the net emission change. Pre-project emissions are based on actual emissions for the 3-year baseline period (2007 through 2009). CTRP fugitive POC emissions are based on the total count of new components associated with the CTRP crude oil storage tanks. POC emission increases are based on emission factors developed using the Correlation Equation Method

(CAPCOA/CARB, 1999) with the BAAQMD Regulation 8, Rule 18 component emission definitions as the screening values with flanges representing all connectors. Total fugitive emissions are estimated by multiplying the emission factor for each component type by the estimated count of each component type. Please refer to Appendix A for baseline emission calculations and Tanks program reports.

Besides combined throughput and POC emission limits, each tank will have its own maximum daily and annual throughput and POC emissions limits for future modification determinations. Shell requested that the daily and annual throughput limits be used as triggers to require district approved emissions calculations to determine whether the originally permitted emissions limit has been exceeded. In other words, no violation will be issued unless either the permitted daily or annual emissions are exceeded or the calculation is not performed.

<u>Basis of the annual emission limits for the 4 storage tanks and 1 mix tank</u>

- The annual throughputs for the 3 large storage tanks (S6069, S6070 and S6071) are based on the maximum annual fill rate that can be achieved assuming the project premise vessel offloading annual average of 120,000 barrels per day.
- The maximum annual throughput for the smaller tank (S1128) is based on a daily fill rate annualized of 55,000 barrels per day.
- The maximum annual throughput for the mix tank S6072 is identical to the throughput premised for offsets for this tank at 550,000 barrels per year.

<u>Basis of the daily emission limits</u>

- For the 4 storage tanks (S6069, S6070, S6071, and S1128), the basis is daily fill rate to maximum volume.
- The basis for the daily emission limit for the mix tank (S6072) is two tank volume turnovers in one day.

Annual and daily POC emissions are calculated assuming drain/fill operations or assuming constant level operations, depending on operation of each tank.

<u>Difference between emission calculations between a storage tank (“drain/fill”) operation versus mix tank (‘constant level”) tank operation</u>

For the CTRP project, emissions from the four storage tanks (S6069, S6070, S6071, and S1128) are calculated using the “drain/fill” method whereas emissions for the mix tank (S6072) are calculated using the “constant level” approach.

Emissions from external and internal floating roof tanks are caused by evaporative losses that occur during standing storage and withdrawal of liquid from the tank. There are two types of losses:

- Standing storage losses (also known as breathing losses) result from evaporative losses through rim seals, deck fittings, and/or deck seams.

- Working losses (also known as withdrawal losses) occur as the liquid level and thus the floating roof are lowered. Some liquid remains on the inner tank wall surface and evaporates.

Both the drain-fill and "constant level" tanks emissions methodologies are the same for standing storage losses. The differences in how the working losses for "drain/fill" and "constant level" tank operations are calculated are described below.

Under typical conditions a "drain-fill" tank is filled up and drained at separate times. As a result, the amount of material that enters or that exits a tank at any given time is equivalent to the change in the volume of material in the tank. For instance, the number of turnovers for a 55MB working volume tank with a throughput of 1,100 barrels over a specified period is 20 (1,100MB/55MB = 20 turnovers). The appropriate method to model this scenario in EPA Tanks 4.09d would be to enter the actual throughput of 1,100 barrels because this throughput is equivalent to the displaced volume. The EPA Tanks program then uses this information to calculate the number of turnovers (20) and then the working losses.

The proposed mix tank, however, will be operated as a "constant level" tank. In a "constant-level" tank, the amount of liquid added to the tank is approximately the same as the amount being removed from the tank and the liquid level stays relatively constant. For these tanks, the AP-42/EPA 4.09d calculation methodology requires that the turnovers be estimated by determining the average change in the liquid height. The displaced volume based on the change in height is summed over the period of time in question to determine the total volume displaced. This total volume displaced is then used with the working volume of the tank to calculate the total number of turnovers.

Based on this required methodology for "constant level" tanks, Shell calculated that the adjusted tank displacement volume for the mix tank would be 550 MB/year. This is equivalent to 10 turnovers (550MB/55MB) annually for this tank, which is the value used to calculate the emissions using the EPA Tanks 4.09d program.

Table 3 shows the daily and annual throughput and emissions limits for the tanks.

TABLE 3 (Daily and Annual Limits)

Source No.	Description	Throughput Limit, barrels/day	Emissions Limit, lbs POC/day	Throughput Limit, barrels/year	Emissions Limit, tons POC/year
6069	Storage Tank	300,000	88	43,800,000	8
6070	Storage Tank	300,000	88	43,800,000	8
6071	Storage Tank	300,000	88	43,800,000	8

6072	Mix Tank	110,000	52	550,000	2
1128	Storage Tank	55,000	24	20,075,000	4

Please refer to Appendix A for detailed annual and daily emission calculations and related Tanks program reports.

2.2 Marine Terminal Operations - Crude oil shipping emissions

With the CTRP, crude oil shipments are expected to increase at the marine terminal, from 30 crude oil vessels per year (the average during the baseline period) to a projected 87 crude oil vessels per year. Crude oil shipping traffic at the marine terminal generates emissions of criteria pollutants, GHGs, and TACs. Emissions were calculated for the 3-year baseline period, post-project, and the net emission change.

A summary of the potential criteria pollutant net emission levels from marine terminal crude oil vessel traffic is provided in Table 4. A detailed discussion of potential criteria pollutant emissions from crude oil shipping is provided in the *Shell Crude Tank Replacement Project Air Quality/Greenhouse Gas Emissions/Public Health Assessment* document prepared for CEQA analysis (ERM, 2011). Crude oil shipping emission calculations are consistent with the methodology established in Shell's Title V operating permit (Condition 7618). The baseline period is defined as the 3-year period ending 31 December 2009. Baseline period and future emissions of SO2 and PM10 reflect CARB fuel sulfur standards for marine fuels.

As shown in Appendix B of the *Shell Crude Tank Replacement Project Air Quality/Greenhouse Gas Emissions/Public Health Assessment* document prepared for CEQA analysis (ERM, 2011), the criteria pollutant emissions from vessels associated with anticipated crude oil shipping activity that may occur after completion of the CTRP tank construction will not exceed the existing limits contained in the applicable authority to construct and permit to operate, or in Shell's Title V operating permit, (Sections 2-1-234.1 and 2-1-234.2), nor will the increased level of crude oil shipping result in emission of any TAC in a quantity greater than that previously emitted (Section 2-1-234.4). Crude oil ship emission calculations on CD are included in Appendix B of the engineering evaluation.

Table 4
CTRP Crude Oil Shipping Emissions

Criteria Pollutant	Tons per Year		
	Baseline	Post-Project	Net

NO_x	58.8	147.7	88.9
SO_2	92.4	19.1	-73.3
PM_{10}	7.6	7.8	0.2
POC	5.0	11.1	6.1
CO	7.7	24.1	16.4

Emission projections were developed to demonstrate that the emissions associated with the anticipated increase in crude oil shipping activity will not exceed the limits contained in Shell's Title V operating permit (Condition 7618) even accounting for revisions made to the Profile Limits to reflect CARB fuel sulfur standards for marine fuels. A summary of the results of this analysis is presented in Table 5.

Table 5
Demonstration of Compliance of Crude Oil Shipping Emissions with Shell Title V Operating Permit (Condition 7618)

Pollutant	Profile Limit (tpy)	Adjusted Profile Limit (tpy)	Baseline		Post-Project	
			Profile (tpy)	In Compliance?	Profile (tpy)	In Compliance?
NO_x	1,811	1,781	1,092	Yes	1,182	Yes
SO2	3,006	2,677	1,226	Yes	1,156	Yes
ROG	337	336	164	Yes	165	Yes
PM_{10}	299	281	234	Yes	234	Yes

The GHG emissions related to crude oil shipping activities are presented in Table 6.

TABLE 6

Greenhouse Gas	Baseline (Metric tons/year)	Post-Project (Metric tons/year)	Net increase (Metric tons/year)
CO_2	10,707	27,723	17,016
CH_4	0.8	0.5	-0.3
N_2O	0.3	0.4	0.1
CO_2e	10,817	27,858	17,041

The total CO_2e emissions are derived by adding CH_4 emissions, multiplied by 21, and nitrous oxide (N_2O) emissions, multiplied by 310, to account for the Global Warming Potential (GWP) of these compounds.

BAAQMD requires vessel emission offsets to be accounted for starting at the Bar Pilot station at 11 nautical miles (nm) from the Golden Gate Bridge in the Pacific Ocean. The methodology used by Shell to calculate vessel emissions for the CTRP Land Use Permit to determine the offsets required by CEQA relies on the calculation for vessel emissions in Shell's Title V permit and uses the number of hours traveled (6 hours one way, 12 hours roundtrip).

To determine the distance traveled during the 6 hour one way trip, an average vessel speed was assumed. The maximum speed limit in the SF Bay is 15 knots. The average speed in SF Bay for tankers has been documented by the California State Lands Commission as 10 knots. The typical tanker speed in the Pacific Ocean is 13-15 knots. As the vessel approaches the Bar Pilot Station located 11 nautical miles (nm) from the Golden Gate Bridge, the vessel slows down to approximately 8 knots to allow for the transfer of the Bar Pilot to the vessel. The vessel then typically speeds up as it approaches the Golden Gate Bridge. Hence, it is reasonable to assume a 10 knot average speed in the Pacific Ocean.

The distance from the Shell Marine Oil Terminal (MOT) to the Golden Gate is approximately 30 nm and from the MOT to the Bar Pilot Station is 41 nm. Shell based its emission calculations on an average 10 knot speed for 6 hours one way transit time which provides a conservative distance traveled far beyond the transit time required to travel to the Bar Pilot station. Complete details on "Vessel Transit Distance" are included in Appendix C.

MOT Loading/Unloading Berths and Marine Vapor Recovery

Shell is limited to a crude oil processing limit of 163.2 MBD applicable to S1420, DH Crude Unit, per permit condition #18618 and no change in this limit is requested or required as a result of the CTRP.

The CTRP makes no changes downstream of the crude oil tanks in the refinery. There are no changes in hydrocarbon processing units that could facilitate a change in the facility product slate (e.g. gasoline, diesel, jet fuel) or in the ability to receive or process increased amounts of crude oil.

LOG Marine Loading Berths 1-4 (S2001 to S2004) are the MOT loading/unloading berths and the marine vapor recovery (MVR) (A100) unit abates these four sources/berths. There are no physical or operational changes to the four berths or MVR as a result of the CTRP. The CTRP emissions from the berths are the combustion emissions from the additional crude oil vessels that will be visiting the wharf as a result of the CTRP. There are no actual emissions from the berths themselves.

The MVR is used during the loading of light materials (per District Rule 8-44). When a vessel is loaded, the hydrocarbons in the vapor space of the vessel must be abated by sending them to the MVR. The MVR combusts the vapors in order to mitigate hydrocarbon emissions. The CTRP does not involve or require the operation of the MVR because the MVR is only operated when material is loaded into a vessel. The MVR is not operated when a vessel offloads its material. There is no displacement of vapors. The CTRP premises the offloading of crude oil from vessels, not the loading of crude into vessels.

2.3 Mitigation/Emission Reduction Projects

POC emission reductions

S967 Retrofit

A retrofit to the existing Tank, S967, will be implemented to generate contemporaneous emission reduction credits to mitigate POC emission increases from the new crude oil storage tanks. Existing S967 is a 69 MBbl capacity, vertical cone-style, fixed-roof storage tank. S967 is used to store Jet A, an aviation fuel. S967 is welded, and is 40 feet high with a diameter of 120 feet. This tank currently is subject to a grandfathered tank group throughput limit (Condition 18618, Part 1).

To reduce POC emissions, Shell proposes to replace the existing fixed-roof on S967 with an internal floating roof. An internal floating roof consists of two components, a roof that floats on the top of the petroleum liquid in the tank, and a fixed roof over the floating roof. The internal floating roof will be installed inside the tank and the existing cone style fixed-roof will be removed and replaced with a new, cone-style fixed roof. The internal floating roof design will limit the volume of airspace above the liquid into which volatile hydrocarbon vapors can evaporate, and thereby will reduce POC emissions. The proposed POC emissions reductions from this retrofit are shown below in Table 7.

TABLE 7

Source Number	Pre-Retrofit Emissions (tpy)	Post-Retrofit Emissions (tpy)	Net Reductions (tpy)
967	7.8	0.4	7.4

As a means of ensuring that the proposed POC emission reductions are enforceable and sufficient to reduce levels of POC to the applicable CEQA threshold, the District will impose a new permit condition with an annual POC mass emission limit of 0.4 tpy (i.e., 800 lbs/year) for S967.

NOx emission reductions

S1426 Operational changes

Operational changes of the existing Catalytic Cracking Unit (CCU), S1426, will be implemented to generate contemporaneous emission reduction credits. This will offset NOx emission increases from increased marine vessel fuel combustion associated with the increase in crude oil shipping activity.

The CCU uses heat, pressure, and catalysts to break large hydrocarbon molecules into smaller ones, thereby converting more crude oil to gasoline blending stocks. The CCU input feedstocks come from the heavier fractions from the Crude Oil Distillation Unit. Emissions from the CCU are currently abated by CO boilers and are limited by refinery-wide and specific CCU emission limits for criteria pollutants (BAAQMD Condition 7618).

To generate the necessary NOx reductions at the CCU to mitigate NOx emissions from increased shipping activity, Shell intends to make operational changes at the CCU and supporting CCU hydrotreater feed units. A combination of all or some of the operational changes summarized below would be used at any given time to achieve the necessary NOx reductions.

- **Optimize Regenerator Conditions:** Shell will reduce the amount of carbon monoxide (CO) in the CCU regenerator and thereby run the unit closer to “full burn”. When a catalytic cracking unit is operated closer to “full burn”, the nitrogen chemistry shifts to favor lower NOx levels in the regenerator, resulting in lower NOx emissions.
- **CCU Feed Quality Management:** Two hydrotreaters currently treat the CCU feed for nitrogen prior to delivery to the CCU. Shell will optimize the performance of the two hydrotreaters in order to minimize the amount of nitrogen in the CCU feed. By lowering the amount of nitrogen in the CCU feed, the amount of potential nitrogen converted ultimately to NOx in the CCU is reduced.
- **Optimize CCU Hydrocarbon Stripper Operations:** The CCU hydrocarbon stripper vessel located between the CCU regenerator and the CCU reactor removes hydrocarbon containing nitrogen from the catalyst before the catalyst enters the regenerator. By operating the CCU stripper (by adjusting and controlling steam rates), the hydrocarbon on the catalyst will be removed and hence the amount of hydrocarbon entering the regenerator will be reduced. By reducing the hydrocarbon entering the regenerator, the amount of nitrogen is reduced and therefore, the amount of potential nitrogen converted ultimately to NOx emissions is reduced.
- **Optimize Catalyst Circulation Rate:** By optimizing the catalyst circulation rate by adjusting operating conditions in the reactor (temperature, water injection rates, etc.), a reduction in NOx emissions can be realized.
- **Import CCU Feed Management:** As market conditions allow, Shell may selectively purchase lower nitrogen CCU feeds in order to lower NOx emissions at the CCU

Annual average NOx emissions from the three CCU CO boilers for the baseline period are shown in Table 8. Baseline emissions are obtained from continuous emissions monitors (CEMS) data at the outlet of the CCU boilers. NOx emissions for the 3-year baseline period, ending 31 December 2009, are presented in Appendix D.

Proposed operational changes at the CCU will result in expected reductions in annual average NOx emissions, as shown in Table 8. As a means of ensuring that the proposed NOx emission reductions are enforceable and sufficient to reduce levels of NOx to the applicable CEQA threshold, the District will impose a new permit condition with an annual NOx mass emission limit of 468 tpy for the CCU.

TABLE 8

	NOx Emissions (tpy)
Baseline NOx Emissions	547
Post-Project NOx Emissions	468
Project NOx Emissions Reductions	-78.90

GHG Emission Reductions

Energy efficiency projects will reduce fuel consumption and result in reductions of GHG emissions, expressed as CO_2e. Such projects will be implemented to mitigate CO_2e emissions from anticipated increased shipping activity to zero net increase of GHG for the CTRP. Three energy projects have been identified as measures to reduce GHG emissions. The projects are as follows:

S1486 Air Preheater Energy Recovery Project

Shell will install an air preheater (APH) at S1486, DH F-40 Crude Unit Feed Heater, to improve the energy efficiency of the heater to reduce GHG emissions. The APH will reduce the amount of fuel consumed by S1486, thus lowering GHG emissions. The APH uses hot flue gases in the S1486 stack to “preheat” combustion air, resulting in lower fuel gas firing. The new technology is a multi-stage tubular unit with hot section of finned cast iron tubes and cold section of tubes, typical and consistent with other updated industry and Shell installations. There are no moving parts. There will be isolation blinds that allow the APH to be taken out of service at any time for maintenance.

The heat recovered from the flue gas is expected to reduce the firing rate at S1486 by 19 MMBtu/hr equating to a reduction in GHG emissions as shown in Table 9. The methodology for calculating the GHG emission reductions is detailed in Appendix E. Shell would measure and demonstrate the energy efficiency improvements by recording the air temperature into and out of the APH and air flow going into and exiting the APH and then calculating the heat gain. This heat gain in the combustion air is standard heat enthalpy thermodynamics in that the energy that the combustion air picks up translates directly to the reduction in fuel gas energy content needed to achieve the required firebox temperature.

TABLE 9

Heater	Net Firing Rate Change (MMBtu/hour)	CO_2e Emissions change (Metric tons/year)
S1486	-19	-8,833

S1486 furnace originally had an APH, which was installed under BAAQMD application number 26133 in 1977. This APH is no longer in service. The unit was a Ljungstrum design that was operated intermittently due to significant operational and maintenance issues. The primary weaknesses of the system included problematic bearing design which hindered plate rotation and ineffective seals between stack gas and combustion air chambers which caused leakage.

Even when this retired APH actually was in service, part of the hot flue gases were bypassed through the stack due to these operational issues. Problems escalated in the early 2000s and despite repairs on the APH in 2004, the unit continued to operate intermittently and not to design levels. Consequently, the unit was shut down permanently in early 2006.

An EIR includes a description of the physical environmental conditions during the baseline period so they can be compared to conditions post project. The original, now out of service APH, was not in operation during the project baseline period and accordingly no emission reductions from it are included in the baseline. Consequently, the emission reductions realized from the new proposed CTRP S1486 APH will be real and credible (see CEQA Guideline 15125(a) and 15126.2(a)).

With respect to CEQA, all criteria pollutants will decrease as a result of the APH operation but NOx needs additional clarification. S1486 APH may result in an increase of NOx emissions compared to its immediate operation after installation but not compared to the S1486's baseline CEQA air quality emissions. The vendor supplied maximum emission factor for S1486 with the APH operating is 0.04 lbs NOx/MMBtu and the expected performance of the S1486 with APH is approximately 0.031 lbs NOx/MMBtu. There will also be an approximate 10% reduction in fuel firing at S1486 post project. The NOx emission factor during the CEQA 3-year baseline of 2007-2009 is 0.074 lbs/MMBtu. Hence, from a CEQA perspective by comparing the emissions during the baseline period to post project emissions, there is no increase at S1486 in NOx emissions with the installation of the APH.

The APH does not require any fuel gas for operation. In terms of greenhouse gas emissions from indirect electricity demand (from the grid), the APH will use two small blowers that will require electricity to operate. The forced draft blower operating duty is 68 kW and the induced draft blower operating duty is 143 kW. Total anticipated operating duty for both blowers is 180 kW (w/capacity factor: 0.85). This negligible electricity demand is considered de minimus and within the total 0.4% incremental increase in facility electricity demand due to the CTRP.

The S1486 APH project meets the definition of "alteration" under BAAQMD Regulation 2, Rule 1, Section 233. An alteration per Section 2-1-233 is to "make any physical change to, or change in the method of operation, of a source, which may affect emissions." The installation of a new APH on S1486 is considered a physical and operational change to S1486.

The average annual NOx emissions using the 2007-2009 CEQA baseline period is 91.6 tpy based on a 3-year average firing rate of 281 MMBtu/hr and 3-year average emission factor of 0.074 lbs NOx/MMBtu HHV.

Anticipated typical NOx emissions post project with the operation of the APH are 49.2 tpy as shown in Appendix F. Consequently, this project does not result in an increase in emissions when comparing baseline NOx emissions of 91.6 tpy to 49.2 tpy post project. To demonstrate that there is no emissions increase as a result of APH project, the District will impose a new permit condition with an annual NOx mass emission limit for S1486. Please refer to Appendix F for complete NOx emissions calculations, source test results used to determine NOx emission factors and written guarantee from the vendor on maximum emission factor of 0.040 lbs NOx/MMBtu for S1486 with the APH operation.

S4021 Distillate Hydrotreater Energy Recovery Project

Shell will implement a project to improve the energy efficiency of the Distillate Hydrotreater (DHT) to reduce fuel gas consumption, resulting in reductions of GHG emissions, expressed as CO_2e. Reductions in GHG emissions will be applied as an emission reduction measure with other proposed energy recovery projects to mitigate the CO_2e emission increases from increased marine vessel fuel combustion associated with the post-CTRP anticipated increase in crude oil shipping activity.

The DHT removes sulfur and nitrogen from CCU feed by mixing feed with hydrogen and allowing the hydrotreating reaction to occur across two reactor catalyst beds. The reactor feed mixture is preheated in a feed/effluent exchanger. Shell proposes to tie-in and use an idle feed/effluent heat exchanger in the DHT, which will provide additional feed preheat that is currently provided by the S4021 fired heater. With the additional exchanger, the heat recovery train can run almost auto-thermally without furnace heat input.

The objective of the project is to increase the energy efficiency and reduce GHG emissions from the DHT by maximizing heat recovery from sections of the unit where heat is currently lost. Heat loss is unrecovered from the effluent exiting from the existing exchanger train. Shell will demonstrate the energy efficiency improvement by calculating the heat recovery and resulting reduction in furnace firing, and therefore reduction in GHG emissions, expressed as CO_2e.

To determine the baseline emissions, furnace operations during the period of 1 March 2007 to 11 July 2009 were chosen to represent a typical operating period. This baseline period is consistent with that used for Shell's application for the Pacific Gas and Electric (PG&E) Non-Residential Retrofit Demand Response Program for the CRU Energy Recovery Project. The average hourly firing rate for S4021, DHT Process Heater, for the baseline period is presented in Table 10.

Emission reductions of CO2e are calculated by determining the net potential firing rate reduction of the DHT S4021 fired heater and applying established emission factors to determine the potential CO2e reductions. It is assumed that any net reduction in DHT S4021 firing rate will result in the consumption of less purchased natural gas. The methodology for calculating this is detailed in Appendix E with results shown in Table 10.

TABLE 10

Heater	Baseline Firing Rate (MMBtu/hour)	Post-Project Firing Rate (MMBtu/hour)	Net Firing Rate Change (MMBtu/hour)	CO_2e Emissions Change (Metric tons/year)
S4021	21.9	6.77	-15.2	-7,066

S1495 Catalytic Reformer Unit Energy Recovery Project

Shell will implement a project to improve the energy efficiency of the Catalytic Reformer Unit (CRU) to reduce fuel gas consumption, resulting in reductions of GHG emissions, expressed as CO_2e. Reductions in GHG emissions will be applied as an emission reduction measure with other proposed energy recovery projects to mitigate the CO_2e emission increases from increased marine vessel fuel combustion associated with the post-CTRP anticipated increase in crude oil shipping activity.

The CRU converts hydrotreated low-octane naphthas from the naphtha hydrotreater, hydrocracker unit, and heavy gas-oil hydrotreater to produce high-octane gasoline blending components. The CRU utilizes reactors in series to conduct the reforming reactions. The reforming reactions are highly endothermic, so heat input by a process heater is required between each of the reactors.

To further improve the energy efficiency of the CRU, Shell will install an additional new vertical feed/effluent heat exchanger upstream of the existing S1495, DH F-49 CRU Preheat Furnace. The objective of the project is to increase the energy efficiency and reduce GHG emissions from the CRU by maximizing heat recovery from sections of the unit where heat is currently lost. Shell will demonstrate the energy efficiency improvement by calculating the heat recovery and resulting reduction in furnace firing, and therefore reduction in GHG emissions, expressed as CO2e.

Along with preheating feed to the CRU reactors, the convection section of S1495 produces steam used elsewhere in the refinery. Reducing the S1495 firing rate reduces the steam make and this CRU steam must be produced by another steam producing unit in the Refinery. Hence, the emission reductions for this project must be reduced by the emissions generated by the additional steam production. As shown in Table 11, for every 2.2 MMBtu/hr reduction in S1495 firing, there is a corresponding increase of 1 MMBtu/hr firing required for making up the lost steam at one of the steam producing units (i.e., 39.6 MMBtu/hr reduction compared to 17.8 MMBtu/hr increase). For the purposes of these emission calculations, Boiler 4 (S1514) is used as a surrogate for the Refinery's overall steam producing units to demonstrate the increase in firing required to make up for the reduction in steam produced by S1495.

To determine the baseline emissions, furnace operations during the period of 1 March 2007 to 11 July 2009 were chosen to represent a typical operating period. This baseline period is consistent with that used for Shell's 2009 application for the Pacific Gas and Electric (PG&E) Non-Residential Retrofit Demand Response Program. The monthly average firing rate on a higher heating value basis is provided in Appendix E. The average hourly firing rates for S1495 and S1514 (as the surrogate steam boiler) for the baseline period are shown in Table 11.

Furnace S1495 was fired on a mixture of refinery fuel gas (RFG) and flexigas (FXG) and furnace S1514 fired exclusively RFG during the baseline period. RFG is composed of fuel gas produced by the refinery and supplemented with purchased natural gas. It is assumed that the volume of fuel gas produced by the refinery is fixed and that any reduction in firing rates will result in a reduction in purchased natural gas.

Emission reductions of CO2e are calculated by determining the net firing rate reduction between S1495 and S1514 and applying established emission factors to determine the net CO2e reductions. The methodology for calculating net CO2e emission reductions is detailed in Appendix E with results shown in Table 11.

TABLE 11

Furnace	Baseline Firing Rate (MMBtu/hour)	Post-Project Firing Rate (MMBtu/hour)	Net Firing Rate Change (MMBtu/hour)	CO_2e Emissions Change (Metric tons/year)
S1495	114.8	75.3	-39.5	-18,363
S1514	113.9	131.6	17.7	8,229
Total	**-**	**-**	**-21.8**	**-10,135**

3.0 CUMULATIVE INCREASE AND OFFSETS

Shell is an existing facility. Table 12 summarizes the cumulative increase in criteria pollutant emissions due to the operation of the CTRP.

Table 12
Cumulative Increase

Pollutant	Increase in plant emissions prior to April 5, 1991 (TPY)	Increase in plant emissions since April 5, 1991 (TPY)	Increase in plant emissions associated with this application (TPY)	Cumulative increase in emissions (Post 4/5/91 + Current application increase) (TPY)
NOx	0	8.100	0	8.100
POC	26.09	0.249	3.40	3.649
CO	0	335.250	0	335.250
PM_{10}	0.11	0.240	0	0.240
SO_2	0	0	0	0
NPOC	11.00	14.700	0	14.700

Post April 5, 1991 POC emissions of 0.249 tpy are secondary emissions attributed to operation of Thermal Oxidizer, A2023 that was permitted under Application #18034. Since, these POC emissions were not offset at the time A2023 was permitted; Shell will have to surrender offsets for 0.249 tpy also besides 3.40 tpy associated with this application.

Table 13
Offsets

Pollutant	Permitted plant emissions (TPY) Pre-April 5, 1991 + Post-April 5, 1991	Actual plant emissions[1] (TPY)	Increase in plant emissions associated with this application (TPY)	Total emissions (Higher of Permitted/Actual Emissions + Emissions associated with this application) (TPY)	Regulation 2-2-302 and 2-2-303 Offset Triggers (TPY)
NOx	8.100	974.09	0	974.09	> 35
POC	26.339	1395.63	3.40	1399.03	> 35
CO	335.250	1041.39	0	1041.39	NA
PM_{10}	0.350	434.25	0	434.25	> 1
SO_2	0	1156.34	0	1156.34	> 1
NPOC	25.70	0	0	25.70	NA

[1] Db → q2 →p → all

It can be seen from Table 13 above that offsets are warranted for POC, since the emissions of the above pollutant are greater than the 35 tons per year offset trigger. It can also be seen that the actual emissions of NOx, POC, CO, PM_{10}, and SO_2 are above the permitted emissions for the above pollutants. This is so because most sources at refineries are grand fathered (i.e., Pre-1971 sources). Therefore, Shell will have to surrender to the District 4.196 TPY of POC Emission Reduction Credits (ERCs) at an offset ratio of 1.15:1[2]. Shell currently owns 5.582 tons of POC ERCs in Certificate #1134 that was issued by the District on November 6, 2008. Shell has surrendered above certificate to the District, and will receive a new certificate in the amount of 1.386 (5.582 – 4.196) tons per year with a new issuance date.

2 Per Regulation 2-2-302, 3.649 x 1.15 = 4.196 TPY.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY

In accordance with BAAQMD Regulation 2, Rule 2, Section 301, a source with the potential to emit 10 pounds or more per highest day of POC, NPOC, NOx, CO, SO_2 or PM_{10} must use BACT. For this application, BACT is triggered for the new and modified crude oil tanks because POC and NPOC emissions could exceed 10 pounds per highest day. BACT is not triggered for the new fugitive components because POC and NPOC emissions would not exceed 10 pounds per highest day.

The District's BACT requirements for External Floating Roof Tanks (EFRTs) are addressed in the District BACT/TBACT Workbook in Document number 167.1.2 dated September 19, 2011. The BACT requirements are reproduced below:

BACT 1. Vapor recovery system with a control efficiency > 98%; and

BACT 2. An external floating roof which has:

a. A liquid mounted primary seal (meeting Reg. 8, Rule 5 design criteria),
b. A zero gap secondary seal (meeting Reg. 8, Rule 5 design criteria),
c. No ungasketed roof penetrations,
d. No slotted pipe guide pole unless it is equipped with a float and wiper seals, and
e. No adjustable roof legs unless they are fitted with vapor seal boots or equivalent.
f. Additionally, a dome is required for tanks that meet all of the following: 1) capacity greater than or equal to 19,815 gallons 2) located at a facility with greater than 20 tpy VOC emissions since the year 2000 and 3) storing a material with a vapor pressure equal to or greater than 3 psia (except for crude oil tanks that are permitted to contain more than 97% by volume crude oil).

The District's BACT requirements for Internal Floating Roof Tanks (IFRTs) are addressed in the District BACT/TBACT Workbook in Document number 167.4.1 dated March 03, 1995. The BACT requirements are reproduced below:

BACT 1. Vapor recovery system with a control efficiency > 98%; and

BACT 2. An internal floating roof which has:

a. A liquid mounted primary seal (meeting Reg. 8, Rule 5 design criteria),
b. A zero gap secondary seal (meeting Reg. 8, Rule 5 design criteria),
c. No ungasketed roof penetrations,
d. No slotted pipe guide pole unless it is equipped with a float and wiper seals, and
e. No adjustable roof legs unless they are fitted with vapor seal boots or equivalent.

NPOC BACT requirements for both EFRTs and IFRTs are the same as POC requirements that are listed above.

All EFRTs and IFRTs that are included in this application will comply with BACT2 requirements.

The dome is a new requirement for the Bay Area, but it has been required in the South Coast AQMD since 2004 for EFRTs per rule 1178 with the exception of crude oil tanks. External floating roof tanks permitted to contain more than 97% by volume crude oil are exempt from the doming requirements of rule 1178. Shell in an e-mail dated September

22, 2011 has confirmed that sources S6069 to S6072, Tanks, will be in crude oil service and will store more than 97% by volume crude oil. To ensure compliance, this requirement will be included in permit conditions for the EFRTs.

For the purposes of BACT1 analysis, one of the largest, highest emitting external floating roof tanks is considered (e.g., S6069). The BACT 1 level of control for an external floating roof tank is specified as a vapor recovery system that achieves 98 percent control efficiency or more. To install a vapor recovery system on an external floating roof tank, a roof or dome must be installed on the tank to allow for capture of vapors that escape the floating roof. This BACT analysis demonstrates that a vapor recovery system is not cost-effective for the proposed project. Consequently, for the proposed project, BACT is equivalent to the BACT2 level of control. BACT2 is an external floating roof with specified seals and appurtenances (BAAQMD-approved design). This level of control is proposed for all of the CTRP external floating roof crude oil tanks. The technical feasibility and cost-effectiveness analysis of BACT1 are presented below.

BACT1 - Vapor Recovery System

The BAAQMD BACT Workbook specifies typical technologies for BACT1, which requires vapor recovery. Typical technologies include thermal incineration, carbon adsorption, refrigerated condensation, or BAAQMD-approved equivalent technology.

Installation of a vapor recovery system which would route tank emissions to the refinery fuel gas system is considered to be a technologically feasible BACT alternative to abate emissions from the proposed crude oil tanks.

The vapor recovery to fuel gas system would consist of a vapor compressor with associated blowers, piping, electrical and control systems that would capture and route tank emissions to the existing refinery fuel gas system. Consistent with Shell standards for similar systems, the vapor recovery system would be equipped with a sphere for vapor collection with a supporting flare system for sphere or compressor maintenance work. The order of magnitude vendor cost estimate (see Budget Estimate from CB&I included in Appendix G) to install this vapor recovery system for S6069 is approximately $26,000,000, including expenses for project management, testing, and commissioning. The annualized equipment costs for construction of this vapor recovery to fuel gas system (assuming a 10-year equipment life and a 7 percent interest rate) are estimated as $3,701,815.

Maximum annual emissions from S6069 constructed as an external floating roof tank without vapor recovery are estimated to be 8 tons. Emissions from S6069 constructed with the vapor recovery system described above would be reduced by approximately 7.88 tons, to a level of 0.12 tons/year. The cost-effectiveness for this level of emissions reduction is estimated as $469,773/ton. The BAAQMD BACT Workbook specifies that maximum cost per ton of POC emissions controlled that would be considered to be cost-effective is $17,500. Therefore, the BACT1 vapor recovery system described above is not cost-effective.

BACT1 – Thermal Incineration

In addition to the thermal oxidizer unit, this technology would require most of the same equipment that would be needed for vapor recovery. Therefore, cost for this technology is expected to be greater than the cost of routing the vapors to the vapor recovery system (i.e., >$469,773 per ton emissions reduced).

From a safety perspective, the applicant prefers devices that do not collect/concentrate vapors or use combustion for control such as external floating roof tanks over thermal incineration (which both collects/concentrates flammable vapors and entails combustion). Compared to an EFRT, if a thermal incinerator were to flame out while the tanks were relieving vapors to the incinerator, the concentration of unburned hydrocarbons emitted from the incinerator would be significantly higher than the emissions coming from the rim of an external floating roof tank.

Also, passive safety systems (external floating roof tanks) are always preferred by facilities over continuously operated active safety systems (thermal incinerators). Active systems which rely on ongoing operating equipment such as valves to open/close to regulate fuel flow and control systems to monitor ignition and flame are more complicated and therein have more likelihood of failure than passive systems.

Hence, installation of a thermal incinerator would not be the preferred technology from a safety perspective (as well as cost-effectiveness).

BACT1 – Carbon Adsorption

Carbon adsorption is not a technologically feasible control alternative to achieve 98% removal efficiency of VOC emissions from crude tank vapors. It also has several drawbacks for permanent use in this application. There would be additional issues of carbon deactivation and potentially safety issues of placing activated carbon in service on vapors containing sulfur compounds, which are present in crude vapor.

Crude vapors contain a mix of VOC species, ranging from light-end hydrocarbons, middle-range hydrocarbons, heavy hydrocarbons, and volatile impurities such as sulfur compounds (i.e., mercaptans, hydrogen sulfide). Each chemical has a different affinity for the activated carbon, depending on that chemical's properties and configuration; thus, each chemical is adsorbed to different degrees (and mass ratio). Control efficiency is therefore different for each VOC species. Light hydrocarbons, such as methane, ethane and propane are not adsorbed well, making it difficult to achieve efficient control of these species. Conversely, certain very heavy hydrocarbons can adsorb so well to carbon that it is very difficult to regenerate the carbon and can build up a heel or deactivate the carbon (EPA APTI 415: Control of Gaseous Emissions, 1999). Covering active adsorption sites by an inert material is referred to as "deactivation." High boiling point and high molecular weight compounds have such an affinity for the carbon that it is extremely difficult to remove them by standard desorption practices. These compounds also tend to react chemically on the carbon surface, forming solids or polymerization products that are extremely difficult to desorb. Loss of carbon activity in this manner is termed *chemical deactivation*. Under the best conditions, large scale carbon adsorption systems have demonstrated between 92-97% recovery of NMOC from crude vapor, with considerable expense and pretreatment (Shipley, Simon, "Developing an effective crude oil vapor recovery system", Port Technology International, Edition 49, Winter 2011). Technical paper "Developing an effective crude oil vapor recovery system" from Port Technology International journal has been included in the application folder for future reference. Overall, carbon adsorption would not be expected to achieve over 98% control of crude vapor VOC.

In addition, sulfur compounds are exothermically adsorbed, which can generate heat. These compounds can deactivate the carbon or in some cases can ignite the carbon beds (causing bed fires).

Carbon adsorption systems can be designed for recovery (i.e., regenerative systems) or non-regenerative applications, where saturated carbon is transported offsite for disposal or offsite regeneration and reuse, and VOC is a waste. Regenerative carbon adsorption systems are difficult to design and operate in crude vapor service. Build-up of impurities or deactivation of carbon must be managed by pretreatment of the vapor stream. While use of non-regenerative carbon adsorption systems could be considered for temporary abatement, the cost and waste generated as a permanent abatement alternative would make this infeasible. For example, per Shell, to abate 2 tons per year of crude vapor emissions, approximately 20 tons per year of carbon would be required. Disposal cost would vary, but would add substantially to operating costs that could make this alternative not cost-effective due to the cost of waste disposal alone if waste amounts were to exceed anticipated levels. Based on Shell's discussion with a representative from industrial waste handling company, Clean Harbors, the range of disposal costs for this waste carbon, including transportation offsite to the disposal facility, would range from $900-$1,200 per ton of waste carbon (depending on actual waste characteristics and location of waste disposal facility). Assuming 20 tons of carbon waste generation per year and 2 tons of POC mitigated per year, this cost range corresponds to approximately $9,000 to $12,000 per ton POC mitigated for the waste disposal alone.

By including the cost of the carbon equipment and the roof installation with the waste disposal costs, the total cost per ton of POC mitigated for the carbon option would likely be well above the BAAQMD cost-effectiveness threshold of $17,500.

Conclusion

Based upon the results of this analysis, none of the abatement technologies reviewed above is technologically feasible and/or cost-effective for crude oil tanks. Hence, BACT2 is determined to be BACT for crude oil tanks.

Please refer to Appendix H for complete BACT analysis.

5.0 TOXICS

POC emissions from CTRP crude oil storage tanks and fugitive components contain compounds that are considered to be toxic air contaminants (TACs). For the annual TAC emissions estimates, post-project POC emissions are speciated into TAC constituents based on the default speciation data obtained from USEPA TANKS 4.09d software for crude oil.

For tanks, total TAC emissions are the sum of the working and breathing loss emissions at the conditions assumed for each tank. The working loss emissions are based on the liquid fraction for each TAC constituent and breathing losses are based on the vapor fraction. The new, replacement, and refurbished tanks (S6069, S6070, S6071, S6072, and S1128) are considered to be new tanks. Consistent with BAAQMD Regulation 2-5-601, annual TAC emissions for new sources are based on post-project emissions (i.e., the potential to emit).

Hourly TAC emissions are based on the maximum hourly operation of the tanks. USEPA TANKS 4.09d software was used to calculate post-project maximum hourly POC emissions from the CTRP crude oil tanks. The premise used as the basis for post-project maximum hourly tank TAC emissions is discussed in detail in the *Shell Crude Tank Replacement Project Air Quality/Greenhouse Gas Emissions/Public Health Assessment* document prepared for CEQA analysis (ERM, 2011), including detailed TANKS 4.09d tank input parameters and TANKS 4.09d output with detailed maximum hourly working and breathing loss emission estimates for each tank. Detailed TANKS 4.09d tank input parameters and TANKS 4.09d outputs are also included in Appendix A of this document.

For fugitive components, annual and hourly TAC emissions are based on the total count of new components associated with the CTRP crude oil storage tanks. Using the same liquid fraction for the same crude oil speciation as for the tanks, TAC emissions were calculated from CTRP component fugitive POC emissions at ambient conditions.

TAC emissions from the CTRP are shown in Table 14 below. Detailed TAC emissions by source are in provided in the *Shell Crude Tank Replacement Project Air Quality/Greenhouse Gas Emissions/Public Health Assessment* document prepared for CEQA analysis (ERM, 2011).

Table 14 CTRP TAC Emissions						
TAC	**Hourly emissions (lbs/hr)**	**Acute TAC trigger level (lbs/hr)**	**Exceeds Acute TTL?**	**Annual emissions (lbs/yr)**	**Chronic TAC trigger level (lbs/yr)**	**Exceeds Chronic TTL?**
Benzene	0.127	2.9	No	343	3.8	**Yes**
Ethylbenzene	0.049	NA	No	82	43	**Yes**
Hexane (n-)	0.104	NA	No	309	270,000	No
Toluene	0.144	82	No	293	12,000	No
Xylenes (m-)	0.168	49	No	273	27,000	No

Because the estimated annual emissions of benzene and ethylbenzene are above the corresponding chronic trigger levels in Table 2-5-1 of the District Regulation 2, Rule 5, a Health Risk Screening Analysis (HRSA) is required.

Per July 6, 2011 memo from Ted Hull, Senior Air Quality Engineer (Toxics Section), the maximum cancer risk is 0.3 in a million, the chronic hazard index is 0.0001, and the acute hazard index is 0.007. In accordance with Regulations 2-5-301 and 302 these are acceptable risks. The memo and HRSA report have been included in Appendix I.

The ISCST3 air dispersion computer model was used to estimate annual average and maximum 1-hour ambient air concentrations. Model runs were made with representative Shell East meteorological data. Elevated terrain was considered using input from the USGS Benicia and Vine Hill 10m digital elevation maps. Model runs were made with Rural dispersion coefficients to best represent the land use in the area.

Each tank was modeled as a continuously emitting circular area source representing the dimensions of the tank.

6.0 STATEMENT OF COMPLIANCE

(viii)

(ix) REGULATION 1 – GENERAL PROVISIONS

Section 1-301 of Regulation 1 prohibits discharge from any source such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public; or which endangers the comfort, repose, health or safety of any such person or the public; or which causes or has a natural tendency to cause injury or damage to business or property. The CTRP is not expected to cause a public nuisance.

(x) REGULATION 2-1-412 PUBLIC NOTICE, SCHOOLS

Section 2-1-412 requires public notice if the new or modified source is located within 1,000 feet of the outer boundary of any K-12 school. The proposed project will be located farther than 1,000 feet from the outer boundary of any school. Therefore, public notice is not required.

REGULATION 2-2-114.1 EXEMPTION, MACT REQUIREMENT

Under BAAQMD Section 2-2-114, The Maximum Achievable Control Technology (MACT) requirement of Section 2-2-317 does not apply to any source where the combined increase in potential to emit from all related sources in a proposed construction or modification is less than 10 tons per year of any HAP and less than 25 tons per year of any combination of HAPs. As shown in Table 15, the increase in HAP emissions from the CTRP storage tanks and associated fugitive components is less than 10 tons per year of any HAP and less than 25 tons per year of all HAPs combined. Therefore, TBACT is not required for the CTRP storage tanks pursuant to Section 2-2-317.

Table 15
CTRP HAP Emissions

HAP	CAS Number	Potential to Emit (tons per year)	HAP Threshold (tons per year)	HAP Threshold Exceeded? (Yes/No)
Benzene	71-43-2	0.171	10	No
Ethylbenzene	100-41-4	0.041	10	No
Hexane (n-)	110-54-3	0.155	10	No
Isooctane	540-84-1	0.019	10	No
Toluene	108-88-3	0.147	10	No
Xylenes (m-)	1330-20-7	0.137	10	No
Total		0.670	25	No

(xi)

(xii) REGULATION 2-2-304 THROUGH 2-2-306 PSD REQUIREMENT

RTP Environmental Associates, Inc. (RTP) performed PSD applicability review on Shell's behalf. The review was done to determine the following:

1) Need to be permitted under the New Source Review, Nonattainment and Prevention of Significant Deterioration programs, or
2) Require reporting and recordkeeping in accordance with 40 CFR 52.21(r)(6).

RTP's analysis of emission increases from the proposed CTRP indicates that the PSD preconstruction permitting requirements will not be triggered. Prior to the EPA's recent announcement that they will be reconsidering the reasonable possibility rule, the annual reporting or recordkeeping of baseline and projected/future actual emissions would also NOT be required because in accordance with the rule there is no reasonable possibility that the potential for an increase in NSR emissions will be greater than 50% of the pollutant specific significance levels when the excludable emissions (i.e., capable of accommodating and unrelated to including demand growth) are not included. However, in light of the reconsideration, both pre-project recordkeeping and post-project recordkeeping and reporting should be considered.

To determine if the CTRP requires major NSR permitting (i.e., if the project is a major modification) or NSR recordkeeping and reporting, the PSD regulations require that the various comparative tests (i.e., APAE- BAE) be performed. Table 16 presents the results from each of these tests for each of the PSD pollutants.

Table 16. Summary of PSD Analysis Results

	Pollutants Emitted - Tons Per Year						
	PSD				NNSR		GHG
	PM_{10}	SO_2	CO	NO_2	NOx	VOC	CO_2e
BASELINE (a)							
Hoteling	2.2	23.8	2.7	17.7	17.7	1.7	3,264
Pumping	4.7	74.2	0.8	15.0	15.0	1.0	8,144
PROJECT EMISSIONS INC.							
New Units							
Tank 541 - Replacement (storage)						3.0	
Tank 544 - Replacement (storage)						3.0	
Tank 545 - Replacement (storage)						3.0	
Tank 1127 - New (mix)						1.8	
Tank 1128 - Refurb./New (storage)						1.6	
Fugitive Components						0.76	
New Units Total:	0.0	0.0	0.0	0.0	0.0	10.2	0.0
Existing Units							
With Project (b)							
Hoteling (Elec. + Steam)	1.2	2.7	4.1	25.1	25.1	2.0	4,335
Pumping (Boiler steam)	3.0	12.8	4.5	21.7	21.7	0.2	20,228
Without Project (c)							
Hoteling (Elec. + Steam)	1.9	4.1	6.4	38.6	38.6	3.1	6,639
Pumping (Boiler steam)	2.0	8.8	3.1	14.8	14.8	0.2	13,854
Excludable (d=c-a)							
Hoteling	0.0	0.0	3.7	20.8	20.8	1.4	3,375
Pumping	0.0	0.0	2.3	0.0	0.0	0.0	5,710
Adjusted PAE (APAE) (e=b-d)							
Hoteling	1.2	2.7	0.5	4.3	4.3	0.6	960
Pumping	3.0	12.8	2.2	21.7	21.7	0.2	14,518
APAE - BAE							
New Units	0.0	0.0	0.0	0.0	0.0	10.2	0
Hoteling	-0.9	-21.1	-2.2	-13.4	-13.4	-1.1	-2,304
Pumping	-1.7	-61.4	1.4	6.7	6.7	-0.7	6,374
Hybrid Project - increases only	0.0	0.0	1.4	6.7	6.7	10.2	6,374
Significance Threshold:	15	40	100	40	40	40	75,000
PSD Applicable	No	No	No	No	No	No	No
PAE - BAE							
New Units	0.0	0.0	0.0	0.0	0.0	10.2	0
Hoteling	-0.9	-21.1	1.4	7.4	7.4	0.4	1,071
Pumping	-1.7	-61.4	3.7	6.7	6.7	-0.7	12,084
Hybrid Project - increases only	0.0	0.0	5.2	14.1	14.1	10.5	13,155
Pre-Project Recordkeeping	No	No	No	No	No	No	No
Post Proj. Rpting/Recordkeeping	No	No	No	No	No	No	No

Where

BAE: baseline actual emissions
PAE: projected actual emissions
APAE: projected actual emissions minus the excludable emissions

As shown in Table 16, the project related emissions increase is less than the significance threshold for each pollutant. As a result, the requirements for PSD and nonattainment NSR permitting are not triggered. Also shown in Table 16, are the results related to tests to determine the need for pre-project recordkeeping and post-project reporting and recordkeeping in accordance with the requirements of 40 CFR 52.21(r)(6). As can be seen, pre-project recordkeeping is not required and post project recordkeeping and reporting are not required for any of the pollutants. It should be noted that in light of the EPA reconsideration of the Reasonable Possibility Rule, RTP recommends that this analysis be kept for purposes of pre-project recordkeeping.

In accordance with the Tailoring Rule's requirements, an estimate of the project related greenhouse gas (GHG) emissions increases was determined. Table 16 presents the results of this effort in terms of the CO2 equivalent emissions (CO2e). As shown, the project related increase of CO2e is below the 75,000 ton/year threshold. As a result, GHGs are not considered to be subject to the regulation for purposes of the CTRP. Please see Appendix J for complete PSD analysis report.

(XIII) REGULATION 2-6 PERMITS – MAJOR FACILITY REVIEW

BAAQMD Rule 2-6, Major Facility Review, applies to major facilities, Phase II acid rain facilities, and any facility in a source category designated by the Administrator of the U.S. Environmental Protection Agency (EPA) in a rulemaking as requiring a Title V operating permit. Shell is a major facility and currently holds a Major Facility Review (MFR) operating permit, also referred to as a Title V operating permit. This project meets the definition of a Minor Permit Revision in accordance with Section 2-6-215, as follows:

- The project is not a major modification of a stationary source pursuant to 40 Code of Federal Regulations (CFR) Parts 51 (NSR) or 52 (PSD);
- The project is not a modification as defined in the New Source Performance Standards (NSPS) (40 CFR Part 60), National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 CFR Part 61), or Section 112 of the Clean Air Act;
- The project does not change or relax any applicable monitoring, reporting or recordkeeping condition in the MFR;
- The project does not avoid any applicable requirements;
- The project does not establish any case-by-case determinations;

- The project equipment is not a portable source; and
- The project does not modify any permit condition to incorporate new EPA requirements.

(XIV) REGULATION 7 ODOROUS SUBSTANCES

BAAQMD Regulation 7 places general limitations on odorous substances and specific emission limitations on certain odorous compounds. This rule only becomes applicable if the BAAQMD receives odor complaints from ten or more complainants within a 90-day period. Shell has not triggered this requirement, and the proposed project is not expected to cause or contribute to any violations in the future.

<u>REGULATION 8-5 ORGANIC COMPOUNDS – STORAGE OF ORGANIC LIQUIDS</u>

The purpose of this Rule is to limit the emissions of organic compounds from organic liquid storage tanks. The proposed new, replacement, and refurbished CTRP crude oil storage tanks would be subject to this rule. Consistent with the Regulation 8, Rule 5 requirements, four new tanks will be constructed as external floating roof tanks and one existing tank will be refurbished as an internal floating roof tank. These tanks will be designed and operated to meet the requirements of Regulation 8, Rule 5. The external floating roof tanks will comply with Regulation 8-5-304 and will be monitored as required in Section 8-5-401. The internal floating roof tank will comply with Regulation 8-5-305 and will be monitored as required in Regulation 8-5-402.

The applicability of Regulation 8, Rule 5 to the existing jet fuel fixed roof tank S967, which will be retrofitted by installing an internal floating roof, will not change. The Permit to Operate and Title V operating permit include S967 as a source subject to a group tank throughput limit (Condition 18618, Part 1). The tank is listed as a permitted source and is exempt from Regulation 8, Rule 5, per Section 8-5-117 (0.5 psia, low vapor pressure).

(xv) REGULATION 8-18 ORGANIC COMPOUNDS- EQUIPMENT LEAKS

Rule 8-18 limits emissions of organic compounds and methane from leaking equipment at petroleum refineries including, but not limited to: valves, connectors, pumps, compressors, pressure relief devices, diaphragms, hatches, sight-glasses, fittings, sampling ports, meters, pipes, and vessels. The rule requires regular inspections, prompt repairs, and recordkeeping and reporting. The CTRP will include the installation of new valves, connectors, and pumps which will be subject to Rule 8-18. Shell is currently subject to Rule 8-18, and will continue to comply with all applicable requirements. The new CTRP fugitive emission components will be incorporated into the refinery's leak detection and repair program for compliance with this regulation.

<u>REGULATION 8-28 ORGANIC COMPOUNDS – EPISODIC RELEASES FROM PRESSURE RELIEF VALVES AT PETROLEUM REFINERIES AND CHEMICAL PLANTS</u>

Regulation 8-28-302 requires that any person installing a new refinery source or modifying an existing refinery source that is equipped with at least one pressure relief device in organic compound service must meet all applicable requirements of Regulation 2, Rule 2, including BACT. The CTRP does not include the installation of any new pressure relief devices, therefore Rule 8-28 does not apply.

<u>NSPS</u>

<u>40 CFR 60 Subpart A – General Provisions</u>

Any source subject to an applicable standard under 40 CFR 60 is also subject to the general provisions of Subpart A. Because the replacement, new, and refurbished storage tanks are subject to 40 CFR 60 Subpart Kb and 40 CFR 60 Subpart GGG, the requirements of Subpart A apply. Subpart A contains requirements for notification of construction or modification and startup, monitoring, recordkeeping and reporting, and performance testing. Shell is required and expected to provide notification to the USEPA administrator at least 60 days prior to construction of equipment subject to Subpart Kb and notification of startup. Shell currently complies with the monitoring, recordkeeping, and reporting requirements of Subpart A and will continue to do so following implementation of the proposed project.

<u>40 CFR 60 Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984</u>

The provisions of this subpart apply to each storage vessel with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. Sources S6069, S6070, S6071, S6072, and S1128 will be subject to NSPS Subpart Kb. Subpart Kb requires tanks storing organic liquids to be equipped with an appropriate vapor loss control device (internal floating roof with seals, external floating roof with seals, or fixed roof tank with vapor recovery and control device). The five new, replacement, and refurbished crude oil storage tanks will be constructed and operated in compliance with the rule requirements.

The applicability of the existing jet fuel fixed roof tank S967, which will be retrofitted by installing an internal floating roof, will not change. This tank is not subject to Subpart Kb and the proposed retrofit is not reconstruction as defined in 40 CFR 60 Subpart A (60.15) and it is not a modification as defined in 40 CFR 60 Subpart A (60.14) because it does not increase emissions.

40 CFR 60 Subpart GGG/GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

The provisions of these subparts apply to affected facilities in petroleum refineries. According to this standard an affected facility includes a group of all the equipment within a process unit in VOC service. The CTRP involves the addition of new fugitive components (valves, flanges, connectors, and pumps) in the crude oil storage tank area. Shell has already designated the crude oil storage tank area as an affected facility subject to the monitoring requirements of 40 CFR 60 Subpart GGG. Consistent with 40 CFR 60.590a(d), 40 CFR 60 Subpart GGGa does not apply to any facility already subject to 40 CFR 60 Subpart GGG, even if that facility is reconstructed or modified after November 7, 2006. Therefore, the new fugitive components would not be subject to 40 CFR 60 Subpart GGGa. They would continue to be subject to the requirements of 40 CFR 60 Subpart GGG.

40 CFR 60 Subpart QQQ—Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems

The provisions of this subpart apply to affected facilities located in petroleum refineries for which construction, modification, or reconstruction is commenced after May 4, 1987. Under this standard an affected facility includes an individual drain system, an oil-water separator and an aggregate facility. An aggregate facility is defined as the drain system together with downstream sewer lines and oil-water separators, down to and including the secondary oil-water separator. The existing individual drain system or downstream oil-water separators serving the crude oil storage tank farm area will not be modified as part of the CTRP, nor will a new aggregate facility be constructed as part of the project. Thus, this subpart does not apply.

NESHAPS

40 CFR 61 Subpart A – General Provisions

Any source subject to an applicable standard under 40 CFR 61 is also subject to the general provisions of Subpart A. Because the replacement, new, and refurbished storage tanks are subject to 40 CFR 61 Subpart FF, the requirements of Subpart A apply. Subpart A contains requirements for monitoring, recordkeeping and reporting.

40 CFR 61 Subpart FF - Subpart FF – National Emission Standard for Benzene Waste Operations

40 CFR Part 61 Subpart FF – National Emission Standard for Benzene Waste Operations applies to owner and operators of chemical manufacturing plants, coke by-product recovery plants, and petroleum refineries and hazardous waste treatment, storage, and disposal facilities that treat, store, or dispose of hazardous waste generated by any of these facilities.

The proposed project will generate increased quantities of benzene-containing wastes. Shell is currently subject to Subpart FF, and will continue to comply with all applicable requirements. As appropriate, CTRP tanks will be incorporated into the refinery's compliance management plans for this regulation.

<u>40 CFR 63 Subpart A – General Provisions</u>

Any source subject to an applicable standard under 40 CFR 63 is also subject to the general provisions of Subpart A. Subpart A requires various notification and recordkeeping for sources subject to any of the Part 63 MACT standards. As discussed below the CTRP storage vessels and equipment leaks will be subject to 40 CFR 63 Subpart CC. Thus, no requirements under Subpart A apply to the proposed project.

<u>40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries</u>

This subpart applies to petroleum refining process units and to related emission points at petroleum refineries. The affected source for this subpart includes all emission points from process units, storage vessels, wastewater streams and treatment facilities, equipment leaks, gasoline loading racks, and marine vessel loading operations. The CTRP crude oil storage tank and fugitive component equipment leaks will be subject to this rule.

Storage tanks subject to Subpart CC are classified as either Group 1 or Group 2 storage vessels. "Group 1 storage vessel" means a storage vessel at an existing source that has a design capacity greater than or equal to 177 cubic meters (46,758 gallons) and stored-liquid maximum true vapor pressure greater than or equal to 10.4 kilopascals (1.5 per square inch [psi]) and stored-liquid annual average true vapor pressure greater than or equal to 8.3 kilopascals (1.2 psi) and annual average HAP liquid concentration greater than 4 percent by weight total organic HAP.

"Group 2 storage vessel" means a storage vessel that does not meet the definition of a Group 1 storage vessel. The three existing crude oil tanks being replaced by the CTRP (S6069, S6070, and S6071) are Group 1 storage vessels. The new (S6072) and refurbished (S1128) CTRP crude oil tanks will also be Group 1 storage vessels. Group 1 storage vessels that are also subject to 40 CFR 60 Subpart Kb are subject to the overlap in Subpart CC at 63.640(n)(1) that specifies that these tanks are subject only to the requirements of 40 CFR 60 Subpart Kb with exceptions in Subpart CC at 63.640(n)(8). This is the case for the replacement, new, and refurbished CTRP crude oil tanks.

The applicability of Subpart CC to the existing jet fuel fixed roof tank S967, which will be retrofitted by installing an internal floating roof, will not change. The tank is subject to 40 CFR 63 Subpart CC as a Group 2 storage vessel, and is subject only to recordkeeping requirements.

Equipment leaks subject to Subpart CC and to 40 CFR 60 Subpart GGG are subject to the overlap for equipment leaks in Subpart CC at 63.640(p)(1). The CTRP fugitive components are subject to both Subpart CC and to 40 CFR 60 Subpart GGG as discussed above. The overlap in Subpart CC specifies that equipment leaks subject to Subpart CC that are also subject to the provisions of 40 CFR 60 Parts 60 and 61 standards promulgated before September 4, 2007 (which includes 40 CFR 60 Subpart GGG) must comply with Subpart CC. Therefore, the new CTRP fugitive components will only be subject to Subpart CC (and thus to 40 CFR 60 Subpart VV) per the overlap in Subpart CC.

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

CEQA requires a review of potential significant environmental impacts from proposed projects. This project has been determined to be subject to CEQA by Contra Costa County (CCC), and will require a Land Use Permit under the Contra Costa County Department of Conservation and Development. The CCC is the Lead Agency for CEQA for this project. In accordance with Regulation 2-1-310.3, the District may not issue an Authority to Construct for this project until final action has been taken by the Lead Agency. A draft Environmental Impact Report (EIR) was prepared by the CCC in July 2011. This EIR includes all sources and activities that are the subject of this application. The 45 day comment period on the draft EIR ended on September 12, 2011. The District is a responsible agency under CEQA and has provided comments to the CCC on the draft EIR. The District comment letter is included in Appendix K. These comments, as well as others received by CCC have been addressed in a revised EIR.

On November 8, 2011, the final EIR was certified by the Contra Costa County Board of Supervisors.

In a number of instances mitigation measures included in the EIR require that the District impose specific conditions on the project to be included in permits issued by the District. Some of these mitigation measures are required by the District as a responsible agency in connection with its own permitting rules and regulations (i.e. MM 4.3-3a). Other mitigation measures to be imposed by the District are required by Contra Costa County as lead agency to comply with CEQA but are not required pursuant to District permitting rules (i.e. MM 4.3-3b, and 4.8-2). The permit conditions imposed by the District authority to construct referenced in Section 7 include all those conditions required by District rules and regulations for the project and also include those specific conditions required by the Lead Agency under CEQA. The CEQA conditions are described below:

The change in emissions from the crude oil storage tanks is subject to CEQA review, as are those from the increased shipping activity. For project-level impact analysis, BAAQMD has adopted operations-related criteria pollutant and greenhouse gas emission thresholds of significance. Shell intends to implement emission reduction projects prior to emission increasing activities of the CTRP to reduce project operating emissions to or below applicable BAAQMD CEQA thresholds. Mitigation projects include the retrofit to the existing S967, Jet Fuel Storage Tank, to generate contemporaneous emissions reductions to mitigate POC emission increases from CTRP storage tanks, operational changes of the existing Catalytic Cracking Unit (CCU) to generate NOx emission reductions to mitigate NOx emissions from increased shipping activity, and energy efficiency projects to reduce fuel consumption and resulting GHG emissions to mitigate GHG emission increases from increased shipping activity.

A summary of the total net annual CTRP operational-related emissions subject to CEQA review is in Table 17 with baseline emissions, post-project emissions and estimated emission reductions for each proposed mitigation project. Details of the proposed emission reduction projects are discussed above in Section 2.0 of this document.

Table 17
Total Net CTRP Annual Emissions with Thresholds of Significance and Mitigation Project Emission Reductions

Emission Scenario	Emissions (tpy)					
	NOx	SOx	PM10	POC	CO	CO2e (Metric tons/yr.)
Post-Project Emissions						
Crude Oil Storage Tanks	--	--	--	11.1	--	--
Wharf Operations – Crude Oil Shipping	147.7	19.1	7.8	11.1	24.1	27,858
Fugitive Components	--	--	--	1.4	--	--
Indirect Emissions[1]	--	--	--	--	--	1,132
Baseline Emissions						
Crude Oil Storage Tanks	--	--	--	1.7	--	--
Wharf Operations – Crude Oil Shipping	58.8	92.4	7.6	5.0	7.7	10,817
Indirect Emissions[1]	--	--	--	--	--	299
Mitigation Decreases						
TK-967 Roof Retrofit	--	--	--	-7.4	--	--
CCU Operational Changes	-78.9	--	--	--	--	--
Energy Efficiency Projects (F-40 APH, CRU and DHT)	--	--	--	--	--	-17,874
Net Project Emissions	**10**	**-73.3**	**0.2**	**9.5**	**16.5**	**0**
BAAQMD CEQA Thresholds of Significance	**10**	**--**	**15**	**10**	**--**	**10,000**

[1] With this project, facility electrical demand will increase due to the installation of new electric in-tank mixers and pumps that will be used to support the operation of the crude oil tanks. Electricity is obtained either from Pacific Gas and Electric (PG&E) Company from the California electricity grid, or from the facility's on-site cogeneration plant. The electrical demand increase is assumed to be provided by PG&E from the electrical grid. The baseline and post-project annual electrical demand for the pumps and mixers is 1,253 MW-hr and 4,753 MW-hr, respectively. The net indirect annual electrical demand as a result is 3,500 MW-hr. Based on this net annual electricity increase of 3,500 MW-hr, the baseline and post-project indirect GHG emissions shown in the above table were calculated for the tank mixer and pump electrical demand based on methods developed in the BAAQMD CEQA Guidelines and the CARB Local Government Operations Protocol, Version 1.0, as referenced within the BAAQMD CEQA Guidelines.

7.0 PERMIT CONDITIONS

7.1 New Permit Conditions

Crude Tank Replacement Project (CTRP) Condition # 25134

For S6069 (TK-17596), Crude Oil Storage Tank, EFR, 300,000 Barrel Capacity
S6070 (TK-17597), Crude Oil Storage Tank, EFR, 300,000 Barrel Capacity
S6071 (TK-17598), Crude Oil Storage Tank, EFR, 300,000 Barrel Capacity

S6072 (TK-17595), Crude Oil Mix Tank, EFR, 55,000 Barrel Capacity
S967 (TK-967), Jet Fuel Storage Tank, IFR, 69,000 Barrel Capacity
S1128 (TK-1128), Crude Oil Storage Tank, IFR, 55,000 Barrel Capacity
S1486, DH F-40 Crude Unit Feed Air Preheater Installation
S1495, DH F-49 Catalytic Reformer Unit (CRU) Preheat Furnace
S1507, EMSR1- CO Boiler #1
S1509, EMSR1- CO Boiler #2
S1512, EMSR1- CO Boiler #3
S4021, DHT Recycle Gas Heater

For S6069, S6070, S6071, S6072, and S1128, TANKS

1. The owner/operator shall not exceed the following material throughput limits during any consecutive twelve-month period:
    a. 43,800,000 barrels for S6069, S6070, S6071, and S1128
    b. 550,000 barrels for S6072
    c. If either material throughput limit in parts 1.a or 1.b is exceeded in any 12-month period, the owner/operator shall conduct a district-approved emissions calculation in order to demonstrate that POC emissions did not exceed the total POC emissions listed in Part 2 in any consecutive twelve-month period. POC emissions for crude oil storage tanks S6069, S6070, S6071, and S1128 shall be calculated assuming drain/fill operations and for mix tank, S6072, assuming constant level operations.

    [Basis: Cumulative Increase, Offsets]

2. The owner/operator of tanks S6069, S6070, S6071, S6072, and S1128 shall ensure that total POC emissions based on the combined maximum throughput limits in parts 1.a and 1.b, do not exceed 22,200 pounds in any consecutive twelve-month period. [Basis: Cumulative Increase, Offsets]

3. The owner/operator shall not exceed the following material throughput limits in any calendar day. If a material throughput limit is exceeded, the owner/operator shall conduct a district-approved emissions calculation in order to demonstrate that POC emissions did not exceed the following maximum permitted emissions limits in any calendar day.

    POC emissions for crude oil storage tanks S6069, S6070, S6071, and S1128 shall be calculated assuming drain/fill operations and for mix tank, S6072, assuming constant level operations.

Tank	Throughput Limit, barrels/day	Emissions Limit, lbs POC/day
S6069	300,000	88

S6070	300,000	88
S6071	300,000	88
S1128	55,000	24
S6072	110,000	52

[Basis: Regulation 2-1-234]

4. The owner/operator shall not exceed the following material throughput limits in any consecutive twelve-month period. If an annual material throughput limit is exceeded, the owner/operator shall conduct a district-approved emissions calculation in order to demonstrate that POC emissions did not exceed the following maximum permitted emissions limits in any consecutive twelve-month period.

   POC emissions for crude oil storage tanks S6069, S6070, S6071, and S1128 shall be calculated assuming drain/fill operations and for mix tank, S6072, assuming constant level operations.

Tank	Throughput Limit, barrels/year	Emissions Limit, tons POC/year
S6069	43,800,000	8
S6070	43,800,000	8
S6071	43,800,000	8
S1128	20,075,000	4
S6072	550,000	2

   [Basis: Regulation 2-1-234]

5. The owner/operator shall ensure that only the following materials be stored in the external floating roof tanks S6069, S6070, S6071, and S6072:
   a. Contents must be at least 97% by volume crude oil;
   b. True vapor pressure must be less than 11 psia.

   [Basis: Cumulative Increase, BACT, Regulation 2, Rule 5]

6. The owner/operator shall ensure that materials stored in S1128 meet the following criteria:
   a. True vapor pressure must be less than 11 psia;
   b. The storage of these materials does not increase toxic emissions above any risk screening trigger level of Table 2-5-1 in Regulation 2-5.

   [Basis: Cumulative Increase, Regulation 2, Rule 5]

7. The owner/operator shall comply with all applicable requirements of 40 CFR Part 60, Subpart Kb and the requirements of District Regulation 8, Rule 5 for tanks S6069, S6070, S6071, S6072 and S1128. [Basis: BACT, NSPS]

8. The owner/operator shall equip tanks S6069, S6070, S6071, S6072 and S1128 with a temperature monitoring device. [Basis: Cumulative Increase]

9. In order to demonstrate compliance with parts 1 through 6, the owner/operator shall maintain a district approved log with monthly summaries of all material throughput including emissions calculations as required per parts 1.c, 2, 3 and 4, vapor pressures of tanks, and contents stored in external floating roof tanks as required per part 5a. This log shall be kept on site for at least 5 years from the date of entry and made available to district staff upon request. [Basis: Cumulative Increase, Recordkeeping]

For S967, JET FUEL STORAGE TANK, INTERNAL FLOATING ROOF, 69,000 BARREL CAPACITY

10. The owner/operator of S967 shall not exceed total material throughput of 7,300,000 barrels in any consecutive twelve-month period. [Basis: Cumulative Increase, Offsets, CEQA]

11. The owner/operator of S967 shall ensure that POC emissions based on the maximum throughput in part 10, do not exceed 800 pounds in any consecutive twelve-month period. [Basis: Cumulative Increase, Offsets, CEQA]

12. The owner/operator shall ensure that materials stored in S967 meet the following criteria:
    a. True vapor pressure must be less than 0.5 psia;
    b. The storage of these materials does not increase toxic emissions above any risk screening trigger level of Table 2-5-1 in Regulation 2-5.

    [Basis: Cumulative Increase, Regulation 2, Rule 5]

13. In order to demonstrate compliance with parts 10 and 11, the owner/operator of S967 shall maintain the total monthly throughput of each material stored including emissions calculations summarized on a consecutive twelve-month basis in a district approved log. This log shall be kept on site for at least 5 years from the date of entry and made available to district staff upon request. [Basis: Cumulative Increase, Recordkeeping]

FUGITIVE COMPONENTS

14. The owner/operator shall submit a count of installed pumps, valves and flanges/connectors and provide each component's unique permanent identification code in this project every 6 months after startup of the first tank until completion of the CTRP. Upon project completion, the owner/operator shall provide the District's

Engineering Division with a final count of all fugitive components. The owner/operator has been permitted to install the following fugitive components:
415 valves in hydrocarbon service;
890 flanges/connectors in hydrocarbon service;
6 pumps in hydrocarbon service;
[Basis: Cumulative Increase, offsets, Regulation 2-5]

15. If any of the fugitive component counts exceed the count stated in Part 14, the plant's cumulative emissions for the project shall be adjusted, subject to APCO approval, to reflect the difference between emissions based on predicted versus actual component counts. The owner/operator shall provide to the District all additional required offsets at an offset ratio of 1.15:1 no later than 21 days after submittal of the final POC fugitive count. If the component count increase triggers any additional regulatory review, the owner/operator shall submit an application to address the increased emissions. The owner/operator submitted 1.610 tons per year of POC offset credits corresponding to the fugitive component counts in Part 14. If the actual component count is less than the predicted, the total emissions in Part 19 may be adjusted accordingly, subject to APCO approval, and all emission offsets applied by the owner/operator in excess of the fully offset permitted total POC emissions may be credited back to the owner/operator upon approval by the APCO. [Basis: offsets, Cumulative Increase]

16. The Owner/Operator of tanks S6069-S6072, S967, and S1128 shall install only the following types of fugitive components:

    a. For valves in hydrocarbon service: (1) bellows sealed, (2) live loaded, (3) graphitic packed, (4) quarter-turn (e.g., ball valves or plug valves), or equivalent technology to comply with provisions in Regulation 8, Rule 18 as determined by the APCO.
    b. For flanges in hydrocarbon service: graphitic-based gaskets, metal ring joints, or equivalent technology to comply with provisions in Regulation 8, Rule 18 as determined by the APCO.
    c. For pumps in hydrocarbon service: double mechanical seal with barrier fluid, or equivalent technology to comply with provisions in Regulation 8, Rule 18 as determined by the APCO.

    [Basis: Cumulative increase, Regulation 8, Rule 18]

17. The Owner/Operator shall comply with a leak standard of 100 ppm of TOC (measured as C1) at valves and flanges and 500 ppm at any pumps installed as part of the application 22045 in hydrocarbon service, unless the owner/operator complies with the applicable minimization and repair provisions contained in Regulation 8-18. [Basis: Cumulative Increase, Regulation 8 Rule 18]

18. The Owner/Operator shall conduct inspections of fugitive components installed as part of application 22045 in hydrocarbon service in accordance with the frequency below:
    Pumps: Quarterly
    Valves: Quarterly

Flanges: Annual
[Basis: Cumulative Increase, Regulations 8 Rule 18]

19. The owner/operator shall not exceed 1.4 tons of POC emissions per consecutive 365-day period measured as C1 from for all fugitive components installed as part of application 22045 in hydrocarbon service. Reporting for this provision shall be performed quarterly and results shall be submitted to the District's Engineering Division on a quarterly basis for two years commencing with the completion of the CTRP. The quarterly reports are due within 30 days of the close of each calendar quarter after the District's issuance of the Permit to Operate for Application 22045.[Basis: Cumulative Increase, offsets]

20. The Owner/Operator shall keep a District-approved log of fugitive component counts installed as part of application 22045, each component's unique permanent identification codes, monitoring results, and any annual emissions estimates required per part 19 for at least five years from date of entry. The log shall be retained on site and made available to district staff upon request.[Basis: offsets, recordkeeping]

For S1486, DH F-40 Crude Unit Feed Air Preheater Installation

21. The owner/operator of S1486 shall not exceed total NOx emissions of 91.6 tons in any consecutive twelve-month period. [Basis: Regulation 2-1-234]

22. To demonstrate compliance with NOx limit of part 21:

    a. No later than 60 days from the startup of S1486 Air Preheater, the owner/operator shall conduct a District-approved source test on the exhaust of S1486 to determine the NOx emissions factor (lbs NOx/MMBtu-HHV) for operation with the air preheater. For operation without the preheater, the NOx factor shall be based on source test results for S1486 with ultra low-NOx burners. At least 7 days prior to the source test, the owner/operator shall notify and obtain approval of the source test procedures from the District's Source Test Manager. Results of the source test shall be submitted to the Director of Compliance and Enforcement, the Source Test Manager, and the Manager of Permit Evaluation at the District no later than 60 days after the source test.
    b. The heat input rate used to calculate the NOx emissions shall be determined monthly and expressed as a daily average heat input rate (MMBTU/day-HHV) for each month.
    c. Monthly firing rates for S1486 shall be determined using a District-approved fuel flow monitor and recorder.

    [Basis: Regulation 2-6-503]

23. The owner/operator shall keep monthly records of S1486 fuel gas firing rates for Part 21 and the initial NOx source test results required by Part 22 for at least five years from the date of entry, and shall make these records available to the District staff upon request. [Basis: Recordkeeping]

For S1507, S1509, and S1512, CO BOILERS

24. The owner/operator shall ensure that total emissions of nitrogen oxides, as NO_2, from the three existing CO Boilers (S1507, S1509, and S1512) do not exceed 468 tons in any consecutive twelve-month period. [Basis: CEQA, Offsets]

25. The owner/operator shall continue to operate the NOx continuous emission monitors on the CO Boilers (S1507, S1509, and S1512) in accordance with the District's Manual of Procedures, to verify compliance with part 24. The owner/operator shall use the CEM data to calculate NOx emissions on a monthly basis. [Basis: CEQA, Offsets, Regulation 2-6-503]

For S1486 (DH F-40 CRUDE UNIT FURNACE), S1495 (DH F-49 CRU PREHEAT FURNACE) AND S4021 (DHT RECYCLE FURNACE)

26. The owner/operator shall ensure that total carbon dioxide equivalents (CO2e) emission reductions from S1486 F-40 Air Preheater, S1495 and S4021 combined meet or exceed 17,874 metric tons per year over any consecutive three year rolling average. [Basis: CEQA]

27. Annual CO2e emissions from S1486 Air Preheater, S1495 and S4021 shall be calculated based on the following:

    a. Emission factors for natural gas for carbon dioxide (CO2), methane (CH4) and nitrous oxide (N2O):

Carbon dioxide (CO2)	53.02 kg/MMBtu
Methane (CH4)	0.9 g/MMBtu
Nitrous oxide (N2O)	0.1 g/MMBtu

    b. Monthly firing rates for S1495 and S4021 as determined by fuel flow monitors.
    c. Monthly inlet and outlet air flow rate and temperature for S1486 Air Preheater.
    d. CEQA Baseline Actual Firing Rate (BAFR)
        i. S1495 114.8 MMBTU/HR HHV
        ii. S4021 21.9 MMBTU/HR HHV
    e. S1495 Efficiency Factor 0.45

    (Note: S1495 furnace produces incremental steam which is added to the overall steam make of the Refinery. Reducing the S1495 firing rate also reduces the steam it produces; therefore, this steam must be produced by another steam producing unit in the Refinery. The emission reductions for this project must be reduced by the emissions generated by the additional steam production. S1495 is less efficient at steam production by a factor of 0.45 compared to facility's steam producing units. Calculation of S1495 fuel reduction must be decreased by this factor because of the additional firing at other steam producing units.)
    f. Global Warming Potential Factors
        i. CO2 1

ii. CH4 21
iii. N20 310

[Basis: CEQA, Regulation 2-6-503]

28. Calculation of CO2e emission reductions from S1486 Air Preheater, S1495, and S4021 shall be based on the following methodology. All firing rate duties are in HHV.

a. Total Firing Rate Reduction
   i. S1495 and S4021
   Total Firing Rate Reduction = [BAFR (S1495)-Actual Firing(S1495)] + [(BAFR(S4021) – Actual Firing(S4021)) – (S1495 Efficiency Factor)[(BAFR(S1495)-Actual Firing(S1495)]

   ii. S1486 Air Preheater
   Total Firing Rate Reduction = Air Preheater Combustion Inlet Air Heat Content –Air Preheater Combustion Outlet Air Heat Content

b. Emission reductions for each pollutant in Part 27.a.=

   [Sum Total Firing Rate Reduction (from Part 28.a.i and 28.a.ii)] [Emission Factor (from Part 27.a)](pollutant Global Warming Potential Factor from Part 27.f)

c. Calculation of CO2e Emission Reductions =

   Sum of CO2e reductions for each pollutant from Part 28.b.

[Basis: CEQA, Regulation 2-6-503]

RECORD KEEPING

29. The owner/operator shall keep records of all necessary information to demonstrate compliance with Parts 24-28 of this condition. All records shall be retained for at least five years from the date of entry, and shall be made available to the District staff upon request. This includes, but is not limited to, NOx CEM data, fuel usage, air flow rates, air temperature, and emissions calculations. [Basis: CEQA, Recordkeeping]

REPORTING

30. Commencing 30 days after start-up of the first tank, and continuing 5 years thereafter, the owner/operator shall submit a copy of the annual report to the District's Engineering Division required by Land Use Permit #LP10-2006 (Condition 3) summarizing the facility's compliance with the Land Use Permit Conditions of

Approval. For each condition, the report shall identify the compliance with the measure, the procedures or standards used to judge the compliance as applicable, times and the dates of the monitoring as applicable. The annual reports shall be submitted no later than 60 days after the end of each calendar year. [Basis: CEQA, Recordkeeping]

31. Commencing 30 days after start-up of the first tank, the owner/operator shall submit to the District's Engineering Division a report detailing any non-compliance with the emission limits listed in Land Use Permit #LP10-2006 for Air Quality Condition #7 (LUP Mitigation Measures 4.3-3a & 4.3-3b), and Greenhouse Gas Emissions #14 (LUP Mitigation Measure 4.8-2).
[Basis: CEQA, Recordkeeping]

7.2 Revised Permit Conditions

Revisions are made to the following permit conditions in underline/strike-out format:

- Condition 7618, REFEMS: Please refer to Appendix L for methodology and calculations performed for each pollutant profile to determine the new 365 day profiles post CARB regulation adjustment. This adjustment for CARB marine fuel sulfur standards is effective upon implementation of California Code of Regulations, Title 17 §93118) (AN 22045, December 2011)
- Condition 11850, S544
- Condition 12174, S545
- Condition 18618, Throughput limits

Condition # 7618
For S14, Tank 14,
S20, Tank 20,
S483, Tank 483
S484, Tank 484
S532, Tank 532
S1067, Tank 1067
S1139, Tank 1139
S1140, Tank 1140
S1141, Tank 1141
S1420, DH Crude Unit

S1480, LUBS F-69 Asphalt Circulation,
S1481, OPCEN F-30 DSU,
S1483, LUBS F-32 Asphalt Circulation,

S1486, DH F-40 CU Feed,
S1487, DH F-41B VFU Feed,

S1488, DH F-41A VFU Feed,
S1490, DH F-43 GOHT Feed
S1491, DH F-44 NHT Feed,
S1492, DH F-45 Primary Column Reboil,
S1493, DH F-46 Stabilizer Reboil,
S1494, DH F-47 Secondary Column Reboil
S1495, DH F-49 CRU Preheat,
S1496, DH F-50 CRU,
S1497, DH F-51 CRU,
S1498, DH F-52 CRU Reboil
S1499, DH F-53 CRU Regen
S1500, DH F-55 SGP Heat Medium
S1502, DH F-57 HCU First Stage Feed
S1503, DH F-58 HCU Second Stage Feed
S1504, DH F-59 HCU Second Stage Reboil
S1505, DH F-60 HP1 Steam Methane Reformer
S1506, CP F-61 CGP Feed,
S1507, UTIL CO Boiler .1
S1508, CP F-63 CFH Feed, S1510 - CP F-66 CCU Preheat,
S1509, UTIL CO Boiler 2
S1510, CP F-66 CCU Preheat,
S1511, CP F-67 CCU LGO Reboil
S1512, UTIL CO Boiler 3
S1515, DH F-71 HCU First Stage Reboil
S1751, Tank 1330
S1752, Tank 1331
S1753, Tank 1332 Gasoline
S1754, Tank 1333 Gasoline
S1755, Tank 1334 Gasoline
S1756, Tank 1335 Gasoline
S1757, Tank 1336
S1758, Tank 1337
S1759, OPCEN Flexicoker (FXU)
S1760, OPCEN F-102 FXU Steam Superheater
S1761, OPCEN F-104 HP2 Steam Methane Reformer
S1763, DH F-126 CU Feed
S1764, OPCENDimersol Plant (DIMER)
S1765, OPCENSulfur Plant 3 (SRU3)
S1767, OPCEN V 1019 Coke Silo
S1768, OPCEN V 1019 Coke Silo
S1769, OPCEN V –1020 Dry Fines Silo
S1770, OPCEN C3/C4 Splitter
S1771 – OPCEN Flexigas Flare
S1774, OPCENHydrogen Plant 2 (HP2)
S1800, UTIL F-88 Boiler
S4002, DC F-13425-A DCU
S4003, DC F-13425-B DCU
S4031, DC F-14012 HGHT Reboil

S4141, DC F-14011 HGHT Feed
S4161, DC H-101 HP3 Steam Methane Reformer
S4191, UTIL Boiler 6 Supplemental Steam Generator 1
S4193, UTIL Boiler 6 Supplemental Steam Generator 2

Condition Modifications Log:
TABLE V revised 10/94, App. No. 13814

Condition B.3.a. and Note 5 of Table IX added 2/98; App. No. 18131.

Condition B.3.a and Note 5 of Table IX amended to allow NOx CEM data for emission calculations (AN 1362, 10/01)

Table II - NOx Baseline reduced by 2 lb/day per Condition ID# 4364 Item 1, for S2000 (AN 4827)

Table II - NOx Baseline reduced by 3089 lb/day per Condition ID# 12271 Item 89, Clean Fuels Project offsets from CO Boilers (AN 8407)

Table IV – SO2 Baseline reduced by 1398 lb/day per Condition ID# 12271 Item 94, Clean Fuels Project offsets from CO Boilers (AN 8407)

Tables II, III, IV, V, and VIII adjusted for CARB marine fuel sulfur standards, effective upon implementation of California Code of Regulations, Title 17 §93118) (AN 22045, December 2011)

A. The owner/operator shall operate the units listed in Table I in such a way that any daily emission increases over the baseline profile are offset by reductions below the profile at a ratio of at least 2.0:1. Compliance shall be demonstrated on a daily basis in the following manner:

1. For each pollutant, actual daily emissions for the previous 364 days plus the day in question shall be ranked in descending order by quantity. The calculation of actual daily emissions shall not be affected by the granting of a variance by the Hearing Board of the District unless such variance specifically includes a variance from Paragraph A (1) of these conditions. In the event of failure or range exceedance of a monitor upon which emissions are based, emissions shall be calculated to be the maximum possible under the prevailing operating conditions in the plant during the event; emission calculations will be based upon theoretical or historical emission factors or other information which demonstrates emission levels to the satisfaction of the APCO. [basis: Regulation 2-2-302]

2. The resulting profile will be compared day by day with the baseline profile. [basis: Regulation 2-2-302]

3. The emissions on each day of the current profile will be subtracted from the corresponding day of the baseline profile. Positive values are profile decreases'. The absolute value of negative values are 'profile -increases'. [basis: Regulation 2-2-302]

4. Profile increases will be totaled; profile decreases will be totaled. Profile increases will be doubled, and the decreases will be subtracted from this total. If the result (the profile excess) is positive, the owner/operator is out of compliance.

   Profile Excess =[(2.0) x (Profile Increases)] - (Profile Decreases)
   [basis: Regulation 2-2-302]

B. EMISSION PROFILES AND EMISSION FACTORS

1. Tables II through VI list the baseline profiles for each pollutant. The baselines reflect actual emissions during the baseline period, less reductions required by regulation of sources under the `cap', and increased by offsets and increases provided by reductions at operations not under the `cap' (i.e., tankage).

   The baseline profiles were calculated as follows (this condition contains a summary of the steps used to arrive at the values in Tables II through VI, and should be updated every time the baseline profile is adjusted):

   a. Actual refinery emissions for the baseline period 1976 - 1978 were calculated using the usage rates contained in application 26786 and the emission factors contained in these conditions.

   b. Actual refinery baseline emissions were averaged over 365 days.

   c. Actual refinery baseline emissions were reduced by any amounts required by District regulations. (Reductions so far applied: SO2 emissions from sulfur recovery units; particulate emissions from CO boilers).
   d. The hydrocarbon baseline profile has been increased by 2300 lb/day due to abatement on tankage (tankage is not included under the cap).

   e. The hydrocarbon baseline profile has been decreased by 1543 lb/day due to increases in fugitive emissions from process units.

   f. The hydrocarbon baseline profile has been increased by 243 lb/day due to shutdown of chemical plants not under the cap (application 29376).

   g. The actual emissions due to shipping in the base year 1977 were added to the adjusted refinery baseline.

   h. The baseline daily emissions were ranked in descending order by quantity. The results (the baseline profiles) are shown in Tables II through VI.

   [basis: Regulation 2-2-302]

2. Tables VII and VIII list the emission factors to be used for marine activities. Any changes or additions will be incorporated into these conditions, and must be approved in writing by the APCO. [basis: Regulation 2-2-302]

3. Table IX lists the emission factors to be used for combustion. The owner/operator may summarize fuel consumption for those furnaces, which have identical emission factors. These factors are subject to annual review and may be changed to reflect source test results and CEM data. the owner/operator shall determine average sulfur content for each gaseous fuel on a daily basis, and for each liquid or solid fuel on a weekly basis.

a. The owner/operator shall use P-24 CEM data and calculated stack flows to estimate NOx emissions form sources S1500, S1502, S1503, S1504, S1505 and S1515. The owner/operator shall use P-23 CEM data and calculated stack flows to estimate NOx emissions from sources S1486, S1487, S1488, S1490, S1491, S1492, S1493, S1494, S1495, S1496, S1497, S1498 and S1499. The owner/operator shall use S1761 and S1763 CEM data and calculated stack flows to estimate NOx emissions from these two heaters. The owner/operator shall use the NOx emission factors in Table IX to calculate NOx emissions during any period for which NOx CEM data is not available for more than 24 hours. For periods less than 24 hours, the owner/operator shall use the average NOx CEM data for the previous 7 day period. (added 2/98, App. No. 18131, amended 2/02, AN 1362. Changes effective once REFEMS computer calculation program is revised)
[basis: Regulation 2-2-302]

4. CCU emission factors will be reviewed annually and will be based on source test results and CEM data. [basis: Regulation 2-2-302]

5. Sulfur plant emissions will be based on the actual measured sulfur emissions. All emissions will be included in the total. The owner/operator will operate the in-stack monitors in such a way as to provide an accurate measurement under all operating conditions. [basis: Regulation 2-2-302]

6. Baseline profiles for particulates, NOx, S02, and CO may be modified in the future in the following ways:

a. The owner/operator may increase the baseline profile by provision of additional offsets by abating or shutting down sources not included in the cap. The amount of offset credited shall be the actual emission reduction (as defined in the District's NSR rule at the time of offset) resulting from abatement or shutdown of the offsetting sources, reduced by the offset ratios prevailing at the time of offset.

b. The owner/operator may increase the baseline profile by buying credits from the Emissions Bank or reduce the profile by making deposits in the bank. Offset ratios shall be those prevailing at the time of offset. The baseline profile shall be adjusted to reflect current RACT emission levels for baseline operations prior to any deposits going into the bank.

c. The baseline profile will be permanently lowered to correspond to reductions required by any future regulations promulgated by the District.

d. The baseline profile will be permanently lowered by the difference between baseline emissions and RACT for any source under the cap that is permanently shut down or removed from the cap. The baseline period used for determination of emissions shall be the same as was used in the evaluation of Permit 26786 (baseline operations shall be as described in Application No. 26786), unless emissions at the affected source were increased as a result of this or other permits; in which case the baseline period shall be the two year period immediately preceding the date of application.

e. If a new source is added to those under the cap, the profile will be permanently lowered by the amount of excess offsets required for onsite offsets under the prevailing NSR rule (i.e. applicable offset ratios and RACT adjustments).

f. If a source already under the cap is modified with a resulting increase in emissions, the baseline profile will be permanently lowered by the amount of excess offsets required for onsite offsets under the prevailing NSR rule (i.e. applicable offset ratios and RACT adjustments).

g. The baseline profile may be adjusted to reflect more accurate emission factors which may become available, providing:

    i. Sufficient data are available to apply the revised emission factor to the-baseline period.
    ii. The revised emission factor is approved by the APCO, incorporated into this permit, and is applied to all future emission calculations.

h. Notwithstanding any of the above, the relaxation of any limits that increase the potential to emit may require a full PSD / NSR review of the source as though construction had not yet commenced on the source.
[basis: Regulation 2-2-302]

7. The baseline profile for hydrocarbons may be modified in the future in the following ways:

    a. The baseline profile will be permanently lowered to correspond to reductions required by any future regulations promulgated by the District.

    b. The baseline profile will be permanently lowered by the difference between baseline emissions and RACT for any source under the cap that is shut down or removed from the cap. The baseline period used for determination of emissions shall be the same as was used in the evaluation of Permit 26786 (baseline operations shall be as described in Application 26786) unless emissions at the affected source were increased as a result of this or other permits; in which case the baseline period shall be the five year period immediately preceding the date of application.

c. The owner/operator may not make deposits in the emissions bank by simply lowering the hydrocarbon cap. The hydrocarbon cap does not meet the requirement of 2-2-606.1 (b). The calculation of baseline for the purposes of banking or new source review for any hydrocarbon source under the cap shall be determined pursuant to the provisions of Regulation 2-2-606.2 or the equivalent regulation in effect at the time of application.

d. If a new source is added to those under the cap, the profile will be permanently lowered by the amount of excess offsets required for onsite offsets under the prevailing NSR rule (i.e.applicable offset ratios and RACT adjustments); the entire emission increase shall be offset by actual emission reductions from specific identifiable sources subject to enforceable permit conditions.

e. If a source already under the cap is modified, the profile will be permanently lowered by the amount of excess offsets required for onsite offsets under the prevailing NSR rule (i.e. applicable offset ratios and RACT adjustments); the entire emission increase shall be offset by actual emission reductions from specific identifiable sources subject to enforceable permit conditions.

[basis: Regulation 2-2-302]

C. NON-COMPLIANCE WILL RESULT IN THE FOLLOWING ACTIONS:

No. of Non-complying days for any one pollutant (per 365 day period)	Action
More than 0	The owner/operator shall notify the District within 15 working days of any non- complying day. One V/N will be issued per day of noncompliance for violation of permit conditions.
More than 5	If the previous 365 days include more than 5 non-complying days, the refinery operations shall be limited in the ways listed below. The owner/operator may submit alternative actions providing equivalent corrective control for consideration by the APCO. Upon APCO approval, the alternative actions may replace the limitations listed below. These limitations shall remain in effect following any day of non-compliance until the owner/operator has demonstrated compliance for three consecutive days.

a. The refinery shall not process more than 124,000 barrels of crude oil per stream day. [basis: Regulation 2-2-302]

b. The refinery shall not process more than 22,000 barrels of Flexicoker feed per stream day. [basis: Regulation 2-2-302]

c. The refinery shall not process more than 65,000 barrels of catalytic cracker feed per stream day. [basis: Regulation 2-2-302]

d. Total fuel usage at sources under the cap shall not exceed 14730 NLFE (Net Liquid Fuel Equivalent) barrels per stream day. [basis: Regulation 2-2-302]

e. Total sulfur content of liquid fuels shall not exceed 1.0 ton/day. In the event that the Flexicoker Unit is down, the total sulfur content of liquid fuels may not exceed 1.3 tons/day. [basis: Regulation 2-2-302]

f. Large cargo vessels (170 MDWEIGHT or greater) shall not be offloaded while any other vessel is being offloaded. Violation of this condition may result in the revocation of all permits. [basis: Regulation 2-2-302]

D. STORAGE CONDITIONS

1. For Tank 14 (S14), Tank –20 (S20), Tank –1139 (S1139), Tank –1140 (S1140), Tank –1141 (S1141), Tank 483 (S483), Tank –484 (S484), Tank –530 (S530), T-531, Tank –532(S532), Tank 1330 (S1751), Tank 1331 (S1752), Tank 1332 Gasoline (S1753), Tank 1333 Gasoline (S1754), Tank 1336 (S1757), and Tank 1337 (S1758), T-538, T-1330, T-1331, T-1332, T-1333, T-1336, T-1337:

   a. Liquid with a true vapor pressure of 1.5 psia or greater shall not be stored in more than 12 of the above tanks at any one time.

   b. The above tanks will be controlled by a vapor recovery system, or equivalent control equipment, capable of controlling hydrocarbon emissions to less than 8 lb/day.

   [basis: Cumulative Increase]

2. Liquid with a true vapor pressure of 1.5 psia or greater shall not be stored in Tank 1076. [basis: Cumulative Increase]

3. Coke Storage Bins and Purge Silos shall be controlled by baghouses capable of reducing mass emissions of particulate matter by a minimum of 99%. [basis: BACT, Cumulative Increase]

E. FUEL CONDITIONS

1. Sulfur content of any liquid fuel burned in furnaces subject to the cap shall not exceed 0.5% by weight. [basis: Regulation 9-1-304]
2. Except during periods of startup and shutdown, while the refinery is processing more than 50 % San Joaquin Valley (SJV) crudes, the H2S concentration of Flexigas shall not exceed 80 ppmv on a daily average, nor 60 ppmv on an annual average. At all other times, except during periods of startup and shutdown, the H2S concentration of the Flexigas shall not exceed 35 ppmv. If the owner/operator can demonstrate that the Flexsorb® cannot achieve the 35 ppmv H2S concentration on the Flexigas while processing less than 50% SJV crudes, the owner/operator may apply to the APCO for re-evaluation and possible revision of this permit condition.
   a. For the purpose of this condition, startup and shutdown of the Flexicoker (S1759) operation shall not exceed 48 hours and 96 hours, respectively.
   b. Flaring of untreated flexigas at the OPC1_FXG Flare (S1771) during startup of the Flexicoker (S1759) shall not exceed 48 hours. SO2 emissions during startup at the OPC1_FXG Flare (S1771) from untreated flexigas burning will not exceed 5 tons per startup. Startup is defined as the period of time between the initiation of feed to the Flexicoker (S1759) and when the Flexsorb Unit (A-751) is online and flexigas composition has stabilized at H2S levels sufficient to meet Condition No. 7618 Part E.2.
   c. Flaring of untreated flexigas at the OPC1_FXG Flare (S1771) during shutdown of the Flexicoker (S1759) shall not exceed 96 hours. SO2 emissions during shutdown at the the OPC1_FXG Flare (S1771) from untreated flexigas burning shall not exceed 8 tons per shutdown.

Shutdown is defined as the period of time between the cessation of normal operation of the Flexsorb Unit (A-751) and when flexigas production at the Flexicoker (S1759) ends.

d. The owner/operator must calculate SO2 emissions for each start-up and shutdown of the Flexicoker (S1759). These startup and shutdown SO2 emissions are to be included in their SO2 cap specified in Table IV of this condition.

[basis: Cumulative Increase]

3. Sulfur content of fuel oil used by tankers larger than 170 MDWEIGHT will not exceed 0.5% (by weight) while discharging crude oil at a rate greater than 35,000 Bbl/hr. [basis: Cumulative Increase]

F. REPORTING

1. The owner/operator shall report the following on a monthly basis:

   a. Daily compliance/non-compliance for each pollutant.

   b. Daily total emissions for each pollutant.
   [basis: Cumulative Increase]

G. RECORDS

1. The owner/operator shall make available to the District, upon request, all records relating to the operation of the equipment covered by this permit. [basis: Cumulative Increase]

TABLE I.

Units and Operations to be Included in Audit:

All refinery combustion devices (including flexigas burned in flares)
Dimersol Unit
Hydrogen Plants
Crude Units
CCU
Sulfur Plants and Tail Gas Units
Wharf Operations
Lightering and Ballasting while within District boundaries

TABLE II.
FACILITY BASELINE PROFILE -- NOx EMISSIONS (LB/DAY)

NOx Baseline reduced 3089 lb/day per Condition ID# 12271 and 2 lb/day per Condition ID# 4364. (AN 1362, Feb. 2002); NOx baseline reduced by 7,121 lbs/day under Application 6904.

Adjustment for CARB marine fuel sulfur standards, effective upon implementation of California Code of Regulations, Title 17 §93118). NOx baseline will be reduced 165.1 lb/day for CARB marine fuel standards (AN 22045, December 2011).

No. of days	~~Pounds per day~~	Pounds per day
1	~~13,444.4~~	12,429.4
2	~~12,786.8~~	11,930.7
3	~~12,306.8~~	11,566.6
4	~~12,126.8~~	11,430.1
5	~~11,934.8~~	11,284.5
6	~~11,925.2~~	11,277.2
7	~~11,862.8~~	11,229.9
8	~~11,822~~	11,198.9
9	~~11,805.2~~	11,186.2
10	~~11,795.6~~	11,178.9
11 to 12	~~11,752.4~~	11,146.1
13	~~11,750~~	11,144.3
14	~~11,747.6~~	11,142.5
15	~~11,723.6~~	11,124.3
16	~~11,697.2~~	11,104.3
17	~~11,690~~	11,098.8
18	~~11,565.2~~	11,004.2
19	~~11,562.8~~	11,002.3
20	~~11,512.4~~	10,964.1
21	~~11,457.2~~	10,922.3
22	~~11,435.6~~	10,905.9
23	~~11,411.6~~	10,887.7
24	~~11,397.2~~	10,876.7
25	~~11,378~~	10,862.2
26	~~11,366~~	10,853.1
27	~~11,351.6~~	10,842.2
28 to 29	~~11,327.6~~	10,824.0
30	~~11,296.4~~	10,800.3
31	~~11,243.6~~	10,760.3
32 to 33	~~11,236.4~~	10,754.8

No. of days	~~Pounds per day~~	Pounds per day
34	~~11,219.6~~	10,742.0
35	~~11,210~~	10,734.8
36	~~11,202.8~~	10,729.3
37	~~11,195.6~~	10,723.8
38	~~11,171.6~~	10,705.6
39	~~11,157.2~~	10,694.7
40	~~11,138~~	10,680.2
41	~~11,111.6~~	10,660.1
42	~~11,102~~	10,652.9
43 to 44	~~11,094.8~~	10,647.4
45	~~11,092.4~~	10,645.6
46	~~11,073.2~~	10,631.0
47	~~11,032.4~~	10,600.1
48	~~10,991.6~~	10,569.1
49	~~10,982~~	10,561.8
50	~~10,979.6~~	10,560.0
51	~~10,965.2~~	10,549.1
52	~~10,948.4~~	10,536.4
53	~~10,936.4~~	10,527.3
54	~~10,931.6~~	10,523.6
55 to 56	~~10,914.8~~	10,510.9
57	~~10,900.4~~	10,500.0
58	~~10,828.4~~	10,445.3
59 to 60	~~10,799.6~~	10,423.5
61 to 63	~~10,749.2~~	10,385.3
64	~~10,730~~	10,370.7
65 to 67	~~10,689.2~~	10,339.8
68	~~10,679.6~~	10,332.5
69	~~10,672.4~~	10,327.0
70	~~10,658~~	10,316.1
71	~~10,643.6~~	10,305.2
72 to 73	~~10,634~~	10,297.9
74	~~10,626.8~~	10,292.4
75	~~10,619.6~~	10,287.0
76	~~10,610~~	10,279.7
77	~~10,595.6~~	10,268.8
78	~~10,583.6~~	10,259.7
79 to 80	~~10,554.8~~	10,237.8
81	~~10,552.4~~	10,236.0
82	~~10,533.2~~	10,221.5
83	~~10,518.8~~	10,210.5
84	~~10,509.2~~	10,203.3

No. of days	~~Pounds per day~~	Pounds per day
85	~~10,504.4~~	10,199.6
86	~~10,502~~	10,197.8
87	~~10,478~~	10,179.6
88	~~10,473.2~~	10,176.0
89	~~10,463.6~~	10,168.7
90	~~10,451.6~~	10,159.6
91	~~10,449.2~~	10,157.7
92	~~10,362.8~~	10,092.2
93 to 94	~~10,346~~	10,079.5
95 to 96	~~10,322~~	10,061.3
97	~~10,247.6~~	10,004.8
98	~~10,226~~	9,988.5
99	~~10,204.4~~	9,972.1
100	~~10,146.8~~	9,928.4
101	~~10,137.2~~	9,921.1
102	~~10,118~~	9,906.6
103	~~10,096.4~~	9,890.2
104	~~10,094~~	9,888.4
105	~~10,091.6~~	9,886.5
106	~~10,031.6~~	9,841.0
107	~~9,966.8~~	9,791.9
108	~~9,954.8~~	9,782.8
109 to 110	~~9,940.4~~	9,771.9
111	~~9,923.6~~	9,759.1
112	~~9,921.2~~	9,757.3
113	~~9,916.4~~	9,753.7
114	~~9,899.6~~	9,740.9
115	~~9,894.8~~	9,737.3
116	~~9,878~~	9,724.5
117	~~9,875.6~~	9,722.7
118	~~9,866~~	9,715.4
119	~~9,861.2~~	9,711.8
120	~~9,858.8~~	9,710.0
121	~~9,849.2~~	9,702.7
122	~~9,842~~	9,697.2
123	~~9,837.2~~	9,693.6
124	~~9,832.4~~	9,689.9
125	~~9,827.6~~	9,686.3
126	~~9,813.2~~	9,675.4
127 to 128	~~9,796.4~~	9,662.6
129	~~9,789.2~~	9,657.1
130	~~9,762.8~~	9,637.2

No. of days	~~Pounds per day~~	Pounds per day
131	~~9,760.4~~	9,635.3
132	~~9,746~~	9,624.4
133	~~9,743.6~~	9,622.6
134	~~9,726.8~~	9,609.9
135	~~9,724.4~~	9,608.0
136 to 137	~~9,712.4~~	9,598.9
138 to 139	~~9,707.6~~	9,595.3
140 to 142	~~9,705.2~~	9,593.5
143	~~9,688.4~~	9,580.7
144 to 145	~~9,686~~	9,578.9
146	~~9,683.6~~	9,577.1
147	~~9,681.2~~	9,575.3
148	~~9,678.8~~	9,573.4
149 to 150	~~9,671.6~~	9,568.0
151	~~9,666.8~~	9,564.3
152 to 154	~~9,664.4~~	9,562.5
155 to 158	~~9,662~~	9,560.7
159	~~9,657.2~~	9,557.1
160	~~9,654.8~~	9,555.2
161 to 162	~~9,638~~	9,542.5
163	~~9,635.6~~	9,540.7
164	~~9,633.2~~	9,538.9
165	~~9,628.4~~	9,535.2
166 to 168	~~9,623.6~~	9,531.6
169	~~9,616.4~~	9,526.1
170	~~9,606.8~~	9,518.8
171	~~9,602~~	9,515.2
172	~~9,599.6~~	9,513.4
173	~~9,597.2~~	9,511.6
174 to 176	~~9,592.4~~	9,507.9
177	~~9,582.8~~	9,500.6
178	~~9,578~~	9,497.0
179	~~9,575.6~~	9,495.2
180	~~9,568.4~~	9,489.7
181 to 182	~~9,566~~	9,487.9
183 to 184	~~9,563.6~~	9,486.1
185	~~9,561.2~~	9,484.3
186	~~9,556.4~~	9,480.6
187 to 188	~~9,551.6~~	9,477.0
189 to 200	~~9,549.2~~	9,475.2
201 to 202	~~9,527.6~~	9,458.8
203	~~9,525.2~~	9,457.0

No. of days	~~Pounds per day~~	Pounds per day
204 to 206	~~9,520.4~~	9,453.3
207	~~9,518~~	9,451.5
208 to 209	~~9,515.6~~	9,449.7
210 to 213	~~9,513.2~~	9,447.9
214 to 216	~~9,510.8~~	9,446.0
217 to 220	~~9,508.4~~	9,444.2
221 to 225	~~9,506~~	9,442.4
226 to 228	~~9,501.2~~	9,438.8
229 to 230	~~9,496.4~~	9,435.1
231	~~9,494~~	9,433.3
232	~~9,489.2~~	9,429.6
233 to 234	~~9,484.4~~	9,426.0
235 to 236	~~9,477.2~~	9,420.5
237	~~9,474.8~~	9,418.7
238 to 239	~~9,472.4~~	9,416.9
240 to 241	~~9,465.2~~	9,411.4
242	~~9,462.8~~	9,409.6
243	~~9,460.4~~	9,407.8
244	~~9,458~~	9,406.0
245	~~9,455.6~~	9,404.2
246 to 247	~~9,453.2~~	9,402.3
248	~~9,448.4~~	9,398.7
249	~~9,438.8~~	9,391.4
250	~~9,434~~	9,387.8
251 to 252	~~9,426.8~~	9,382.3
253	~~9,424.4~~	9,380.5
254	~~9,419.6~~	9,376.9
255 to 259	~~9,414.8~~	9,373.2
260	~~9,407.6~~	9,367.8
261 to 278	~~9,395.6~~	9,358.7
279	~~9,381.2~~	9,347.7
280	~~9,378.8~~	9,345.9
281 to 282	~~9,369.2~~	9,338.6
283	~~9,366.8~~	9,336.8
284 to 285	~~9,364.4~~	9,335.0
286 to 290	~~9,362~~	9,333.2
291 to 294	~~9,359.6~~	9,331.4
295 to 297	~~9,357.2~~	9,329.5
298 to 301	~~9,354.8~~	9,327.7
302 to 304	~~9,352.4~~	9,325.9
305 to 308	~~9,350~~	9,324.1
309 to 312	~~9,347.6~~	9,322.3

No. of days	~~Pounds per day~~	Pounds per day
313	~~9,342.8~~	9,318.6
314	~~9,340.4~~	9,316.8
315	~~9,304.4~~	9,289.5
316	~~9,297.2~~	9,284.0
317	~~9,285.2~~	9,274.9
318	~~9,280.4~~	9,271.3
319 to 325	~~9,261.2~~	9,256.7
326 to 365	~~9,242~~	9,242.2

TABLE III.
FACILITY BASELINE PROFILE -- HYDROCARBON EMISSIONS (LB/DAY)

Adjustment for CARB marine fuel sulfur standards, effective upon implementation of California Code of Regulations, Title 17 §93118) POC baseline will be reduced 3.3 lb/day for CARB marine fuel sulfur standards (AN 22045, December 2011).

No. of days	~~Pounds per day~~	Pounds per day
1	~~13,842.4~~	3,207.4
2	~~13,688.8~~	3,176.2
3	~~12,284.8~~	3,051.4
4	~~12,114.4~~	3,020.2
5	~~11,761.6~~	2,955.4
6	~~11,591.2~~	2,902.6
7	~~11,101.6~~	2,825.8
8	~~11,024.8~~	2,821.0
9	~~10,614.4~~	2,701.0
10	~~10,552.0~~	2,413.0
11	~~10,530.4~~	2,353.0
12	~~10,477.6~~	2,345.3
13	~~10,446.4~~	2,292.9
14	~~10,427.2~~	2,270.3
15	~~10,141.6~~	2,261.8
16	~~9,829.6~~	2,227.0
17	~~9,673.6~~	2,218.5
18	~~9,416.8~~	2,194.0
19	~~8,600.8~~	2,187.4
20	~~8,598.4~~	2,166.8

No. of days	~~Pounds per day~~	Pounds per day
21	~~8,548.0~~	2,163.7
22	~~8,543.2~~	2,162.6
23	~~8,320.0~~	2,160.0
24	~~8,226.4~~	2,158.4
25	~~8,185.6~~	2,157.5
26	~~8,140.0~~	2,143.2
27	~~8,089.6~~	2,127.6
28	~~7,679.2~~	2,119.8
29	~~7,638.4~~	2,107.0
30	~~7,595.2~~	2,066.2
31	~~7,549.6~~	2,066.0
32	~~7,429.6~~	2,063.5
33	~~7,391.2~~	2,063.3
34	~~7,146.4~~	2,052.1
35	~~6,860.8~~	2,043.3
36	~~6,812.8~~	2,030.3
37	~~6,752.8~~	2,028.3
38	~~6,671.2~~	2,026.0
39	~~6,620.8~~	2,023.5
40	~~6,479.2~~	2,014.5
41	~~6,385.6~~	2,009.7
42	~~6,313.6~~	2,003.0
43	~~5,857.6~~	2,002.5
44	~~5,855.2~~	2,000.9
45	~~5,831.2~~	1,998.8
46	~~5,754.4~~	1,996.5
47	~~5,749.6~~	1,990.5
48	~~5,744.8~~	1,988.6
49	~~5,740.0~~	1,976.3
50	~~5,740.0~~	1,964.1
51	~~5,732.8~~	1,962.1
52	~~5,732.8~~	1,954.0
53	~~5,730.4~~	1,951.0
54	~~5,730.4~~	1,946.9
55	~~5,728.0~~	1,944.9
56	~~5,723.2~~	1,944.4
57	~~5,723.2~~	1,940.1
58	~~5,716.0~~	1,937.3
59	~~5,682.4~~	1,932.6

No. of days	~~Pounds per day~~	Pounds per day
60	~~5,651.2~~	1,929.0
61	~~5,598.4~~	1,928.1
62	~~5,593.6~~	1,923.3
63	~~5,456.8~~	1,920.9
64	~~5,437.6~~	1,920.9
65	~~5,423.2~~	1,913.7
66	~~5,399.2~~	1,906.5
67	~~5,380.0~~	1,906.2
68	~~5,315.2~~	1,906.1
69	~~5,260.0~~	1,904.9
70	~~5,243.2~~	1,904.1
71	~~5,212.0~~	1,904.1
72	~~4,859.2~~	1,901.7
73	~~4,844.8~~	1,901.7
74	~~4,775.2~~	1,901.0
75	~~4,765.6~~	1,900.8
76	~~4,751.2~~	1,900.6
77	~~4,657.6~~	1,900.3
78	~~4,463.2~~	1,900.3
79	~~4,408.0~~	1,900.0
80	~~4,326.4~~	1,900.0
81	~~4,268.8~~	1,899.8
82	~~4,266.4~~	1,899.8
83	~~4,180.0~~	1,899.7
84	~~4,069.6~~	1,899.5
85	~~3,949.6~~	1,899.5
86	~~3,858.4~~	1,899.3
87	~~3,820.0~~	1,899.1
88	~~3,716.8~~	1,897.4
89	~~3,690.4~~	1,895.9
90	~~3,668.8~~	1,893.2
91	~~3,668.8~~	1,893.0
92	~~3,402.4~~	1,889.7
93	~~3,325.6~~	1,886.2
94	~~3,212.8~~	1,885.2
95	~~3,181.6~~	1,884.5
96	~~3,056.8~~	1,883.3
97	~~3,025.6~~	1,882.3
98	~~2,960.8~~	1,879.1

Compliance Assurance Monitoring Analysis
Shell Martinez Refinery, Facility A0011

No. of days	~~Pounds per day~~	Pounds per day
99	~~2,908.0~~	1,877.7
100	~~2,831.2~~	1,876.3
101	~~2,826.4~~	1,875.5
102	~~2,706.4~~	1,875.3
103	~~2,418.4~~	1,873.9
104	~~2,298.4~~	1,872.9
105	~~2,048.8~~	1,865.7
106	~~2,020.0~~	1,863.3
107	~~2,015.2~~	1,856.3
108	~~2,008.0~~	1,856.1
109	~~1,969.6~~	1,856.1
110	~~1,950.4~~	1,856.1
111	~~1,945.6~~	1,855.6
112	~~1,933.6~~	1,853.7
113	~~1,928.8~~	1,853.7
114	~~1,926.4~~	1,852.1
115	~~1,926.4~~	1,851.6
116	~~1,919.2~~	1,851.3
117	~~1,912.0~~	1,851.3
118	~~1,909.6~~	1,850.9
119	~~1,909.6~~	1,848.9
120	~~1,907.2~~	1,848.9
121	~~1,907.2~~	1,848.9
122	~~1,904.8~~	1,848.9
123	~~1,895.2~~	1,846.5
124	~~1,883.2~~	1,846.2
125	~~1,880.8~~	1,836.9
126	~~1,878.4~~	1,836.5
127	~~1,871.2~~	1,834.5
128	~~1,868.8~~	1,834.5
129	~~1,861.6~~	1,834.5
130	~~1,861.6~~	1,833.7
131	~~1,861.6~~	1,832.1
132	~~1,859.2~~	1,832.1
133	~~1,859.2~~	1,829.7
134	~~1,856.8~~	1,829.7
135	~~1,856.8~~	1,829.6
136	~~1,854.4~~	1,827.3
137	~~1,854.4~~	1,827.3

No. of days	~~Pounds per day~~	Pounds per day
138	~~1,854.4~~	1,826.8
139	~~1,854.4~~	1,826.6
140	~~1,852.0~~	1,824.9
141	~~1,842.4~~	1,822.5
142	~~1,840.0~~	1,822.3
143	~~1,840.0~~	1,817.7
144	~~1,840.0~~	1,816.8
145	~~1,837.6~~	1,815.3
146	~~1,837.6~~	1,815.3
147	~~1,835.2~~	1,815.3
148	~~1,835.2~~	1,815.3
149	~~1,832.8~~	1,812.9
150	~~1,832.8~~	1,812.9
151	~~1,830.4~~	1,810.8
152	~~1,828.0~~	1,810.5
153	~~1,823.2~~	1,810.5
154	~~1,820.8~~	1,810.5
155	~~1,820.8~~	1,808.1
156	~~1,820.8~~	1,808.1
157	~~1,820.8~~	1,806.2
158	~~1,818.4~~	1,805.7
159	~~1,818.4~~	1,805.7
160	~~1,816.0~~	1,804.3
161	~~1,816.0~~	1,803.3
162	~~1,816.0~~	1,803.3
163	~~1,813.6~~	1,803.3
164	~~1,813.6~~	1,799.2
165	~~1,811.2~~	1,798.5
166	~~1,811.2~~	1,797.8
167	~~1,808.8~~	1,796.8
168	~~1,808.8~~	1,796.8
169	~~1,808.8~~	1,796.1
170	~~1,804.0~~	1,796.1
171	~~1,801.6~~	1,783.4
172	~~1,801.6~~	1,781.7
173	~~1,787.2~~	1,779.6
174	~~1,782.4~~	1,776.9
175	~~1,782.4~~	1,776.9
176	~~1,777.6~~	1,772.1

No. of days	~~Pounds per day~~	Pounds per day
177	~~1,765.6~~	1,760.1
178	~~1,765.6~~	1,760.1
179	~~1,765.6~~	1,760.1
180	~~1,763.2~~	1,757.7
181	~~1,760.8~~	1,755.3
182	~~1,753.6~~	1,748.6
183	~~1,751.2~~	1,746.5
184	~~1,748.8~~	1,744.3
185	~~1,746.4~~	1,742.2
186	~~1,746.4~~	1,742.2
187	~~1,746.4~~	1,742.2
188	~~1,744.0~~	1,740.1
189	~~1,744.0~~	1,740.1
190	~~1,744.0~~	1,740.1
191	~~1,741.6~~	1,737.9
192	~~1,739.2~~	1,735.8
193	~~1,739.2~~	1,735.8
194	~~1,739.2~~	1,735.8
195	~~1,739.2~~	1,735.8
196	~~1,734.4~~	1,731.5
197	~~1,734.4~~	1,731.5
198	~~1,732.0~~	1,729.4
199	~~1,732.0~~	1,729.4
200	~~1,732.0~~	1,729.4
201	~~1,732.0~~	1,729.4
202	~~1,732.0~~	1,729.4
203	~~1,732.0~~	1,729.4
204	~~1,732.0~~	1,729.4
205	~~1,732.0~~	1,729.4
206	~~1,732.0~~	1,729.4
207	~~1,732.0~~	1,729.4
208	~~1,732.0~~	1,729.4
209	~~1,729.6~~	1,727.2
210	~~1,729.6~~	1,727.2
211	~~1,729.6~~	1,727.2
212	~~1,729.6~~	1,727.2
213	~~1,729.6~~	1,727.2
214	~~1,729.6~~	1,727.2
215	~~1,727.2~~	1,725.1

No. of days	~~Pounds per day~~	Pounds per day
216	~~1,727.2~~	1,725.1
217	~~1,727.2~~	1,725.1
218	~~1,727.2~~	1,725.1
219	~~1,727.2~~	1,725.1
220	~~1,727.2~~	1,725.1
221	~~1,727.2~~	1,725.1
222	~~1,727.2~~	1,725.1
223	~~1,727.2~~	1,725.1
224	~~1,727.2~~	1,725.1
225	~~1,727.2~~	1,725.1
226	~~1,724.8~~	1,723.0
227	~~1,724.8~~	1,723.0
228	~~1,724.8~~	1,723.0
229	~~1,724.8~~	1,723.0
230	~~1,724.8~~	1,723.0
231	~~1,724.8~~	1,723.0
232	~~1,724.8~~	1,723.0
233	~~1,724.8~~	1,723.0
234	~~1,722.4~~	1,720.8
235	~~1,722.4~~	1,720.8
236	~~1,722.4~~	1,720.8
237	~~1,722.4~~	1,720.8
238	~~1,722.4~~	1,720.8
239	~~1,722.4~~	1,720.8
240	~~1,722.4~~	1,720.8
241	~~1,722.4~~	1,720.8
242	~~1,722.4~~	1,720.8
243	~~1,722.4~~	1,720.8
244	~~1,722.4~~	1,720.8
245	~~1,722.4~~	1,720.8
246	~~1,720.0~~	1,718.7
247	~~1,720.0~~	1,718.7
248	~~1,720.0~~	1,718.7
249	~~1,720.0~~	1,718.7
250	~~1,720.0~~	1,718.7
251	~~1,720.0~~	1,718.7
252	~~1,720.0~~	1,718.7
253	~~1,720.0~~	1,718.7
254	~~1,720.0~~	1,718.7

No. of days	~~Pounds per day~~	Pounds per day
255	~~1,720.0~~	1,718.7
256	~~1,717.6~~	1,716.6
257	~~1,717.6~~	1,716.6
258	~~1,717.6~~	1,716.6
259	~~1,717.6~~	1,716.6
260	~~1,717.6~~	1,716.6
261	~~1,717.6~~	1,716.6
262	~~1,717.6~~	1,716.6
263	~~1,717.6~~	1,716.6
264	~~1,717.6~~	1,716.6
265	~~1,717.6~~	1,716.6
266	~~1,717.6~~	1,716.6
267	~~1,717.6~~	1,716.6
268	~~1,715.2~~	1,714.4
269	~~1,715.2~~	1,714.4
270	~~1,715.2~~	1,714.4
271	~~1,715.2~~	1,714.4
272	~~1,715.2~~	1,714.4
273	~~1,715.2~~	1,714.4
274	~~1,715.2~~	1,714.4
275	~~1,715.2~~	1,714.4
276	~~1,715.2~~	1,714.4
277	~~1,715.2~~	1,714.4
278	~~1,715.2~~	1,714.4
279	~~1,715.2~~	1,714.4
280	~~1,715.2~~	1,714.4
281	~~1,715.2~~	1,714.4
282	~~1,715.2~~	1,714.4
283	~~1,715.2~~	1,714.4
284	~~1,715.2~~	1,714.4
285	~~1,715.2~~	1,714.4
286	~~1,715.2~~	1,714.4
287	~~1,715.2~~	1,714.4
288	~~1,715.2~~	1,714.4
289	~~1,715.2~~	1,714.4
290	~~1,715.2~~	1,714.4
291	~~1,715.2~~	1,714.4
292	~~1,715.2~~	1,714.4
293	~~1,715.2~~	1,714.4

No. of days	~~Pounds per day~~	Pounds per day
294	~~1,715.2~~	1,714.4
295	~~1,715.2~~	1,714.4
296	~~1,715.2~~	1,714.4
297	~~1,715.2~~	1,714.4
298	~~1,715.2~~	1,714.4
299	~~1,715.2~~	1,714.4
300	~~1,715.2~~	1,714.4
301	~~1,715.2~~	1,714.4
302	~~1,712.8~~	1,712.3
303	~~1,712.8~~	1,712.3
304	~~1,712.8~~	1,712.3
305	~~1,712.8~~	1,712.3
306	~~1,712.8~~	1,712.3
307	~~1,712.8~~	1,712.3
308	~~1,712.8~~	1,712.3
309	~~1,712.8~~	1,712.3
310	~~1,712.8~~	1,712.3
311	~~1,712.8~~	1,712.3
312	~~1,710.4~~	1,710.1
313	~~1,710.4~~	1,710.1
314	~~1,710.4~~	1,710.1
315	~~1,710.4~~	1,710.1
316	~~1,710.4~~	1,710.1
317	~~1,710.4~~	1,710.1
318	~~1,710.4~~	1,710.1
319	~~1,710.4~~	1,710.1
320	~~1,710.4~~	1,710.1
321	~~1,710.4~~	1,710.1
322	~~1,710.4~~	1,710.1
323	~~1,710.4~~	1,710.1
324	~~1,710.4~~	1,710.1
325	~~1,710.4~~	1,710.1
326	~~1,708.0~~	1,708.0
327	~~1,708.0~~	1,708.0
328	~~1,708.0~~	1,708.0
329	~~1,708.0~~	1,708.0
330	~~1,708.0~~	1,708.0
331	~~1,708.0~~	1,708.0
332	~~1,708.0~~	1,708.0

No. of days	~~Pounds per day~~	Pounds per day
333	~~1,708.0~~	1,708.0
334	~~1,708.0~~	1,708.0
335	~~1,708.0~~	1,708.0
336	~~1,708.0~~	1,708.0
337	~~1,708.0~~	1,708.0
338	~~1,708.0~~	1,708.0
339	~~1,708.0~~	1,708.0
340	~~1,708.0~~	1,708.0
341	~~1,708.0~~	1,708.0
342	~~1,708.0~~	1,708.0
343	~~1,708.0~~	1,708.0
344	~~1,708.0~~	1,708.0
345	~~1,708.0~~	1,708.0
346	~~1,708.0~~	1,708.0
347	~~1,708.0~~	1,708.0
348	~~1,708.0~~	1,708.0
349	~~1,708.0~~	1,708.0
350	~~1,708.0~~	1,708.0
351	~~1,708.0~~	1,708.0
352	~~1,708.0~~	1,708.0
353	~~1,708.0~~	1,708.0
354	~~1,708.0~~	1,708.0
355	~~1,708.0~~	1,708.0
356	~~1,708.0~~	1,708.0
357	~~1,708.0~~	1,708.0
358	~~1,708.0~~	1,708.0
359	~~1,708.0~~	1,708.0
360	~~1,708.0~~	1,708.0
361	~~1,708.0~~	1,708.0
362	~~1,708.0~~	1,708.0
363	~~1,708.0~~	1,708.0
364	~~1,708.0~~	1,708.0
365	~~1,708.0~~	1,708.0

TABLE IV.
FACILITY BASELINE PROFILE -- SOX EMISSIONS (LB/DAY)

SO2 baseline reduced 1398 lb/day per Condition ID# 12271. (AN 1362, Feb. 2002)
SO2 baseline reduced by 80 lb/day for Flexsorb project
(AN 4106, June 2002)
Note: the 110.2 lb/day reduction was a calculation error. The 14.6 Ton/yr reduction for the Flexsorb Project is equal to 80.0 lb/day.

SO2 baseline reduced 1,802.9 lb/day for CARB marine fuel sulfur standard (AN 22045, December 2011).

No. of days	~~**Pounds per day**~~	**Pounds per day**
1	~~22,943~~	14,983.2
2	~~22,931~~	14,982.6
3	~~22,724.6~~	14,972.7
4	~~22,657.4~~	14,969.4
5	~~22,578.2~~	14,965.6
6	~~22,407.8~~	14,957.3
7	~~22,141.4~~	14,944.5
8	~~22,119.8~~	14,943.4
9	~~22,045.4~~	14,939.8
10	~~22,031~~	14,939.1
11	~~21,985.4~~	14,936.9
12	~~21,774.2~~	14,926.7
13	~~21,771.8~~	14,926.6
14	~~21,683~~	14,922.3
15	~~21,606.2~~	14,918.6
16	~~21,476.6~~	14,912.3
17	~~21,392.6~~	14,908.3
18	~~21,371~~	14,907.3
19	~~21,344.6~~	14,906.0
20	~~20,994.2~~	14,889.0
21	~~20,941.4~~	14,886.5
22	~~20,915~~	14,885.2
23	~~20,787.8~~	14,879.1
24	~~20,778.2~~	14,878.6
25	~~20,643.8~~	14,872.1
26	~~20,564.6~~	14,868.3
27	~~20,497.4~~	14,865.0
28	~~20,490.2~~	14,864.7
29	~~20,432.6~~	14,861.9

No. of days	~~Pounds per day~~	Pounds per day
30	~~20,430.2~~	14,861.8
31	~~20,411~~	14,860.8
32	~~20,394.2~~	14,860.0
33	~~20,372.6~~	14,859.0
34	~~20,322.2~~	14,856.6
35	~~20,247.8~~	14,853.0
36	~~19,983.8~~	14,840.2
37	~~19,947.8~~	14,838.5
38	~~19,506.2~~	14,817.1
39	~~19,491.8~~	14,816.4
40	~~19,489.4~~	14,816.3
41	~~19,338.2~~	14,809.0
42	~~19,287.8~~	14,806.6
43	~~19,057.4~~	14,795.4
44	~~19,047.8~~	14,795.0
45	~~19,043~~	14,794.7
46	~~18,939.8~~	14,789.7
47	~~18,937.4~~	14,789.6
48	~~18,915.8~~	14,788.6
49	~~18,822.2~~	14,784.1
50	~~18,817.4~~	14,783.8
51	~~18,810.2~~	14,781.0
52	~~18,759.8~~	14,780.6
53	~~18,601.4~~	14,773.4
54	~~18,536.6~~	14,770.3
55	~~18,443~~	14,765.7
56	~~18,375.8~~	14,762.5
57	~~18,311~~	14,759.4
58	~~18,128.6~~	14,750.5
59	~~18,121.4~~	14,750.2
60	~~18,075.8~~	14,748.0
61	~~18,056.6~~	14,747.1
62	~~18,039.8~~	14,746.3
63	~~17,975~~	14,743.1
64	~~17,965.4~~	14,742.7
65	~~17,948.6~~	14,741.8
66	~~17,943.8~~	14,741.6
67	~~17,931.8~~	14,741.0
68	~~17,907.8~~	14,739.9

No. of days	~~Pounds per day~~	Pounds per day
69	~~17,763.8~~	14,732.9
70	~~17,720.6~~	14,730.8
71	~~17,713.4~~	14,730.5
72	~~17,711~~	14,730.4
73	~~17,708.6~~	14,730.2
74	~~17,682.2~~	14,729.0
75	~~17,581.4~~	14,724.1
76	~~17,567~~	14,723.4
77	~~17,480.6~~	14,719.2
78	~~17,444.6~~	14,717.5
79	~~17,413.4~~	14,716.0
80	~~17,363~~	14,713.5
81	~~17,307.8~~	14,710.9
82	~~17,305.4~~	14,710.8
83	~~17,291~~	14,710.1
84	~~17,233.4~~	14,707.3
85	~~17,231~~	14,707.2
86 to 87	~~17,221.4~~	14,706.7
88	~~17,214.2~~	14,706.4
89	~~17,211.8~~	14,706.2
90	~~17,187.8~~	14,705.1
91	~~17,185.4~~	14,705.0
92	~~17,135~~	14,702.5
93	~~17,096.6~~	14,700.7
94	~~17,065.4~~	14,699.2
95	~~17,048.6~~	14,698.4
96	~~17,046.2~~	14,698.2
97	~~17,024.6~~	14,697.2
98	~~17,010.2~~	14,696.5
99	~~17,000.6~~	14,696.0
100	~~16,974.2~~	14,694.8
101	~~16,962.2~~	14,694.2
102	~~16,952.6~~	14,693.7
103	~~16,943~~	14,693.2
104	~~16,940.6~~	14,693.1
105	~~16,899.8~~	14,691.2
106	~~16,866.2~~	14,689.5
107	~~16,859~~	14,689.2
108	~~16,849.4~~	14,688.7

No. of days	~~Pounds per day~~	Pounds per day
109	~~16,847~~	14,688.6
110	~~16,803.8~~	14,686.5
111	~~16,791.8~~	14,685.9
112	~~16,789.4~~	14,685.8
113	~~16,765.4~~	14,684.7
114	~~16,751~~	14,684.0
115	~~16,734.2~~	14,683.2
116	~~16,717.4~~	14,682.3
117	~~16,712.6~~	14,682.1
118	~~16,710.2~~	14,682.0
119	~~16,695.8~~	14,681.3
120	~~16,669.4~~	14,680.0
121	~~16,633.4~~	14,678.3
122	~~16,631~~	14,678.2
123	~~16,619~~	14,677.6
124	~~16,609.4~~	14,677.1
125	~~16,592.6~~	14,676.3
126	~~16,587.8~~	14,676.1
127	~~16,571~~	14,675.3
128	~~16,568.6~~	14,675.2
129	~~16,563.8~~	14,674.9
130	~~16,535~~	14,673.5
131	~~16,527.8~~	14,673.2
132	~~16,515.8~~	14,672.6
133	~~16,499~~	14,671.8
134	~~16,487~~	14,671.2
135	~~16,472.6~~	14,670.5
136	~~16,458.2~~	14,669.8
137	~~16,422.2~~	14,668.1
138	~~16,417.4~~	14,667.8
139 to 140	~~16,400.6~~	14,667.0
141	~~16,388.6~~	14,666.5
142	~~16,369.4~~	14,665.5
143	~~16,364.6~~	14,665.3
144	~~16,362.2~~	14,665.2
145	~~16,357.4~~	14,664.9
146	~~16,352.6~~	14,664.7
147	~~16,350.2~~	14,664.6
148	~~16,295~~	14,661.9

No. of days	~~Pounds per day~~	Pounds per day
149	~~16,232.6~~	14,658.9
150	~~16,218.2~~	14,658.2
151	~~16,191.8~~	14,656.9
152 to 153	~~16,187~~	14,656.7
154	~~16,184.6~~	14,656.6
155	~~16,175~~	14,656.1
156	~~16,172.6~~	14,656.0
157	~~16,163~~	14,655.6
158	~~16,141.4~~	14,654.5
159 to 160	~~16,139~~	14,654.4
161	~~16,134.2~~	14,654.2
162	~~16,105.4~~	14,652.8
163	~~16,083.8~~	14,651.7
164	~~16,067~~	14,651.3
165	~~16,062.2~~	14,650.9
166	~~16,055~~	14,650.7
167	~~16,052.6~~	14,650.2
168	~~16,043.0~~	14,649.8
169	~~16,035.8~~	14,649.4
170	~~15,971~~	14,646.3
171	~~15,963.8~~	14,645.9
172	~~15,954.2~~	14,645.5
173	~~15,927.8~~	14,644.2
174	~~15,913.4~~	14,643.5
175	~~15,903.8~~	14,643.0
176	~~15,896.6~~	14,642.7
177	~~15,891.8~~	14,642.4
178	~~15,865.4~~	14,641.2
179	~~15,860.6~~	14,640.9
180	~~15,846.2~~	14,640.2
181	~~15,839~~	14,639.9
182 to 183	~~15,822.2~~	14,639.1
184	~~15,815~~	14,638.7
185	~~15,781.4~~	14,637.1
186	~~15,774.2~~	14,636.8
187	~~15,740.6~~	14,635.1
188 to 189	~~15,716.6~~	14,634.0
190	~~15,702.2~~	14,633.3
191	~~15,695~~	14,632.9

No. of days	~~Pounds per day~~	Pounds per day
192	~~15,685.4~~	14,632.5
193 to 194	~~15,683~~	14,632.4
195	~~15,663.8~~	14,631.4
196 to 197	~~15,656.6~~	14,631.1
198 to 199	~~15,637.4~~	14,630.2
200	~~15,615.8~~	14,629.1
201	~~15,575~~	14,627.1
202	~~15,555.8~~	14,626.2
203	~~15,529.4~~	14,624.9
204	~~15,467~~	14,621.9
205 to 207	~~15,447.8~~	14,621.0
208	~~15,438.2~~	14,620.5
209	~~15,433.4~~	14,620.3
210	~~15,426.2~~	14,619.9
211	~~15,423.8~~	14,619.8
212	~~15,421.4~~	14,619.7
213	~~15,416.6~~	14,619.5
214	~~15,414.2~~	14,619.4
215	~~15,409.4~~	14,619.1
216	~~15,404.6~~	14,618.9
217	~~15,402.2~~	14,618.8
218	~~15,399.8~~	14,618.7
219	~~15,397.4~~	14,618.6
220 to 221	~~15,395~~	14,618.4
222	~~15,392.6~~	14,618.3
223	~~15,387.8~~	14,618.1
224	~~15,368.6~~	14,617.2
225	~~15,366.2~~	14,617.0
226	~~15,361.4~~	14,616.8
227 to 229	~~15,359~~	14,616.7
230	~~15,354.2~~	14,616.5
231	~~15,349.4~~	14,616.2
232	~~15,342.2~~	14,615.9
233 to 234	~~15,339.8~~	14,615.8
235	~~15,337.4~~	14,615.7
236	~~15,330.2~~	14,615.3
237	~~15,323~~	14,615.0
238	~~15,315.8~~	14,614.6
239	~~15,313.4~~	14,614.5

No. of days	~~Pounds per day~~	Pounds per day
240	~~15,308.6~~	14,614.3
241	~~15,306.2~~	14,614.1
242	~~15,287~~	14,613.2
243	~~15,284.6~~	14,613.1
244	~~15,282.2~~	14,613.0
245	~~15,279.8~~	14,612.9
246	~~15,277.4~~	14,612.8
247	~~15,275~~	14,612.6
248 to 250	~~15,272.6~~	14,612.5
251 to 252	~~15,270.2~~	14,612.4
253 to 254	~~15,265.4~~	14,612.2
255	~~15,263~~	14,612.1
256 to 257	~~15,260.6~~	14,611.9
258	~~15,253.4~~	14,611.6
259	~~15,234.2~~	14,610.7
260	~~15,231.8~~	14,610.5
261	~~15,227~~	14,610.3
262	~~15,224.6~~	14,610.2
263	~~15,222.2~~	14,610.1
264	~~15,219.8~~	14,610.0
265	~~15,195.8~~	14,608.8
266	~~15,193.4~~	14,608.7
267 to 268	~~15,188.6~~	14,608.5
269 to 270	~~15,186.2~~	14,608.3
271	~~15,181.4~~	14,608.1
272	~~15,176.6~~	14,607.9
273	~~15,174.2~~	14,607.8
274	~~15,171.8~~	14,607.6
275	~~15,133.4~~	14,605.8
276	~~15,119~~	14,605.1
277	~~15,044.6~~	14,601.5
278	~~15,001.4~~	14,599.4
279	~~14,967.8~~	14,597.8
280	~~14,965.4~~	14,597.7
281	~~14,955.8~~	14,597.2
282	~~14,891~~	14,594.1
283 to 287	~~14,881.4~~	14,593.6
288 to 294	~~14,869.4~~	14,593.0
295	~~14,622.2~~	14,581.1

Compliance Assurance Monitoring Analysis
Shell Martinez Refinery, Facility A0011

No. of days	~~Pounds per day~~	Pounds per day
296	~~14,610.2~~	14,580.5
297 to 307	~~14,600.6~~	14,580.0
308 to 325	~~14,588.6~~	14,579.5
326 to 365	~~14,579~~	14,579.0

TABLE V (revised10/94,App.No.13814)
MODIFIED FACILITY BASELINE PROFILE—PARTICULATE EMISSIONS

Particulate matter baseline reduced 99.0 lb/day for CARB marine fuel sulfur standards (AN 22045, December 2011).

No. of days	~~Pounds per day~~	Pounds per day
1	~~2,137.8~~	1,658.6
2	~~2,070.6~~	1,642.4
3	~~2,044.2~~	1,636.1
4	~~2,034.6~~	1,633.8
5	~~2,020.2~~	1,630.3
6	~~2,015.4~~	1,629.1
7	~~2,010.6~~	1,628.0
8	~~2,008.2~~	1,627.4
9	~~2,001.1~~	1,625.7
10	~~1,996.2~~	1,624.5
11	~~1,991.4~~	1,623.3
12	~~1,989.1~~	1,622.8
13	~~1,984.2~~	1,621.6
14	~~1,981.8~~	1,621.0
15	~~1,962.6~~	1,616.4
16 to 17	~~1,957.8~~	1,615.3
18 to 19	~~1,955.4~~	1,614.7
20	~~1,953.1~~	1,614.1
21	~~1,948.2~~	1,612.9
22	~~1,945.8~~	1,612.4
23	~~1,941.1~~	1,611.2
24	~~1,938.6~~	1,610.6
25	~~1,931.4~~	1,608.9
26	~~1,929.1~~	1,608.3
27	~~1,926.6~~	1,607.7
28	~~1,912.2~~	1,604.3
29	~~1,909.8~~	1,603.7
30	~~1,905.1~~	1,602.6
31	~~1,897.8~~	1,600.8
32	~~1,871.4~~	1,594.5
33	~~1,864.2~~	1,592.7
34	~~1,861.8~~	1,592.1
35	~~1,859.4~~	1,591.6

No. of days	~~Pounds per day~~	Pounds per day
36	~~1,857.1~~	1,591.0
37 to 38	~~1,854.6~~	1,590.4
39	~~1,852.2~~	1,589.8
40	~~1,842.6~~	1,587.5
41	~~1,837.8~~	1,586.4
42 to 43	~~1,833.1~~	1,585.2
44	~~1,830.6~~	1,584.6
45	~~1,821.1~~	1,582.3
46	~~1,806.6~~	1,578.8
47	~~1,801.8~~	1,577.7
48	~~1,792.2~~	1,575.4
49	~~1,780.2~~	1,572.5
50 to 52	~~1,777.8~~	1,571.9
53	~~1,775.4~~	1,571.3
54 to 55	~~1,773.1~~	1,570.8
56 to 57	~~1,770.6~~	1,570.2
58	~~1,761.1~~	1,567.9
59 to 61	~~1,758.6~~	1,567.3
62 to 63	~~1,756.2~~	1,566.7
64	~~1,753.8~~	1,566.1
65	~~1,749.1~~	1,565.0
66	~~1,744.2~~	1,563.8
67 to 69	~~1,737.1~~	1,562.1
70 to 71	~~1,722.6~~	1,558.6
72	~~1,717.8~~	1,557.5
73	~~1,715.4~~	1,556.9
74	~~1,713.1~~	1,556.3
75	~~1,710.6~~	1,555.7
76 to 78	~~1,708.2~~	1,555.1
79	~~1,705.8~~	1,554.6
80	~~1,703.4~~	1,554.0
	~~1,698.6~~	
81	~~1,698.2~~	1,552.8
82	~~1,696.2~~	1,552.3
83 to 86	~~1,693.8~~	1,551.7
87 to 88	~~1,691.4~~	1,551.1
89 to 90	~~1,689.1~~	1,550.5
91	~~1,686.6~~	1,549.9
92 to 94	~~1,681.8~~	1,548.8

No. of days	~~**Pounds per day**~~	**Pounds per day**
95 to 96	~~1,679.4~~	1,548.2
97 to 99	~~1,677.1~~	1,547.7
100	~~1,674.6~~	1,547.1
101 to 102	~~1,672.2~~	1,546.5
103 to 104	~~1,669.8~~	1,545.9
105 to 106	~~1,665.1~~	1,544.8
107 to 110	~~1,660.2~~	1,543.6
111	~~1,657.8~~	1,543.0
112 to 116	~~1,655.4~~	1,542.4
117 to 119	~~1,653~~	1,541.9
120 to 121	~~1,650.6~~	1,541.3
	~~1,648.2~~	
122	~~1,642.2~~	1,540.7
123 to 124	~~1,645.8~~	1,540.1
125 to 126	~~1,643.4~~	1,539.5
127 to 128	~~1,641.1~~	1,539.0
129 to 133	~~1,638.6~~	1,538.4
134 to 135	~~1,636.2~~	1,537.8
136 to 140	~~1,633.8~~	1,537.2
141 to 143	~~1,631.4~~	1,536.7
144 to 148	~~1,629.1~~	1,536.1
149 to 151	~~1,626.6~~	1,535.5
152 to 154	~~1,621.8~~	1,534.3
155 to 157	~~1,619.4~~	1,533.8
158 to 159	~~1,617.1~~	1,533.2
160 to 167	~~1,612.2~~	1,532.0
168 to 170	~~1,609.8~~	1,531.5
171 to 173	~~1,607.4~~	1,530.9
174 to 178	~~1,602.6~~	1,529.7
179 to 180	~~1,600.2~~	1,529.1
181	~~1,597.8~~	1,528.6
182 to 186	~~1,595.4~~	1,528.0
187 to 188	~~1,593.1~~	1,527.4
189	~~1,590.6~~	1,526.8
190	~~1,588.2~~	1,526.3
191	~~1,585.8~~	1,525.7
192 to 195	~~1,583.4~~	1,525.1
196 to 197	~~1,581.1~~	1,524.5
198 to 199	~~1,578.6~~	1,523.9

No. of days	~~**Pounds per day**~~	**Pounds per day**
200 to 202	~~1,576.2~~	1,523.4
203 to 204	~~1,573.8~~	1,522.8
205 to 206	~~1,571.4~~	1,522.2
207 to 209	~~1,569.1~~	1,521.7
210 to 211	~~1,566.6~~	1,521.0
212 to 214	~~1,564.2~~	1,520.5
215 to 218	~~1,561.8~~	1,519.9
219 to 225	~~1,559.4~~	1,519.3
226 to 235	~~1,557.1~~	1,518.8
236 to 247	~~1,554.6~~	1,518.2
248 to 252	~~1,552.2~~	1,517.6
253 to 263	~~1,549.8~~	1,517.0
264 to 267	~~1,547.4~~	1,516.4
268 to 271	~~1,545.1~~	1,515.9
272 to 276	~~1,542.6~~	1,515.3
277	~~1,537.8~~	1,514.1
	~~1,535.4~~	
278 to 280	~~1,525.4~~	1,513.5
281 to 283	~~1,533.1~~	1,513.0
284 to 288	~~1,530.6~~	1,512.4
289	~~1,525.8~~	1,511.2
290 to 296	~~1,523.4~~	1,510.6
297 to 307	~~1,521.1~~	1,510.1
308 to 325	~~1,513.8~~	1,508.3
326 to 365	~~1,506.6~~	1,506.6

TABLE VI.
FACILITY BASELINE PROFILE -- CARBON MONOXIDE EMISSIONS (LB/DAY)

No. of days	Pounds per day
1 to 365	6904.0

TABLE VII.
EMISSION FACTORS -- WHARF OPERATIONS

Material	Loading Emission Factor, lb/1000 gal
Finished Gasolines	1.4
Light Gasoline Components	
Alkylate	1.4
HT C5/100 St Run	1.4
C5/240 Cat Crk	1.4
C5/180 Hydrocrackate	1.4
Dis Light Naphtha	1.4
Heavy Gasoline Components	
Reformate	1.4
240/450 Cat Crk	1.4
Dist Heavy Naphtha	1.4
Cat Reformer Feed	1.4
Shell Jet A	.05
Shell Mineral Spirits	.05
DSU Mineral Spirits	.05
Shell 1300 Solvent	.05
Crudes	
Alaskan North Slope	1.7
Labuan	1.7
Heavy S.J. Valley	.06
Others	1.7
Heavy Feed Stocks	
Coker Heavy Gas Oil	.016
Cat Cracker Feed	.005
Vacuum Flashed Dist	.005
Heavy Flashed Dist	.005
Coker Feed	.016
Fuel Oils	
Shell Dieseline	.005

Marine Diesel	.005
Shell Thin Fuel Oil 30	.005
Shell Thin Fuel Oil 40	.005
Shell Thin Fuel Oil 60	.005
Shell Thin Fuel Oil 80	.005
Shell Thin Fuel Oil 100	.005
Unfin Cracked Gas Oil	.002
Shell Light Fuel Oil	.002
Shell Steam Ship Fuel Oil	.002
Shell Marine International Grade	.002
Shell Industrial Fuel Oil	.002
Shell Thin F.U. 120	.002
Shell Thin F.O. 150	.002
Shell Thin F.U. 180	.002
Shell Thin F.U. 240	.002
Shell Thin F.U.280	.002
Shell Thin F.O. 320	.002
Shell Thin F.O. 380	.002
Shell Thin F.O. MV 240/11.4	.002
Shell Thin F.O. MV 280/11.4	.002
Shell Thin F.O. MV 320/11.4	.002
Shell Thin F.O. MV 380/11.4	.002
Miscellaneous Cutter Stock	.002
Shell Special Industrial Fuel Oil	.002
Shell UMF Grade C	.002
Shell Mect. Treating Aromatic Oil	.002
Shellflex 371	.002

Lube Oils

HVI 100 Neut TQ	.00004
HVI 250 Neut MQ	.00004
HVI 65/210	.00004
HVI 150 Brt Stk	.00004
HVI 100 Neut MQ	.00004
LVI 60 Neut MQ	.00004
LVI 100 Neut MQ	.00004
100 Base Stk 80 UR	.00004
LVI 450 Neut	.00004
LVI 90/210 Neut	.00004
60 Spray Base	.00004
100 Spray Base 92 UR	.00004
MVI 400 Neut	.00004
MVI 80/210 Neut RQ	.00004
Diala A	.00004
Diala AX	.00004
35 Base Stock	.00004

Asphalts

AR 2000 Asphalt	.00004

AR 4000 Asphalt	.00004
AR 8000 Asphalt	.00004
WOR Flux	.00004
80 Vis Blend Stock	.00004

TABLE VIII.

SHIPPING COMBUSTION EMISSION FACTORS
(lb/1000 gallon fuel)

Adjustment of emission factors in Table VIII for CARB marine fuel sulfur standards, effective upon implementation of California Code of Regulations, Title 17 §93118)

	Organic	**SO_2**		**NOx**	**Particulate Matter**	
		~~0.5%~~ 0.0015%	~~2.0%~~ 0.1%		~~0.5%~~ 0.0015%	~~2.0%~~ 0.1%
Steamships						
Hoteling	~~3.10~~ 0.25	~~79.77~~	~~319.08~~ 14.20	~~20.90~~ 20.00	~~7.03~~	~~18.99~~ 3.30
Other (also listed as “Full Load” in some versions)	~~3.10~~ 0.25	~~79.77~~	~~319.08~~ 14.20	~~48.21~~ 24.00	~~7.03~~	~~18.99~~ 3.30
Internal Combustion Engines						
~~Residual~~	~~32.80~~	~~78.78~~	~~315.11~~	~~339.60~~	~~35.00~~	~~35.00~~
Marine Diesel Oil	32.80	~~70.69~~	13.39	367.00	~~20.00~~	13.16
CARB Diesel (Tugs)	12.99	~~38.97~~ 0.12	--	571.22	~~24.98~~ 14.33	--

SHIPPING FUEL COMBUSTION RATES (gal/hr)

(gal/hr)**Ship Size**	**Fuel**	**Combustion Rate (gal/hr)**							
		Maneuvering	**Hotelling**	**Cargo Discharge Rate (bbl/hr)**					
				3,000	**7,500**	**11,000**	**20,000**	**50,000**	**85,000**
Steamships									
30 MDWT	~~Residual~~ Marine Diesel Oil	~~304~~ 326	~~39~~ 42	~~147~~ 157	~~294~~ 315				
45 MDWT	~~Residual~~ Marine Diesel Oil	~~417~~ 447	~~47~~ 50	~~184~~ 197		~~504~~ 540			
60 MDWT	~~Residual~~ Marine Diesel Oil	~~567~~ 608	~~76~~ 81			~~631~~ 676			
70 MDWT	~~Residual~~ Marine Diesel Oil	~~666~~ 714	~~93~~ 100			~~650~~ 696			
200 MDWT	~~Residual~~ Marine Diesel Oil	~~1,057~~ 1,133	~~143~~ 153				~~1,000~~ 1,071	~~1,188~~ 1,273	~~1,656~~ 1,774
Motorships									
30 MDWT	~~Residual~~ Marine Diesel Oil or Marine Gas Oil for use in boilers		~~84~~ 90	~~147~~ 158	~~294~~ 315				
	Diesel	420	42	42	42				
70 MDWT	~~Residual~~ Marine Diesel Oil or Marine Gas Oil for use in boilers		~~84~~ 90			~~650~~ 696			
	Diesel	420	42			42			
150 MDWT	~~Residual~~ Marine Diesel Oil or Marine Gas Oil for use in boilers		~~84~~ 90				~~759~~ 813	~~898~~ 962	
	Diesel	588	42				42	42	
120/135 MDWT	~~Residual~~ Marine Diesel Oil or Marine Gas Oil for use in boilers		~~84~~ 90				~~759~~ 813	~~898~~ 962	
	Diesel	588	42				42	42	
Tugs									
	CARB	30							

	Diesel								

TABLE IX.

Emission Factors -- Combustion
(lb/MMBTU; * = lb/MMSCF; and ** = lb/bbl)

CO BOILERS	HC	PART	NOx	CO	SOx
Natural Gas	.0162	.015	.7	.0039	.0006
Refinery Gas	.0162	.02	.7	.0039	S(.171)* (Note 1)
Residual Fuel	.042**	.55**	.7	.0040	S(7.2)** (Note 2)
LSFO	.042**	.084**	.7	.0040	S(6.3)** (Note 3)
Flexigas	.00162	.005	.05	.0039	S(.177)* (Note 4)
ALL OTHER HEATERS (Note 5)					
Natural Gas	.0162	.015	.2	.0039	.0006
Refinery Gas	.0162	.02	.2	.0039	S(.171)* (Note 1)
Residual Fuel	.042**	.55**	.82	.0040	S(7.2)** (Note 2)
LSFO	.042**	.084**	.23	.0040	S(6.3)** (Note 3)
Flexigas	.00162	.005	.05	.0039	S(.177)* (Note 4)

Notes:
(1) S = sulfur content of Refinery Gas in ppm (60 in base case)
(2) S = sulfur content of fuel oil in weight% (1.0 in base case)
(3) S = sulfur content of LSFO in weight%
(4) S = sulfur content of FXG in ppm
(5) For sources S1486, S1487, S1488, S1490 through S1500, S1502, S1503, S1504, S1505, S1515, S1761 and S1763, The owner/operator shall use NOx CEM data to calculate NOx emissions. If CEM data is not available, see Condition B.3.a.. (added 2/98, App. No. 18131, amended 2/02, AN 1362)

Condition # 11850
For S544, Tank 544:

1. Deleted per Application 22045 as S544 has been replaced by S 6070.

Condition # 12174
For S545, Tank 545:

1. Deleted per Application 22045 as S545 has been replaced by S6071.

Condition # 18618
General Throughput Conditions and other miscellaneous monitoring requirements for Title V:

1. The following throughput limits are based upon District records at the time of MFR permit issuance. Exceedance of those limits for which Regulation 2-1-234.3 was the identified basis are not a violation of the permit if the operator can, within 60 days, provide documentation demonstrating the throughput limit should be higher, established in accordance with 2-1-234.3, and the excess throughput complies with the new limit. Exceedance of those limits which have other permit conditions or application information as the basis are a violation of Regulation 2-1-307 immediately upon exceedance of the limit. (basis: Regulation 2-1-234.3, Regulation 2-1-307)

S-#	Description	Daily Limit	Annual Limit
3	Tank 3		S3+S4+ S1076 ≤ 130,971 bbl/day x 365
4	Tank 4		S3+S4 +S1076 ≤ 130,971 bbl/day x 365
13	Tank 13		36,000 bbl/day x 365
14	Tank 14		143,657 bbl/day x 365
20	Tank 20		13,131 bbl/day x 365
21	Tank 21 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+S572+S573+S598+S815+S985+S1043+S1044+S1045+ S1160+S6068 ≤ 42,000 bbl/day x 365
23	Tank 23 Asphalt Storage		S21 +S23+S24+S26+S497+S560+S561 +S572+S573+S598+S815+S985+S1043+S1044+S1045+S1160+S6068 ≤ 42,000 bbl/day x 365
24	Tank 24 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+S572+S573+S598+S815+S985+S1043+S1044+ S1045+1160+S6068 ≤ 42,000 bbl/day x 365
26	Tank 26 Asphalt Storage		S21 +S23+S24+S26+S497+S560+S561 +S572+S573+S598+S815+S985+S1043+S1044+S1045+S1160+S6068 ≤ 42,000 bbl/day x 365
257	Tank 257		10,526 bbl/day x 365
483	Tank 483		S483+S484+S530 + S532 < 217,097 bbl/day x 365
484	Tank 484		S483+S484+S530 + S532 <

S-#	Description	Daily Limit	Annual Limit
			217,097 bbl/day x 365
497	Tank 497 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1 043+S1044+ S1045+S1160+S6068 ≤ 42,000 bbl/day x 365
530	Tank 530		S483+S484+S530 + S532 < 217,097 bbl/day x 365
532	Tank 532		S483+S484+S530 + S532 < 217,097 bbl/day x 365
548	Tank 548		S548+S549+S1006+S1235+ S1236 < 5,412 bbl/day x 365
552	Tank 552 Asphalt Storage		S552+S553+S554+S555+S556+S5 57+S558+S559 +S567 + S568< 10,650 bbl/day x 365
553	Tank 553 Asphalt Storage		S552+S553+S554+S555+S556+S5 57+S558+S559 +S567 + S568< 10,650 bbl/day x 365
554	Tank 554 Asphalt Storage		S552+S553+S554+S555+S556+S5 57+S558+S559 +S567 + S568< 10,650 bbl/day x 365
555	Tank 555 Asphalt Storage		S552+S553+S554+S555+S556+S5 57+S558+S559 +S567 + S568< 10,650 bbl/day x 365
556	Tank 556 Asphalt Storage		S552+S553+S554+S555+S556+S5 57+S558+S559 +S567 + S568< 10,650 bbl/day x 365
557	Tank 557 Asphalt Storage		S552+S553+S554+S555+S556+S5 57+S558+S559 +S567 + S568< 10,650 bbl/day x 365
558	Tank 558 Asphalt Storage		S552+S553+S554+S555+S556+S5 57+S558+ S559 +S567 + S568 < 10,650 bbl/day x 365
559	Tank 559 Asphalt Storage		S552+S553+S554+S555+S556+S5 57+S558+S559 +S567 + S568< 10,650 bbl/day x 365
560	Tank 560 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1 043+S1044+

S-#	Description	Daily Limit	Annual Limit
			S1045+S1160+S6068 ≤ 42,000 bbl/day x 365
561	Tank 561 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1043+S1044+ S1045+S1160+S6068 ≤ 42,000 bbl/day x 365
567	Tank 567 Asphalt Storage		S552+S553+S554+S555+S556+S557+S558+S559 +S567 + S568< 10,650 bbl/day x 365
568	Tank 568		S552+S553+S554+S555+S556+S557+S558+S559 +S567 + S568< 10,650 bbl/day x 365
572	Tank 572 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1043+S1044+ S1045+S1160+S6068 ≤ 42,000 bbl/day x 365
573	Tank 573 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1043+S1044+ S1045+S1160+S6068 ≤ 42,000 bbl/day x 365
598	Tank 598 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1043+S1044+ S1045+S1160+S6068 ≤ 42,000 bbl/day x 365
610	Tank 610		S610+S1133 ≤ 48,000 bbl/day x 365
611	Tank 611		82,217 bbl/day x 365
612	Tank 612		S612+S613 < 210,686 bbl/day x 365
613	Tank 613		S612+S613 < 210,686 bbl/day x 365
815	Tank 815 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1043+S1044+

S-#	Description	Daily Limit	Annual Limit
			S1045+ S1160+S6068 < 42,000 bbl/day x 365
967	Tank 967		7,300,000 bbl/year
985	Tank 985 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1 043+S1044+ S1045+S1160+S6068 < 42,000 bbl/day x 365
1006	Tank 1006		S548+S549+S1006+S1235+ S1236 < 5,412 bbl/day x 365
1031	Tank 1031		S1031+S1046+S1051+S1134+ S1159+S1753+S1754+S1755+ S1756 < 508,114 bbl/day x 365
1043	Tank 1043 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1 043+S1044+ S1045+S1160+S6068 < 42,000 bbl/day x 365
1044	Tank 1044 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1 043+S1044+ S1045+S1160+S6068 < 42,000 bbl/day x 365
1045	Tank 1045 Asphalt Storage		S21 +S23+S24+S26+S497+S560+S561 +S572+S573+S598+S815+S985+S 1043+S1044+ S1045+S1160+S6068 < 42,000 bbl/day x 365
1046	Tank 1046		S1031+S1046+S1051+S1134+S11 59+S1753+S1754+S1755+ S1756 < 508,114 bbl/day x 365
1051	Tank 1051		S1031+S1046+S1051+S1134+S11 59+S1753+S1754+S1755+ S1756 < 508,114 bbl/day x 365
1076	Tank 1076		S3+S4 +S1076 < 130,971 bbl/day x 365
1128	Tank 1128	55,000 bbl/day	20,075,000 bbl/year
1129	Tank 1129		120,000 bbl/day x 365

S-#	Description	Daily Limit	Annual Limit
1130	Tank 1130		S1130+S1131 < 47,314 bbl/day x365
1131	Tank 1131		S1130+S1131 < 47,314 bbl/day x 365
1133	Tank 1133		S610+S1133 ≤ 48,000 bbl/day x 365
1134	Tank 1134		S1031+S1046+S1051+S1134+S1159+S1753+S1754+S1755+ S1756 < 508,114 bbl/day x 365
1140	Tank 1140		27,840 bbl/day x365
1146	Tank 1146		S1146+S1147 < 14,640 bbl/day x 365
1147	Tank 1147		S1146+S1147 < 14,640 bbl/day x 365
1159	Tank 1159		S1031+S1046+S1051+S1134+S1159+S1753+S1754+S1755+ S1756 < 508,114 bbl/day x 365
1160	Tank 1160 Asphalt Storage		S21+ S23+S24+S26+S497+S560+S561+ S572+S573+S598+S815+S985+S1043+S1044+ S1045+ S1160+S6068 ≤ 42,000 bbl/day x 365
1161	Tank 1161		240,000 bbl/day x 365
1235	Tank 739 Chem Storage		S548+S549+S1006+S1235+ S1236 < 5,412 bbl/day x 365
1236	Tank 740 Chem Storage		S548+S549+S1006+S1235+ S1236 < 5,412 bbl/day x 365
1417	OPCEN Distillate Saturation Unit (DSU)	26,000 bbl/day	365 x Daily Limit
1420	DH Crude Unit (CU)	178,800 bbl/day	59,568,000 bbl/yr
1423	DH Gas Oil Straightrun Hydrotreater (GOHT)	28,000 bbl/day	365 x Daily Limit
1425	DH Catalytic Reformer Unit (CRU)	32,000 bbl/day	365 x Daily Limit
1426	CP Catalytic Cracking Unit (CCU)	79,500 bbl/day	365 x Daily Limit
1428	CP Catalytic Feed Hydrotreater (CFH)	60,000 bbl/day	19,856,000 bbl/yr
1429	CP Catalytic Gasoline Hydrotreater (CGH)	27,500 bbl/day	365 x Daily Limit
1430	CP Alkylation Plant (ALKY)	14,000 bbl/day alkylate produced	365 x Daily Limit
1431	CP Sulfur Plant 1 (SRU1)	S1431+S1432 < 331 Equivalent Long Tons/Day	365 x Daily Limit
1432	CP Sulfur Plant 2 (SRU2)	S1431+S1432 < 331	365 x Daily Limit

S-#	Description	Daily Limit	Annual Limit
		Equivalent Long Tons/Day	
1445	DH Hydrogen Plant 1 (HP1)	75,000,000 scf/day H2	24,710,500,000 scf/yr H2
1449	DH Hydrocracking Unit (HCU)	46,000 bbl/day	365 x Daily Limit
1507	UTIL CO Boiler 1	5,568 MMBTU/day (LHV) 6,125 MMBTU/day (HHV)	365 x Daily Limit
1509	UTIL CO Boiler 2	5,568 MMBTU/day (LHV) 6,125 MMBTU/day (HHV)	365 x Daily Limit
1512	UTIL CO Boiler 3	5,568 MMBTU/day (LHV) 6,125 MMBTU/day (HHV)	365 x Daily Limit
1751	Tank 1330		S1751+S1752 < 45,953 bbl/day x 365
1752	Tank 1331		S1751+S1752 < 45,953 bbl/day x 365
1753	Tank 1332 Gasoline		S1031+S1046+S1051+S1134+ S1159+S1753+S1754+S1755+ S1756 < 508,114 bbl/day x 365
1754	Tank 1333 Gasoline		S1031+S1046+S1051+S1134+ S1159+S1753+S1754+S1755+ S1756 < 508,114 bbl/day x 365
1755	Tank 1334 Gasoline		S1031+S1046+S1051+S1134+ S1159+S1753+S1754+S1755+ S1756 < 508,114 bbl/day x 365
1756	Tank 1335 Gasoline		S1031+S1046+S1051+S1134+ S1159+S1753+S1754+S1755+ S1756 < 508,114 bbl/day x 365
1757	Tank 1336	S1757+S1758+S4334 ≤125,829 bbl/day	365 x Daily Limit
1758	Tank 1337	S1757+S1758+S4334 ≤125,829 bbl/day	365 x Daily Limit
1759	OPCEN Flexicoker (FXU)	48,300 bbl/day	16,245,500 bbl/yr
1764	OPCEN Dimersol Plant (DIMER)	4,000 bbl/day dimate produced	365 x Daily Limit
1765	OPCEN Sulfur Plant 3 (SRU3)	150 equivalent long ton/day	365 x Daily Limit
1774	OPCEN Hydrogen Plant 2 (HP2)	43,500,000 scf/day H2	14,600,000,000 scf/yr H2
1900	MAINT_Machine Shop Parts Cleaner		S1900 + S1903 ≤ 192 gal/yr solvent
1903	MAINT Paint Shop Solvent Tub		S1900 + S1903 ≤ 192 gal/yr solvent
3000	Portable Vacuum Distillation Unit (CCR Technologies Inc.)	168 MMBTU/day	365 x Daily Limit
4001	DC Delayed Coking Unit (DCU)	65,000 bbl/day	365 x Daily Limit

S-#	Description	Daily Limit	Annual Limit
4020	DC Distillate Hydrotreater (DHT)	60,000 bbl/day	365 x Daily Limit
4080	DC Isomerization Unit (ISOM)	15,100 bbl/day	365 x Daily Limit
4140	DC Heavy Cracked Gasoline Hydrotreater (HGHT)	23,200 bbl/day	365 x Daily Limit
4160	DC Hydrogen Plant –3 (HP3)	90,000,000 scf/day	365 x Daily Limit
4180	OPCEN Sulfur Plant 4 (SRU4)	140 long tons/day	365 x Daily Limit
4190	UTIL Boiler 6 Gas Turbine 1	13,152 MMBTU/day	365 x Daily Limit
4191	UTIL Boiler 6 Supplemental Steam Generator 1	6,192 MMBTU/day	365 x Daily Limit
4192	UTIL Boiler 6 Gas Turbine 2	13,152 MMBTU/day	365 x Daily Limit
4193	UTIL Boiler 6 Supplemental Steam Generator 2	6,192 MMBTU/day	365 x Daily Limit
4334	Tank13276 Alkylate	S1757+S1758+S4334 $\leq$125,829 bbl/day	365 x Daily Limit
6069	Tank 17596	300,000 bbl/day	43,800,000 bbl/yr
6070	Tank 17597	300,000 bbl/day	43,800,000 bbl/yr
6071	Tank 17598	300,000 bbl/day	43,800,000 bbl/yr
6072	Tank 17595	110,000 bbl/day (constant level operation)	550,000 bbl/yr (constant level operation)

2. Effective April 1, 2004, the facility shall maintain daily throughput records for all sources listed in the Table in Part 1 of this condition that are not tanks summarized on a consecutive 12-month basis in a District approved log, or shall be able to generate these records within 5 working days. The facility shall maintain annual throughput records for all storage tanks. These records shall be kept on site and made available for District inspection for a period of 60 months from the date that the record was made. (basis: Regulation 2-1-234.3)

3. Effective April 1, 2004, for S1486, S1487, S1488, S1491, S1492, S1493, S1495, S1496, S1497, S1498, S1500, S1504, S1508, S1510, S1511, S1763, S4002, and S4003, the owner/operator shall conduct a visible emissions inspection at each source after every 1 million gallon of liquid fuel combusted, to be counted cumulatively over a 5 year period. If a visible emissions inspection documents opacity, a method 9 evaluation shall be completed within 3 working days, or during the next scheduled operating period if the unit ceases firing on diesel fuel within the 3 working day time frame. (basis: Regulation 2-6-409.2).

4. Effective April 1, 2004, for S1486, S1487, S1488, S1491, S1492, S1493, S1495, S1496, S1497, S1498, S1500, S1504, S1507, S1508, S1509, S1510, S1511, S1512, S1763, S4002,

and S4003, the owner/operator shall sample and analyze the liquid fuel to determine its sulfur content after every 1 million gallon of liquid fuel is combusted, to be counted cumulatively over a 5 year period, or at least once every 5 years, whatever comes first. Such quantity ot liquid fuel combusted and any resulting sampling and analysis shall be recorded monthly in a District approved log. The log and all supporting documentation (such as analytical results) shall also be kept for a period of 5 years from the date of entry and made available for inspection upon request. (basis: Regulation 2-6-409.2).

5. Effective April 1, 2004, S1650, S1767, S1768, and S1769 shall be checked for visible emissions quarterly. The visible emissions check shall take place while the equipment is operating and during daylight hours. If any visible emissions are detected, the operator shall take corrective action within one day, and check for visible emissions after corrective action is taken. If no visible emissions are detected, the operator shall continue to check for visible emissions at the same frequency. [basis: Regulation 2-6-409.2]

6. Effective April 1, 2004, during exterior tube cleaning of heaters or boilers (S1480, S1481, S1483, S1486, S1487, S1488, S1491, S1492, S1493, S1495, S1496, S1497, S1498, S1500, S1504, S1506, S1508, S1510, S1511, S1760, S1763, S1490, S1499, S1494, S1502, S1503, S1504, S1505, S1515, S1761, S1762, S1800, S4002, S4003, S4021, S4031, S4141, S4161, S4191, and S4193), the owner/operator shall check for visible emissions The visible emissions check shall take place while the tube is being cleaned and during daylight hours. If anyvisible emissions are detected, the operator shall take corrective action within one day, and check for visible emissions after the corrective action is taken. If no visible emissions are detected, the operator shall continue to check for visible emissions on an hourly basis until the tube cleaning activity is completed. [basis: Regulation 2-6-409.2]

7. Effective April 1, 2004, the operator shall keep records of all visible emissions checks per Parts 3, 5, and 6 of this condition, the person performing the check, and all corrective action taken. The records shall be retained for five years and shall be made available to District personnel upon request. [basis: Regulation 2-6-409.2]

8. Effective April 1, 2004, for the sources subject to Regulation 6-1-330 (S1431, S1432, S1765, and S4180) the owner/operator shall conduct a District approved source test annually to determine the concentration of SO3 or H2SO4, or both, expressed as 100% H2SO4 . The results of the source test shall be made available to the District within 60 days of the source test and kept for a minimum of 5 years from the date of the report. The frequency of source testing required under this condition shall be reduced to once every five years if three consecutive annual source tests document that emissions are less than 50 percent of the standard. The frequency of source testing shall revert back to once per year, if a source test documents that emissions are 50 percent of the standard or more. The source testing frequency can again be reduced to once every five years if another three consecutive annual source tests document that emissions are less than 50 percent of the standard. [basis: Regulation

2-6-409.2]

9. Effective April 1, 2004, for the CO Boilers (S1507, S1509, and S1512), the owner/operator shall conduct a District approved source test annually on each source to determine its grain loading rate. The results of the source tests shall be made available to the District within 60 days of the source test and kept for a minimum of 5 years from the date of the report. The frequency of source testing required under this condition shall be reduced to once every five years if three consecutive annual source tests document that emissions are less than 50 percent of the standard. The frequency of source testing shall revert back to once per year, if a source test documents that emissions are 50 percent of the standard or more. The source testing frequency can again be reduced to once every five years if another three consecutive annual source tests document that emissions are less than 50 percent of the standard. [basis: Regulation 2-6-409.2]

(Condition Deleted)

11. The owner/operator shall notify the District in writing by fax or email no less than three calendar days in advance of any scheduled startup or shutdown of any process unit and as soon as feasible for any unscheduled startup or shutdown of a process unit, but no later than 48 hours after the unscheduled startup/shutdown or within the next normal business day. The notification shall be sent in writing by fax or email to the Director of Enforcement and Compliance. The requirement is not federally enforceable.
[basis: Regulation 2-1-403]

12. Effective January 1, 2005, the owner/operator shall not flare more than the following limits of vent gas, as defined in Regulation 12-11-210, at following sources:

a.	S1471 LOP Auxiliary Flare + S1472 LOP Main Flare	630,000 lbs/hr
b.	S1771 OPCEN Flexigas Flare	750,000 lbs/hr
c.	S1772 OPCEN HC Flare	510,000 lbs/hr
d.	S4201 Clean Fuels Flare	2,000,000 lbs/hr

(basis: Regulation 8-1-110.3; 2-1-403)

13. Effective January 1, 2005, in order to demonstrate compliance with Part 12 of this condition, the owner/operator shall record on an hourly basis the pounds of vent gas flared at S1471, S1472, S1771, S1772, and S4201 Flares. The owner/operator shall maintain these records for a period of five years from the date of entry and make sure records are available for the APCO upon request. (basis: Regulation 8-1-110.3; 2-6-409.2; 2-6-501)

14. Conditions for monitoring smoking flares (except for those flares that exclusively burn flexicoker gas with or without supplemental natural gas). Effective January 1, 2005, for the purposes of these conditions, a flaring event is defined as a flow rate of vent gas flared in any consecutive 15 minutes period that continuously exceeds 330 standard cubic feet per minute (scfm) for S1471, S1472, S1772, and S4201. If during a flaring event, the vent gas flow rate drops below 330 scfm and then increases

above 330 scfm within 30 minutes, that shall still be considered a single flaring event, rather than two separate events. For each flaring event during daylight hours (between sunrise and sunset), the owner/operator shall inspect the flare within 15 minutes of determining the flaring event, and within 30 minutes of the last inspection thereafter, using video monitoring or visible inspection following the procedure described in Part 15 of this condition. (basis: Regulation 2-6-409.2)

15. Effective January 1, 2005, the owner/operator shall use the following procedure for the initial inspection and each 30-minute inspection of a flaring event for S1471, S1472, S1772, and S4201 .

    a. If the owner/operator can determine that there are no visible emissions using video monitoring, then no further monitoring is necessary for that particular inspection.

    b. If the owner/operator cannot determine that there are no visible emissions using video monitoring, the owner/operator shall conduct a visual inspection outdoors using either:
    i. EPA Reference Method 9; or
    ii. Survey the flare by selecting a position that enables a clear view of the flare at least 15 feet, but not more than 0.25 miles, from the emission source, where the sun is not directly in the observer's eyes.

    c. If a visible emission is observed, the owner/operator shall continue to monitor the flare for at least 3 minutes, or until there are no visible emissions, whichever is shorter.

    d. The owner/operator shall repeat the inspection procedure for the duration of the flaring event, or until a violation is documented in accordance with Part 17. After a violation is documented, no further inspections are required until the beginning of a new calendar day.
    (basis: Regulation 6-1-301, 2-1-403)

16. Effective January 1, 2005, the owner/operator shall comply with one of the following requirements if visual inspection is used:
    a. If EPA Method 9 is used, the owner/operator shall comply with Regulation 6-1-301 when operating the flare.
    b. If the procedure of 15.b.ii is used, the owner/operator shall not operate a flare that has visible emissions for three consecutive minutes.
    c. (basis: Regulation 2-6-403)

17. Effective January 1, 2005, the owner/operator shall keep records of all flaring events, as defined in Part 14. The owner/operator shall include in the records the name of the person performing the visible emissions check, whether video monitoring or visual inspection (EPA Method 9 or visual inspection procedure of Part

15 of this condition) was used, the results of each inspection, and whether any violation of this condition (using visual inspection procedure in Part 15 of this condition) or Regulation 6-1-301 occurred (using EPA Method 9). (basis: Regulation 2-6-501; 2-6-409.2)

18. Effective January 1, 2005, for those flares that exclusively burn flexicoker gas with or without supplemental natural gas the owner/operator shall conduct a visual emission inspection weekly following the protocol in Part 16 a, b or c and shall comply with Parts 17 and 18 of this condition. If no visible emissions are observed after 52 weekly inspections, then this condition no longer applies to the flare. (basis: Regulation 2-6-501; 2-6-409.2)

19. Effective January 1, 2005, the owner/operator shall operate S4201, A101, A102, and A103 Flares in a manner that complies with H2S fuel gas limit in 60.104(a)(1) and the monitoring requirements in 60.105 at all times, except during periods that the owner/operator burns fuel gas that was released to the flare as a result of relief valve leakage or other emergency malfunctions, or burns process upset gases as defined in 60.101(e).. (basis: 60.104(a)(1); Regulation 2-1-403)

8.0 RECOMMENDATION

Staff recommends the following:

1. Issue an authority to construct to Shell for the following new sources:

S6069	**Crude Oil Storage Tank, External Floating Roof, 300,000 Barrel Capacity (TK-17596) – Replacement for S541**
S6070	**Crude Oil Storage Tank, External Floating Roof, 300,000 Barrel Capacity (TK-17597) – Replacement for S544**
S6071	**Crude Oil Storage Tank, External Floating Roof, 300,000 Barrel Capacity (TK-17598) – Replacement for S545**
S6072	**Crude Oil Mix Tank, External Floating Roof, 55,000 Barrel Capacity (TK-17595) – Replacement for S1127**

2. Issue an authority to construct to Shell for the following modified sources:

S967	**Jet Fuel Storage Tank, Internal Floating Roof, 69,000 Barrel Capacity (TK-967) [Tank retrofit to replace fixed roof with internal floating roof]**
S1128	**Crude Oil Storage Tank, Internal Floating Roof, 55,000 Barrel Capacity (TK-1128) [Tank Refurbishment for crude oil service]**

3. Issue an authority to construct to Shell for the following altered sources:

S1486	**DH F-40 Crude Unit Furnace [Installation of Air Preheater]**
S1495	**DH F-49 CRU Preheat Furnace [Installation of Heat Exchanger]**
S4021	**DHT Recycle Process Heater [Installation of Heat Exchanger]**

4. Approve various changes to permit conditions 7618 and 18618.

5. Archive following sources and corresponding permit conditions 11850 and 12174 in the District databank:

S541	**Crude Oil Storage Tank, External Floating Roof (TK-541)**
S544	**Crude Oil Storage Tank, External Floating Roof (TK-544)**
S545	**Crude Oil Storage Tank, External Floating Roof (TK-545)**

By: ____

Sanjeev Kamboj Date

Senior Air Quality Engineer

ENGINEERING EVALUATION
SHELL MARTINEZ REFINERY; PLANT 11
APPLICATION #22287

3.0 BACKGROUND

The Shell Martinez Refinery (Shell) has submitted this permit application to create a new permit condition to limit concentrations of SO_2 and NOx emissions from S1426, Catalytic Cracking Unit (CCU), as required by Shell's Consent Decree (CD) for the following sources:

S1507 UTIL CO Boiler 1
S1509 UTIL CO Boiler 2
S1512 UTIL CO Boiler 3

The case number for the CD is H-01-0978.

On March 21, 2001, Shell entered into a voluntary settlement with the Environmental Protection Agency (EPA) to resolve environmental issues. A CD was lodged with the EPA that includes requirements for conducting an optimization study to minimize NOx emissions from Shell's CCU, conduct a demonstration based upon the results of the optimization, and to propose short-term and long-term concentration based limits for NOx emissions. In addition, the CD includes requirements for performing a study to establish the optimized additive rate of SO_2 reducing catalyst additive, conduct a demonstration based upon the results of the optimization, and to propose short-term and long-term concentration based limits for SO_2 emissions.

On February 5, 2007, as required by the CD, Shell submitted two technical reports to the EPA as a basis for establishing SO_2 and NOx limits for S1426, CCU. The two reports included the "Amended SO2 Additive Demonstration Phase Results (SO_2 Demonstration Report), and the "NOx Optimization Study Results and Amended Proposal of Short and Long-Term NOx Limits" (NOx Optimization Report). Based on CEM data collected at the three CO boilers, the reports proposed short-term and long-term concentration-based limits for SO_2 and NOx emissions from the CCU's CO boilers for periods during which the CO boilers are being used to combust CCU regenerator off-gas. On June 1, 2010 following the EPA's review of these reports, the EPA established final limits for SO2 and NOx emissions from the CCU CO boilers. This letter has been included in Attachment A of this document.

As part of the SO_2 demonstration report submitted to the EPA on February 5, 2007, Shell also included a plan to minimize SO_2 emissions from the CCU during periods of Catalytic Feed Hydrotreater (CFH) and Distillates Hydrotreating Unit (DHT) outages. During hydrotreater outages in which the Hydrotreater (HT) outage plan is applicable, CCU SO_2 emissions will be excluded from compliance demonstration with the short-term SO_2 limits. On April 28, 2010, the EPA approved the HT outage plan. The EPA approval letter as well as Hydrotreater Outage Plan has been included in Attachment B of the evaluation.

The HT outage plan requires Shell to submit a report upon conclusion of each HT outage during which the HT outage plan was applicable. Until the CD is terminated, Shell is required to submit a HT outage plan report to both EPA and the BAAQMD. After the CD is terminated, Shell is required to continue to submit a HT outage plan to the BAAQMD.

A new permit condition will be created that will include the following SO_2 and NOx emissions limits from three CO boilers:

CO Boiler Operation	Compliance Period	SO_2 Limit, ppmvd @ 0% O2
2 or 3 CO Boilers	365-day rolling average	109.1
3 CO Boilers	7-day rolling average	156.0
2 CO Boilers	7-day rolling average	204.2

CO Boiler	Compliance Period	NOx Limit, ppmvd @ 0% O2
S1507	365-day rolling average	130.6
S1507	24-hour rolling average	168.4
S1509	365-day rolling average	127.4
S1509	24-hour rolling average	156.9
S1512	365-day rolling average	113.1
S1512	24-hour rolling average	142.7

There will be no physical modifications or alterations to any of the sources affected by this application. Currently, sources S1507, S1509, and S1512 are subject to permit condition #12271, part 85 (combined NOx daily emission limit) and part 90 (combined SO_2 daily emission limit). They will continue to be subject to and comply with NOx and SO_2 limits of condition #12271. Therefore, the proposed limits will not result in an increase in any regulated air pollutant from the CO boilers.

This is a minor revision of the Major Facility Review permit for the following reasons:

- The change is not considered a major modification under 40 CFR Parts 51 (NSR) or 52 (PSD).
- The change is not considered a modification under 40 CFR Parts 60 (NSPS), 61 (NESHAPS), or Section 112 of the Clean Air Act (HAP).
- There is no significant change or relaxation of monitoring.
- No term is established to allow the facility to avoid an applicable requirement.
- No case-by case determination has been made.
- No facility-specific determination for ambient impacts, visibility analysis, or increment analysis on portable sources has been made.

4.0 EMISSIONS SUMMARY

As mentioned in the Background section, the proposed new NOx and SO_2 limits will not increase emissions of any regulated air pollutant.

2.1 PLANT CUMULATIVE INCREASE

The cumulative emission increase is zero for all the criteria pollutants because annual emissions for this plant are not increasing due to this application.

2.3 BEST AVAILABLE CONTROL TECHNOLOGY

In accordance with BAAQMD Regulation 2, Rule 2, Section 301, a modified source with the potential to emit 10 pounds or more per highest day of POC, NPOC, NOx, CO, SO_2 or PM_{10} that has an increase in emissions must use BACT. Regulation 1-217 defines modification as a change that results in an increase in emissions. For this application, BACT is not triggered because the proposed new limits will not result in an increase in any emissions as mentioned in Emissions Summary section above.

2.4 TOXICS

New source review of Toxic Air Contaminants (BAAQMD Rule 2-5) requires the Best Available Control Technology for Toxics (TBACT) for sources that result in cancer risk greater than 1.0 in one million and/or chronic hazard index greater than 0.20. The proposed changes at sources S1507, S1509, and S1512 would not result in an increase in toxic emissions, thus the New Source Review of Toxic Air Contaminants does not apply.

2.4 OFFSETS

Since there is no increase in emissions at this plant as mentioned in Section 2.0 above, offsets are not required for this application.

6.0 STATEMENT OF COMPLIANCE

BAAQMD REGULATIONS

The CO boilers (S1507, S1509, and S1512) will continue to comply with Regulation 6, Rule 1 (Particulate Matter-General Requirements) including 6-1-301, 304, 310, and 311 which require that particulate emissions not exceed a Ringelmann 1.0 except during tube cleaning when emissions limit is Ringelmann 2.0, that particulate emissions not exceed 0.15 gr/dscf @ 6% O_2, and that rate of emissions do not exceed allowable limits based on process weight rate.

The CO boilers are subject to Regulation 9, Rule 10 (Nitrogen Oxides and Carbon Monoxide from Boilers, Steam Generators, and Process Heaters in Petroleum Refineries). After the inclusion of new NOx and SO_2 emission limits to comply with CD, the CO boilers will continue to comply with refinery wide NOx emission limit of section 303.1 and interim NOx emission limit of section 304.

The CO boilers will continue to comply with liquid fuel sulfur content limit of 0.5% by weight of Regulation 9, Rule 1, Section 304.

NSPS

Subpart J

The CO boilers will continue to comply with NSPS 40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries, including section 60.104(a)(1).

NESHAPS

The CO boilers will continue to be subject to and comply with NESHAP Subpart EEE including sections 63.1217(a)(1)(i), 63.1217(a)(2)(i), 63.1217(a)(3)(i), 63.1217(a)(4)(i), 63.1217(a)(5)(i), 63.1217(a)(6)(i), and 63.1217(a)(7).

MAJOR FACILITY REVIEW

Shell has a Major Facility Review permit as required by BAAQMD Regulation 2, Rule 2, since it is considered a major source of emissions. The changes proposed in this application will require changes to the existing Title V permit and Statement of Basis. These changes will be handled in Title V Minor Revision Application Number 22288.

CEQA

The project is considered to be ministerial under the District's CEQA Regulation 2-1-311 and therefore is not subject to CEQA review. The engineering review for this project requires only the application of standard permit conditions and standard emissions factors as outlined in the District Permit Handbook Chapter 2.1. Also, this application is simply incorporating CD requirements into the Title V permit.

PUBLIC NOTICE

The proposed project is not located within 1,000 feet of any school. Therefore, it is not subject to public notification requirements of Regulation 2-1-412.

PSD does not apply.

7.0 PERMIT CONDITIONS

Condition # 25247

Plant #11, Application #22287

For S1507, UTIL CO Boiler 1 (COB 1)
S1509, UTIL CO Boiler 2 (COB 2)
S1512, UTIL CO Boiler 3 (COB 3)

1. SO_2 limits: CO Boiler 1 (S1507), CO Boiler 2 (S1509), and CO Boiler 3 (S1512) associated with operation of the CCU (S1426) shall comply with the following short-term (7-day) and long-term (365-day) rolling average SO_2 limits when abating CCU flue gas:

CO Boiler Operation	Compliance Period	SO2 Limit, ppmvd @ 0% O2
2 or 3 CO Boilers	365-day rolling average	109.1
3 CO Boilers	7-day rolling average	156.0
2 CO Boilers	7-day rolling average	204.2

A flow-weighted average SO_2 concentration, based on the combination of CO boilers abating CCU flue gas, shall be used to demonstrate compliance with the above SO_2 limits, subject to the following methodology:

a. Long-Term Limit (365-day rolling average):
   i. The long-term SO_2 limit shall apply to the CO boilers abating CCU flue gas at all times that the CCU is operating, including periods of startup, shutdown, and malfunction.
   ii. For each operating day in which the CCU is not operating, no SO_2 value shall be used in the average, and those days shall be skipped in determining the 365-day average.

b. Short-Term Limits (7-day rolling average):
   i. The short-term SO2 limits shall apply to the CO boilers abating CCU flue gas at all times that the CCU is operating, excluding periods of CCU startup, shutdown, and malfunction, and except as provided in 1.b.ii. below.
   ii. During hydrotreater outages of the Catalytic Feed Hydrotreater (CFH) S1428 and/or Distillate Hydrotreater (DHT) S4020, the Refinery may comply with the Hydrotreater Outage Plan (See Application 22287, 2012), or with the short-term SO2 limits.
   iii. For each operating day in which the CCU is not operating, no SO2 value shall be used in the average, and those days shall be skipped in determining the 7-day average.

c. The daily flow-weighted average SO2 concentration used in calculating the 7-day and 365-day rolling averages shall be monitored and recorded for each operating day, and will be determined from the clock hour averages of CEM data and calculated stack flow rates for each CO boiler abating CCU flue gas.

[Basis: Equilon Consent Decree, paragraphs 13, 14, 42, and 43]

2. NOx limits: CO Boiler 1 (S1507), CO Boiler 2 (S1509), and CO Boiler 3 (S1512) associated with the operation of CCU (S1426) shall comply with the following short-term (24-hour) and long-term (365-day) rolling average NOx limits when abating CCU flue gas:

CO Boiler	Compliance Period	NOx Limit, ppmvd @ 0% O2
COB 1	365-day rolling average	130.6
COB 1	24-hour rolling average	168.4
COB 2	365-day rolling average	127.4
COB 2	24-hour rolling average	156.9
COB 3	365-day rolling average	113.1
COB 3	24-hour rolling average	142.7

Compliance with the above NOx concentration limits for each CO boiler shall be subject to the following methodology:

a. Long-Term Limit (365-day rolling average):
   i. The long-term NOx limit for each COB shall apply to the CO boilers abating CCU flue gas at all times that the CCU is operating, including periods of startup, shutdown, and malfunction.

ii. For each operating day in which the CCU is not operating, no NOx value shall be used in the average, and those days shall be skipped in determining the 365-day average.
iii. The daily average NOx concentration used in calculating the 365-day rolling average shall be monitored and recorded for each operating day, and will be determined from the clock hour averages of CEM data for each CO boiler abating CCU flue gas.

b. Short-Term Limit (24-hour rolling average):
i. The short-term NOx limit for each COB shall apply to the CO boilers abating CCU flue gas at all times that the CCU is operating, excluding periods of startup, shutdown, and malfunction.
ii. For each clock hour in which the CCU is not operating, no NOx value shall be used in the average, and those hours shall be skipped in determining the 24-hour average.
iii. The hourly average NOx concentrations used in calculating the 24-hour rolling average shall be monitored and recorded for each operating day, and will be determined from the clock hour averages of CEM data for each CO boiler abating CCU flue gas.

[Basis: Equilon Consent Decree, paragraphs 13, 14, 42, and 43]

8.0 RECOMMENDATION

Waive Authority to Construct and issue a modified Permit to Operate to Shell for the following:

- New permit condition (pc #25247) to limit concentrations of SO2 and NOx emissions from S1426, Catalytic Cracking Unit (CCU), as required by Shell's Consent Decree (CD) for the following sources:

S1507	**UTIL CO Boiler 1**
S1509	**UTIL CO Boiler 2**
S1512	**UTIL CO Boiler 3**

By: ____

Sanjeev Kamboj Date
Senior Air Quality Engineer

ATTACHMENT A

EPA letter that established final SO_2 and NOx limits

ATTACHMENT B

Hydrotreater Outage Plan and EPA Approval Letter

Appendix A
Hydrotreater Outage Plan

For purposes of this plan, a hydrotreater outage shall mean the period of time during which the operation of the FCCU is affected as a result of catalyst change out operations or shutdowns required by ASME pressure vessel requirements or state boiler codes, or as a result of a malfunction that prevents the hydrotreater from effectively producing the quantity and quality of feed necessary to achieve the established FCCU emission performance.

SMR has two (2) hydrotreating units which provide FCCU feed - 1) Cat Feed Hydrotreater (CFH), and 2) Distillates Hydrotreating Unit (DHT). Periodically these hydrotreating units will undergo an outage to replace the spent catalyst and to perform other maintenance, repair and replacement. In most instances, the outage will occur in a pre-planned manner and there is adequate time in advance of the outage to adjust feedstock inventories and other operating conditions to minimize emissions. However, in some instances there may be an unplanned equipment failure, malfunction, or other unplanned situation (e.g. power failure, fire, loss of hydrogen or gas oil feed source, equipment failure, etc.) that would result in a hydrotreater outage with little or no advance planning time. Some of the emission mitigations steps used for a planned outage are unavailable for an unplanned outage.

Operating variables that affect emissions from the FCCU during a hydrotreater outage include charge rate, sulfur and nitrogen content of the feed, type and quantity of feedstock components, tankage constraints, use of and rate of SOx reducing additives, outage duration, lead time prior to outage, and the operating or shutdown status of other process units. During planned or unplanned hydrotreater outages, the refinery can choose to

1) Continue to comply with the short-term 7-day rolling average SO_2 limits, or
2) Comply with this hydrotreater outage plan.

The following steps must be followed to maintain compliance with the hydrotreater outage plan, during which time the short-term 7-day rolling average SO_2 limits will not apply. However, all data generated while the FCCU is operating during the hydrotreater outage period will be used to determine compliance with the long-term 365-day rolling average limit. All reasonable attempts will be made to minimize the duration of the hydrotreater outage.

<u>Emission Mitigation Steps during a FCCU Feed Hydrotreater Outage</u>

1. As far as practical and to the extent practical, in advance of an planned outage of either of the hydrotreating units, CFH or DHT, the inventory in the sweet gas oil storage tank(s) will be positioned such that the sweet gas oil inventory is maximized. To the extent practicable, planned hydrotreater outages will be conducted concurrently with planned FCCU outages.

2. To the extent practical in advance of a planned hydrotreating unit outage, the sour gas oil storage tank(s) inventory will be minimized. Minimizing sour gas oil inventory prior to the outage will allow the Refinery’s

sour gas oil producing units to continue to operate as long as possible before impacting FCCU operations. To the extent practical, sour gas oil produced during the hydrotreater outage will be stored in the sour gas oil tank(s) for hydrotreating after the hydrotreating unit is back in operation.

3. During the hydrotreating unit outage, the FCCU will receive feed from the Refinery's sweet gas oil storage tanks. As the FCCU continues to operate over the course of the hydrotreater outage, the level of the sweet gas oil inventory will drop. If the hydrotreater outage duration is such that the volume of sweet gas oil feed required for the FCCU during the shutdown period is expected to exceed the available sweet gas oil inventory, it may be necessary to supplement the FCCU hydrotreated feed with higher than normal amounts of unhydrotreated gas oil. Minimum sulfur content of FCCU feed during an outage will not be targeted to be less than typical levels to prevent rapid depletion of sweet gas oil inventory. The quantity of sour gas oil combined into the FCCU sweet gas oil feed will be limited such that:

    a. The available sweet gas oil inventory is utilized to the fullest extent practical during the projected duration of the hydrotreater outage,

    b. The FCCU complies with the long-term 365-day rolling average SO_2 concentration limit, and

    c. The SO_2 emissions from the CO Boilers will not exceed a 7-day rolling average mass limit of 9.8 lbs/thousand lbs coke burned.

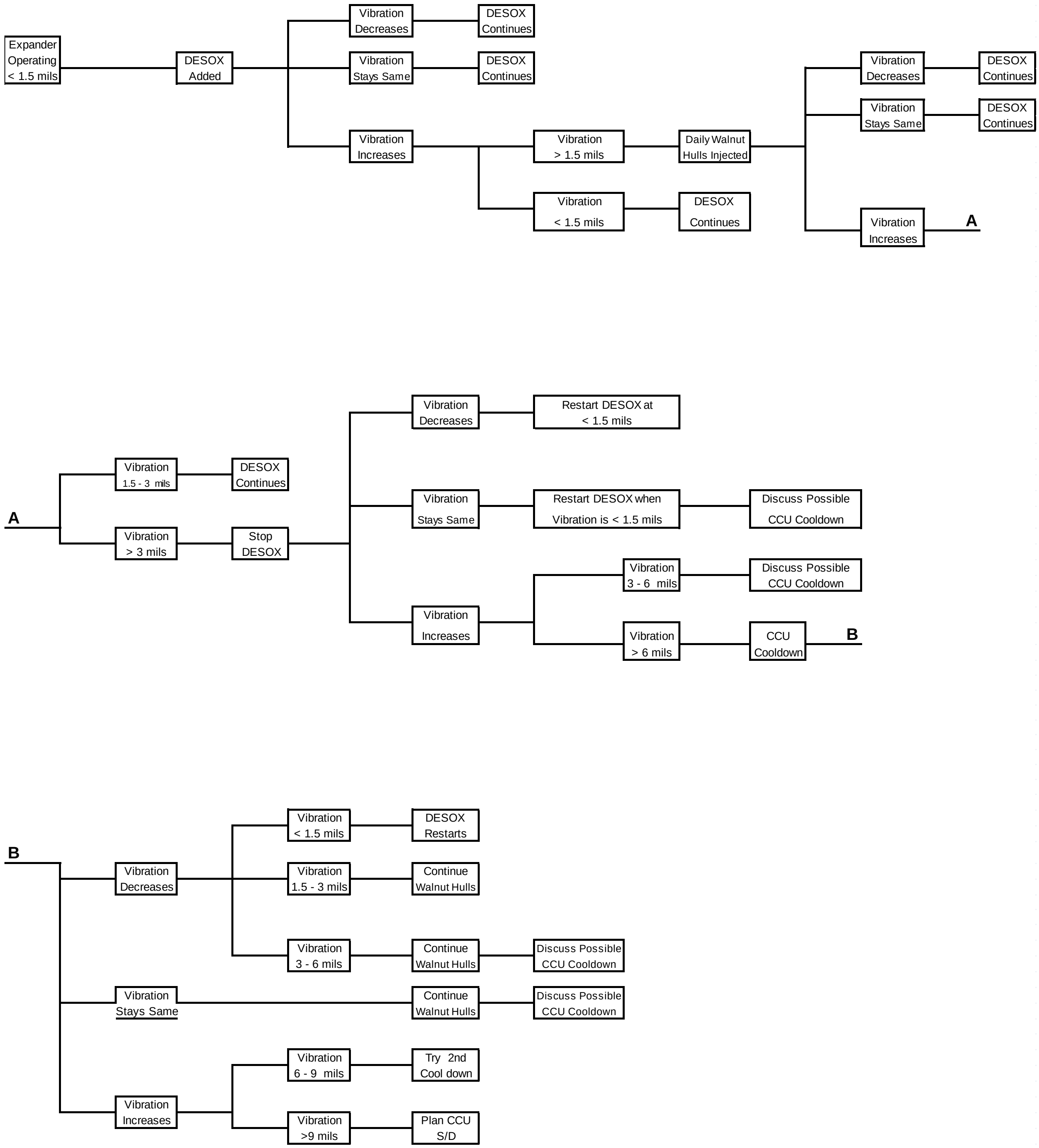
4. To the extent that the Refinery is not already adding SOx reducing catalyst additives up to a maximum level of 10 wt% of the total daily catalyst addition rate, additive additions will be increased up to this level, or as required to meet the FCCU stack short-term SO2 emission limits established for normal operations, or as limited by the FCCU Expander Vibration Decision Tree (Appendix B), whichever is less.

5. The Refinery will begin adding SOx reducing catalyst additives at the maximum additive rate 2 weeks (14 days) prior to a known or planned HT outage, when possible. In the event of an unplanned outage, the Refinery will reach the maximum additive rate within 24 hours of the start of the HT outage. In any event, if the Refinery is able to meet the short-term limit for SO2, the Refinery does not need to comply with any of the pollutant specific terms of the HT outage plan.

6. Upon conclusion of each HT outage during which the HT outage plan was applicable rather than the short-term limit, the Refinery shall submit within 60 days a report identifying those time periods to the BAAQMD. This report will describe, in detail, the steps taken to comply with this HT outage plan during these periods. The report will contain all data (compiled on a daily average basis) including the concentration of SO2 necessary to document that each requirement of the plan was fully implemented.

Appendix B

FCCU Expander Vibration Decision Tree for SO2 Reducing Catalyst Additives



ENGINEERING EVALUATION
Shell Martinez Refinery
Plant: 11
1763Application: 25810

BACKGROUND

Shell Martinez Refinery (Shell) has applied to obtain an Authority to Construct (AC) and/or a Permit to Operate (PO) for the following equipment:

S-6073 On-Site Portable Emergency Standby Diesel Fire Pump Engine
2005 Caterpillar, Model: C18 ACERT
700 bhp, 5.2 MMBtu/hr

The Emergency Diesel Engine Generator Set (S-6073) will be located at 3485 Pacheco Blvd., Martinez, CA 94553 and is equipped with the best available control technology (BACT) for minimizing the release of air borne criteria pollutants and harmful air toxins due to fuel combustion. The criteria pollutants are nitrogen oxides (NOx), carbon monoxide (CO), precursor organic compounds (POC) from unburned diesel fuel, sulfur dioxide (SO_2) and particulate matter (PM_{10}). All of these pollutants are briefly discussed on the District's web site at www.baaqmd.gov.

S-6073 meets the Environmental Protection Agency and California Air Resources Board (EPA/CARB) Tier 3 Off-road standard. The engine will burn commercially available California low sulfur diesel fuel. The sulfur content of the diesel fuel will not exceed 0.0015% by weight. The operation of the engine should not pose any health threat to the surrounding community or the public at large.

The engine is subject to attached condition no. 22850.

(xvi) EMISSIONS

S-6073 has been certified by CARB to be cleaner burning engine. Except for SO_2, the emission factors for this engine are from the CARB Certification (CARB Executive Order #U-R-001-0262). The SO_2 emissions were calculated based on the maximum allowable sulfur content (0.0015 wt% S) of the diesel fuel with assumption that all of the sulfur present will be converted to SO_2 during the combustion process. The POC emission factor is assumed to be 5% of the total CARB's certified NOx and POC (NMHC+NOx) factor based on District Policy.

Basis:
- 700 hp output rating
- 50 hr/yr operation for testing and maintenance
- 37.9 gallons/hr max fuel use rate
- NMHC + NOx, CO, and PM_{10} emission factors provided by CARB Certification with Executive Order #U-R-001-0262

- POC is assumed to be 5% of NMHC + NOx.
- NOx is assumed to be 95% of NMHC + NOx.
- SO_2 emissions are quantified based on the full conversion of 0.0015 wt% (~ 15 ppm) sulfur in the ULS diesel fuel. The SO_2 emission factor was derived from EPA AP-42, Table 3.4-1.
- CO_2e emissions are quantified based on the following emission factors, GWPs, and high heat value from 40 CFR Part 98:
    a. CO_2 emission factor: 73.96 kg/MMBtu
    b. CH_4 emission factor: 0.003 kg/MMBtu
    c. N_2O emission factor: 0.0006 kg/MMBtu
    d. CO_2 GWP: 1
    e. CH_4 GWP: 21
    f. N_2O GWP: 310
    g. High heat value of 0.138 MMBtu/gallon

  Simplified, the CO_2e emission factor is 163.6 lb/MMBtu, which is derived as follows: ((73.96 kg/MMBtu * 1) + (0.003 kg/MMBtu * 21) + (0.0006 kg/MMBtu * 310)) * 2.2046 lb/kg = 163.6 lb/MMBtu

Annual Average Emissions:
Annual emissions are calculated based on the number of hours per year of operation for testing and maintenance. See Table 1.

Daily Emissions:
Daily emissions are calculated to establish whether a source triggers the requirement for BACT (10 lb/highest day total source emissions for any class of pollutants). 24-hr/day of operation will be assumed since no daily limits are imposed on intermittent and unexpected operations. See Table 1.

Table 1. Annual and Daily Emissions from CARB/EPA Certified Data

ource	Operating Hours (hr/yr)	Max Rated Output (bhp)	Fuel Use Rate (gal/hr)	Calculated MMBtu/hr	Pollutant	Emission Factor		Max Daily Emissions (lb/day)	Annual Emissions (lb/yr)	Annual Emission (TPY)
-6073	50	700	37.9	5.2	NOx	2.8	g/bhp-hr	102.3	213.1	0.10
					POC	0.15	g/bhp-hr	5.4	11.2	0.00
					CO	2.1	g/bhp-hr	77.3	161.0	0.08
					PM_{10}	0.12	g/bhp-hr	4.4	9.2	0.00
					SO_2	0.001515	lb/MMBtu	0.2	0.4	0.00 (negligibl
					CO_2e	163.6	lb/MMBtu	20,418	42,536	21.26

PLANT CUMULATIVE INCREASE

Shell at "3485 Pacheco Blvd., Martinez, CA 94553" (Plant No. 11) is an existing Title V facility. Therefore, the District's database contains information on existing emissions at the plant. Table 2 summarizes the cumulative increase in criteria pollutant emissions that will result at Plant 11 from the operation of S-6073.

Table 2. Plant Cumulative Emission Increase

Pollutant	Existing Emissions, Post 4/5/91 (TPY)	New Increase with This Application (TPY)	Cumulative Emissions (TPY)
NOx	0.000	0.107	0.107
POC	0.000	0.006	0.006
CO	335.250	0.081	335.331
PM_{10}	0.000	0.005	0.005
SO_2	0.000	(negligible)	0.000

TOXIC RISK SCREENING ANALYSIS

This application required a Toxics Risk Screening Analysis because the diesel particulate emissions from the operation of S-6073 are greater than the toxic trigger level. Regulation 2-5 requires that the cumulative impacts from all related projects permitted within the last two years be included in the risk screening analysis. Shell does not have any related project permitted within the last two years. Therefore, the only project included in the Toxics Risk Screening Analysis was the installation of diesel engine S-6073.

Table 3. Diesel Exhaust Particulate Matter Emissions

Toxic Pollutant Emitted	Emission Rate (lb/yr)	Risk Screening Trigger (lb/yr)
PM_{10} (Diesel Particulate)	9.2	0.34

S-6073 meets Best Available Control Technology for toxics (TBACT) since the diesel particulate emissions are less than 0.15 g/bhp-hr. For an engine that meets the TBACT requirement, it must also pass the toxic risk screening level of less than ten in a million. Estimates of residential risk assume exposure to annual average toxic air contaminant concentrations occur 24 hours per day, 350 days per year, for a 70-year lifetime. Risk estimates for offsite workers assume exposure occurs 8 hours per day, 245 days per year, for 40 years. Risk estimates for students assume a higher breathing rate, and exposure is assumed to occur 10 hours per day, 36 weeks per year, for 9 years.

Based on 50 hours per year of operation, the emergency generator set passed the Health Risk Screening Analysis (HRSA) conducted on November 26, 2013 by the District's Toxic Evaluation Section. The source poses no significant toxic risk, since the increased cancer risk to the maximally exposed receptor (Resident) is 0.09 in a million. The hazard index for a resident is 0.00003. The increased cancer risk to workers is 0.08 in a million and the hazard index is 0.00006. The source is not located near students. Thus, in accordance with Regulation 2, Rule 5, this source is in compliance with the TBACT and project risk requirements.

(xvii) BACT

In accordance with Regulation 2, Rule 2, Section 301, BACT is triggered for any new or modified source with the potential to emit 10 pounds or more per highest day of POC, NPOC, NOx, CO, SO_2 or PM_{10}.

BACT is triggered for NOx and CO since the maximum daily emissions of these pollutants exceed 10 lb/day each. Please refer to the discussion on "Daily Emissions" on page 2 of this evaluation. District's BACT/TBACT Workbook does not address emergency standby diesel fire pump engines. For purposes of BACT analysis, on-site portable engines are considered stationary engines. Since CARB Stationary Diesel ATCM requirements are at least as stringent as current BACT determinations and applicable NSPS, it is proposed that BACT for stationary emergency standby diesel fire pump engines be compliance with the CARB Stationary Diesel ATCM. The following shows compliance of S-6073 with the requirements of the CARB Stationary Diesel ATCM:

> The CARB Stationary Diesel ATCM Section 93115.6(a)(4)(A)(1)(a) requires new direct-drive emergency standby fire pump engines to meet the applicable emission standards for all pollutants as specified in the Table 2 (Emissions Standards for New Stationary Emergency Standby Direct-Drive Fire Pump Engines > 50 bhp) in the ATCM for the model year and NFPA nameplate power rating. These emission standards are tabulated in Table 4 and are compared with the CARB-certified emission rates of S-6073. Table 4 shows compliance of S-6073 with the ATCM requirements of Section 93115.6(a)(4)(A)(1)(a).

Table 4. ATCM compliance

Pollutant	CARB Certified Emissions Rates (g/bhp-hr)	ATCM Limits, per Section 93115.6(a)(4)(A)(1)(a) (g/bhp-hr)
NMHC+NOx	2.9	7.8
CO	2.1	2.6
PM_{10}	0.12	0.40

The CARB Stationary Diesel ATCM Section 93115.6(a)(4)(A)(1)(b) requires new direct-drive emergency standby fire pump engines to meet the new fire pump engine certification requirements and emission standards required by 40 CFR §60.4202(d). However, S-6073 is a 2005 model year engine and therefore is not subject to the requirements in 40 CFR §60.4202(d).

S-6073 will operate for no more than 50 hours per year for maintenance and reliability testing and therefore complies with the ATCM requirements of Section 93115.6(a)(4)(A)(1)(c).

OFFSETS

Offsets must be provided for any new or modified source at a facility that emits more than 10 TPY of POC or NOx per Regulation 2-2-302, and at a major facility that emits more than 1 TPY of PM_{10} or SO_2 per Regulation 2-2-303.

Shell at "3485 Pacheco Blvd., Martinez, CA 94553" (Plant No. 11) is a major facility for all criteria pollutants. Offsets are required for the following pollutants:

NOx Offset Required = (Increase) * (Offset Ratio) = (0.107 TPY) * (1.15/1.0) = 0.123 TPY
POC Offset Required = (Increase) * (Offset Ratio) = (0.006 TPY) * (1.15/1.0) = 0.007 TPY
PM_{10} Offset Required = (Increase) * (Offset Ratio) = (0.005 TPY) * (1.0/1.0) = 0.005 TPY
SO_2 Offset Required = (Increase) * (Offset Ratio) = (negligible)

Shell possesses and has submitted Emission Reduction Credit (ERC) certificates to cover the offset obligations calculated above. Table 5 summarizes these ERC certificates.

Table 5. ERC certificates submitted by Shell for this application

Pollutant	Certificate No.	Current Balance (TPY)	Offsets Required (TPY)		Remaining Balance (TPY)
			New (from Application 25810)	Pre-existing (from Previous Applications)	
NOx	1366	13.800	0.123	0.000	13.677
POC	1366	16.268	0.007	0.000	16.261
PM_{10}	1377	8.634	0.005	0.000	8.629
SO_2	1366	0.100	0.000	0.000	0.100

CODE OF FEDERAL REGULATIONS (CFR)

Title 40: Protection of Environment
Part 89: Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines
Subpart B: Emission Standards and Certification Provisions

§89.112 Oxides of nitrogen, carbon monoxide, hydrocarbon, and particulate matter exhaust emission standards.

(a) Exhaust emission from nonroad engines to which this subpart is applicable shall not exceed the applicable exhaust emission standards contained in Table 1, as follows:

Table 1.—Emission Standards (g/kW-hr)

Rated Power (kW)	Tier	Model Year[1]	NOx	HC	NMHC + NOx	CO	PM
kW<8	Tier 1	2000	—	—	10.5	8.0	1.0
	Tier 2	2005	—	—	7.5	8.0	0.80
8≤kW<19	Tier 1	2000	—	—	9.5	6.6	0.80
	Tier 2	2005	—	—	7.5	6.6	0.80
19≤kW<37	Tier 1	1999	—	—	9.5	5.5	0.80
	Tier 2	2004	—	—	7.5	5.5	0.60
37≤kW<75	Tier 1	1998	9.2	—	—	—	—
	Tier 2	2004	—	—	7.5	5.0	0.40
	Tier 3	2008	—	—	4.7	5.0	
75≤kW<130	Tier 1	1997	9.2	—	—	—	—
	Tier 2	2003	—	—	6.6	5.0	0.30
	Tier 3	2007	—	—	4.0	5.0	
130≤kW<225	Tier 1	1996	9.2	1.3	—	11.4	0.54
	Tier 2	2003	—	—	6.6	3.5	0.20
	Tier 3	2006	—	—	4.0	3.5	
225≤kW<450	Tier 1	1996	9.2	1.3	—	11.4	0.54
	Tier 2	2001	—	—	6.4	3.5	0.20
	Tier 3	2006	—	—	4.0	3.5	
450≤kW≤560	Tier 1	1996	9.2	1.3	—	11.4	0.54
	Tier 2	2002	—	—	6.4	3.5	0.20
	Tier 3	2006	—	—	4.0	3.5	
kW>560	Tier 1	2000	9.2	1.3	—	11.4	0.54
	Tier 2	2006	—	—	6.4	3.5	0.20

[1] The model years listed indicate the model years for which the specified tier of standards take effect.

(b) Exhaust emissions of oxides of nitrogen, carbon monoxide, hydrocarbon, and nonmethane hydrocarbon are measured using the procedures set forth in subpart E of this part.

(c) Exhaust emission of particulate matter is measured using the California Regulations for New 1996 and Later Heavy-Duty Off-Road Diesel Cycle Engines. This procedure is incorporated by reference. See §89.6.

S-6073 is subject to the emission standards set forth in 40 CFR Part 89. Based on the emission factors provided by CARB Certification with Executive Order #U-R-001-0262, S-6073 is in compliance with the emission standards set forth in 40 CFR Part 89.

CARB AIRBORNE TOXIC CONTROL MEASURE (ATCM)

The owner/operator of S-6073 is subject to the Airborne Toxic Control Measure (ATCM) for diesel particulate matter from portable engines rated at 50 hp and greater because the engine does not fit into the definition of a "stationary source" provided in §93116.2(a)(34) but does into the definition of "portable" provided in §93116.2(a)(29). This ATCM was amended in 2011, and the most recently amended ATCM became effective on February 19, 2011.

Per §93116.3(b)(2)(E), portable diesel-fueled engines that have not been permitted or registered prior to January 1, 2010, shall not be permitted or registered unless they are certified to the most stringent standard contained in the federal or California emission standards for nonroad engines. However, until January 1, 2017, a district may issue a permit or registration for an engine not meeting the most stringent of the federal or California emission standard set for nonroad engines if:

1. The engine is certified to meet an emission standard set pursuant to 40 CFR Part 89, Part 1039 or set forth in the equivalent categories of title 13 , Cal. Code Regs.; and
2. For Tier 1 and Tier 2 engines only, the engine shall have operated in California at any time during the period from January 1, 2008 to December 31, 2010. The responsible official shall provide documentation to prove the engine's operation to the satisfaction of the Air Pollution Control Officer. Engines certified to a more stringent emission standard than Tier 2 are not subject to subsection (E)2.

Per CARB Certification with Executive Order #U-R-001-0262, S-6073 meets the emission standard set pursuant to 40 CFR Part 89. (Please see the "Code of Federal Regulations" section of this evaluation report.) S-6073 is not subject to the requirements of 40 CFR Part 1039 because it is a 2005 model year engine. Therefore, the owner/operator of S-6073 is in compliance with the current ATCM for diesel particulate matter from portable engines rated at 50 hp and greater. The interpretation of §93116.3(b)(2)(E) has been confirmed by Dave Brown of CARB, who can be contacted at (916) 324-1129 or dabrown@arb.ca.gov.

STATEMENT OF COMPLIANCE

S-6073 is an on-site portable emergency standby diesel fire pump engine. For purposes of determining compliance with applicable District's rules, the District treats on-site portable engines as stationary engines.

Source S-6073 is subject to and expected to be in compliance with the requirements of District Regulation 1-301 (*Public Nuisance*), Regulation 6-1-303 (*Particulate Matter and Visible Emissions*), Regulation 9-1 (*Sulfur Dioxide*) and Regulation 9-8 (*NOx and CO from Stationary Internal Combustion Engines*). In order to ensure compliance with the requirements of these regulations, the facility will be conditionally permitted to meet the requirements.

From Regulation 1-301, no person shall discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance or annoyance to any considerable number of persons or the public; or which endangers the comfort, repose, health or safety of any such persons or the public, or which causes, or has a natural tendency to cause, injury or damage to business or property. For purposes of this section, three or more violation notices validly issued in a 30 day period to a facility for public nuisance shall give rise to a rebuttable presumption that the violations resulted from negligent conduct.

S-6073 is subject to the limitations of Regulation 6-1-303 (*Particulate Matter*). Regulation 6, Rule 1, Section 303 states that a person shall not emit for a period or periods aggregating more than three minutes in any hour, a visible emission that is as dark or darker than No. 2 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to an equivalent or greater degree, nor shall said emission, as perceived by an opacity sensing device in good working order, where such device is required by District Regulations, be equal to or greater than 40% opacity. This low PM_{10} emitting engine is not expected to produce visible emissions or fallout in violation of this regulation, and it will be assumed to be in compliance with Regulation 6 pending a regular inspection.

S-6073 is also subject to the SO_2 limitations of Regulation 9-1-301 (*Limitations on Ground Level Concentrations of Sulfur Dioxide*), Regulation 9-1-302 (*Limitations Sulfur Dioxide Emissions*) and 9-1-304 (*Burning of Solid and Liquid Sulfur Dioxide Fuel*). From Regulation 9-1-301, the ground level concentrations of SO_2 will not exceed 0.5 ppm continuously for 3 consecutive minutes or 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Per Regulation 9, Rule 1, Section 302, a person shall not emit from any source a gas stream containing sulfur dioxide in excess of 300 ppm (dry). And Regulation 9, Rule 1, Section 304, states that a person shall not burn any liquid fuel having sulfur content in excess of 0.5% by weight. Compliance with Regulation 9, Rule 1 is very likely since diesel fuel with a 0.0015% by weight sulfur is mandated for use in California.

From Regulation 9, Rule 8 (*NOx and CO from Stationary Internal Combustion Engines*), Section 110.5 (*Emergency Standby Engines*), S-6073 is exempt from the requirements of Regulations 9-8-301 (*Emission Limits on Fossil Derived Fuel Gas*), 9-8-302 (*Emission Limits on Waste Derived Fuel Gas*), 9-8-303 (*Emissions Limits – Delayed Compliance, Existing Spark-Ignited Engines, 51 to 250 bhp or Model Year 1996 or Later*), 9-8-304 (*Emission Limits – Compression-Ignited Engines*), 9-8-305 (*Emission Limits – Delayed Compliance, Existing Compression-Ignited Engines, Model Year 1996 or Later*), 9-8-501 (*Initial Demonstration of Compliance*) and 9-8-503 (*Quarterly Demonstration of Compliance*). However, it is subject to the monitoring and record keeping procedures described in Regulation 9-8-530 (*Emergency Standby Engines, Monitoring and Recordkeeping*). The requirements of this Regulation are included in the permit conditions below.

S-6073 is also subject to and expected to comply with Regulation 9-8-330 (*Emergency Standby Engines, Hours of Operation*) since non-emergency hours of operation will be limited in the permit conditions to 50 hours per year.

This application is considered to be ministerial under the District's Regulation 2-1-311 and therefore is not subject to CEQA review. The engineering review for this project requires only the application of standard permit conditions and standard emission factors in accordance with Permit Handbook Chapter 2.3.

PSD is not triggered.

This facility is located greater than 1,000 feet from the nearest school and therefore is not subject to the public notification requirements of Regulation 2-1-412.

(xviii) PERMIT CONDITIONS

CONDITION 22850--

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 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)]

End of Conditions

RECOMMENDATION

I recommend that Shell be issued an Authority to Construct and/or Permit to Operate for the following equipment:

S-6073 On-Site Portable Emergency Standby Diesel Fire Pump Engine
2005 Caterpillar, Model: C18 ACERT
700 bhp, 5.2 MMBtu/hr

Prepared by: ______________________________ **Date:** ______________________

(xix) Kevin Oei
Air Quality Engineer

Appendix B
Compliance Assurance Monitoring

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S3	Tank 3	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S4	Tank 4	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S13, S1751, S1752, S1753, S1754, S1757, S1758	Fixed Roof Tanks	VOC	N	A26/A103 Flare[1] - S13	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
			N	A25/A101 Flare[1] - 1751, 52, 53, 54, 57, 58	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S14, S19, S20, S534,S610, S611, S612, S613, S1133, S1134, S1139, S1140, S1141, S483, S484, S530, S532	Fixed Roof Tanks	VOC	N	A26/A103 Flare[1] - S14, 19, 20, 534, 1139, 1140, 1141	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
			N	A25/A101 Flare[1] - S610, 611, 612, 613, 1133, 1134		--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
			N	A56/A102 Flare[1]- S483, 484, 530, 532		--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S21	Tank 21	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S23, S26, S571, S572, S573, S1524, S867, S868,S497	Storage Tanks and Loading Rack	PM	N	NA[6]	See Note	--	--	None	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt[6]

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S24, S552, S553, S554, S555, S556, S557, S558, S559, S1523, S560, S561, S815, S985, S567, S1043, S1044, S1045, S1160, S1048, S1525	Storage Tanks and Loading Racks	NA	N	NA[6]	See Note	--	--	None	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt[6]
S34	Tank 34	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S63	Tank 63	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S224	Tank 224	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S257	Tank 257	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S355	Tank 355	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S396	Tank 396	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S397	Tank 397	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S432	Tank 432	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S540	Tank 540	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S545	Tank 545	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S548	Tank 548	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S549	Tank 549	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S568	Tank 568	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S598	Tank 598	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S856	Tank 856	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S876	Tank 876	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S952	Tank 952	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S961	Tank 961	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S967	Tank 967	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S992	Tank 992	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S1006	Tank 1006	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1017	Tank 1017	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1018	Tank 1018	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1031	Tank 1031	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1041	Tank 1041	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1046	Tank 1046	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1051	Tank 1051	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1063	Tank 1063 ETP 1	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1067	Tank 1067 ETP 1	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1070	Internal Floating Roof Tank	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1072	Tank 1072	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1075	Tank 1075	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1076	Tank 1076	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1077	Tank 1411	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1116	Tank 1116 Fresh Acid	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1117	Tank 1117 Skim	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1128	Tank 1128	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1129	Tank 1129	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1130	Tank 1130	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1131	Tank 1131	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1146	Tank 1146	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1147	Tank 1147	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1159	Tank 1159	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1161	Tank 1161	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1186	Tank 1186	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1191	Tank 1256 Crude Oil Storage	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1192	Tank 1257 Crude Oil Storage	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1235	Tank 739 Chem Storage	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1236	Tank 740 Chem Storage	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S1408	LUBS Asphalt Blending and Shipping	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1417, S1420,S 1421, S1423, S1424, S1428, S1430, S1434, S1447, S1427, S1429, S1433, S1435, S1436, S1446, S1448, S1449	OPCEN Distillate Saturation Unit, DH Crude Unit, DH Vacuum Flasher Unit, CP Catalytic Gas Plant, CP Alkylation Plant, DH Saturates Gas Plant, DH Hydrocracking Unit, and Treaters and Hydrotreaters	VOC	Y	A22 -S1421	See Note	--	--	--	N	--	Y	40 CFR 64.2 (a)(1)	Not subject to FE emission limitation	Not Subject
			N	A33/ S1471/S1472 LOP Flare [1]- S1417, 1420,1421,14 23,1424, 1427, 1428, 1429, 1430, 1433,1434,14 35,1436, 1446, 1447, 1448, 1449	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1422	DH Marine Fuel Oil Blender	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1425	DH Catalytic Reformer Unit (CRU)	HCl	N	A33/S1471(Fla re)/A1472 (Flare)[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2 (a)(1)	No Control Device	Not Subject
S1431, S1432	CP Sulfur Plant (SRU1, SRU2)	NA	N	A52 - S1431 A1431 - S1432 A1501/A1517 /S1471 (LOP Flare) - S1431, S1432[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1445	DH Hydrogen Plant 1 (HP1)	VOC	N	A33/S1471 (Flare)/S1472 (Flare)[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1457	Cooling Water Tower (CWT-32)	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1462	LOG Distillate Blender (Jet & Diesel Fuel)	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1463	LOG Gasoline Blender	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1464	LOG Thin Fuel Blender (Wharf)	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1465	LOG Light Oil Products Gross Oil	NA	Y	A1465/ A1467	See Note	--	--	--	N	--	Y	40 CFR 64.2 (a)(1)	Not subject to FE emission limitation	Exempt[5]

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
	Separator													
S1466	LOG Wastewater Pond 8	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1467	LOG BioTreater for wastewater Pond 7	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1468	LOG Wastewater Pond 6	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1469	LOG API Separator with inlet Box and Bar Screen (ETP 1)	NA	Y	A20120/ A20090/ A1402/ A1401/ A1469/ A1470/ A1471/ A1472/ A1473/ A1474/ A1475/ A1476	See Note	--	--	--	N	--	Y	40 CFR 64.2 (a)(1)	Not subject to FE emission limitation	Exempt[5]
S1470	LOG LPG Loading Flare	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1471	LOP Auxiliary Flare	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S1426	CP Catalytic Cracking Unit (CCU)	PM	Y	A12/ A13 / A14/ A33 / A1426 / A1427	See Note	0.15 grain per dscf	SIP 6-310	COMS	Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						Ringelmann No. 1 for no more than 3 minutes/hour	SIP 6-301		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
							Condition # 12911 Part 4		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						20% opacity for no more than 3 minutes/hour	SIP 6-302		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						30 % opacity, except for one 6 minute average opacity reading in 1 hour	NSPS 40 CFR 60 Subpart J 60.102(a)(2)		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						CO emissions shall not exceed 500 ppmv	NESHAP 40 CFR 63 Subpart UUU 63.1565(a)(1)		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						Ringelmann No. 0.5 for no more than 3 minutes/hour for Catalyst Storage and Injectio	BAAQMD Condition #12911 Part 2		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
						n System								
						4.10 P 0.67 lb/hr particulate, where P is process weight rate in ton/hr	SIP 6-311		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						PM emissions shall not exceed 1.0 lb per 1000 lb of coke burn-off plus incremental emissions of 0.10 lb/MMBtu for liquid or solid auxiliary fuel burned in downstream boilers	NSPS 40 CFR 60 Subpart J 60.102(a)(1) and 60.102(b)		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
							NESHAP 40 CFR 63 Subpart UUU 63.1564(a)(1)(i)		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
		CO	Y	S1507/ S1509/ S1512[1]	See Note	CO emissions shall not exceed 500 ppmv	NSPS 40 CFR 60 Subpart J 60.103(a) NESHAP 40 CFR 63 Subpart UUU 63.1565(a)(1)	CO CEMS	Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
		NOX	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		SO2	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S1472	LOP Main Flare	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1480	LUBS F-69 Asphalt Circulation	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1481	OPCEN F-30 DSU	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1483	LUBS F-32 Asphalt Circulation	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1486	DH F-40 CU Feed	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1487	DH F-41B VFU Feed	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1488	DH F-41A VFU Feed	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1490	DH F-43 GOHT Feed	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1491	DH F-44 NHT Feed	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1492	DH F-45 Primary Column Reboil	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1493	DH F-46 Stabilizer Reboil	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1494	DH F-47 Secondary Column Reboil	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1495	DH F-49 CRU Preheat	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1496	DH F-50 CRU	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1497	DH F-51 CRU	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1498	DH F-52 CRU Reboil	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1499	DH F-53 CRU Regen	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1500	DH F-55 SGP Heat Medium	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1502	DH F-57 HCU First Stage Feed	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1503	DH F-58 HCU Second Stage Feed	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1504	DH F-59 HCU Second Stage Reboil	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1505	DH F-60 HP1 Steam Methane	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
	Reformer													
S1506	CP F-61 CGP Feed	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1507, S1509, S1512	UTIL CO Boiler 1, 2, & 3	PM	Y	A12/ A13/ A14	See Note	Ringelmann No. 1 for no more than 3 minutes/hour	SIP 6-301	COMS	Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						Ringelmann No. 2 for no more than 3 minutes/hour during tube cleaning	SIP 6-304		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						0.15 grain per dscf at 6% O_2	SIP 6-310.3		Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						E = 4.10 P 0.67 lb/hr particulate, where P is process weight rate in ton/hr	SIP 6-311		Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
		NOx	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		SO_2	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		CO	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1508	CP F-63 CFH Feed	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1510	CP F-66 CCU Preheat	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1511	CP F-67 CCU LGO Reboil	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S1514	UTIL F-70 Boiler 4	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1515	DH F-71 HCU First Stage Reboil	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1578, S1579, S1766	Sulfur Pits for Sulfur Plant (Plant 1, Plant 2, Plant 3)	SO2	Y	A1501 / A1517 / A4181	See Note	250 ppmv SO2 at 0% O2	NSPS 40 CFR 60 Subpart J 60.104 (a)(2)(i)	SO2 CEMS	Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
							NESHAP 40 CFR 63 Subpart UUU 63.1568(a)(1)(i)		Y	Y - proposed 9/11/1998	Y	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1598	MAINT Gasoline Dispensing Facility	NA	Y	A23	See Note	--	--	--	N	--	Y	40 CFR 64.2 (a)(1)	Not subject to FE emission limitation	Exempt[5]
S1650	MAINT Sandblasting Sand Hopper	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1750	Tank 1218 Spent Acid	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1755	Tank 1334 Gasoline	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1756	Tank 1335 Gasoline	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1759	OPCEN Flexicoker	NA	N	A751/ S1771(Flare) /S1772(Flare)[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1760	OPCEN F-102 FXU Steam Superheater	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1761	OPCEN F-104 HP2 Steam Methane Reformer	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1762	DH F-128 CRU Interheater	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1763	DH F-126 CU Feed Heater	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1764, S1770, S1774	OPCEN Dimersol Plant, C3/C4 Splitter, Hydrogen Plant 2	NA	N	S1772 - Flare[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S1765	OPCEN Sulfur Plant (SRU3)	SO2	Y	A76/ A2023 / A4181	See Note	≤ 250 ppmvd SO2 at 0% oxygen, 12-hour rolling average	NSPS 40 CFR 60 Subpart J 60.104 (a)(2)(i)	SO2 CEMS	Y	N		40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
							NESHAP 40 CFR 63 Subpart UUU 63.1568(a)(1)(i)	SO2 CEMS	Y	Y Subpart UUU was proposed 9/11/98		40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
						250 ppmv SO2 dry, at 0% oxygen	Regulation 9-1-307	SO2 CEMS	Y	N		40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						Concentration ≤ 250 ppmvd at 0% oxygen, averaged over 24 hours	BAAQMDCondition #19748Part 7	SO2 CEMS	Y	N		40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		CO	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		NOx	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1766	Sulfur Pit for Sulfur Plant 3	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1767, S1768, S1769	Flexicoker Unit Coke Silos	PM	Y[7]	A77 A771 - S1769	See Note	Ringelmann No. 1 for no more than 3 minutes/hour	SIP 6-301	Continuous quarterly visible emissions inspection during operations (Condition 18618 Part 5 & 7)	Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						0.15 grain per dscf	SIP 6-310		Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						4.10 P 0.67 lb/hr particulate, where P is process	SIP 6-311		Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
						weight rate in ton/hr								
						99% control efficiency of baghouse	BAAQMD Condition #7618 Part D.3		Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
S1771	OPCEN Flexigas Flare	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1772	OPCEN Hydrocarbon Flare	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1778	Cooling Water Tower (CWT-50)	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1779	OPCEN CPI Oil/Water Separator	NA	Y	A1779/ A1780/ A1781/ A1782	See Note	--	--	--	N	--	Y	40 CFR 64.2 (a)(1)	Not subject to FE emission limitation	Exempt[5]
S1800	UTIL F-88 Boiler 5	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1802	LOGV-1533 Odorant Storage Tank	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1803	OPCEN Coke Corral	PM	N	A1803[7]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject - Water spray is not within the CAM control device definition because it does not destroy or remove air pollutant(s).
		VOC	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S1804	MAINT Paint Spray Booth and Facility Coating	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1805	Tank 12038	VOC	Y	A1805	See Note	Change out with unspent carbon upon breakthrough	Condition # 4298 Parts 5 and 6 and 40 CFR 61.354(d) and 40 CFR 61.349(a)(2)(ii)	Carbon Adsorption	N	Y proposed 1/7/1993	Y	40 CFR 64.2 (b)(1)(i)	Standard/Limit adopted post 1990	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
						defined as detection at its outlet of 50 ppm VOC, measured as methane and Abatement efficiency of at least 95% by weight								
S1900	MAINT Machine Shop Parts Cleaner	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1902	MAINT Seal Room Parts Cleaner	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S1903	MAINT Paint Shop Solvent Tub	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S2000	OPCEN Corrosion Inhibitor Injection	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S2001, S2002, S2003, S2004	LOG Marine Loading Berths (Berths 1, 2, 3 & 4)	VOC	Y	A100	See Note	Destruction efficiency ≥ 95 weight % VOC emission shall not exceed 2 lb/1000 barrels loaded or reduced by at least 95% by	SIP 8-44-301 BAAQMD 8-44-304.1, SIP 8-44-301	Temperature CPMS	Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
						weight								
S2007	LOG Dissolved Nitrogen Floatation Unit North ETP 1 (DNF)	NA	Y	A2007/ A2008/ A2017/ A2020	See Note	--	--	--	N	--	Y	40 CFR 64.2 (a)(1)	Not subject to FE emission limitation	Exempt[5]
S2008	LOG Dissolved Nitrogen Floatation Unit South ETP 1 (DNF)	NA	Y	A2009/ A2012/ A2017/ A2020	See Note	--	--	--	N	--	Y	40 CFR 64.2 (a)(1)	Not subject to FE emission limitation	Exempt[5]
S2010	LOG Wastewater Junction Boxes (Equipped with low-pressure water seals on select atmospheric vents)	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S2011	LOG Wastewater Collection Sumps (4)	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S2012	Perchloroethylene Storage System	NA	N	A33/S1471/S1472 LOP Flare[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S2013	Tank 12467	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S2014	LOG Final ETP 1&2 Holding Ponds 5C and 5D	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S2445	Tank 12445	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S2446	Tank 12446	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S3000	Portable Vacuum Distillation Unit (CCR Technologies Inc.)	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S4001, S4020, S4050, S4080, S4140, S4160	Delayed Coking Unit, DC Distillate Hydrotreater, DC Catalytic Gas Depentanizer, DC Isomerization Unit, DC Heavy Cracked Gasoline Hydrotreater, DC Hydrogen Plant 3	NA	N	S4201 - Flare[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S4002, S4003	DC F-13425-A & B DCU	NOx	Y	A4002/A4003	See Note	NOx emissions shall not exceed 10 ppmv dry at 3% O2, 3-hour average	BAAQMD Condition #12271, Part 35	NOx CEMS	Y	Y proposed 1995	Y	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
		SO2	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		CO	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		VOC	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S4005	Delayed Coking Unit Coke Handling	PM	Y[7]	A4005/A4006	See Note	Ringelmann No. 1 for no more than 3 minutes/hour	SIP 6-301	Water content monitoring & Records	Y - Condition 12271 Part 77, L and M daily water content monitoring	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						Ringelmann No. 0.5 and 10% opacity for no more than 3 minutes/hour	Condition # 12271 Part 75	Water content monitoring & Records		N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						4.10 P 0.67 lb/hr particulate, where P is process weight rate in ton/hr	SIP 6-311	Water content monitoring & Records		N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						0.15 grain per dscf	SIP 6-310	Water content monitoring & Records		N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
						Moisture content of coke, upon discharge from the crusher, shall be maintained at 8% by weight or more	BAAQMD Condition #12271, Part 77	Water content monitoring & Records		N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						Coke Barn and Truck/Railcar Loading Hopper PM emissions shall not exceed 0.01 grain/dscf	BAAQMD Condition #12271, Part 79 and 81	Sampling, records and reporting		N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
S4021	DC -F-13909 DHT Recycle	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S4141, S4031	DC F-14011 HGHT Feed and DC F-14012 HGHT Reboil	NOx	Y	A4141	See Note	NOx emissions shall not exceed 10 ppmv dry at 3% O2, 3-hour average	BAAQMD Condition #12271, Part 35	NOx CEMS	Y	Y proposed 1995	Y	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
		CO	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		SO2	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S4161	DC H-101 HP3 Steam Methane Reformer	NOx	Y	A4161	See Note	NOx emissions shall not exceed 10 ppmv dry at 3% O2, 3-hour average	BAAQMD Condition #12271, Part 29	NOx CEMS	Y	Y proposed 1995		40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		SO2	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		CO	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S4180	OPCEN Sulfur Plant 4 (SRU4)	SO2	Y	A4180 / A4181	See Note	Sulfur Plant 4 and SCOT unit shall achieve 99.9% weight conversion of reduced S compounds to elemental S	BAAQMD Condition #12271, Part 65	SO2 CEMS	Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						Conversion Efficiency > 95 weight %	Condition # 12271 Part 68	SO2 CEMS	Y	Y proposed 1997	Y	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
						≤ 250 ppmvd SO2 at 0% oxygen, 12-hour rolling average	NSPS J40 CFR60.104(a)(2)	SO2 CEMS	Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
							NESHAP 40 CFR 63 Subpart UUU 63.1568(a)(1)(i)	SO2 CEMS	Y	Y-proposed 9/11/1998	Y	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
		VOC	N	S4201 (Flare)[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
			N			--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		NOx	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		CO	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S4190, S4192	UTIL Boiler 6 Gas Turbine 1 & 2	NOx	Y	A4191/A4190 - S4190 A4192/4193 - S4192	See Note	NOx ≤ 5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	NOx CEMS	Y	Y proposed 1995	Y	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
						9 ppmv dry at 15% O2 for gaseous fuel firing3-hour average	SIP 9-9-301.3	NOx CEMS	Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
						25 ppmv dry at 15% O2 for non-gaseous fuel firing 3-hour average		NOx CEMS	Y	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
		SO2	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		VOC	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S4191, S4193	UTIL Boiler 6 Supplemental Steam Generator 1 & 2	NOx	Y	A4191/A4190 - S4191 A4192/4193 - S4193	See Note	NOx ≤ 5 ppmv, dry @ 15% O2, averaged over 3 hr	Condition # 12271 Part 24c	NOx CEMS	Y	Y proposed 1995	Y	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
		NOx	N	NA	See Note	Natural gas and distillate oil: 0.20 lb NOx/MMBtu and Residual oil: 0.40 lb NOx/MMBtu	NSPS 40 CFR 60 Subpart Db 60.44b(a)(4)	NOx CEMS	Y	ND[2]	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		SO2	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		VOC	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		CO	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S4201	DC Clean Fuels Flare	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S4210	Cooling Water Tower (CWT-13278)	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S4211, S4212	DC V-13222 and V-13441 ISOM Maintenance Drop Out Vessel	VOC	N	S4201 (Flare)[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		NOX	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		CO	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		SO2	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S4307	Tank 14687 MDEA Make-up	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S4309	Tank 14517 DEA	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S4310	Tank –13285 Sour Water	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S4311	DC V-12555 ISOM Perchloroethylene Vessel	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S4319, S4350, S4356	Recovered Oil & Process Wastewater Tanks	VOC	N	A56/A102 Flare[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S4322	Tank 14571 Sour Water	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S4329	Tank 13260 Pentane	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S4330	Tank 13261 Pentane	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S4334, S1114, S1115	Tanks	VOC	N	A25/A101 Flare[1] - S4334	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
			N	A33/S1471/S1472 LOP Flare[1] - 1114, 1115		--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
			Y	A1114 - S1114,1115	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S4338	LOG Pentane Loading Facility	NA	N	S1470 - Flare[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S4347	OPCEN Pit for Sulfur Plant 4	SO2	Y	A4181	See Note	Conversion Efficiency > 95 weight %	Condition # 12271 Part 68	SO2 CEMS	Y	Y proposed 1997	Y	40 CFR 64.2(b)(1)(i) and 40 CFR 64.2(b)(1)(vi)	Standard/Limit proposed post 1990 & Continuous Compliance Determination Method	Exempt
						≤ 250 ppmvd SO2 at 0% oxygen, 12-hour rolling average	NSPS J40 CFR60.104 (a)(2)		Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
							NESHAP 40 CFR 63 Subpart UUU 63.1568(a)(1)(i)		Y	N	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt
		PM	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		CO	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
		NOx	N	NA	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S4349	Tank 13262 Pentane	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S5112, S5113, S5114, S5125	Proto Vessels	VOC	N	A26/A103 Flare[1]	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Not Subject
S5115, S5116	Dissolved Nitrogen Flotation Units North	VOC	Y	A5115, A5116	See Note	Abatement efficiency of at	NESHAP 40 CFR 63 Subpart FF 63.649(a)(2)	61.354(d) & Condition 11313	Y- Daily monitoring of carbon breakthrough	ND[2]	Y	40 CFR 64.2(b)(1)(vi)	Continuous Compliance Determination Method	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
	ETP2					least 95% by weight	(ii)							
S5117	LOG Biotreater Tank SPM-14121 ETP 2	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S5118	LOG SPM-14135 Bioclarifier ETP 2	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S5119	LOG SPM-14137 Bioclarifier ETP 2	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S5121	LOG SPM-14111 DNF Float Tank ETP 2	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6051	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6052	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6053	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6054	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6055	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6056	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6057	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6059	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6060	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6061	Flexicoker Unit (FXU) Transloading	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6062	Ethanol Tank	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6068	Tank 22	PM	N	A57[6]	See Note	--	--	None	N	N	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt[6]
S6069	Tank 17596	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6070	Tank 17597	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6071	Tank 17598	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6072	Tank 17595	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S6073	Diesel Engine	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S7000	ETP-3 Aeration Tank and Clarifier	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt

Source #	Source Description	Pollutant	Control Device Used?	Control Device Description	PTE Emissions > 100 tpy criteria or > 10 tpy HAP	Federally Enforceable Emissions Limit or Standard		Monitoring (Compliance Monitoring Requirements) from Title V Permit	Continuous Compliance Determination	Basis of Limit Proposed after Nov. 15 1990? (Y/N)	Exempt from CAM?			Conclusion
			Y/N			Limit	Reference		(Y/N)	(Y/N)	(Y/N)	Citation	Description	
S12490	LOG Tank 12519 Wastewater ETP 1&2	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S12491	LOG Tank 12520 Wastewater ETP 1&2	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt
S17095	Tank 17095	NA	N	--	See Note	--	--	--	N	--	Y	40 CFR 64.2(a)(2)	No Control Device	Exempt

[1] 40 CFR 64.1 states that inherent process equipment is not considered to be a type of control device. Inherent process equipment means equipment that is necessary for the proper or safe functioning of the process, or material recoery equipment that the owner or operator documents is installed and operated primarily for purposes other than compliance with air pollution regulations. The listed source(s) are not abated by a control device and therefore not subject to CAM.
[2] ND indicates that it was not necessary to determine the regulatory adoption date because there is an alternate exemption from the regulation.

[3] Analysis only includes HAP and criteria pollutants.

[5] All limits are not federally enforceable or abatement device not required by a federally enforceable limit.

[6] These storage tanks were subject to SIP Regulation 6 only when in asphalt service. Asphalt production at the Shell Martinez Refinery has been eliminated and proposed Title V permit revisions designate these tanks for exempt material service only. Further, the mist eliminators on the tanks are not considered to meet the definition of a control device because they do not destroy or remove air polluants.
[7] Water spray is not within the CAM control device definition because it does not destroy or remove air pollutants(s). Per 40 CFR 64, a control device does not include passive control measures that act to prevent pollutants from forming, such as the use of seals, lids, or roofs to prevent the release of pollutants, use of low-polluting fuel or feedstocks, or the use of combustion or other process design features or characteristics. This includes low NOx burner technology.

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 which allows the District to impose requirements.

CAA
The federal Clean Air Act

CAAQS
California Ambient Air Quality Standards

CAM
Compliance Assurance Monitoring per 40 CFR Part 64

CAPCOA
California Air Pollution Control Officers Association

CEM
Continuous Emission Monitor

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

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.

District
The Bay Area Air Quality Management District

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.

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.

MOP
The District's Manual of Procedures.

NAAQS
National Ambient Air Quality Standards

NESHAP
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.

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

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 as defined by BAAQMD Regulation 2-6-218

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

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
cu. ft.	=	cubic foot
cfm	=	cubic feet per minute
dscf	=	dry standard cubic foot
dscfm	=	dry standard cubic foot per minute
g	=	gram
gal	=	gallon
gpm	=	gallons per minute

gr	=	grain
hp	=	horsepower
hr	=	hour
lb	=	pound
in	=	inch
max	=	maximum
m2	=	square 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
tpy	=	tons per year
yr	=	year

ENGINEERING EVALUATION
Shell Martinez Refinery
3485 Pacheco Blvd., Martinez, CA 94553
Plant Number: 11
Application Number: 29043

BACKGROUND
The Applicant has submitted an application for an Authority to Construct for the following:

S-6049 **Emergency Standby Diesel Generator Set**
Caterpillar, Model C4.4, 2017
Family Name: HPKXL04.4NR1
132 bhp, 0.90 MMBTU/hr

The engine will be used to provide emergency power for the radio communication system. Shell plans on installing the engine the first quarter of 2018.

EMISSION CALCULATIONS
Criteria Pollutants

Pollutant	Emission Factor (g/hp-hr)	Emissions		
		Annual (lb/yr)	Annual (TPY)	Maximum Daily (lb/day)
NOx	2.56	37.22	0.019	17.86
NMHC	0.11	1.60	0.001	0.77
CO	0.7	10.18	0.005	4.88
PM_{10} = $PM_{2.5}$ (diesel particulate)	0.09	1.31	0.001	0.63
SO2	0.0055	0.08	0.000	0.04

Basis:
- 132 hp Max Rated Output – 6.57 gallons/hr Max Fuel Use Rate = 0.90 MMBTU/hr Max Combustion Capacity
  50 hr/yr maximum Non-Emergency Operations per the stationary Airborne Toxic Control Measure (ATCM)
- The (NO_x+NMHC), CO, and PM_{10} emission factors are from the Manufacturer's Performance Data Sheet
- The SO_2 emission factor is based on 15ppm sulfur in ULSD fuel derived from EPA AP-42, Table 3.4-1.
- Annual emissions are based on the annual limit (50 hr/yr) of operation for testing and maintenance
- Max daily emissions are based on 24hr/day since no daily limits are imposed on emergency operations

Toxic Pollutants
The only Toxic Air Contaminant listed on Table 2-5-1 emitted from S-6049 is diesel particulate which has a chronic trigger level of 0.34 lb/yr. It is assumed that all of the PM_{10} is diesel particulate. Based on the above calculations the annual diesel particulate emissions are 0.63 lb/year.

Cumulative Increase

The cumulative increase for criteria pollutants resulting from the planned operation of S-6049 at 50 hours per year:

Pollutant	Application Emissions Increase (TPY)
NOx	0.019
POC	0.001
CO	0.005
PM_{10} = $PM_{2.5}$ (diesel particulate)	0.001

STATEMENT OF COMPLIANCE:

Regulation 2 - Permits, Rule 1 – General Requirements

Ministerial Projects (Section 2-1-311)

An application that is classified as ministerial is exempt from the District's CEQA requirements in *Section 2-1-310 Applicability of CEQA.* To be classified as ministerial the engineering evaluation and basis for approval or denial of the permit application is subject to specific procedures, fixed standards and objective measurements set forth in the District's Permit Handbook and BACT/TBACT Workbook.

> Chapter 2.3.1 of the District's Permit Handbook sets forth evaluation guidelines for Stationary Diesel Engines and has been used to evaluate these engines. As such, this application is classified as ministerial and these sources are exempt from District CEQA review with respect to air emissions.

Public Notice, Schools (Section 2-1-412)

A new or modified source located within 1,000 feet of the outer boundary of a K-12 school site which results in the increase in emissions of a toxic air contaminant in Table 2-5-1 of *Regulation 2, Rule 5 New Source Review of Toxic Air Contaminants* shall prepare and distribute a public notice in accordance with subsections 412.1 and 412.2 of *Regulation 2, Rule 1 General Requirements*.

>The outer boundary of the nearest K-12 school, Martinez Junior High School, is more than 1,000 feet from the location of this facility as shown in the attached Google Earth ruler screenshot. Therefore, this application is not subject to the public notification requirements of this regulation.

Regulation 2 - Permits, Rule 2 – New Source Review

PSD Project (Section 2-2-224)

This section defines a PSD project as one at a major PSD facility *and* where there is a significant increase in emissions of a PSD pollutant *and* where there is a significant net increase in emissions of a PSD pollutant.

>There will not be a significant increase in emissions of a PSD pollutant from the operation of S-6049 therefore, this project is not a PSD project.

Best Available Control Technology Requirement (Section 2-2-301)

Any new or modified source that has the potential to emit 10.0 pounds or more per highest day of precursor organic compounds (POC), non-precursor organic compounds (NPOC), nitrogen oxides (NOx), sulfur dioxide (SO_2), PM_{10} or carbon monoxide (CO) is required to use Best Available Control Technology as defined in *Regulation 2-2-206 Best Available Control Technology (BACT)*.

> S-6049 triggers BACT for NOx since the proposed maximum daily emissions of NOx exceeds the BACT limit of 10 lb/day. BACT for this source is derived from the CARB ATCM Standards and set forth in the *BAAQMD BACT/TBACT Workbook for IC Engine Compression Ignition: Stationary Emergency, non-Agricultural, non-direct drive fire pump, Document # 96.1.3, Revision 7 dated 12/22/2010.* The more restrictive BACT 1 standard is not applicable to this engine because it will be limited to operate as an emergency standby engine. The Manufacturer's emission rate and BACT 2 emission limit for each pollutant is summarized below and demonstrates compliance for S-6049.

Pollutant	**Manufacturer's Performance Data (g/bhp-hr)**	**BACT2 Emission Limits 300<HP<600 (g/bhp-hr)**
$PM_{2.5}$ = PM_{10}	0.09	0.15
NMHC + NOx	2.67	3.0
CO	0.7	2.6

Offset Requirements, POC and NOx (Section 2-2-302)

Federally enforceable emission offsets shall be provided at a ratio of 1.15:1.0 for any new or modified source at a facility that that emits or will be permitted to emit more than 35 tons per year, on a pollutant specific basis, of POC or NOx.

>Shell is permitted to emit more than 35 tons of POC per year and must to provide offsets at a ratio of 1.15:1.0 for the 0.443 tpy POC emissions increase resulting from this project. Shell has requested that the required 0.509 tpy of POC be taken from Banking Certificate 1285 which has a balance of 1.386 tpy POC. The District will issue a new Banking Certificate to cover the unused emission reduction credits.

Offset Requirement, PM_{10} and Sulfur Dioxide, NSR (2-2-303)

Regulation 2-2-303 establishes emission offset requirements for PM_{10}, $PM_{2.5}$, and Sulfur Dioxide from new or modified sources located at a Major Facility.

>Shell is a Major Facility and S-6049 is subject to the offset requirements of *Regulation 2-2-302*. Per Section 2-2-303.1, if the un-offset cumulative increase in emissions of PM_{10}, $PM_{2.5}$, or Sulfur Dioxide exceeds 1 ton per year (on a pollutant specific basis), the applicant shall provide offsets at a 1:1 ratio for the un-offset cumulative increase. For this project there is no cumulative increase of Sulfur Dioxide; and the cumulative increase of $PM_{2.5}$ and PM_{10} is 0.001 tpy for each. The prior un-offset cumulative increase for PM_{10} is 0.24 tpy. Therefore, the post project un-offset cumulative increase for $PM_{2.5}$ and PM_{10} remains below 1 ton and offsets are not required for $PM_{2.5}$ or PM_{10} for this project.

Regulation 2- Permits, Rule 5 New Source Review of Toxic Air Contaminants

General (2-5-100)

Regulation 2-5-101 –Description states that any new or modified source of toxic air contaminant (TAC) shall be evaluated for potential public exposure and health risk. *Regulation 2-5-110 Exemption, Low Emission Levels* provides an exemption if, for each toxic air contaminant, the increase in emissions from the project is below the trigger levels listed in Table 2-5-1 of Regulation 2-5.

Diesel particulate emissions from the planned operation of S-6049 are calculated to be 0.63 lb/year which exceeds the trigger level of 0.34lb/year. Therefore S-6049 is subject to the requirements of this regulation.

>As determined using the District's HRSA Streamlining Policy Checklist for Stationary Emergency Standby and Fire Pump Diesel Engines, this project qualifies for the District's May 6, 2015 HRSA Streamlining Policy for Stationary Diesel-Fired Engines used for Backup Power or Fire Pumps. Based on this policy, the District has determined that this project will comply with the District TBACT requirements and will result in health impacts of less than 10 in a million cancer risk and less than 1.0 chronic hazard index based on conservative HRSA screening procedures. Therefore, this project will comply with Regulation 2, Rule 5. A refined HRSA is not required for this application.

Regulation 6 - Particulate Matter, Rule 1 - General Requirements

Ringelmann No. 1 Limitation (6-1-301)

Except as provided in Sections 6-1-303, 6-1-304 and 6-1-306, a person shall not emit from any source for a period or periods aggregating more than three minutes in any hour, a visible emission which is as dark or darker than No. 1 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to an equivalent or greater degree.

>Since S-6049 will emit a very small amount of PM_{10} it is expected to comply with *Regulation 6-1-301* pending a regular inspection.

Opacity Limitation (6-1-302)

Except as provided in Sections 6-1-303, 6-1-304 and 6-1-306, a person shall not emit from any source for a period or periods aggregating more than three minutes in any hour an emission equal to or greater than 20% opacity as perceived by an opacity sensing device, where such device is required by District regulations.

>Since S-6049 will emit a very small amount of PM_{10} it is expected to comply with *Regulation 6-1-302* pending a regular inspection.

Ringelmann No. 2 Limitation (Section 6-1-303)

All engines less than 1500 in^3 displacement, or any engine used solely as a standby source of motive power must meet the Ringelmann No. 2 Limitations of *Regulation 6-1-303* which states that a person shall not emit from any source for a period or periods aggregating more than three minutes in any hour, a visible emission which is as dark or darker than No. 2 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to an equivalent or greater degree. **>**Since S-6049 has a displacement of 268 in^3 it is subject to *Regulation 6-1-303.* The engine is expected to comply with this section pending a regular inspection.

Visible Particles (Section 6-1-305)

A person shall not emit particles which are large enough to be visible as individual particles at the emission point or of such size and nature as to be visible individually as incandescent particles.

>Since S-6049 will emit a very small amount of PM_{10} it is not expected to produce visible emissions or fallout in violation of this regulation and will be assumed to be in compliance with *Regulation 6-1-305* pending a regular inspection.

Regulation 9 – Inorganic Gaseous Pollutants, Rule 1 Sulfur Dioxide

S-6049 is subject to the following sections of Regulation 9, Rule 1 and will comply with all sections by burning Ultra Low Sulfur Diesel with a sulfur content of 15ppm.

Limitations on Ground Level Concentrations (Section 9-1-301)

Sulfur Dioxide emissions shall not result in ground level concentrations in excess of 0.5ppm continuously for 3 consecutive minutes or 0.25 ppm averaged over 60 consecutive minutes or 0.05ppm averaged over 24 hours.

General Emission Limitation (Section 9-1-302)

A gas stream containing Sulfur Dioxide shall not contain sulfur dioxide in excess of 300ppm (dry).

Fuel Burning (Liquid and Solid Fuels) (Section 9-1-304)

The sulfur content of liquid fuel burned shall not exceed 0.5% by weight.

Regulation 9 – Inorganic Gaseous Pollutants, Rule 8 NOx and CO from Stationary Internal Combustion Engines

Exemptions (Section 9-8-110)

Section 110.5 exempts emergency standby engines from the requirements of Sections 9-8-301 through 305, 501 and 503.

Emergency Standby Engines, Hours of Operation (Section9-8-330)

S-6049 is subject to the requirements of *Regulation 9-8-330* which limits reliability related operation of the engines to 50 hours per year.

>Permit Conditions for S-6049 will include operating limits that meet this standard.

Monitoring and Records (Section 9-8-500)

This engine is subject to the reporting requirements of Sections 502 and 530.

>Permit Conditions for S-6049 will include reporting requirements that meet this standard.

Regulation 10 – Standards of Performance for New Stationary Sources

New Source Performance Standards (NSPS)

Any new or modified source is required to comply with *Regulation 10, Standard of Performance for New Stationary Sources* – which is Title 40, Part 60 of the Code of Federal Regulation incorporated by reference. According to 40 CFR Section 60.4200(a)(1)(i) engines are subject to 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines if they have a displacement of less than 30 liters per cylinder where the model year is 2007 or later, for engines that are not fire pump engines. S-6049 is a 4 cylinder engine with a total displacement of 4.5 liters, so each cylinder has a volume less than 30 liters and this engine is subject to NSPS

Section 60.4205(b) requires that owners and operators of these engines comply with the emission standards in Section 60.4202, which refers to 40CFR89.112 and 40CFR89.113 for all pollutants.

> S-6049 meets the limits for engines between 100 hp and 175 hp, as shown in the table below:

Pollutant	Manufacturer's Performance Data (g/bhp-hr)	40CFR89.112 Emission Limits (g/bhp-hr)
PM	0.1	0.22
NMHC + NOx	2.6	3.0
CO	0.7	3.7

Sections 60.4206 and 60.4211(a) require that the owner/operator operate and maintain the engine according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

> The owner/operator is expected to comply with this requirement.

Section 60.4207(b) requires that by October 1, 2010, the owner/operator must use fuel that complies with 40 CFR 80.510(b). This means that the fuel must have a sulfur content of 15 parts per million (ppm) maximum, and a cetane index of 40 or a maximum aromatic content of 35 volume percent.

> The owner/operator is expected to comply with this requirement because CARB allows only ultra-low sulfur diesel to be used in California.

Section 60.4209(a) requires a non-resettable hour meter.

> S-6049 will be subject to standard permit conditions that includes this requirement.

> S-6049 will comply with the requirements of Section 60.4211(c) because it has been certified in accordance with 40 CFR Part 89 under engine family HPKXL04.4NR1.

> Standard permit conditions limiting operation to 50 hours per year for reliability testing except for operating during emergencies at S-6049 ensure that it will comply with the requirement in Section 60.4211(e) which limits such operation to less than 100 hours per year.

Regulation 11 – National Emission Standards for Hazardous Air Pollutants

National Emission Standards for Hazardous Air Pollutants (NESHAP)

This engine is subject to 40 CFR 63, Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, because it is located at a major facility for hazardous air pollutants. Per 40 CFR 63.6590(c)(1), a new or reconstructed stationary RICE located at an area source must meet the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines. This engine is in compliance with the requirements of 40 CFR part 60 subpart IIII, as shown in the "NSPS" section of this evaluation.

Other Regulations

The District is charged with enforcing the requirements of California's Air Toxic Control Measure for Stationary Compression Ignition Engines *Title 17, California Code of Regulations, Section 93115* for the purpose of reducing diesel particulate matter (PM) and criteria pollutant emissions from stationary diesel-fueled compression ignition (CI) engines.

Airborne Toxic Control Measure (ATCM) for Emergency Standby Diesel-Fueled CI Engines (>50 bhp)

Subsection 93115.6(a)(3)(A)(1)(a) sets forth Emission Standards for new stationary emergency standby diesel fueled compression ignition engines with maximum engine power greater than or equal to 100 HP but less than 175 HP.

>S-6049 is subject to and meets the requirement of this section of the ATCM as shown in the table below:

Pollutant	Manufacturer's Performance Data Sheet Emission Rate (g/bhp-hr)	ATCM Emission Standards (g/bhp-hr)
PM	0.1	0.15
NMHC + NOx	2.67	3.0
CO	0.7	3.7

Subsection 93115(a)(3)(A)(1)(b) requires that new stationary emergency standby diesel-fueled engines (>50bhp) be certified to the emission standards as specified in *40 CFR, Part 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*.

>The Manufacturer's Specification Sheet shows that S-6049 has been certified to meet EPA Tier 3 standards and therefore, S-6049 complies with this section of the ATCM.

Subsection 93115(a)(3)(A)(1)(c) limits the non-emergency operation of 50 hours/year for maintenance and testing. **>**Permit Conditions for S-6049 will limit non-emergency operation to 50 hours/year and as such S-6049 will comply with this section of the ATCM.

CONDITIONS

I recommend the following permit condition for S-6049:

COND# 22850 --------------------------------------

1. The owner/operator shall not exceed 50 hours per year per engine for reliability-related testing.
 [Basis: "Regulation 2-5]
2. The owner/operator shall operate each emergency standby engine only for the following purposes: to 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 while mitigating emergency conditions or while emission testing to show compliance with District, State or Federal emission limits is not limited.
 [Basis: Title 17, California Code of Regulations, section 93115, ATCM for Stationary CI Engines]

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: Title 17, California Code of Regulations, section 93115, ATCM for Stationary CI Engines]
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: Title 17, California Code of Regulations, section 93115, ATCM for Stationary CI Engines]

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/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: Title 17, California Code of Regulations, section 93115, ATCM for Stationary CI Engines]

RECOMMENDATIONS:

I recommend that the Authority to Construct be waived and a Permit to Operate be issued for the following:

S-6049 **Emergency Standby Diesel Generator Set**
Caterpillar, Model C4.4, 2017
Family Name: HPKXL04.4NR1
132 bhp, 0.90 MMBTU/hr

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Anne C Werth 02/28/18