Exhibit 2

AMERICAN BOTTOM CONSERVANCY * ENVIRONMENTAL INTEGRITY PROJECT

June 14, 2007

Illinois EPA,
Hearing Officer,
1021 N. Grand Ave. E., P.O. Box 19276,
Springfield, IL 62794-9276
Via email rachel.doctors@illinois.gov

RE: Proposed Permits for ConocoPhillips Wood River Refinery, Application Nos. 0605005 and 06110049; I.D. No.: 119090AAA and 119050AAN

Dear Hearing Officer:

The American Bottom Conservancy[1] and the Environmental Integrity Project[2] (Commenters) submit the following comments on the proposed permit for ConocoPhillips Wood River Refinery (Wood River) for a Coker and Refinery Expansion (CORE) Project. We have serious concerns about the refining of tar sands, both in terms of upstream impacts of extraction (see comments submitted by Pembina Institute, which we endorse and incorporate into our comments) and in terms of potential emissions from the refining process itself, and from the increased emissions from tailpipes of vehicles using fuel produced from tar sands.

We have identified several deficiencies that must be remedied before Illinois EPA issues ConocoPhillips Wood River permits for the CORE Project.

1. Before issuing a final permit, Commenters request that Illinois EPA address the deficiencies raised by Julia May in the attached technical analysis. These deficiencies include:

    - Failure to undergo PSD review for SO2 emissions;
    - Failure to require appropriate controls on flaring;
    - Failure to look at alternatives to the dangerous Delayed Coker;
    - Failure to examine the Greenhouse Gas concerns from this Project;

[1] American Bottom Conservancy is an Illinois not-for-profit organization working to protect the people and resources of Illinois.
[2] The Environmental Integrity Project is a nonpartisan, nonprofit organization established in March of 2002 by former EPA enforcement attorneys to advocate for more effective enforcement of environmental laws.

2. Because the CORE Project is located in a nonattaiment area for ozone, Wood River is required to offset its Volatile Organic Matter emissions increases. According to the draft permit, Wood River will utilize emission reductions from "Permanent Shutdown of Facility." Draft Permit, 3.2.3.b.i. However, the facility is not identified in the draft permit. At the public hearing, the environmental director for the Wood River Refinery indicated that ConocoPhillips planned on purchasing emission reduction credits from a company located in Missouri. It is vital to ensure that ConocoPhillips use a proper baseline and only use legal offsets that meet all of the requirements in Illinois Admin. Code 35:203.303. Illinois EPA must analyze these offsets and provide the information to the public to ensure that the community does not bear the burden of Wood River's expansion. In addition, as detailed in Julia May's comments, ConocoPhillips has drastically underestimated the increase in Volatile Organic Matter from the Project and thus Illinois EPA must require additional offsets.

3. *Illinois* EPA *has not* fully analyzed the cumulative impacts from the ConocoPhillips CORE project. The CORE Project will use feedstock from Canadian tar sands, which is dirtier and has higher levels of aromatics, paraffins, and cycloparaffins, and produce significantly higher particulate emissions. [Source: Oil Sands Chemistry and Engine Emissions Roadmap Workshop, attached, a report issued as the result of a workshop held by the U.S. Department of Energy, Natural Resources Canada and the National Research Council of Canada, June 6-7, 2005. The workshop brought together experts from engine and fuels technology, refining, the oil sands industry and other related industries. Among the findings: there is still a lack of understanding of how oil sands-derived fuels impact the performance of emission control devices, such as soot filters, NOx and EGR system performance. See also a recent report from the Natural Resources Defense Council, the Western Resource Advocates, and Pembina Institute, which discusses issues surrounding the *refining* of Canadian tar sands. Available at http://www.nrdc.org/energy/drivingithome/contents.asp]. Further, synthetic crude oil derived from upgrading of oil sands differs from conventional light crudes in hydrocarbon-type composition (paraffins, cycloparaffins and aromatics.) In addition, it contains more middle and heavy distillates and it has a substantially higher proportion of cyclic hydrocarbons than conventional crudes. Despite these differences, Illinois EPA has not analyzed the impact on the Greater St. Louis-Metro East ozone or PM2.5 nonattainment area (nor included the higher emissions in their modeling) due to the increase in emissions from the use of the refined product, i.e. tailpipe emissions Until Illinois EPA fully analyzes the impacts from refining oil from Canadian tar sands as well as the impacts from use of the refined products, Illinois EPA should not allow any facility to refine Canadian tar sand oil.

4. The Endangered Species report submitted by ConocoPhillips is inadequate. ConocoPhillips' consultant, Trinity Consultants, used what appears to be an inappropriate model for the deposition modeling and the follow-up evaluation—using one for hazardous waste combustion facilities rather than for the refining of tar sands. In addition the data used in the model appears not to be for tar sand feedstock, but for existing feedstock. Illinois EPA must not issue this permit until ConocoPhillips has properly studied the impacts of this Project on endangered and threatened species.

Before issuing a final permit for the CORE Project, Illinois EPA must remedy the current deficiencies in the draft permit.

Sincerely,

Karla Raettig
Counsel
Environmental Integrity Project

Kathy Andria (AH)

Kathy Andria
President
American Bottom Conservancy

June 14, 2007

Illinois EPA,
Hearing Officer,
Re: ConocoPhillips CORE project,
1021 N. Grand Ave. E., P.O. Box 19276,
Springfield, IL 62794-9276

RE: Proposed Permits for ConocoPhillips Wood River Refinery, Application Nos. 0605005 and 06110049; I.D. No.: 119090AAA and 119050AAN

Dear Hearing Officer:

In addition to American Bottom Conservancy and the Environmental Integrity Project, the attached comments are submitted on behalf of the Illinois Chapter of the Sierra Club.[1] Thank you for your attention to this matter.

Sincerely,

Karla Raettig
Environmental Integrity Project

[1] The Sierra Club is a national organization working to protect the Nation's clean air and clean water, and our national heritage. The Sierra Club has over 700,000 members nationwide, including 26,000 in Illinois.

Julia May, Environmental Consultant
3122 College Ave., Berkeley, CA 94705
jmay@sbcglobal.net, 510/658-2591

June 14, 2007

Illinois EPA,
Hearing Officer,
1021 N. Grand Ave. E., P.O. Box 19276,
Springfield, IL 62794-9276

Via email rachel.doctors@illinois.gov

Re: ConocoPhillips Wood River CORE Project (Coker and Refinery Expansion); New Source Review Permit Application

Dear Hearing Officer,

Thank you for your attention to this massive refinery expansion. The ConocoPhillips Wood River (CORE) Project represents a major new direction in U.S. refinery operations due to the plans to drastically modify the refinery in order to begin importing heavy Canadian tar sands directly for American use. The CORE Project is a test case of this new and highly polluting trend for permanent modifications to U.S. refineries, which will lock in the use of dirtier feedstocks and highly intensive energy use for decades to come. (Tar sands oil production also causes severe impacts in Canada, including degradation of pristine boreal forest, discussed in other comments on this Project.) This Project requires extremely careful evaluation due to the hazardous nature of the Project and long-term implications. The Project also requires careful evaluation of the existing commitments of ConocoPhillips to clean up the refinery due to past environmental violations independent of this expansion.

I was asked to review the permitting documents due to my engineering background and pollution prevention experience evaluating oil refinery expansions for the past 20 years.[1] I reviewed the CORE Project Application, draft proposed Permit, and associated documents and found the following:

- **This refinery is undergoing modifications and expansion for the purpose of processing cheaper, dirtier crude oil, with resultant increased local and global pollution and hazards that will lock in dirtier refining for decades.**

[1] Biographical Summary: B.S.Engineering, University of Michigan, 1981, National Semiconductor, Design Engineer: 1981-1985, Communities for a Better Environment 1987-2003: Lead Scientist, Clean Air Program Director, Private Consultant 2004-present: Technical assistance on refinery environmental issues to refinery neighbors and trade unions inside and outside of California. Main focus since 1988 -- evaluating oil refinery air pollution sources, identifying refinery pollution prevention options, project alternatives, proposing refinery regulatory options, providing technical assistance to community organizations. 2006-2007 – Hired as consultant to the South Coast Air Quality Management District regulatory agency (Los Angeles region) to provide technical assistance to local community organizations to evaluate South Coast (Los Angeles region) refineries and identify achievable further reduction measures.

Dirtier crude oil inputs (with more carbon, higher sulfur content, and more heavy metals) mean more intensive refining in the dirtiest processes in order to crack the heavy, long hydrocarbon molecules into gasoline and diesel, and to remove increased sulfur contamination. This necessitates high-energy use (with huge increases in emissions of greenhouse gases such as CO2 that are entirely unmitigated) and results in much greater presence of contaminants within the refinery, causing increased local hazards. The CORE Project will increase the potential for upset conditions and associated emissions due to the higher temperature processing, high-pressure cracking, hydrotreating, coking, sulfur recovery, and other processes.

- **The CORE Project hides pollution increases for the new Project behind credits for pollution controls separately required as a result of past Clean Air Act violations.** Pollution controls for two highly polluting existing FCCUs (Fluid Catalytic Cracking Units) should have been put in place long ago to bring this refinery up to par with most refineries in the U.S. The new dirty crude and refinery expansion Project should be evaluated separately from the required pollution controls, which address past violations.

- ***Even after the Wet Gas Scrubber SOx reductions*, ConocoPhillips Wood River will have higher SOx emissions than the average California or Texas refinery.**

- **The CORE Project does not meet federal and local regulatory requirements for achieving the lowest emission rates, best available controls and other requirements, especially for flares.** Many additional safeguards and requirements for further reducing emissions from the Project and applying LAER (Lowest Achievable Emissions Rates), BACT (Best Available Control Technology), and additional PSD requirements (for Prevention of Significant Deterioration of air quality) should have been applied.

- **ConocoPhillips has applied to be allowed to operate during breakdowns when pollution controls are not working**, undermining the effectiveness of proposed controls. This is especially harmful when the tar sands inputs and other Project components are highly likely to increase upset conditions at the refinery.

- **The CORE Project has the potential to greatly increase dangerous accidents at the refinery due to the use of a Delayed Coker, found by EPA and OSHA to present severe hazards even when Best Practices are used.** These hazards include fires, releases of toxic fumes, Carbon Monoxide, toxic dust, Hydrogen Sulfide (H2S), hot geyser eruptions of petroleum coke, and severe dangers to workers including burns and asphyxiation.

- **There are many additional clear hazards from this Project, but the Project application failed to provide basic information,** and did not provide sufficient time for analysis of heavy metal and other pollutant impacts of coking, analysis of PM2.5 emissions and secondary formation of PM 2.5 caused by increased Project emissions of SOx and NOx, application of Best Available Control Technology for additional refinery sources, etc. A few of these issues are listed at the end of this comment.

- **The broader impacts of the use of Canada tar sands in the U.S. should have been required as part of a consideration of alternatives.** These should have included the overall impacts of additional coking, additional energy use, additional hydrogen use, additional sulfur recovery, additional flaring, refinery and pipeline accidents, additional use of coke as fuel in power plants, impacts of pipelines for tar sands, and differences in impacts on regional air quality in the final refinery products of gasoline and diesel products and their use in vehicles (due to new inputs at the refinery). As extensive as this list is, it is not by any means complete. These impacts and long-term implications are severe when considering added criteria, toxic, and greenhouse gas emissions, as well as destruction of land and water resources, and impacts on people, plants, and wildlife in the U.S. and Canada.

I. The CORE Project hides SOx increases behind credits for pollution controls required separately due to past violations

<u>ConocoPhillips SOx emissions are among the worst</u>

The Table below from the CORE Project application touts a reduction of 11,168 tons per year in SO2 reductions due to the CORE Project.[2]

TABLE ES-1. TOTAL NET EMISSIONS INCREASES

	Criteria Pollutant	Total Net Emissions Increase (tons/yr)	Major Modification Threshold (tons/yr)
PSD Pollutants	NO_x	(5.8)	40
	CO	927.2	100
	PM	(154.4)	25
	PM_{10}	(234.1)	15
	SO_2	(11,168.2)	40
NANSR Pollutants	NOx	(13.0)	40
	VOM	370.2	40

CORE Project descriptions seem to play up the reductions in SO2 emissions from the new project (also frequently referred to as SOx), as a wonderful attribute of the Project.

[2] *Coker and Refinery Expansion (CORE) New Source Review Permit Application Amendment,* ConocoPhillips Wood River Refinery, Facility ID 119090AAA, Originally Submitted May 12, 2006, Revised October 17, 2006, page E-1

However, the important issue is why these emissions were so high to begin with (and also so high after the Project is implemented). Comparing other oil refinery SOx emissions shows that most refineries in the U.S. don't have emissions even approaching those of the applicant. The CORE Application gives baseline SO2 emissions from just two refinery sources (6,077.6 tpy from FCC1 and 5,389.9 from FCC2)[3] totaling 11,468 tpy.[4] Small additional SO2 emissions are also listed for a few other sources. (The total SO2 baseline emissions for the Wood River and Distillation refinery are not provided on this chart in Appendix C. There may be additional significant SO2 emissions from these facilities from parts of the refinery that are not included as part of the refinery expansion which should be provided to the public as part of the Project description and for consideration of alternatives to the Project.)

Online data (compiled below) is available for comparing SOx emissions from the Project applicant with other refineries in Texas, the San Francisco Bay Area, and the Los Angeles region (all areas of intensive refining activity). The California Air Resources Board provides data for each separate refinery as listed below:

San Francisco Bay Area Refineries 2005[5]	**City**	**SOx emissions, tons per year (tpy)**
Shell	Martinez	1671
Chevron	Richmond	1566
Valero	Benicia	6411
Tesoro	Martinez	2647
ConocoPhillips	Rodeo	368
Average SF Bay Area Refineries		**2532**
Total SF Bay Area Refineries		**12,662**
South Coast Refineries, Los Angeles Region 2005[6]		
BP West Coast Prod. LLC	Carson	1221
Chevron Products Co.	El Segundo	1142
Exxon Mobil Oil Corporation	Torrance	737
Ultramar Inc	Wilmington	605
ConocoPhillips Company	Wilmington	486
ConocoPhillips Company	Carson	202
ConocoPhillips Total		688
Equilon Enter., LLC, SH	Wilmington	386
Average South Coast Refineries		**683**
Total South Coast Refineries		**4779**
Average these two CA regions (which include most of the state's refineries)		**1607**
Total these two CA regions		**17441**

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[3] Fluid Catalytic Cracking Units

[4] Table C-1: CORE Project Emission Increases Summary 101706.pdf, from Application Appendix C

[5] http://www.arb.ca.gov/app/emsinv/facinfo/faccrit.php?grp=1&dbyr=2005&all_fac=C&sort=SOXHi&co_=&ab_=SF&facid_=&dis_=&city_=&fsic_=&fname_=&fzip_=&chapis_only=&CERR=&dd=, spreadsheet attached as Exhibit A

[6] http://www.arb.ca.gov/app/emsinv/facinfo/factox.php?grp=1&dbyr=2005&all_fac=C&sort=PolHi&showpol=SOX&co_=&ab_=SC&facid_=&dis_=&city_=&fsic_=&fname_=&fzip_=&chapis_only=&dd, spreadsheet attached as Exhibit B

The 2005 data above for oil refineries (with Standard Industrial Code or SIC 2911) shows that in the San Francisco Bay Area, the average SOx emissions for each oil refinery was about 2,532 tons per year (tpy), far lower than the ConocoPhillips (CP) Wood River refinery baseline SOx emissions of 11,468 tpy (from FCC1 and FCC2). (These Bay Area refinery SOx emissions have since been reduced due to reductions in flaring emissions.) The total emissions from the entire Bay Area region (with its five refineries) reports SOx emissions at 12,662 tpy in 2005, which is the same order of magnitude as the emissions from just the CP Wood River facility from its two FCC units. Furthermore, the Wood River refinery reported baseline (11,468 tpy) is over twice the SOx emissions reported for the entire Los Angeles region's several refineries (about 4,779 tpy for the LA region).

These two regions in California contain most of the state's refineries. For comparison between the CP Wood River and the large capacity California oil refinery, the BP South Coast facility has crude oil capacity of 260,000[7] barrels per day (bpd) and 1221 tpy of SOx listed above (both 2005 data). CP Wood River has approximately 306,000 bpd crude oil capacity, with about 11,468 tpy of SOx, making CP Wood River's SOx emissions almost 8 times higher than BP's emissions per barrel of crude oil processed.[8]

The State of Texas also provides online refinery SOx emissions data for 2004,[9] which averaged about 1,985 tpy for each separate oil refinery listed (facilities with oil refinery SIC 2911). Taking an average by adding refineries together with the same name and same County but excluding the single highest emitter in the State gives an average of 1786 tpy, again about an order of magnitude lower than CP Wood River facility. Only one refinery in the entire State of Texas (Phillips 66) had reported emissions similar to the Wood River facility. Any way you look at it, CP Wood River's environmental performance is extremely poor for SO2 emissions compared to almost any refinery in the State of Texas.

Texas Commission on Environmental Quality (TCEQ), Texas Refinery SO2 Emissions:			
COMPANY	SITE	County	SO2 tpy
MOTIVA ENTERPRISES, L.L.C.	PORT ARTHUR PLANT	JEFFERSON	256
DIAMOND SHAMROCK REFINING CO LP	MCKEE PLANTS	MOORE	1999
MARATHON PETROLEUM COMPANY LLC	TEXAS CITY REFINERY	GALVESTON	187
VALERO REFINING COMPANY TEXAS	COMPLEX 6B 7 8	NUECES	2422
VALERO REFINING-TEXAS LP	VALERO REFINING COMPANY	NUECES	339
VALERO REFINING-TEXAS LP Total		NUECES	2760
SHELL OIL CO	DEER PARK PLANT	HARRIS	2575
WESTERN REFINING COMPANY	EL PASO REFINERY	EL PASO	22

[7] Environmental Statement, BP West Coast Products Company LLC, Carson Refinery, Updated 6/21/2006 http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/V/verfied_site_reports/N_America/Carson_2005.pdf

[8] (11,468 tpy of SO2 from ConocoPhillips Wood Rivers / 306,000 bpd crude oil capacity) / (1221 tpy BP SO2 / 260,000 bpd crude oil capacity) = almost 8 times higher

[9] From Texas Commission on Environmental Quality, entitled: Wednesday, September 20, 2006, 2004 State Sum, Sorted by SIC Code, filename: Texas Pt Source Inventory sorted by SIC, pdf attached as Exhibit C, http://www.tceq.state.tx.us/assets/public/implementation/air/ie/pseisums/03ss_sic.

WESTERN REFINING COMPANY	EL PASO REFINING	EL PASO	434
WESTERN REFINING COMPANY Total		EL PASO	456
TRIGEANT, LTD.	TRIGEANT LTD	NUECES	174
LYONDELL CITGO REFINING LP	LYONDELL-CITGO	HARRIS	505
VALERO REFINING TEXAS LP	HOUSTON REFINERY	HARRIS	3678
DELEK REFINING LTD	DELEK TYLER REFINERY	SMITH	914
FLINT HILLS RESOURCES LP	WEST REFINERY	NUECES	92
VALERO REFINING CO TEXAS	TEXAS CITY REFINERY	GALVESTON	359
CITGO REFINING & CHEMICALS CO LP	WEST REFINERY	NUECES	174
CITGO REFINING & CHEMICALS CO	CORPUS CHRISTI REFINERY	NUECES	1340
CITGO REFINING & CHEMICALS CO Total		NUECES	1513
ALON USA LP	BIG SPRING REFINERY	HOWARD	3722
DIAMOND SHAMROCK REFINING CO	THREE RIVERS	LIVE OAK	377
PASADENA REFINING SYSTEM	PASADENA PLANT	HARRIS	1438
CONOCOPHILLIPS CO	SWEENY REFINERY PETROCHEM	BRAZORIA	2280
EXXONMOBIL OIL CORP	BEAUMONT REFINERY	JEFFERSON	7499
TOTAL PETROCHEMICALS USA INC	PORT ARTHUR REFINERY	JEFFERSON	167
PHILLIPS 66 CO	BORGER REFINERY	HUTCHINSON	11786
KOCH PETROLEUM GROUP LP	CORPUS CHRISTI EAST	NUECES	82
BP PRODUCTS NORTH AMERICA INC	TEXAS CITY REFINERY	GALVESTON	5208
EXXONMOBIL CORP	EXXONMOBIL REF &	HARRIS	1670
PREMCOR REFINING GROUP	VALERO PORT ARTHUR REFINERY	JEFFERSON	3170
Texas Average of each separate facility above			1985
Texas Average again with facilities added together but with single worst excluded			**1786**
Texas Total			52,868

All this data demonstrates that the existing CP Wood River facility is far out of line in environmental performance for SOx emissions. The reduction in SOx from the CORE Project is not an innovative action ahead of its time, but a basic necessity to bring the refinery out of the ranks of the worst facilities. Furthermore, these long overdue SOx reductions are being used to cover up increased emissions due to the new plans for importing cheaper, dirtier, more sulfurous crude oil from Canadian tar sands, when the SOx reductions should have been done on their own merits and considered separately.

Even after SO2 reductions by Wet Gas Scrubbers, the facility still has high SO2

Even after the reductions from the CORE Project are achieved, the total emissions rate for the sources listed in Project Application Appendix C Table C-1 is 1891 tons per year of SOx.[10] The Table does not provide total SOx for all refinery sources, only emissions from individual sources in the project, so the total for the refinery may be even higher. When compared to the average SO2 emissions for refineries in other regions, the CP Wood River facility after the reductions will have larger SO2 emissions than the average refinery in Texas (with 1786 tpy). This Texas average included adding separate Texas facilities together with the same name and same County (which increases the average), and included all except the very worst single facility in the state. (That Texas refinery, which emitted 11,786 tpy, is a major outlier compared to all refineries listed by the state, as shown in the table above.)

Thus even after the addition of the Wet Scrubbers on the FCCUs to reduce SOx emissions, CP emissions (1891 tpy) will still be larger than the averages for either the States of Texas (1,786) or California (1,607 tpy), and also higher than the largest California refinery (BP with 1,221 tpy). ConocoPhillips Wood River therefore cannot be considered to provide the best controls for SOx, or even to meet the average rate of control, after the proposed SOx reductions.

ConocoPhillips SOx reductions using Wet Gas Scrubbers are already required because of a Consent Decree with EPA based on past environmental violations

CP was required to put in pollution controls (including the Wet Gas Scrubbers which are the source of the SOx emissions reductions from FCCU units[11]) because the U.S. EPA and state agencies alleged past and continuing environmental violations at CP refineries, including the Wood River facility, according to the Consent Decree settlement reached with ConocoPhillips:

> *Whereas, the United States alleges, upon information and belief, that COPC has violated and/or continues to violate the following statutory and regulatory provisions:*
>
> 1) *Prevention of Significant Deterioration . . . for heaters and boilers and fluid catalytic cracking unit catalyst regenerators for nitrogen oxide ("NOx"), sulfur dioxide ("SO_2"), carbon monoxide ("CO", and particulate matter ("PM").*
>
> 2) *New Source Performance Standards ("NSPS") . . . for sulfur recovery plants, fuel gas combustion devices, and fluid catalytic cracking unit catalyst regenerators; . . .*
>
> 5) *New Source Performance Standards . . . for sulfuric acid plants;*

[10] The total of emissions listed for the sources at the refinery after the CORE Project in Appendix C Table C-1 is not provided (only the change in emissions is listed), however, the column entitled "Potential/Projected Actual Emission Rate (tons/yr)" provides emissions expected after the CORE Project for individual units, which totals on the Table to 1891 tons/yr.

[11] United States of America and the States of Illinois, Louisiana and New Jersey, Commonwealth of Pennsylvania and the Northwest Clean Air Agency v. ConocoPhillips Company; Civil Action No. H-05-0258, entered by the District Court for the Southern District of Texas on January 27, 2005 (Consent Decree), page 53

The Consent Decree states that ConocoPhillips may not take credit for reductions achieved through the Consent Decree requirements, which include the Wet Gas Scrubber installations on the FCCUs. It then purports to allow ConocoPhillips to:

> *utilize emissions reductions from the installation of controls required by this Consent Decree in determining whether a project that includes both the installation of controls under this Consent Decree and other construction that occurs at the same time and is permitted as a single project triggers major New Source Review requirements*;

CD, ¶262(d). However, this provision of the CD is clearly contrary to the Clean Air Act, which expressly prohibits the use of emissions reductions required by the Act as offsets. CAA §173(c)(2). ConocoPhillips should not be allowed to use emission reductions generated by compliance with the consent decree as offsets for this Project because the emission reductions are required to bring ConocoPhillips into compliance with the Act. To the extent that the CD violates the Clean Air Act, it is invalid.

Without taking credits for Wet Gas Scrubbers, and including realistic SOx flare emissions, the CORE Project shows SO2 increases & triggers PSD for SO2

If reductions from other Projects were separated and not credited to the CORE Project, all the increases due to the CORE Project would become more apparent, and would result in major increases of SOx, especially when including flaring emissions missing from the evaluation, exceeding the PSD (Prevention of Significant Deterioration) threshold of 40 tpy.

The Appendix C Table C-1 finds that the CORE Project results in a reduction of 11,132 tpy of SO2 emissions (decreases of 5,909.6 from FCC1 and 5,221.9 from FCC2). If these reductions (which are the result of the Wet Gas Scrubbers added to the facility required by the Consent Decree) were separated and not credited to the CORE Project, the Project would result in a reduction of 36 tpy of SOx.[12] Furthermore, when sources of increased SOx from flaring, missing from the application are included, hundreds of tons per year or more emissions from flaring are added due to the Project. These are described later in this comment. These emissions can be prevented by installing BACT and LAER for new flares and for existing flares, which will process additional gases due to production increases. However, as currently proposed, the Project SOx increase exceeds 40 tpy, and triggers PSD for SO2, requiring BACT evaluation and implementation for new or modified sources emitting SO2.

To the extent the decreases listed for other "Contemporaneous" reductions for other projects were or will be carried out due to previous consent decree requirements or other requirements of the Clean Air Act, they are not allowable for use as offsets. IEPA should provide the public with a detailed evaluation of this issue and historical review of reasons for these contemporaneous projects in order to clarify the potential illegal use of offsets

[12] 11,168- 11,132 = 36 tpy of SO2

by ConocoPhillips for this Project. The offsets listed in the previously cited Appendix C to the application lists the use of offsets from contemporaneous projects of 1,580 tpy SOx at startup of "FCCU-3 and DU-2 LC Startup", and additional offsets of 1,585 tpy from contemporaneous projects when the CORE Project is finalized. These offsets add up to 3,165 tpy of SOx.

In order to clearly evaluate the CORE Project and alternatives, it is important to look at its impact without the offsets by Wet Gas Scrubbers which are not allowable under the Clean Air Act (11,132 tpy), and separately from offsets of 3,165 tpy SOx from other Projects. In this light, the actual project by itself will result in emissions increases of 3,129 tpy of SOx, without including the hundreds of tons per year of additional SOx that flares can emit due to this refinery expansion.

The 25 ppm SOx limit does not represent BACT and should be further tightened

The draft permit requires CP to meet a limit of 25 ppmvd SOx on a 365-day rolling average basis and 50 ppmvd on a 7-day rolling average basis, at 0% O_2, pursuant to Paragraphs 57 and 60 of the Consent Decree. However, a review of BACT achieved in practice and documented through a project performed in cooperation with the US EPA, the University of Texas, and the Texas Commission on Environmental Quality (TCEQ),[13] found that the Valero facility in Corpus Christi, Texas met a 20 ppm limit in 2003, as shown through continuous emission monitors. This would represent a 20% further reduction in SOx from the FCCU units if applied compared to the 25 ppm limit (assuming 0% oxygen) which should be required for the Project.

> ***Description:***
> *Valero determined that drastic reductions of SO2 and particulate emissions from the Fluid Catalytic Cracker Unit (FCCU) could be achieved. With a new technologically advanced scrubber, emissions are less than the maximum allowed by fedral and state regulations. [sic]*
>
> ***P2 Application:***
> *This scrubber design, by Belco Technologies Corporation, incorporates a patented spray tower absober followed by a filtering module and then a hydrocyclone water droplet separator. The emission control technology exceeds EPA and TNRCC 'BACT' criteria for SO2 and particulate reductions. The project has reduced Valero's allowable emissions of SO2 from 178 ppm to 50 ppm. In addition, particulate emissions are 43% lower than EPA's new source performance standards for FCCU's, and have been verified by independent testing.*

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[13] "*The Southwest Network for Zero Waste is a group of environmental professionals dedicated to finding money-saving options for conserving our natural resources. We are a collaborative project of the U.S. Environmental Protection Agency, the University of Texas, and regional environmental agencies. Together we work to identify pollution prevention options for large and small businesses as well as consumers.*". This entry for technology installed at Valero Refining, Submitted 2003, Corpus Christi, TX, *Contact: Allan Schoen, Phone: (512) 289-3286*, attached as Exhibit D
http://www.zerowastenetwork.org/success/story.cfm?StoryID=353&RegionalCenter=

Environmental Benefits:

On-line continuous SO2 monitors demonstrate the unit can treat FCCU flue gas to less than 20 ppm SO2. The opacity is consistantly below 20%. *[emphasis added]*

II. Flaring operations don't meet CO BACT and VOM LAER requirements nor federal requirements to prevent routine flaring

The CORE Project will build 2 new flares and increase the use of existing flares. Flares from the Project are subject to the following:

- **BACT is required for flare CO emissions:** Flaring operations of the CORE Project cause emissions of Carbon Monoxide (CO). The CORE Project exceeds PSD thresholds for CO, therefore Best Available Control Technology (BACT) is required for new and modified CO sources, including flares.
- **LAER is required for flare VOM emissions:** Since the facility is in a non-attainment zone for ground level ozone, flare VOM (Volatile Organic Material) emissions are subject to Lowest Achievable Emission Rate (LAER) because they cause the formation of ground-level ozone.
- **Federal prohibition on routine flaring requires prevention methods to minimize SOx emissions:** A U.S. EPA Enforcement Alert[14] found that

  Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, Practice Not Considered 'Good Pollution Control Practice,'

  May Violate Clean Air Act

  . . . EPA investigations suggest that flaring frequently occurs in routine, nonemergency situations or is used to bypass pollution control equipment. This results in unacceptably high releases of sulfur dioxide and other noxious pollutants and may violate the requirement that companies operate their facilities in a manner consistent with good air pollution practices for minimizing emissions. "Good pollution control practices include: • Procedures to diagnose and prevent malfunctions;

Unfortunately, none of these requirements are met by the CORE Project. The application failed to provide the necessary analysis on available methods including but not limited to installing sufficient compressor and backup compressor capacity to rigorously prevent and minimize entire flaring events and thus achieve maximum controls and lowest emissions from flaring. Such methods minimize all pollutants including CO, VOM, SOx, NOx, PM, CO2, and potentially heavy metals, PAHs, and

[14] *EPA Enforcement Alert,* Vol. 3, Number 9, October 2000, attached as Exhibit E, http://www.epa.gov/compliance/resources/newsletters/civil/enfalert/flaring.pdf

dioxins from flaring, and are in operation at other refineries such as the Shell Martinez California refinery described later in this comment. Furthermore, the CORE Project did not require readily available flare monitoring methods which would accurately identify flare emissions.

Project CO flaring emissions do not meet BACT requirements

The Project Summary provided by the Illinois Environmental Protection Agency (IEPA) finds:[15]

> *The proposed CORE Project triggers the PSD permitting requirements due to the potential CO emissions increase. The new and modified units that will contribute to the increase in CO emissions include . . .*
>
> - *Two new flares . . .*
>
> ***As part of a PSD review for CO emissions, a Best Available Control Technology (BACT) analysis is required. . . . First, the BACT analysis must include consideration of the most stringent available technologies, (i.e., those which provide the "maximum degree of emissions reduction").*** *[emphasis added]*

However this PSD review for CO emissions failed to evaluate the most stringent technologies available, which prevent entire flaring events and thus achieve the maximum degree of emissions reductions (see Shell Martinez refinery discussion later in the comment).

The CORE Application also incorrectly evaluates technically feasible control options and BACT for CO as follows:

> ***7.3.3 ELIMINATION OF TECHNICALLY INFEASIBLE CONTROL OPTIONS***
> *There are no technically feasible CO control options for the new and modified flares.*
>
> ***7.3.4 RANKING REMAINING CONTROL OPTIONS BY CONTROL EFFECTIVENESS***
> *There are no technically feasible CO control options for the new and modified flares.*
>
> ***7.3.5 COST EVALUATION***
> *There are no technically feasible CO control options for the new and modified flares.*
>
> ***7.3.6 SELECTION OF BACT***
> ***As was previously discussed, there are no technically feasible CO control options for the new and modified flares. However, it is still necessary to evaluate BACT emission limits for CO. All but one of the BACT emission limits shown in the RBLC establish only pound per hour and ton per year limits. However, such limits are not transferable to other units. Therefore,***

[15] *Project Summary for Construction Permit Applications from ConocoPhillips Wood River Refinery and ConocoPhillips Wood River Products Terminal for a Coker and Refinery Expansion (CORE) Project,* Illinois Environmental Protection Agency, page 10

ConocoPhillips proposes a CO emission limit of 0.37 lbs/MMBtu for the new and modified flares. page 7-9 [emphasis added]

These statements are simply wrong. Other refineries have put in place technology and operations which minimize flaring emissions by preventing flaring events. Such preventative methods were not evaluated for the CP Wood River permit. Rigorous monitoring has been put in place to demonstrate that the number of flaring events and total annual emissions are low compared to other refineries (as described in more detail later in this comment).

The Project Application also states:

> *Due to the inherent design of a flare (i.e., the pilot gas exhaust does not pass through a duct or stack), it is not possible to use any post-combustion air pollutant control devices.* ***Furthermore, no process changes that would reduce the CO emissions exist. Since the flares serve as VOM control devices in an 8-hour ozone non-attainment area, their operation is necessary.*** *Therefore, no CO control technologies exist for the new flares.* page 7-9

This statement is again wrong in concluding that there is no way to reduce CO emissions from flaring and at the same time to reduce VOM emissions. This statement concludes that either the VOM must be burned in the flare or else emitted to the atmosphere when in fact, recycling VOM back to the refinery fuel gas system will prevent both VOM and CO emissions. Preventing flaring events completely or minimizing the quantities of gases burned in the flares is the best method to prevent both VOM and CO emissions and all other flaring emissions (including CO2). Such methods were not evaluated at all in the CORE Project application.

The Application section 7.3 evaluation is also incorrect in proposing a CO emissions limit of 0.37 lbs/MMBtu as BACT. While it does not appear that the IEPA is applying the 0.37 lbs/MMBtu limit proposed by ConocoPhillips as a permit conditions, this is what CP is requesting. In case IEPA is still considering this limit or has somehow included it in its calculations underlying the basis of other permit limits, the following comments are offered urging IEPA to reject such a notion.

The 0.37 lbs/MMBtu CO emissions limit proposed by ConocoPhillips is nonsensical and unenforceable

The 0.37 lbs/MMBtu proposed limit is actually an average emission factor used by EPA for estimating the amount of CO emissions per BTU of gas burned when flaring occurs. This emission factor has nothing to do with BACT. Such a limit would allow unlimited hours of routine flaring at this average rate, and by definition is not the best available technology but is instead the average calculated emission rate, for CO (averaged over all refineries) when flaring occurs.

Carbon monoxide emissions during flaring occur due to combustion inefficiency, which is a varying factor. If a flare was 100% efficient in combusting the fuels in the flare, all the VOM fueling the flares would be burned into CO2, and there would be no CO emissions at all. Flare efficiency varies according to the quality of the gases burned, the capacity of the flare gases, how well the flare mixes the fuels and air, flare exit velocity, wind conditions, etc. Combustion efficiency can vary from extremely inefficient (down to only 60% of VOM combusted, or even lower) up to over 99% efficiency, where most of the VOM is combusted into CO2.

Regulators in Texas and California require that combustion efficiency down to 93% be used for calculating flare emissions when gases routed to the flare have a low BTU content instead of the 98% frequently used. While most flare emissions calculations assume high efficiency at about 98% or more, many studies show that combustion efficiency can go down very low, down to the 49% or even 30%, as discussed in the attached comment by Dr. Phyllis Fox to the BAAQMD on the Draft Bay Area flare monitoring rule just before its adoption.[16] This means that combustion efficiency varies from low, to average, to high flare efficiency. The ratio of emitted CO, CO2, VOM, etc., also varies. Choosing EPA's average CO emissions factor (related to average combustion efficiency conditions) as a replacement for BACT is like picking the average emissions from an automobile and calling it BACT for car emissions. This is an apples and oranges comparison and fundamentally illogical.

There is no way to enforce the 0.37 lbs/MMBtu CO emission limit, since it is by definition an emission factor and not a measurement. The only way to measure whether the CORE Project flares meet this limit would be to use Optical Sensing with high-tech computerized light beams which detect chemicals emitted above the flare stack hundreds of feet in the air by detecting light wave frequencies. Experimental measurements of some flare gases have been done through Optical Sensing, but this far from a standardized system is highly specialized and rare. (The State of Texas set up an experimental program to evaluate whether such optical systems could be used to measure gases from flaring which was not completed.) Regardless, no such system has been proposed by ConocoPhillips in this case to enforce the 0.37 lbs/MMBtu CO emission limit. It would be extremely convenient for ConocoPhillips to have an emission limit that is by definition already met no matter how many tons of pollutants are emitted by the flares, since the limit would by definition always be equal to the amount of emissions calculated.

Project VOM flaring emissions do not meet LAER requirements

The Project Summary also finds:

> ***The proposed CORE Project triggers NA NSR permitting requirements for VOM emissions since the refinery and the terminal are located in a non-***

[16] *COMMENTS on Regulation 12, Miscellaneous Standards of Performance, Rule 11, Flare Monitoring at Petroleum Refineries, Draft (April 7, 2003),* Prepared by J. Phyllis Fox, Ph.D., P.E., DEE, Consulting Engineer, Berkeley, CA, April 16, 2003, pages 9-12, attached as Exhibit F

attainment area for ozone. The new and modified units that will contribute to the increase in VOM emissions include:

- *Two new flares,* *(page 15)*

The RBLC database states for past permits that since flares are themselves VOM control devices, no additional control of the VOM that is generated through the combustion of pilot fuel gas is necessary. Therefore, no additional VOM control technologies are necessary for the two new flares. (page 19)

This statement incorrectly implies that the main source of VOM from flaring is due to the refinery pilot flame, that this source should be the main source evaluated for LAER requirements, and that no other flare emissions source need be evaluated for LAER. While pilot and purge gases[17] are significant sources of emissions, they are not usually the largest source. The largest source of flare VOM comes from the additional VOM gases routed to the flare when the flare is in use. Since flares do not have perfect combustion, a certain portion of VOM escapes combustion and is emitted to the air. Flares on the average are usually considered to have a combustion or destruction efficiency of VOM of about 98% with good combustion conditions. In that case the remaining about 2% of VOM routed to the flare escapes combustion, and is emitted to the air.

Two percent may sound small, but since flares are sized to handle huge volumes of gases, 2% of VOM emitted to the air can equal dozens of tons of VOM, and the same flaring event can emit dozens more tons of other pollutants (such as CO and SOx) in one day. See my attached comment to the Bay Area Air Quality Management District (BAAQMD) before the adoption of the flare control Regulation 12 Rule 12. This comment charts huge flare events which occurred at individual refineries before the adoption of the Bay Area flare control rule required flare prevention and rigorous Flare Minimization Plans.[18] The highest flare event charted occurred at the ConocoPhillips Rodeo California refinery, at 70,000 lbs of SOx in one day. Numerous other events are documented based on required monitoring data with dozens of tons of pollutants each in one day.

Therefore the statement above that "since flares themselves are VOM control devices, no additional control of the VOM that is generated through the combustion of pilot fuel gas is necessary" is doubly inaccurate. The Lowest Achievable Emissions Rate will be the rate that prevents flare events entirely, rather than burning VOM but still emitting large portions of it to the atmosphere. Title 35 of the Illinois Administrative Code[19] describes LAER requirements as follows:

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[17] Flare pilot gas keeps the flare pilot flame running and flare purge gas makes sure that oxygen does not enter the refinery fuel gas system. These gases are used continuously even when the flare is not being used to burn refinery gases, so these gases can cause significant emissions of VOM and combustion products.

[18] *Comments on Proposed BAAQMD Regulation 12, Rule12, Miscellaneous Operations, Flares at Petroleum Refineries,* Julia May, 4/13/05, attached as Exhibit G

[19] Title 35: Environmental Protection, Subtitle B: Air Pollution, Chapter I: Pollution Control Board, Subchapter a: Permits and General Provisions, Part 201, Permits and General Provisions, Subpart C: Requirements for Major Stationary Sources in Nonattainment Areas, tp://www.ipcb.state.il.us/documents/dsweb/Get/Document-11907/

Section 203.301, Lowest Achievable Emission Rate

a) *For any source, lowest achievable emission rate (LAER) will be the more stringent rate of emissions based on the following:*

1) *The most stringent emission limitation which is contained in the implementation plan of any state for such class or category of stationary source, unless it is demonstrated that such limitation is not achievable; or*

2) ***The most stringent emission limitation which is achieved in practice by such a class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source.*** *In no event shall the application of this term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source performance standard adopted by United States Environmental Protection Agency (USEPA) pursuant to Section 111 of the Clean Air Act and made applicable in Illinois pursuant to Section 9.1 of the Act.*

b) ***The owner or operator of a new major stationary source shall demonstrate that the control equipment and process measures applied to the source will produce LAER***

The CORE Application failed to evaluate LAER achieved in practice by refineries which rigorously apply flare prevention methods. The Shell Martinez California refinery has documented its methods to achieve very low flaring emissions in a Flare Minimization Plan.

The draft permit limits blend emissions from new flares and other sources so that no total separate flare BACT or LAER emissions limits are provided

The draft permit conditions for section "4.7 Flares" gives the following emissions limits within the flaring section. However, these limits include more than just flaring. "DCUF" below refers to the Delayed Coker Unit Flare, which may include other units related to the Coker. "HP2" below includes HP2 H-1 (Hydrogen Plant Heater 1), CWT 24 (presumably Cooling Water Tower 24), HP2F (Hydrogen Plant 2 Flare), and HP Fugitives (Hydrogen Plant fugitive emissions). Unfortunately, the flare emissions are not provided separately, so it is impossible to tell exactly what, if any, flare emissions have been calculated for the CORE Project for BACT and LAER for flare CO and VOM emissions. No specific flare limit has been set.

4.7 *Flares*

4.7.6 *Production and Emission Limitations*

a. *Emissions from the affected units shall not exceed the following limits. Compliance with the annual limits shall be determined from a running total of 12 months of data:*

	Emissions (Tons/Year)				
Emission Unit	*CO*	*NO_x*	*SO_2*	*VOM*	*PM/PM_{10}*
DCUF	*24.3*	*4.5*	*644.5*	*4.1*	---
*HP2**	*147.9*	*246.8*	*127.2*	*24.8*	*45.6*

** Note: HP2 includes HP2 H-1, CWT 24, HP2F, and HP2 Fugitives.* (page 62)

The Project must provide a clear and complete Project description and provide permit limits for the individual sources to ensure that each one meets required BACT and LAER provisions.

One new flare is lacking steam or air assist

The draft permit conditions shown below state that the HP2 Flare is non-assisted (either with air or steam). Steam or air-assisted flares are considered basic for providing good mixing and to increase combustion efficiency. Non-assisted flares should not be considered to meet BACT requirements.

Emission Unit	Description
DCUF	New Coker Flare, Steam-Assisted
HP2F	New HP-2 Flare, Nonassisted

There are numerous proven methods for preventing flaring events and lowering emissions which were not evaluated for the CORE Project

Proven methods for reducing the number of flaring episodes and the quantity of gases burned in the flare and thus reducing all flaring emissions include: 1) **adding sufficient compressor capacity** to ensure that gases are recycled in the refinery gas recovery system for fuel (especially important when the refinery is being expanded so that more gases will be produced that will end up in the flare if not prevented), 2) **installing backup compressors** so that if one flare compressor fails or is unavailable for any reason, the backup system is in place and flaring is prevented in unanticipated circumstances, 3) **slowing vessel depressurization** so that during planned shutdown gases do not overwhelm the gas recovery system, 4) **permanently fixing equipment that repeatedly malfunctions** and causes repeated, unnecessary "emergency" flaring, 5) **designing thicker process vessel walls to increase allowable pressures** and consequently allow storage of gases in vessels during shutdowns instead of flaring, 6) **setting in place detailed procedures to diagnose and eliminate unnecessary flaring** .

These methods have been put in place at existing refineries, and have been shown to lower the number and magnitude of flaring events, as proven through monitoring gases within the flares. No analysis on such methods was provided for the CORE Project despite the requirement found by IEPA that flares meet BACT and LAER for VOM and CO emissions.

The SCAQMD identified flare gas recovery through compressor capacity as equipment that would reduce flaring events in its staff report [20] published prior to adoption of its Flare Control Regulation 1118:

> *C. FLARE GAS RECOVERY SYSTEMS*
>
> ***An alternative control option to minimizing the volume of vent gases routed to flares is to simply prevent the vent gases from being combusted in the flare by recovering them with a flare gas recovery system.*** *In light of increasing environmental concerns, this flare gas recovery system control option is becoming popular, especially since there is an economic incentive due to recovery of valuable gas. The system usually consists of a set of compressors, a heat exchanger, a phase separator and associated pumps.* ***The vent gas is compressed, cooled and routed to an amine scrubber for removal of sulfur compounds, and subsequently may be used as fuel gas or feed for refinery processes.*** *A flare system generally consists of a header or manifold that collects the flare gases from various sources, a knockout drum, a liquid seal (usually water)* (p. II-2)

The BAAQMD also identified flare gas recovery compressor capacity and better management practices as methods which reduced flaring events in the Bay Area in the staff report[21] published prior to adoption of the Flare Control Regulation 12-12:

> *Emissions from flare operations at each Bay Area refinery have decreased since the District began work on development of the flare monitoring rule in 2002.* ***Reports from refiners and analysis by staff have shown a reduction of total organics of approximately 85% since the time period covered by the TAD. These reductions are primarily due to adding flare gas compressor capacity and better management practices.*** (page 1)
>
> *Since the beginning of the District's technical assessment efforts in 2002, each refinery has implemented one or more of the strategies described above.* ***The***

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[20] *Draft Staff Report for Proposed Amended Rule 1118 – Emissions from Refinery Flares,* October 2005, SCAQMD, attached as Exhibit H

[21] *Staff Report Proposed Regulation Regulation 12, Miscellaneous Standards of Performance Rule 12, Flares at Petroleum Refineries,* BAAQMD, July 8, 2005, attached as Exhibit I

most significant of these involve installation of new flare gas recovery compressors at one refinery. Installation of additional compressor capacity and improvement of the reliability of the existing flare gas compressors at other refineries have also significantly reduced emissions. *During the rule development process, refiners have presented trend charts to the District that show up to 60% reduction in emissions since 2002.* (page 7)

Both these agencies identified additional compressor capacity for flare gas recovery as well as additional methods as successful in minimizing flaring events and their associated emissions. These methods were not evaluated for the CORE Project for BACT and LAER for reducing VOM, CO, and SOx emissions from flaring from the Project.

BACT and LAER should be at least as stringent as the equipment and practices in place at the Shell Martinez, California Refinery

At a minimum, the methods already in place at the Shell refinery in Martinez California should be considered BACT, and put in place for the ConocoPhillips CORE Project. Shell can likely do better still, but the methods applied by Shell have proven to result in much lower flaring emissions than other refineries. A discussion in my previously cited comments to the BAAQMD (*Comments on Proposed BAAQMD Regulation 12, Rule 12)* show that even before adoption of the Bay Area flare regulation, Shell Martinez had no large flaring events compared to the other refineries' documented huge and routine flaring events, where dozens of tons of VOM and SOx were routinely emitted in each of many separate one-day events. Since that time, Shell Martinez has continued to exhibit very low flaring emissions. Shell also eliminated the one remaining area of low-level but constant flaring by one of its four flares for the unique flexigas operations (which flares in the range of about 100 lbs/day). (The other three Shell flares were documented to show continuing very low flaring for the past two years.)

The Shell Martinez Refinery identified many methods for minimizing flaring in its Flare Minimization Plan[22] (attached), completed and submitted as required to the Bay Area Air Quality Management District (BAAQMD) pursuant to the BAAQMD flare Regulation 12 Rule 12. This Flare Minimization Plan should be evaluated and the equipment and practices applied to ConocoPhillips Wood River facility in detail in order to meet required BACT and LAER standards. Shell's Flare Minimization Plan finds:

1.0 SUMMARY

The Shell Martinez refinery (SMR), a leader in minimizing flare emissions, has achieved significant reductions in flaring within the past few years. These

[22] *Shell Martinez Refinery, Regulation 12 Rule 12, Flare Minimization Plan*, Redacted Version, Revised March 25 2007, Submitted to: Bay Area Air Quality Management District, attached as Exhibit J

reductions are the direct result of practices and procedures addressing source control and equipment reliability improvement.

In addition to the reductions achieved in the past, significant improvements to flare gas recovery recently occurred. With the OPCEN hydrocarbon flare gas recovery system starting up in late 2006, the average recovery efficiency for all process flares now exceeds 99.9%. This project's impact can best be evaluated using average annual emissions over the past two years, including emergency flaring. Using this as a basis, with the OPCEN hydrocarbon flare gas recovery system online, combined emissions from the four process flares at the Martinez refinery are expected to be less than 1.5 tons/year, *contributing less than 0.2% of the refinery's total permitted emissions of non-methane hydrocarbon.*

Finally, the plan evaluates a number of options for additional capital equipment and modifications to operating procedures to further reduce the volumes of gas flared. *As the refinery already has very significant capital infrastructure for flare gas recovery in place, procedural modifications can be used to achieve much higher returns on a $/ton emissions reduction basis. New refinery procedures described in this Flare Minimization Plan address actions to further minimize flaring during process upsets and additional planning requirements for maintenance and turnaround activities. Careful planning of any activity with the potential for flaring is the most successful minimization approach that has been employed at SMR. Procedures for reporting and investigating all flaring provide a means to learn from unanticipated events. The result of this work will be further reductions in flaring.*

As stated above, Shell Martinez expects flaring emissions of VOM from all four flares together to be less than 1.5 tpy. This is not a "guestimate" but is based on two years of monitoring data and extensive attention to providing sufficient compressor capacity, monitoring and operating procedures, demonstrated in practice at the Shell Martinez Refinery. Shell's Non-Methane HydroCarbon (NMHC) emissions from three flares (equivalent to IEPA's VOM emissions, which also exclude methane), are listed below, and add up to 0.28 tpy. This is compiled from BAAQMD monthly flare reports[23] by the refineries provided online to the public:

Total 3 Shell Flares 2006

	VOM (tpy)
1. Shell Clean Fuels Flare	0.03
2. Shell LOP Flare	0.19
3. Shell Opcen Fxg Flare	0.06
Total	**0.28**

Shell had one additional Flare (the Opcen Flare), which previously flared at relatively low levels (in the range of about 100 lbs of VOM per day), but constantly. No large flare

[23] http://www.baaqmd.gov/enf/flares/index_2006.htm, spreadsheet with data attached as Exhibit K

events occurred at this or any Shell flare in recent years, however the total annual flaring emissions from the Opcen Flare were significant since the low level was continuous throughout the day and year, but these emissions have also been reduced to almost zero.

Shell flare emissions for fourth flare **before** added compressor capacity were significant, but dropped almost to zero since compressor addition

	2006 VOM (tpy)	5 months: Nov 2006 – March 2007 VOM (tpy)
4. Shell Opcen Flare	21.1	0.1

Since November 2006, the last remaining source of common flaring at Shell was eliminated by adding compressor capacity allowing recovery of these gases. The Shell Opcen flare emissions have now been reduced to effectively zero, by adding compressor capacity and by optimizing conditions for burning the low btu gases recovered as fuel for refinery burners, with combustion conditions designed to handle these specialized gases. Since November 1, 2006, there have been only two days of flaring in five months, apparently due to project start-up debugging (according to BAAQMD November 2006 - March 2007 flare reports,[24] the most recent data available). The total VOM emissions for these five months from this flare is now down to 0.1 tpd, compared to the previous operation with constant flaring averaging about 138 lbs/day, every day. Shell's Flare Minimization Plan confirms this reduction, as does the BAAQMD online flare data.

Actual Shell operation demonstrated in the data above is even better than the 1.5 tpy projected by Shell for its long term commitment. **This data includes emergency flaring emissions.** Shells' 1.5 tpy VOM limit should be applied to ConocoPhillips as LAER. Since ConocoPhillips Wood River is a larger refinery than the Shell facility with plans to expand even further, the Shell LAER value of 1.5 tpy VOM may be increased. Taking into account the larger size of the CP Wood River facility and applying the ratio of CP's crude capacity to Shell's capacity in barrels per day results in a LAER value of 5.9 tpy VOM for flaring for the overall refinery for CP, including emergency flaring.[25] Shell states in its Flare Minimization Plan that it has been able to meet the low flaring emissions including emergencies in a safe manner. Nothing in the BAAQMD flare control rule with its Flare Minimization Plan (FMP) requirement causes any compromise in safe refinery operations, which allow flaring in a true emergency. However, the FMP does require rigorous monitoring, reporting, planning, and evaluation of flare events, and equipment improvements so that methods and hardware are in place in advance to prevent flaring and prevent emergencies. These methods make the refinery much safer by preventing emergency shutdowns and drastically reducing repeated flaring emissions.

Not only did Shell include sufficient compressor capacity to prevent flaring in its facility, but Shell, installed two compressors for dedicated use in the Delayed Coking Area, with each compressor separately having large enough capacity to handle gases from this area of the refinery in case one of the compressors has to be taken out of service. When compressors are out of service either for planned or unplanned reasons at

[24] http://www.baaqmd.gov/enf/flares/index.htm, spreadsheet with data attached as Exhibit L
[25] (385,000 barrels per day (bpd) projected for CP / 98,500 bpd Shell crude input) x 1.5 = 5.9 tpy VOM

other refineries with no backup, major flaring can occur. Shell has prevented this problem which recurs at many refineries which do not have strict permit conditions on flaring. Since flaring from Delayed Coking operations results in high sulfur emissions, having dedicated backup in this case means not only reduced emissions of CO and VOM by eliminating flaring episodes completely, but also reduced SOx emissions (which cause public nuisances and which are especially harmful to people with asthma). Shell's Flare Minimization Plan finds:

> ***Process units in the Delayed Coking Area are served by a dedicated flare system.*** *A sketch of this flare system is provided in Figure 7. This system is comprised of collection headers, liquid knockout vessel(s),* ***two recovery compressors,*** *piping to route recovered gas to gas treaters, water seal vessel(s), the flare header proper, and the flare field12.* ***Piping provides sufficient flexibility to operate in various configurations, allowing continuous and reliable operation during turnarounds, inspection and maintenance activities. Technical details of the system are provided in Appendix B.***
>
> *Process units in the Delayed Coking Area that are served by the DCU flare system include the Delayed Coker, Isomerization, Distillate and Heavy Gasoline Hydrotreaters, the Cat Gas Depentanizer, Sulfur Recovery Unit 4 and Hydrogen Plant 3. Capacity of the two existing DCU flare recovery compressors is approximately 4 million standard cubic feet per day (MMSCFD) each, for a total of 8 MMSCFD.* ***Typical header gas flow, in the absence of relief events or unusual operations, is around 2 MMSCFD – well within the capacity of one compressor.*** *Since both compressors are normally in operation except during maintenance when one is out of service,* ***there is typically about 6 MMSCFD reserve capacity available to recover unexpected flows during relief events,*** *or increased vent flows associated with planned and unplanned events.* ***When one of the two flare recovery compressors is out of service for maintenance, the compressor remaining in service is able to recover the routine flare header flow.***
>
> ***The ability to take one compressor out of service for routine maintenance without flaring provides the ability for sufficient maintenance to ensure reliable compressor operation. Only one of the two compressors is maintained at any one time.*** *Typical preventative maintenance involves a 'minor' (process-side) overhaul or a 'major' (process-side + running gear) overhaul. A process-side overhaul typically includes: replacing suction and discharge valves, overhauling suction valve unloaders, replacing piston rod packing, replacing piston rings and rider bands, and inspescting piston rods and cylinder liners. A running gear overhaul typically includes: inspecting crossheads and connecting rods, replacing connecting rod bushings and bearings, inspecting crankshaft and main bearings, cleaning lube oil system, and miscellaneous work on instrumentation and auxiliary equipment.* page 4-21

Unfortunately, CP Wood River has not provided any data within the CORE Project application on flaring from the Project. The Project is required to provide information from the last five years on increases and decreases from different projects, but flaring has been left out of this mix. The Project application provided no information on existing or planned flare compressor capacity, no information on monitoring practices or quality control procedures for monitoring, and no information on root causes of flaring in the past at the facility, nor the volume, duration, and emissions of individual flaring events. The CORE Project does state that some compressor capacity will be available for the

Delayed Coker flare, but provides no information on the amount of compressor capacity nor the baseline of flaring for this or any flare at the facility.

Without monitoring of the volume and concentrations of pollutants within the flare, and without designing sufficient gas recovery capacity not only for the existing refinery, but for the expanded refinery, increased and poorly quantified flaring is sure to result.

Monitoring gases inside the flare is key in evaluating emissions and preventing flaring and is required by Title V

A key method for preventing unnecessary flaring is to require rigorous flare monitoring, root cause analysis of flaring, and a flare minimization plan. Without good monitoring, estimations of emissions from flaring can be extraordinarily inaccurate. Furthermore, root cause analyses are inaccurate without good monitoring, making it all but impossible to quantify the flaring, and to correct the actual cause and degree of impacts of flaring. Monitoring devices are readily available to track the flow of gases within the flare, which provides quantity of gas volumes. Additional monitoring of the concentration of VOM and sulfur compounds within the flare, in combination with good information on flare volume and on pilot and purge gas to the flare during periods when the flares are not in use, together provide good information on the mass of pollutants burned within the flare. Using these monitored data in combination with health protective estimations of the flare's combustion or destruction efficiency of the gases burned in the flare, can provide a good estimate of the flare emissions.

Unfortunately, the proposed CORE permit only gives lip service to these issues for flare monitoring and root cause analysis. It is surprising that despite readily available monitoring equipment for flaring, and since the Consent Decree found that flaring violations occurred in the past by ConocoPhillips, there are no requirements in the permit for putting flow monitors and gas concentration monitors at the flare header itself, as required in the Los Angeles and San Francisco Bay regions flare monitoring regulations. The monitoring conditions in the CORE Project permit are a reiteration of federal requirements for flare monitoring, which were in place in the past, even when ConocoPhillips had the violations. Even these requirements are vaguely stated. BACT, LAER, and PSD requirements necessitate improved monitoring in order to accomplish the emissions reductions required from flaring. Improved monitoring has been worked out and debugged in detail as part of the California flare monitoring regulations and in practice at the many California refineries. This body of work provides a ready-made solution for deficiencies in the CORE Project application, by providing proven methods that can be incorporated directly into the permit.

Attached is the BAAQMD Flare Monitoring Rule 12-11.[26] I have also summarized in detail the provisions of this rule over the next two pages, in order to illustrate the kinds of monitoring issues that have already been worked out. This rule covers monitoring

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[26] http://www.baaqmd.gov/dst/regulations/rg1211.pdf , BAAQMD Regulation 12 Rule 11attached as Exhibit M

hydrocarbons, sulfur compounds, required detection limits, test methods, gas flow verification, reporting requirements, and flare video monitoring, and has developed solutions through discussions with monitoring manufacturers, with oil refineries, regulators, and the impacted public. The Shell Martinez Refinery Flare Minimization Plan also emphasized the importance of monitoring and thorough root cause analysis as the fundamental basis for preventing flaring emissions, especially needed for the CORE Project due both to the facility's history of non-compliance and to the massive expansion proposed. I urge IEPA to incorporate each and every requirement of the BAAQMD Flare Monitoring Rule into the CORE Project permit conditions.

Furthermore, tighter monitoring and reporting requirements were adopted subsequent to the monitoring rule by the BAAQMD as part of the Flare Control Regulation 12-12 adoption.[27] These additional conditions should be added to the CORE Project permit:

> ***Reportable Flaring Event:*** *Any flaring where more than 500,000 standard cubic feet per calendar day of vent gas is flared or where sulfur dioxide (SO2) emissions are greater than 500 pounds per day. For flares that are operated as a backup, staged or cascade system, the volume is determined on a cumulative basis; the total volume equals the total of vent gas flared at each flare in the system. For flaring lasting more than one calendar day, each day of flaring constitutes a separate flaring event unless the owner or operator demonstrates to the satisfaction of the APCO that the cause of flaring is the same for two or more consecutive days. A reportable flaring event ends when it can be demonstrated by monitoring required in Section 12-12-501 that the integrity of the water seal has been maintained sufficiently to prevent vent gas to the flare tip. For flares without water seals or water seal monitors as required by Section 12-12-501, a reportable flaring event ends when the rate of flow of vent gas falls below 0.5 feet per second.*

The Texas Commission on Environmental Quality (TCEQ) also found that an accurate emissions inventory must be developed first in order to identify and develop control options for refinery flare emissions, which emphasizes the importance of flare monitoring as part of flare emission control:[28]

> ***Emission Reductions from Petroleum Refinery Flares.*** *This control measure applies to all gas flares used at petroleum refineries, sulfur recovery plants and hydrogen production plants.* ***Step I-evaluate and assess to develop an accurate emissions inventory from flare operations. Step II-thoroughly investigate control options to identify the most feasible and cost-effective control strategies available to reduce emissions from refinery flares.***

[27] http://www.baaqmd.gov/dst/regulations/rg1212.pdf , attached as Exhibit N
[28] *TCEQ Master Control Strategy List, Point Sources,* page 5, 9/7/2005, attached as Exhibit O http://www.nctcog.org/trans/air/sip/future/lists/TCEQ-Point%20Source%20List.pdf

BAAQMD FLARE MONITORING RULE 12-11 REQUIREMENTS (Summary):

DATA REPORTING REQUIREMENTS:

Electronic Monthly Report to agency

- **Total volumetric flow** of vent gas in standard cubic feet for each day, for the month, and each hour.
- **Composition:**
  - **If vent gas composition monitored by sampling:** Total hydrocarbon content as propane by volume, methane by volume, and, hydrogen sulfide by volume, and if any additional compounds, the content by volume of each.
  - **If vent gas composition monitored by a continuous analyzers**: Average total hydrocarbon content as propane by volume, average methane by volume, and total reduced sulfur by volume or H2S by volume of vent gas flared for each hour, and if additional compounds monitored, average content by volume for each additional compound for each hour.
- **Molecular weight:** If flow monitor measures molecular weight, the average for each hour of the month.
- **Pilot and purge gas:** Type of gas used, volumetric flow for each day and the month, and means used to determine flow.
- **Root cause for large events:** For any 24-hour period during which more than 1 million standard cubic feet of vent gas was flared, a description of the flaring including the cause, time of occurrence and duration, the source or equipment from which the vent gas originated, and any measures taken to reduce or eliminate flaring.
- **Downtime:** Flare monitoring system downtime periods, including dates and times.
- **Archive Video monitoring:** The archive of images recorded for the month for video monitoring
- **Daily reporting of methane, non-methane, SOx:** For each day and for the month provide calculated methane, non-methane and sulfur dioxide emissions. For the purposes of calculations only, flare control efficiency of 98 percent shall be used for hydrocarbon flares, 93 percent for flexi-gas flares or if, based on the composition analysis, calculated lower heating value of vent gas is <300 BTU/SCF.

Flow Verification Report every six months for each flare, included in the corresponding monthly report. The report shall compare flow as measured by the flow monitoring equipment and a flow verification for the same period or periods of time, \

MONITORING AND RECORDS

Vent Gas Flow Monitoring: Vent gas to the flare must be continuously monitored for volumetric flow by a device with:

- **Composition Monitoring requirements:**
  - Minimum detectible velocity of 0.1 foot per second.
  - Continuous measurement over range of flow rates corresponding to velocities from 0.5-275 feet/second in header
  - Monitoring manufacturer's specified accuracy of ±5% over the range of 1 to 275 feet per second.
  - Device installed at location where measured volumetric flow is representative of flow to the flare or to the flare system in the case of a staged or cascading flare system consisting of more than one flare.
  - The owner or operator shall provide access for the government enforcement agency to verify proper installation and operation of the flare monitoring system.
  - Flow monitoring system maintained within ±20% accuracy as demonstrated by flow verification report.

Vent Gas Composition Monitoring:

- Vent gas monitored for composition, whether by sampling, integrated sampling or continuous monitoring, taken from a location at which samples are representative of vent gas composition. If flares share a common header, a sample from the header will be deemed representative of vent gas composition for all flares served by the header.
- Provide access for the government enforcement agency to collect vent gas samples to verify the analyses.
- Monitor vent gas composition using one of the following four methods:
  - One sample shall be taken within 30 minutes of the commencement of flaring, for each day on which flaring occurs
  - Samples may be taken from the flare header or from an alternate location at which samples are representative of vent gas composition.

- **Monitor vent gas composition using one of the following four methods:**
  - **Sampling:** If the flow rate of vent gas flared in any consecutive 15-minute period continuously exceeds 330 standard cubic feet per minute (SCFM), a sample shall be taken within 15 minutes, except that, for flares exclusively serving sulfur or ammonia plants, a sample shall be taken within 1 hour or composition data representing worst-case conditions shall be provided by the owner or operator and verified by the enforcing agency. The sampling frequency thereafter shall be one sample every three hours and shall continue until the flow rate of vent gas flared in any consecutive 15-minute period is continuously 330 SCFM or less. In no case shall a sample be required more frequently than once every 3 hours.
  - **Integrated sampling:** If flow rate of vent gas flared in any consecutive 15 minute period continuously exceeds 330 standard cubic feet per minute (SCFM), integrated sampling shall begin within 15 minutes and continue until the flow rate of vent gas flared in any consecutive 15 minute period is continuously 330 SCFM or less. Requires minimum of one aliquot for each 15-minute period until sample container full.
  - **Continuous analyzers:** Continuously monitor for total hydrocarbon, methane, and, depending upon the analytical method used, H2S or total reduced sulfur. The hydrocarbon analyzer shall have a full-scale range of 100% total hydrocarbon. Maintain each analyzer to within 20% when compared to any field accuracy tests or within 5% of full scale.
  - **Continuous analyzer employing gas chromatography:** Monitor for total hydrocarbon, methane, and H2S. The gas chromatography system shall be maintained to be accurate to within 5% of full scale.

Pilot Monitoring: Flare equipped and operated with automatic igniter or continuous burning pilot, in good working order. If pilot flame is employed, flame shall be monitored with a device to detect presence of the flame. If an electric arc ignition system is employed, the system shall pulse on detection of loss of pilot flame and until the pilot flame is reestablished.

Pilot and Purge Gas Monitoring: Monitor volumetric flows of purge and pilot gases by flow measuring devices, or by other parameters so that volumetric flows of pilot and purge gas may be calculated based on pilot design and parameters monitored.

Recordkeeping Requirements: Maintain records for all the information required to be monitored for five years.

General Monitoring Requirements:

- Periods of flare monitoring system inoperation are limited, during periods of inoperation alternate methods are required, monitors shall be maintained and calibrated in accordance with manufacturer's specifications
- All in-line continuous analyzer and flow monitoring data continuously recorded by electronic data acquisition system capable of one-minute averages. Flow monitoring data recorded as 1-minute averages.

Video Monitoring: Install and maintain equipment that records real-time digital image of the flare and flame at frame rate of no less than 1 frame per minute. Recorded image shall be of sufficient size, contrast, and resolution to be readily apparent in overall image or frame, and include embedded date and time stamp. Equipment shall archive images for each 24-hour period.

TESTING, SAMPLING, AND ANALYTICAL METHODS:

Samples and integrated samples shall be analyzed using the following test methods, or latest revision:

- Total hydrocarbon content and methane content of vent gas shall be determined using ASTM Method D1945-96, ASTM Method UOP 539- 97, or EPA Method 18 ; H2S content of vent gas shall be determined using ASTM Method D1945-96 or ASTM Method UOP 539-97.

If vent gas composition monitored using continuous analyzers, analyzers shall employ:

- Total hydrocarbon content and methane content of vent gas shall be determined using EPA Method 25A or 25B; total reduced sulfur content of vent gas shall be determined using ASTM Method D4468-85; H2S content shall be determined using ASTM Method D4084-94.

If vent gas composition is monitored with a continuous analyzer employing gas chromatography, meet:

- ASTM Method D1945-96 or latest revision, or ASTM Method UOP 539- 97 or latest revision; analyze samples for total hydrocarbon content, methane content, and H2S content; minimum sampling frequency shall be one sample every 30 minutes.

Flow Verification Test Methods: Vent gas flow shall be determined using one or more of the following methods:

- BAAQMD District Manual of Procedures, Volume IV, ST-17 and ST-18; 602.2 EPA Methods 1 and 2;
- Other flow monitoring devices or process monitors, or any verification method recommended by the manufacturer of the flow monitoring equipment installed, or tracer gas dilution or velocity.

Major flaring at ConocoPhillips due to the new expansion can be expected without rigorous monitoring, compressor capacity, process control, and permit conditions

Appendix A to the Consent Decree: *List of Flaring Devices at the Covered Refineries* lists 9 existing flares at the CP facilities, a large number of flares to begin with, even without the CORE Project expansion:

Appendix A: List of Flaring Devices at the Covered Refineries

Wood River	*Alkylation Flare*
	Aromatics North Flare
	Aromatics South Flare
	Distilling West Flare
	North Property Ground Flare
	Lube (HCNHT) Flare
	Distilling Flare
	Benzene Loading Flare
	VOC Flare (and Spare)

The CORE Project proposes building more flares, but provides no information on the baseline amount of compressor capacity, nor the amount, if any, that this capacity would be increased for the new project. As found by the BAAQMD and SCAQMD, compressor capacity is key in preventing flaring. It allows the refinery to recycle gases back to the refinery to be used as fuel, rather than burning these gases in the flare and creating unnecessary additional air pollution. As discussed in the Shell Martinez Flare Minimization plan, adding compressor capacity allowed Shell to reduce to very low levels compared to other refineries, including emergency flaring.

As discussed earlier, the CORE Project application and draft permit failed completely to evaluate added compressor capacity and other flare prevention techniques which would reduce VOM and CO emissions.

Another Bay Area refinery (Tesoro in Avon, previously Tosco) that had the worst continuous flaring record at the beginning of the rulemaking process (and which only had two flares compared to CP Wood Rivers' nine) reduced its emissions greatly by adding compressor capacity. While counting the number of flares does not directly tell us the volume of gases processed, it is a very likely assumption that the CP Wood River facility with its nine flares and additional new flares to be added, and with its much greater refinery crude throughput has a much higher potential to emit than the Tesoro facility did with its two flares.

The Tesoro refinery had daily flaring amounting to many tons per day of SOx and hydrocarbon emissions. After adding compressor capacity, the flaring at this facility was drastically reduced. See the attached original BAAQMD spreadsheet for Tesoro done in October 2003, for data from the previous two years.[29] The original BAAQMD

[29] Tesoro Oct 03 BAAQMD database, attached as Exhibit P

assessment found many tons per day on average of hydrocarbon emissions and SOx emissions from Tesoro, before the reductions at the facility due to added compressor capacity.

The CORE Project application and evaluation documents provide no information on baseline flaring emissions nor on the increase due to the increased production at the refinery. Not only is there a large potential to emit at the new flares, but emissions at existing flares will increase due to the Project because of production increases at the facility. The Project application is not complete without this key piece of information and must be reopened.

As examples of the large flaring events which can occur, charts from my previously cited and attached comments on the BAAQMD Flare Control Rule 12-12 *(Comments on Proposed BAAQMD Regulation 12, Rule12)* are excerpted below (compiled from BAAQMD flare monitoring data). These data show major flaring at these facilities before adoption of the BAAQMD flare control regulation, which are likely to be much higher at the ConocoPhillips Wood River facility due to its size, and due to EPA's finding that violations of federal flare regulations had occurred. EPA's statements in the Consent Decree imply that routine flaring was occurring, but information on this baseline condition at the facility was not provided in the Project Application.

The charts on the following pages represent reduced flaring compared to previously higher levels in the Bay Area. These levels were also reduced further after adoption of the flare control regulation, using principles and equipment that must be applied with specificity to the CORE Project.

The charts illustrate flaring events from two example Bay Area refineries in 2004 before adoption of the flare control rule. These events show SOx emissions from flaring events at individual refineries frequently above 10,000 lbs in one day (and up to 70,000 lbs in one day), and VOM emissions from flaring frequently above thousands of pounds (and up to about 22,000 lbs in one day). Shell Martinez during this period by contrast had no flaring events with SOx emissions greater than 1,000 lbs, and only one event with flaring more than 500 lbs. Shell had no flaring events with VOM emissions greater than 300 lbs. These flaring events included emergency flaring, so Shell's record demonstrates clearly the feasibility of controlling flaring through prevention mechanisms. Attached are spreadsheets from the BAAQMD providing the data making up these charts.[30]

The BAAQMD Staff Report of 2005 for the flare control rule also found:

> ***Emissions from refinery flares are currently estimated at 2 tons per day of total organic compounds (TOC) and 4 tons per day of sulfur dioxide (SO2). These emission levels reflect the reductions realized as a result of actions taken by Bay Area refiners in recent years.*** *The proposed regulation will capture these reductions to ensure no backsliding to flaring practices of the past. These emissions levels are expressed as daily averages, however; actual emissions on*

[30] http://www.baaqmd.gov/enf/flares/index_2004.htm, spreadsheet with data attached as Exhibit Q (Tesoro Avon 2004) and Exhibit R (Conoco Rodeo 2004)

any given day range from 0 to 12 tons TOC and 0 to 61 tons of SO2. The proposed rule calls for refiners to develop flare minimization plans to further reduce these emissions. (page 2)

As discussed earlier, this same report found:

> *Emissions from flare operations at each Bay Area refinery have decreased since the District began work on development of the flare monitoring rule in 2002.* ***Reports from refiners and analysis by staff have shown a reduction of total organics of approximately 85% since the time period covered by the TAD. These reductions are primarily due to adding flare gas compressor capacity and better management practices.*** (page 1)

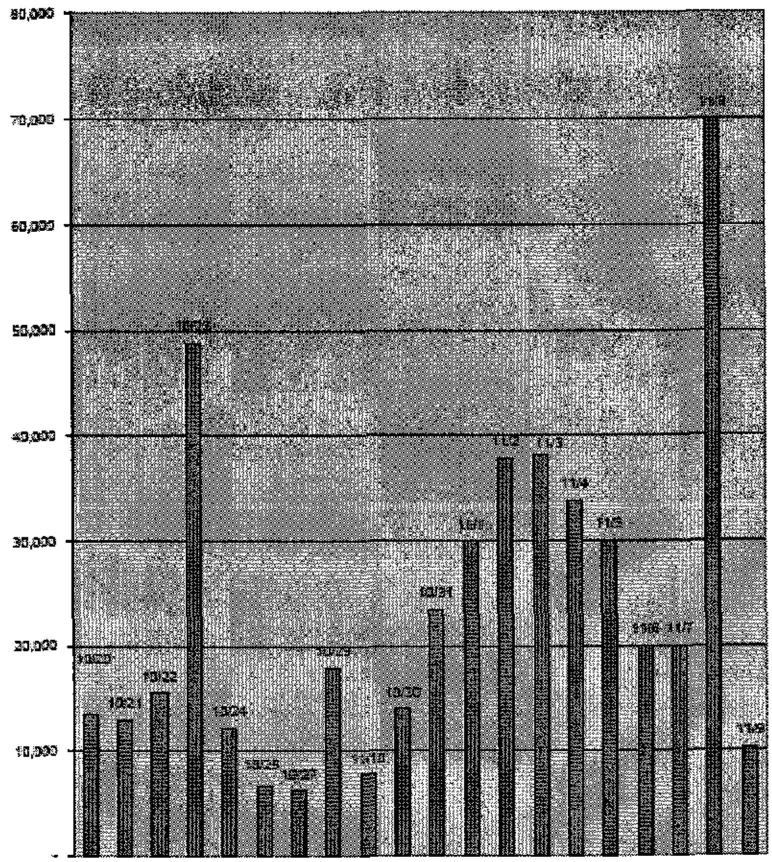
The 2 ton per day (tpd) average found in the report (730 tons per year) is the total TOC (Total Organic Compounds, or VOM plus methane) for all five Bay Area refineries. The report found these emissions had been reduced by 85% reduction to reach the 2 tpd level due to major compressor capacity added to the refineries. This means that previous emissions were about 13 tons per day, or 4866 tons per year before the special activities to reduce flaring for the five Bay Area refineries according to the BAAQMD. These five refineries had a total capacity of 781,000 bpd, about 2 1/2 times the ConocoPhillips Wood River capacity of 306,000 bpd.

Although it is unlikely that ConocoPhillips Wood River performed as well as the average Bay Area refinery before the Bay Area reductions occurred (since US EPA found that ConocoPhillips Wood River violated federal laws for flaring), if CP Wood River performed as well per barrel of crude oil processed, baseline emissions for ConocoPhillips Wood River would be about 1898 tons per year of TOC. Furthermore, the CORE Project represents a large increase in refinery capacity from 306,000 bpd to 385,000 bpd (an increase in production of 26%). Flaring emissions will likely increase more than 26% because the facility is increasing production in the most intensive part of the refinery, with higher-sulfur inputs. With a 26% increase compared to 1898 tons per year, **emissions from flaring at ConocoPhillips Wood River would increase by almost 500 tons per year.** This estimation uses conservative assumptions that can underestimate flaring. Clearly this source has a major potential for emissions. Baseline flaring emissions and compressor capacity at the refinery must be provided to the public, and potential increases from flaring must be evaluated in light of all this evidence at other refineries.

Please also see the attached report *Flaring Prevention Measures.*[31] This report evaluated in great detail BAAQMD data reported by the refineries and Flare Minimization Plans, which found that the dirtiest refinery processes caused more flaring and dirtier flaring than other refinery processes. This issue applies strongly to the CP Wood River facility, which is expanding refining of the dirtiest refinery processes.

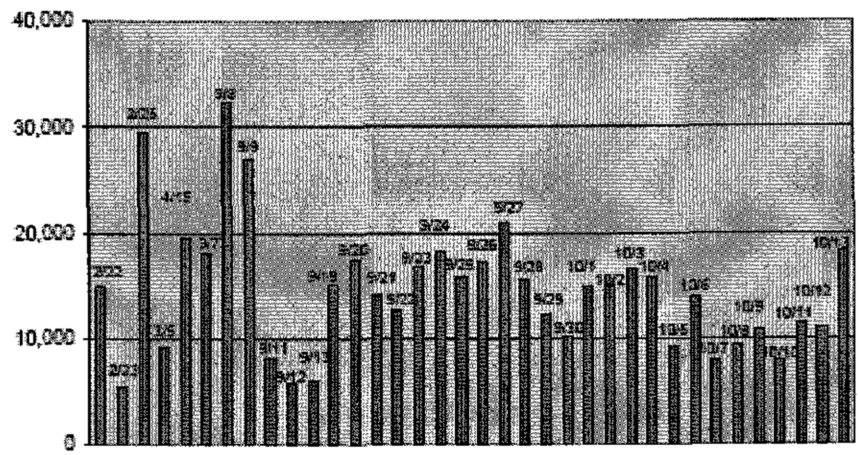
[31] *Flaring Prevention Measures* , Communities for a Better Environment (CBE), Greg Karras, April 2007, attached as Exhibit S

(lbs) ConocoPhillips Rodeo CA largest reported 2004 sulfur dioxide flaring events



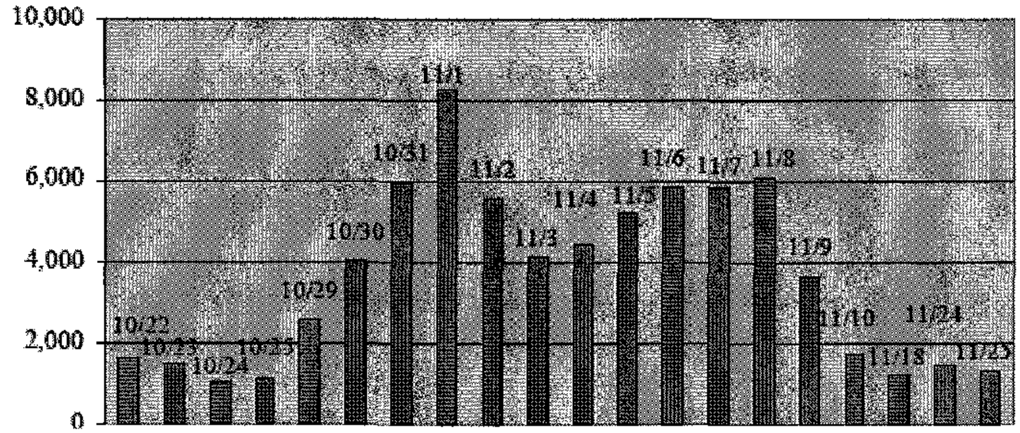
Conoco-Phillips in Rodeo reported the largest sulfur dioxide flaring events in 2004. 20 events generated more than 5,000 lbs. of sulfur dioxide and over 26 events generated over 1,000 lbs of sulfur dioxide each.

(lbs) Tesoro's largest reported 2004 sulfur dioxide flaring events

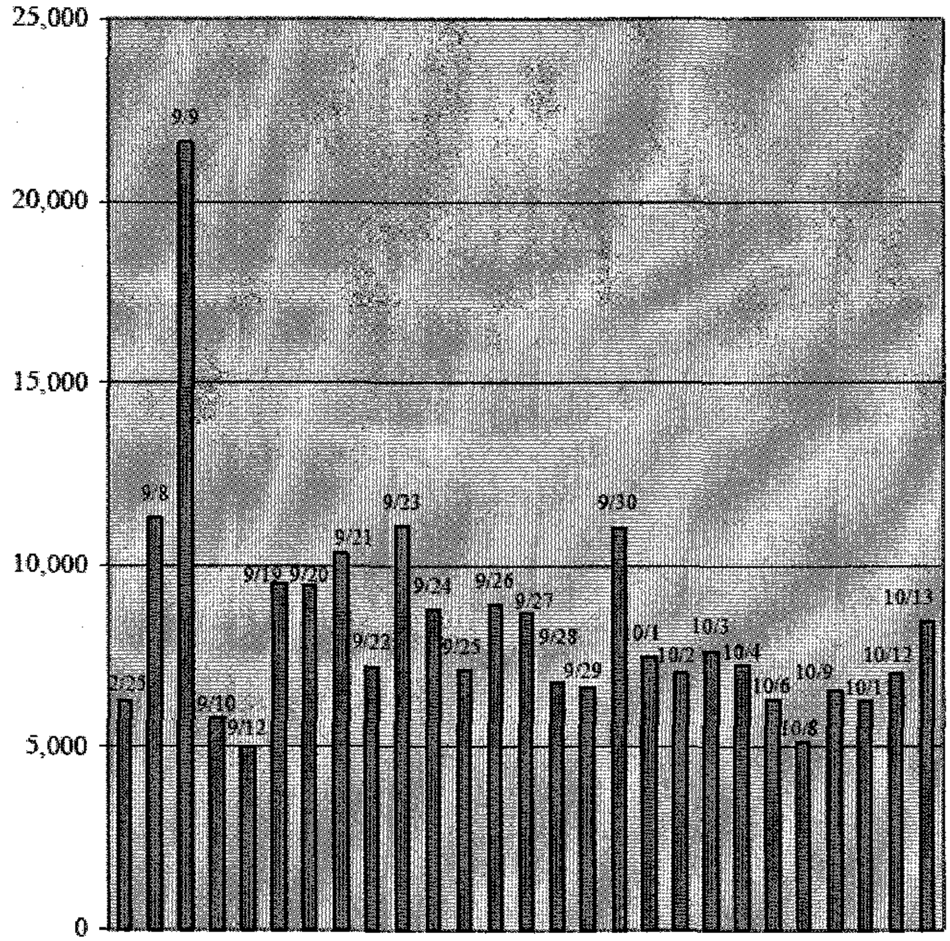


Tesoro in Avon had 36 flaring events that generated more than 5,000 lbs. of sulfur dioxide each.

(lbs) ConocoPhillips Rodeo CA largest reported 2004 VOM flaring events



(lbs) Tesoro Avon CA largest reported 2004 VOM flaring events



III. Delayed Coker Units (DCUs) have been found by EPA and OSHA to cause unique, frequent, and severe hazards

Because of severe and repeated accidents associated with Delayed Cokers, a Chemical Safety Alert (*Hazards of Delayed Coker Unit (DCU) Operations*, August 2003) was jointly published by US EPA, the Occupational Safety and Health Administration (OSHA), the U.S. Dept. of Labor, and the Chemical Emergency Preparedness and Prevention Office.[32] This alert (attached) found that Delayed Coker Units are increasing in use due to their ability to process lower quality crude oil, as higher quality crude becomes less and less available to refiners. The safety alert found that DCU operations cause unique hazards that must be addressed.

> *The increasingly limited supply of higher quality crude oils has resulted in greater reliance on more intensive refining techniques. . . . One of the most popular processes for upgrading heavy ends is the DCU [Delayed Coker Unit], a severe form of thermal cracking requiring high temperatures for an extended period of time.*
>
> *This process yields higher value liquid products and creates a solid carbonaceous residue called "coke." As the supply of lighter crude oils has diminished, refiners have relied increasingly on DCUs.*
>
> *Unlike other petroleum refinery operations, the DCU is a semi-batch operation, involving both batch and continuous stages.* ***The batch stage of the operation (drum switching and coke cutting) presents unique hazards and is responsible for most of the serious accidents attributed to DCUs.*** *The continuous stage (drum charge, heating, and fractionation) is generally similar to other refinery operations and is not further discussed in this document. About 53 DCUs were in operation in the United States in 2003, in about one third of the refineries.*
>
> ***In recent years, DCU operations have resulted in a number of serious accidents despite efforts among many refiners to share information regarding best practices for DCU safety and reliability. EPA and OSHA believe that addressing the hazards of DCU operations is necessary given the increasing importance of DCUs in meeting energy demands, the array of hazards associated with DCU operations, and the frequency and severity of serious incidents involving DCUs.***

This important alert lists the processes that cause many specific hazards not found in the existing Tesoro coking process. **US EPA found Delayed Coker Units to cause**

[32] *Hazards of Delayed Coker Unit (DCU) Operations*, August 2003, A Chemical Safety Alert of US EPA (EPA 550-F-03-001), www.epa.gov/ceppo, the U.S. Dept. of Labor, CEPPO, (Chemical Emergency Preparedness and Prevention Office), and Occupational Safety and Health Administration (OSHA) Directorate of Science, Technology and Medicine, Office of Science and Technology Assessment, attached as Exhibit T

refinery accidents, extreme hazards to workers, releases of hazardous materials and toxic gases, and fires:

- Fires due to unquenched material at temperatures well above the ignition point and reactions that lead to spontaneous combustion.
- Accidental releases of toxic fumes including hydrogen sulfide (H2S), carbon monoxide (CO), polynuclear aromatics (PNAs) and toxic dust,
- Geysers/eruptions of hot coke, sudden hot tar ball ejection, undrained hot water release, hot coke avalanche, and platform removal/falling hazard,
- Accidental and sudden releases of high pressure water jets, due to coke cutting water jets within delayed coker drum etching established channels, instead of breaking up coke as intended, causing worker injuries and even dismemberment,
- Severe worker hazards including scalding steam causing severe burns, worker asphyxiation due to coke absorbing all available oxygen, heat stress and physical injuries such as crushing or pinching injuries due to moving parts.

This Chemical Safety Alert makes it abundantly clear that added safety mechanisms need to be in place when siting and permitting delayed cokers but no special evaluations or conditions are provided for this unit.

IV. Added CORE Project Greenhouse Gases will be Enormous and Permanent

The CORE Project does not evaluate alternatives to the Project as required, which would avoid severe Project energy use and Greenhouse Gas emissions

The draft Construction Permit for the CORE Project states:

> 2.5 **The Illinois EPA has broadly considered alternatives to this project, as required by 35 IAC 203.306.** Much of the equipment requiring LAER is existing equipment on site which has been idle. Alternative sites would not possess the necessary piping infrastructure, and alternative sizes of equipment would not necessarily meet the consumer demands for gasoline supply. Accordingly, the benefits of the proposed project significantly outweigh its environmental and social costs. (page 5)

The Illinois regulation section cited above is as follows:

> ***Section 203.306 Analysis of Alternatives***[33]
> *The owner or operator shall demonstrate that benefits of the new major source or major modification significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification, based upon an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source.*

However, unfortunately the draft Construction Permit was premature in finding that the IEPA has broadly considered alternatives to the Project. For example, the extremely high energy use of the new Project and resultant emissions of Greenhouse Gases (GHGs) should have been considered pursuant to Section 203.306, as a major environmental and social cost of the Project. At a minimum, this major cost should be identified and evaluated, so that alternatives can be seriously evaluated by the public as well.

Governor Blagojevich has launched the State of Illinois' Global Warming Initiative, as shown on the IEPA website:[34]

> *In 2006 Governor Blagojevich announced a new global warming initiative that will build on Illinois' role as a national leader in protecting the environment and public health. The announcement marked the beginning of a long-term strategy by the state to combat global climate change, and builds on the steps the state has already taken to reduce greenhouse gas (GHG) emissions, such as enhancing the use of wind power, biofuels and energy efficiency.*

Regarding the impacts of Climate Change, the Governor's Executive Order[35] finds:

> ***WHEREAS**, the consensus is that increasing emissions of greenhouse gases are causing global temperatures to rise at rates that could cause worldwide economic disruption, environmental damage and public health crises;*
>
> ***WHEREAS**, global warming is largely due to the combustion of fossil fuels that release carbon dioxide and other greenhouse gases that trap heat in the atmosphere;*
>
> ***WHEREAS**, the Intergovernmental Panel on Climate Change and the National Academy of Sciences have reported that atmospheric carbon dioxide is at the highest level in more than 500,000 years;*
>
> ***WHEREAS**, average global temperatures were the hottest on record ten of the past sixteen years. Scientists have predicted that temperatures in Illinois could*

[33] http://www.ipcb.state.il.us/documents/dsweb/Get/Document-11911/
[34] http://www.epa.state.il.us/air/climatechange/ , attached as Exhibit U
[35] http://www.illinois.gov/Gov/pdfdocs/execorder2006-11.pdf , attached as Exhibit V

rise significantly by the end of this century, leading to hotter summers, shorter winters, and increased drought and flood events;

WHEREAS*, these effects could strain drinking water supplies, overwhelm sewage treatment capacity, reduce the water level of Lake Michigan, destroy wetlands, erode soil, and harm croplands, ecosystems and habitats, among other damaging effects;*

WHEREAS*, leading climatologists have estimated that less than a decade remains before global warming could be irreversible and that governments, businesses and households must act now to reduce greenhouse gas emissions;*

In addition to the Governor's findings, the U.S. Global Change Research Program (USGCRP) published a report[36] on impacts of Climate Change in the Midwest, which finds that, higher summer temperatures and resultant increased air pollution in the Midwest will result from Climate Change. Hotter summers increase the formation of photochemically reactive smog constituents, such as ground-level ozone, which forms through chemical reactions of VOM and NOx on hot days. Consequently, this region which is non-attainment for ozone, will have higher levels of ozone due to climate change. The report also found that heat-related deaths in the region due to Climate Change will increase, and the report as a whole found many other severe impacts due to climate change. Here is a brief excerpt on air pollution and heat-related death impacts:

Health and Quality of Life in Urban Areas

A reduction in extremely low temperatures and an ***increase in extremely high temperatures are expected.*** *. . . During the summer, however, in cities, heat-related stresses are very likely to be exacerbated by the urban heat island effect,a phenomenon in which cities remain much warmer than surrounding rural areas. This elevates nighttime temperatures,and in combination with the greater expected rise of nighttime temperatures compared to those of daytime,there will be less relief at night during heat waves.* ***Elevated nighttime temperatures were a notable characteristic of the 1995 heat wave that resulted in over 700 deaths in Chicago. In addition, during heat waves in the Midwest, air pollutants are trapped near the surface, as atmospheric ventilation is reduced. Without strict attention to regional emissions of air pollutants,the undesirable combination of extreme heat and unhealthy air quality is likely to result.*** (page 55)

Please see the report for additional specific and severe impacts in the Midwest due to Climate Change. The public is relying on IEPA to seriously evaluate alternatives to the

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[36] *Climate Change Impacts on the United States, The Potential Consequences of Climate Variability and Change, Overview: Midwest,* by the National Assessment Synthesis Team, US Global Change Research Program, 2000, http://www.usgcrp.gov/usgcrp/Library/nationalassessment/7MW.pdf, attached as Exhibit W, (The U.S. Global Change Research Program (USGCRP) is a government research program codified by Congress in the Global Change Research Act of 1990.) Full webpage: http://www.usgcrp.gov/usgcrp/Library/nationalassessment/overviewmidwest.htm

CORE Project that will not only protect public health from toxins and regional smog constituents, but also from Project greenhouse gases that will in turn exacerbate air pollution and public health threats.

<u>CORE Project CO2 and Methane Greenhouse Gas Emissions can be readily calculated by ConocoPhillips</u>

The CORE Project includes many new or expanded combustion sources that burn fossil fuels (especially high-carbon fuels which result in enormous CO2 emissions). Furthermore, the IEPA VOM definition exempts Methane, a potent Greenhouse Gas (GHG), 20 times stronger than CO2, which is a hydrocarbon commonly found with other hydrocarbon fuels in the refinery. Many emissions points in the refinery emit methane. Alternatives to the Project should have reviewed the environmental and social impacts of emissions of CO2 and Methane, which requires a quantification of these emissions. A full review of project alternatives should have also included prevention and/or mitigation for GHG emissions.

<u>CO2 Emissions estimates were provided by ConocoPhillips in Rodeo California for a recent major refinery expansion proposal (after public pressure)</u>

ConocoPhillips has publicly announced its plans to reduce Greenhouse Gas emissions. The company chairman and chief executive James J. Mulva reportedly stated: [37] *"Voluntary programs are not going to meet the challenge of climate change,"* Mr. Mulva said. *"The longer we wait - two or five years or more from now - it won't be mitigation, it will be adaptation."* Unfortunately, the ConocoPhillips Wood River CORE Project is moving drastically in the opposite direction, with much more energy-intensive processing of the very heaviest, high carbon inputs (from Canada Tar Sands).

ConocoPhillips is pursuing permits for major energy-intensive refinery expansions in other parts of the country, including Rodeo California. CP Rodeo, unlike the Wood River facility, provided analysis of GHG emissions in the Final Environmental Impact Report (Final EIR) required for the Project (although the Rodeo Draft EIR had no estimation for GHGs, and was only changed after public pressure to do so). The Final EIR provided an estimate of CO2 emissions increases for that project of about 1.25 million metric tons per year (about 1.33 million U.S. tons per year).[38] The GHG emissions inventory for the entire Bay Area was estimated by the BAAQMD at 85.4

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[37] *ConocoPhillips: The anti-Exxon: The Texas-based oil company breaks with the other U.S. majors to support mandatory national regulation of greenhouse gas emissions,* Fortune's Marc Gunther, April 11, 2007, attached as Exhibit X,

http://money.cnn.com/2007/04/10/news/companies/pluggedin_gunther_conocophillips.fortune/index.htm

[38] *ConocoPhillips Rodeo Refinery Clean Fuels Expansion Project, Final Environmental Impact Report, Volume 1 – Response to Comments,* Contra Costa County April 2007, Community Development Department, SCH 2005092028, LP 052048, page 2-6, excerpt attached as Exhibit Y

million tons per year of CO2 equivalents,[39] so the ConocoPhillips Rodeo Project increase **by itself** represents more than 1% of all Bay Area GHG emissions, including all Bay Area oil refinery, all power plants, all cars, trucks, ships, all consumer products, all agricultural sources, etc. This is an astonishingly large figure for one project increase by itself. Even this large number is likely underestimated.

The Wood River CORE Project is missing this estimation in its application, evaluation, and permit conditions, which must be corrected to include CO2 and methane emissions associated with the Project in order to demonstrate whether the Project benefits will outweigh the environmental and economic impacts as required.

The CORE Project expansion represents a much larger refinery and expansion (up to 385,000 barrels per day (bpd), compared to the ConocoPhillips Rodeo refinery 76,000 bpd refinery.[40] The CORE Project will involve extremely high-carbon material processing, which results in more CO2 emissions than lower carbon materials. CO2 emissions may be much higher for the CORE Project than for the ConocoPhillips Rodeo CA facility, which are already extremely large.

The Attorney General (AG) of the State of California filed an appeal to the County government agency which approved the Final EIR for ConocoPhillips Rodeo, because the Final EIR stated that since there were no published criteria for deciding whether these CO2 emissions were significant, they could not evaluate the significance of these emissions. The Attorney General's letter (attached) found that these emissions **increases** were larger than many of the State's Early Action measure **decreases**, effectively wiping out reductions made in other sectors to reduce GHG emissions. The Attorney General's letter asked the County to reconsider the impact of these major emissions.

The Greenhouse Gas emissions for the ConocoPhillips Wood River are likely to be even higher than for the Rodeo facility, can readily be calculated by ConocoPhillips, and need to be estimated to comply with Illinois regulations. Estimating these emissions also just makes plain good sense since the Project will set refinery practices and environmental and economic impacts for many decades.

V. Key issues need evaluation, including coking, PM.25, and others

There are many additional clear hazards from this Project, but the Project application failed to provide basic information for public analysis, and the time for public review was short considering the fact that the public had to pull together much basic data. ConocoPhillips should be required to supplement the application to provide information on these issues. IEPA should re-evaluate the Project taking into account these additional issues and re-open the comment period. Additional evaluations should include:

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[39] *Source Inventory of Bay Area Greenhouse Gas Emissions,* Bay Area Air Quality Management District, November 2006, 939 Ellis Street, San Francisco, California, 94109, page 5, http://www.baaqmd.gov/pln/ghg_emission_inventory.pdf
[40] http://www.eia.doe.gov/neic/rankings/refineries.htm, attached as Exhibit Z

- **An evaluation of emissions and impacts of increased coking at the facility including heavy metal, CO2, and other pollutant emissions** to air, water, and soil contamination. This is especially necessary given the proposed input of Canadian tar sands. The Project hearing transcript clearly records that this was not considered for the Project. Data on the range, minimum, and maximum concentrations of heavy metals, sulfur compounds, selenium, carbon content, and other contaminants in tar sands inputs to the refinery, impacts of these pollutants, should have been provided by ConocoPhillips. Tar sands are particularly heavy (high-carbon) inputs for the refinery, resulting in this Project in a large amount of coking and energy use. Pollution prevention methods and Project alternatives that would prevent associated heavy metal, CO2, and other emissions from coking operations should have been publicly evaluated.

  Attached is one document listing some impacts of coke use, and identifying SO2 and SO3 stack emissions and "a significant amount of heavy metals in the ash" as a negative impact of this fuel (*Challenges and Economics of Using Petroleum Coke for Power Generation* [41]). This document finds:

  > *The primary issues with this pulverized coke combustion technology are:*
  >
  > - *SO_X emissions -* ***The higher sulfur content in petroleum coke (exceeding 5 percent) is a negative for this fuel.*** *Sulfur in the coke is primarily converted to SO_2.* ***However, because of the significant amount of heavy metals such as vanadium in the ash, large amounts of SO_3 are also formed.*** *A wet FGD system, while capable of removing over 95 percent of SO_2, can scrub only about 20 percent of SO_3 [8]. Since SO_3 increases the flue gas dew point and the air heater exit gas temperature must be kept above the dew point, higher sulfur content adversely affects the boiler efficiency.* ***Control of SO_3 stack emissions would require a wet precipitator in addition to a dry electrostatic precipitator (ESP) and a wet FGD system.***
  > - *NO_X emissions -* ***The low volatile matter in coke makes this fuel harder to burn unless the firing temperature is raised, and longer residence time is provided. High flame temperature and a relatively high nitrogen content lead to higher relative nitrogen oxide (NO_X).*** *To achieve the desired residence time and reduce NO_X formation, a down-shot, low-NO_X burner design (if available) is often used. Further, with low-NO_X burners, the level of NO_X reduction is not as large as with the wall and tangential fired boilers. Thus a larger selective catalytic reduction (SCR) system may be required. For certain emission requirements levels, even a larger SCR may not be adequate. Low volatile content can also lead to higher unburned carbon and associated lower boiler efficiency.*

[41] World Energy Commission, http://www.worldenergy.org/wec-geis/publications/default/tech_papers/17th_congress/1_2_26.asp , attached as EXHIBIT Z2

Much more detailed data must be required of ConocoPhillips, rather than requiring the public to effectively provide the analysis by pulling together this information. Coking is a very high temperature and pressure process of the dirtiest, most contaminated bottom of the barrel refinery products and is a dangerous process. Emissions of contaminated particulate matter, other criteria pollutants, toxic heavy metals, and greenhouse gases can be extreme, especially considering fugitive emissions and accidental releases. These should all have been evaluated.

- **Full evaluation of emissions PM2.5 from the Project, including secondary formation of PM2.5 caused by SOx and NOx emissions** from the Project.
- **Evaluation of emissions and impacts of the Project to the public from irritating and harmful chemicals causing odors,** including odors due to flaring, fugitive H2S emissions from higher sulfur products at the refinery, and many other sources.
- **Evaluation of the many additional issues recorded in the public hearing transcript that went unaddressed.** The public brought up key environmental and health issues and questions about basic data and impacts of the Project. The transcript records show that many times, these issues were not evaluated. There should be a follow-up on all questions evaluated
- **Additional evaluation of BACT and LAER for sources including:**
    - **Replacing Slotted Guidepoles on Tanks with Unslotted Guidepoles** and requiring this for new and existing sources (Slotted Guidepoles on tanks are known to have huge emissions),
    - **Additional evaluation of emissions from existing refinery tanks**, which will have increased throughput due to the Project, which should be upgraded to BACT, and which should be listed in full for the entire refinery for an evaluation of baseline conditions including tank type, product, throughput, information on tank fittings and controls, past violations, tank degassing procedures, tank cleaning procedures, etc.,
    - **Venting of Pressure Relief Devices to gas recovery systems** (while adding sufficient compressor capacity so that this does not cause additional flaring),
    - **Air emissions from wastewater ponds** and/or wastewater tanks, (a major source of air emissions), evaluation of upstream controls to prevent contamination of wastewater that leads to air and water emissions of hydrocarbons and other pollutants, enclosure of any open wastewater systems, and data on concentration of hydrocarbons including lighter products and heavy diesel-range and other components in the wastewater.
    - **Fugitive emissions for the refinery as a whole to provide baseline conditions and increases due to the increased overall production** at the

facility which will likely lead to increased emissions of H2S and other fugitive emissions. Information on frequency of inspection of gas and liquid leaks from valves, flanges, pumps, and compressors, fugitive dust from coking operations, and information on any past violations of the facility relating to these operations. Lists should be provided including the numbers of all types of valves, flanges, pumps, and compressor seals, and evaluation of BACT and LAER application for all of these, including use of bellows sealed valves, double-sealed and magnetically sealed pumps and compressors, and backup compressors to allow maintenance without causing flaring.

In conclusion, it is urgent that the IEPA require ConocoPhillips to provide additional analysis on the matters identified above, and more importantly, additional pollution monitoring, reductions, and serious consideration of project alternatives. These issues will impact neighbors and the global and regional environment for decades to come and also cause permanent local and global impacts. Your time in scrutinizing and correcting these severe problems is well-appreciated. Thanks for your attention to these matters.

Sincerely,

Julia May

Environmental Consultant

Attachments, Exhibits A-Z, and Z2

--List of Electronic Filename attachments shown below

EXHIBIT D Success stories - How Valero Refining saved money by reducing waste, a pollution prevention case study_files
EXHIBIT U Illinois Climate Change Advisory Group_files
EXHIBIT X ConocoPhillips backs carbon regulation - Apr_ 11, 2007_files
EXHIBIT Z Top U_S_ Refineries - Energy Information Administration_ Energy Rankings_files
EXHIBIT Z2 CHALLENGES AND ECONOMICS OF USING PETROLEUM COKE FOR POWER GENERATION_files
EXHIBIT A CA Air Resources Board Bay Area fac SOx 2005
EXHIBIT B CA Air Resources Board South Coast fac SOx 2005
EXHIBIT C Texas Pt Source Inventory sorted by SIC
EXHIBIT D Success stories - How Valero Refining saved money by reducing waste, a pollution prevention case study
EXHIBIT E EPA Enforcement Alert on Flaring
EXHIBIT F BAAQMD Flare Monitoring Regulation 12 Rule 11 Comments Dr. Fox 2005
EXHIBIT G Final Comment JMay to BAAQMDon Draft Flare Rule April 2005
EXHIBIT H SCAQMD Staff Report PAR1118_DSR_SHP
EXHIBIT I BAAQMD flare rule1212_staffreport_0708
EXHIBIT J shell martinez CA flare minimiz plan
EXHIBIT K Shell flare emissions 2006
EXHIBIT L Shell Flare Partial 2007
EXHIBIT M BAAQMD Reg 1211 Flare Monitoring
EXHIBIT N BAAQMD reg 1212 flare control
EXHIBIT O TCEQ-Point Source List
EXHIBIT P Tesoro Oct 03 BAAQMD database
EXHIBIT Q Tesoro Avon CA 2004 flare emissions
EXHIBIT R ConocoPhillips Rodeo CA 2004 flare emissions
EXHIBIT S Flaring Prevention Measures Karras CBE
EXHIBIT T Delayed Coker Hazards
EXHIBIT U Illinois Climate Change Advisory Group
EXHIBIT V Illinois Governor execorder2006-11 on Climate Change
EXHIBIT W US National Assessment of Climate Change Midwest
EXHIBIT X ConocoPhillips backs carbon regulation - Apr_ 11, 2007
EXHIBIT Y Excerpt ConocoPhillips Rodeo CA Final EIR CO2 emissions
EXHIBIT Z Top U_S_ Refineries - Energy Information Administration_ Energy Rankings
EXHIBIT Z2 CHALLENGES AND ECONOMICS OF USING PETROLEUM COKE FOR POWER GENERATION

American Bottom Conservancy
P.O. Box 4242, Fairview Heights, IL 62208
abc@prairienet.org

June 16, 2007

Ms. Rachel Doctors
Hearing Officer
Illinois EPA

Via email Rachel.doctors@illinois.gov

Re: ConocoPhillips Wood River CORE Public Comments

Dear Ms. Doctors:

In our rush to submit public comment by the June 15 deadline, we inadvertently omitted some documents and comments on the ConocoPhillips (COP) Wood River Coker and Refinery Expansion (CORE) draft permit. We ask that you accept this additional public comment, which should arrive at the offices of the Illinois EPA at the same time as if we had submitted them by the Friday midnight deadline and sooner than if they had been postmarked and mailed by the deadline.

We appreciate that you extended the deadline by a week, but as we indicated in our request for an extension, there are three extremely complex permits and citizens were prejudiced by the short comment period. Because the comment would arrive at the IEPA office at the same time as comments emailed at midnight and even before comments postmarked by midnight Friday, June 15, there should therefore be no prejudice to ConocoPhillips. (We note that construction of the pipeline that would carry bitumen from the tar sands in Alberta, Canada, to the Wood River refinery for this project has not yet been authorized by the federal government. It is still in the draft Environmental Impact Statement phase of permitting.)

Should IEPA not agree to evaluate the cumulative impacts to air quality of the refining of tar sands and the use of tar sands-derived fuel on air quality as we requested in our earlier comment, we request that IEPA consider alternatives to the COP proposed process; i.e., primary upgrading by combined hydrocracking, hydrotreating and smaller coking units rather than relying primarily on delayed coking and hydrotreating as planned. Hydrocracking is a more sophisticated and modern process that, in tandem with smaller cokers and aggressive hydrotreating, would produce cleaner fuels, with less waste petroleum coke by-product. The combined hydrocracking-coking-hydrotreating process would also produce considerably more usable refined light products for the company. According to sources we have consulted, thermal coking without the hydrocracking step results in 65-70 per cent conversion rate to usable product as opposed to a much higher 85-92 per cent conversion rate from combined hydrocracking/after-coking/hydrotreating.

Tar sands are higher in cycloparaffins and aromatics and emit more particulates. We believe that the addition of a hydrocracking step—as used to great success in Canada—would result in lower emissions from the refinery and from tailpipes in the areas where the fuels would be used. This is especially important in the Greater St. Louis/Metro East area, which is nonattainment for both ozone and fine particulates. Our region would be impacted not only by dirtier diesel and gasoline tailpipe emissions but also from commercial and military aviation fuel emissions. We sit just under the takeoff and landing path for Lambert International Airport in St. Louis and are home to Scott Air Force Base in Belleville. The change from using six giant cokers as planned to a hydrocracker and smaller cokers would results in both substantially lower refinery emissions and water usage and pollution.

We also assume that ConocoPhillips would want to maximize its product output even though the combined hydrocracking-coking process would be more expensive than the older, cheaper, simple coking method. It is our understanding that the entire cost of the refinery expansion can be written off by ConocoPhillips for state and federal tax purposes. Fully half of the entire cost of the expansion can be written off the very first year it is in operation. See Attachment ABC1--2005 Energy Tax Incentives Act (title XIII of the Energy Policy Act of 2005), Section 179C. In addition, the hydrocracker should qualify for Illinois pollution control tax subsidies and perhaps even sales tax exemptions.

We also note that in the current Senate Finance Energy Bill Tax Title, reported out of committee on June 14, 2007, ConocoPhillips would be allowed to collect a $1 per gallon subsidy for renewable diesel fuel for the first 60 million gallons produced and 50 cents a gallon for every additional gallon. That is a substantial source of potential revenue for the company.

We also ask that you consider requiring ConocoPhillips to gasify its coke rather than shipping it to local utilities and that you require the strictest of controls on the gasification process and on the consumption of the syngas produced by that process which is used to displace consumption of natural gas as a plant fuel and source of hydrogen to make clean fuels.

ConocoPhillips can well afford the best available technologies and controls at the Wood River refinery. According to information on its website, www.conocophillips.com, its net income last year was $15.6 billion with a 26.5 per cent return to shareholders. In the first quarter of 2007, the company had a net income of $3.5 billion. Gasoline prices have been at historic highs and are predicted to go much higher. The cost per barrel of Canadian tar sands will be considerably less than conventional crude, although it is unlikely to cost consumers less at the pump, resulting in even higher profits to those companies using the cheaper, dirtier feedstock.

Electing a process that would produce more product would also help to deflect criticism leveled at big oil companies that they conspire to restrict supplies. (And although outside the purview of IEPA and this permit, increasing the size of the proposed pipeline from Alberta, Canada to ConocoPhillips' Wood River refinery from 30 inches to 36 or even 42 inches would also help increase supply, alleviate fuel shortages and further blunt critics' claims of supply manipulation.)

We also bring your attention to several papers obtained from the Lake Michigan Air Directors Consortium (LADCO) website (www.ladco.org): Midwest Regional Planning Organization (MRPO) on Petroleum Refinery Best Available Retrofit Technology (BART), (Attachment ABC2), and Attachment ABC3, an MRPO White Paper on Candidate Control Measures for Petroleum Refineries. Information about the ConocoPhillips Wood River Refinery indicates inconsistencies referred to in Julia May's comments and discrepancies between reported emissions and permitted emissions.

Thank you for your consideration of these additional comments.

Sincerely,

Kathy Andria

Kathy Andria
President.

Attachments

EXHIBIT A

(Portions omitted)

South Coast Oil Refinery SOx Emissions available from the California Air Res

Downloaded from California Air Resources Board (CARB) website, by J. May, Environmental Consu
FACILITY SEARCH RESULTS, Database year is 2005. Air Basin is SOUTH COAST. Sorted by SO
http://www.arb.ca.gov/app/emsinv/facinfo/factox.php?grp=1&dbyr=2005&all_fac=C&sort=PolHi&sho

CO	AB	FACID	DIS	FNAME
19	SC	131003	SC	BP WEST COAST PROD LLC BP CARSON REF
19	SC	800030	SC	CHEVRON PRODUCTS CO
19	SC	800089	SC	EXXONMOBIL OIL CORPORATION
19	SC	800026	SC	ULTRAMAR INC (NSR USE ONLY)
19	SC	800363	SC	CONOCOPHILLIPS COMPANY
19	SC	114801	SC	RHODIA INC.
19	SC	800370	SC	EQUILON ENTER. LLC, SHELL OIL PROD. US
19	SC	180001	SC	LOS ANGELES INT AIRPORT
19	SC	800362	SC	CONOCOPHILLIPS COMPANY
19	SC	131249	SC	BP WEST COAST PRODUCTS LLC,BP WILMINGTC
19	SC	25070	SC	LA COUNTY SANITATION DISTRICTS
36	SC	800181	SC	CALIFORNIA PORTLAND CEMENT CO (NSR USE)
19	SC	7427	SC	OWENS-BROCKWAY GLASS CONTAINER INC
19	SC	108701	SC	SAINT-GOBAIN CONTAINERS, INC.
19	SC	800075	SC	LA CITY, DWP SCATTERGOOD GENERATING STN
30	SC	180009	SC	JOHN WAYNE AIRPORT
33	SC	100154	SC	COLMAC ENERGY INC
36	SC	180024	SC	ONTARIO INT. AIRPORT
19	SC	8547	SC	QUEMETCO INC
19	SC	124838	SC	EXIDE TECHNOLOGIES
33	SC	1073	SC	US TILE CO
19	SC	42514	SC	LA COUNTY SANITATION DIST (CALABASAS)
19	SC	44577	SC	LONG BEACH CITY, SERRF PROJECT
30	SC	40196	SC	GUARDIAN INDUSTRIES CORP.
19	SC	117247	SC	EQUILON ENTERPRISES, LLC
19	SC	180007	SC	BOB HOPE AIRPORT
19	SC	49111	SC	SUNSHINE CANYON LANDFILL
19	SC	800183	SC	PARAMOUNT PETR CORP (EIS USE)
19	SC	35302	SC	OWENS CORNING
19	SC	106797	SC	SAINT-GOBAIN CONTAINERS, INC.
30	SC	45448	SC	GAS RECOVERY SYST LLC (COYOTE CANYON)
19	SC	50310	SC	WASTE MGMT DISP &RECY SERVS INC (BRADLE
19	SC	42633	SC	LA COUNTY SANITATION DISTRICTS (SPADRA)
19	SC	180008	SC	LONG BEACH-DAUGHERTY FIELD AIRPORT
30	SC	50418	SC	ORANGE COUNTY, IWMD(OLINDA)
19	SC	113873	SC	MM WEST COVINA LLC
30	SC	69646	SC	ORANGE COUNTY, IWMD (BOWERMAN)
19	SC	4477	SC	SO CAL EDISON CO
19	SC	37336	SC	COMMERCE REFUSE TO ENERGY FACILITY
19	SC	12912	SC	LIBBEY GLASS INC
19	SC	180013	SC	VAN NUYS AIRPORT
30	SC	115389	SC	AES HUNTINGTON BEACH, LLC
19	SC	800236	SC	LA CO. SANITATION DIST
33	SC	180026	SC	MARCH AIR FORCE BASE

EXHIBIT B

(Portions omitted)

RN	ACCOUNT	COMPANY	SITE	COUNTY	REG	SIC	PM10	PM2.5	VOC	NOX	SO2	CO
RN100219187	PG0044L	SAVAGE-HARRINGTON ENERGY	HARRINGTON STATION	POTTER	1	1241	94.50	33.61		0.00	0.00	0.00
RN100209329	CY0013T	DUKE ENERGY FIELD SERVICES LP	IMPERIAL	CRANE	7	1311	2.38	0.00	52.95	96.13	0.00	144.21
RN100209345	KD0008G	EXXONMOBIL CORP	RITA COMPRESSOR STATION	KENEDY	15	1311	0.34	0.34	1.88	40.14	0.00	62.06
RN100209436	EB0197H	DUKE ENERGY FIELD SERVICES LP	ANDECTOR PETROLEUM STN	ECTOR	7	1311	2.55	2.56	75.27	994.11	0.10	176.88
RN100209477	UA0156Q	ENBRIDGE PIPELINES (NE TEXAS) LP	INDIAN ROCK GAS PLANT	UPSHUR	5	1311	0.99	0.18	26.75	44.04	40.56	41.62
RN100209519	CY0015P	DUKE ENERGY FIELD SERVICES LP	CRANE BOOSTER	CRANE	7	1311	7.38	7.38	14.51	1,211.69	0.00	37.71
RN100209600	MR0118P	EAGLE ROCK ENERGY	STINNETT BOOSTER 12	MOORE	1	1311	0.21	0.21	14.20	23.27	0.01	39.17
RN100209667	JA0029O	ENBRIDGE GATHERING NORTH TEXAS LP	WIZARD WELLS COMP STA	JACK	3	1311	0.68	0.68	15.27	38.57	0.02	28.22
RN100209709	JF0016Q	ENTERPRISE HYDROCARBONS LP	THOMPSONVILLE GAS	JIM HOGG	15	1311	5.74	5.71	4.77	212.91	2.94	21.15
RN100209725	CF0066N	DUKE ENERGY FIELD SERVICE LP	CARSON BOOSTER	CARSON	1	1311	0.52	0.52	20.18	336.05	0.04	76.63
RN100209774	CI0175U	MASTERS RESOURCES LLC	A1 PLATFORM	CHAMBERS	12	1311	0.44	0.44	19.63	37.77	0.00	35.12
RN100209808	WN0069E	DEVON GAS SERVICES LP	MCALISTER	WISE	4	1311	2.26	2.26	16.08	77.80	0.00	116.31
RN100209960	RH0010G	ENBRIDGE PIPELINE TEXAS GATHERING LP	NW MENDOTA GAS PLANT	ROBERTS	1	1311	0.54	0.54	13.27	58.45	0.01	41.45
RN100210067	PE0016P	WESTERN GAS RESOURCES INC	GOMEZ GAS PLANT	PECOS	7	1311	8.99	8.99	17.56	101.11	314.83	93.65
RN100210265	RK0063D	WTG JAMESON LP	SALLIE ODOM STATION	RUNNELS	3	1311	0.83	0.83	6.61	24.26	67.48	36.11
RN100210616	HD0055B	DUKE ENERGY FIELD SERVICES, L.L.C.	HOLT STATION	HANSFORD	1	1311	0.00	0.00	35.30	47.06	226.81	69.81
RN100210681	RU0007C	EXXONMOBIL CORP	E TEXAS GAS PLT	RUSK	5	1311	1.82	1.82	26.42	87.65	2.70	140.51
RN100210699	UB0025V	DUKE ENERGY FIELD SERVICES LP	WEIR BOOSTER	UPTON	7	1311	2.82	2.82	49.66	132.18	0.58	143.70
RN100210905	MQ0063W	EXXONMOBIL CORP	CONROE CENTRAL	MONTGOMERY	12	1311	0.00	0.00	17.39	0.02	0.00	0.02
RN100211028	WC0031E	REGENCY GAS SERVICES WAHA LP	SOUTH PYOTE GAS	WARD	7	1311	0.00	0.00	10.95	50.33	0.27	34.81
RN100211069	CI0177Q	MASTERS RESOURCES LLC	F1 PLATFORM	CHAMBERS	12	1311	0.40	0.40	19.47	62.57	0.03	62.89
RN100211077	NA0100L	EXXONMOBIL CORP	TRAWICK CTRL TREATING STN	NACOGDOCHES	10	1311	2.62	2.62	31.22	84.96	0.00	72.56
RN100211275	GH0046V	EAGLE ROCK ENERGY	LEFORS RED RIVER COMPRESSOR	GRAY	1	1311	0.96	0.96	11.26	161.31	0.03	104.52
RN100211326	NA0078G	EXXONMOBIL CORP	TRAWICK EAST STATION	NACOGDOCHES	10	1311	2.14	2.14	18.58	88.03	0.00	15.65
RN100211465	RG0045V	HILCORP ENERGY CO	FANNIE HEARD LEASE	REFUGIO	14	1311	1.61	1.61	57.56	117.45	0.10	113.98
RN100211473	HT0016G	WEST TEXAS GAS PROCESSING LP	EAST VEALMOOR GAS	HOWARD	7	1311	13.68	13.66	82.72	777.05	126.84	533.77
RN100211499	NA0075I	EXXONMOBIL CORP	TRAWICK WEST	NACOGDOCHES	10	1311	1.43	1.43	17.00	57.05	0.00	10.46
RN100211622	MQ0007J	EXXONMOBIL CORP	CONROE COMPRESSOR STATION	MONTGOMERY	12	1311	12.03	12.03	63.62	658.63	0.00	81.58

RN	ACCOUNT	COMPANY	SITE	COUNTY	REG	SIC	PM10	PM2.5	VOC	NOX	SO2	CO
RN100211713	CI0010H	TEXAS PETROLEUM INVESTMENT CO	ANAHUAC COMPRESSOR STATION	CHAMBERS	12	1311	0.38	0.38	25.98	2.63	0.00	12.25
RN100211754	HT0059L	WEST TEXAS GAS PROCESSING LP	VEALMOOR	HOWARD	7	1311	4.42	4.42	31.41	209.35	0.00	77.75
RN100211846	UB0002K	NUSTAR JOINT VENTURE	WILSHIRE PLANT	UPTON	7	1311	4.97	4.97	26.95	342.38	9.21	159.91
RN100211895	HG2972B	KAISER-FRANCIS OIL COMPANY	NORTH MILTON	HARRIS	12	1311	1.69	1.69	18.35	2.13	0.03	29.87
RN100211960	DC0009S	OXY USA WTP LP	WELCH CO2 PLANT	DAWSON	7	1311	0.23	0.23	19.83	7.55	101.82	24.20
RN100212042	AA0045S	MOSBACHER ENERGY CO.	MOSBACHER ENERGY CO.	ANDERSON	5	1311	0.05	0.05	2.89	0.76	165.26	1.80
RN100212083	BI0008J	WEST TEXAS GAS PROCESSING LP	REINECKE COMPRESSOR STATION	BORDEN	7	1311	1.37	1.37	11.78	57.84	0.02	15.91
RN100212133	SQ0068T	DUKE ENERGY FIELD SERVICES LP	JUNO COMPRESSOR	SUTTON	8	1311	0.08	0.08	43.76	114.42	0.08	125.74
RN100212158	WN0035G	ENBRIDGE GATHERING NORTH TEXAS LP	WEST DECATUR PLANT	WISE	4	1311	2.05	2.05	10.14	46.32	0.03	23.28
RN100212190	BL0719M	HILCORP ENERGY CO.	HILCORP WILSON COMPRESSOR	BRAZORIA	12	1311	0.62	0.62	12.30	18.66	0.05	38.85
RN100212299	BI0011W	WTG GAS PROCESSING LP	GOOD BOOSTER STATION	BORDEN	7	1311	2.22	2.22	26.86	151.08	0.03	35.98
RN100212398	BL0421R	BLUE DOLPHIN PIPE LINE COMPANY	BUCCANEER PLANT	BRAZORIA	12	1311	0.02	0.02	3.32	1.98	0.00	0.30
RN100212414	CF0089B	PHILLIPS PETROLEUM COMPANY	BURNETT BOOSTER A	CARSON	1	1311	0.77	0.77	18.00	35.14	0.00	37.77
RN100212506	GJ0278E	ENBRIDGE PIPELINES EAST TEXAS LP	WILLOW SPRINGS PLANT	GREGG	5	1311	0.20	0.17	11.46	85.72	0.02	6.92
RN100212530	WN0217K	DEVON GAS SERVICES LP	EAST RHOME COMPRESSOR	WISE	4	1311	3.52	3.52	78.69	196.28	0.01	180.55
RN100212877	SO0007V	RANGE RESOURCES	CONGER GATHERING FACILITY	STERLING	8	1311	0.34	0.34	34.60	278.97	2.23	304.48
RN100212927	KE0007J	OXY USA WTP LP	SALT CREEK FIELD WS. NO. 8	KENT	3	1311	1.00	1.00	11.93	123.68	0.00	36.16
RN100213206	HG0230U	TANDEM ENERGY CORPORATION	TOMBALL COMPRESSOR STATION	HARRIS	12	1311	0.01	0.01	10.70	0.96	0.00	1.82
RN100213222	SJ0022L	DUKE ENERGY FIELD SERVICES LP	NELSON BOOSTER	SHERMAN	1	1311	0.23	0.23	16.26	104.96	0.00	6.56
RN100213362	HW0014A	DUKE ENERGY FIELD SERVICES, L.P.	SANFORD BOOSTER	HUTCHINSON	1	1311	1.04	1.04	16.62	302.92	0.08	302.92
RN100213396	SJ0017E	BP AMERICA PRODUCTION CO	HUDSON COMPRESSOR	SHERMAN	1	1311	1.37	1.37	3.08	174.09	0.03	22.29
RN100213503	MR0049F	DUKE ENERGY FIELD SVCS LP	BELVA BOOSTER	MOORE	1	1311	0.07	0.07	17.62	296.40	0.08	295.98
RN100213628	MR0097R	BP AMERICA PRODUCTION CO	SUNRAY GAS PLANT	MOORE	1	1311	1.41	1.31	56.20	141.60	113.94	214.70
RN100213834	HL0007V	DUKE ENERGY FIELD SERVICES, L.P.	URSCHEL BOOSTER	HEMPHILL	1	1311	0.00	0.00	30.00	418.75	0.10	54.17
RN100213933	LJ0028D	DUKE ENERGY FIELD SERVICES, L.P.	TWIN GROVE BOOSTER	LIPSCOMB	1	1311	0.29	0.29	6.44	53.10	0.02	63.10
RN100214022	CZ0006F	BELVAN CORP	MIDWAY LANE GAS PLANT	CROCKETT	8	1311	3.14	3.14	24.65	92.20	77.70	65.59

EXHIBIT C

(omitted)

EXHIBIT D

Search

Case Study Database

Add Story | Search Case Studies |

Valero Refining

Year Submitted: 2003
Process: Stack Gas Cleaning
Industry: Petroleum Refining
Wastes Reduced: Stack Emissions
Substance: SO2
Equipment: Spray Tower Absorber
Location: Corpus Christi TX
No. of employees: 485
Contact: Allan Schoen
Phone: (512) 289-3286

Description:

Valero determined that drastic reductions of SO2 and particulate emissions from the Fluid Catalytic Cracker Unit (FCCU)could be adchieved. With a new technologically advanced scrubber, emissions are less than the maximum allowed by fedral and state regulations.

P2 Application:

This scrubber design, by Belco Technologies Corporation, incorporates a patented spray tower absober followed by a filtering module and then ahydrocyclone water droplet separator. Theemission control technology exceeds EPA and TNRCC 'BACT' criteria for SO2 and particulate reductions. The project has reduced Valero's allowable emissions of SO2 from 178 ppm to 50 ppm. In addition, particulate emissions are 43% lower than EPA's new source performance standards for FCCU's, and have been verified by independent testing.

Environmental Benefits:

On-line continuous SO2 monitors demonstrate the unit can treat FCCU flue gas to less than 20 ppm SO2. The opacity is consistantly below 20%.

Details of Reductions

Source: TCEQ

EXHIBIT E

United States Environmental Protection Agency

Office of Enforcement and Compliance Assurance (2248A)

EPA 300-N-00-014 (revised)

EPA

Enforcement Alert

Volume 3, Number 9 | Office of Regulatory Enforcement | October 2000

Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases

Practice Not Considered 'Good Pollution Control Practice'; May Violate Clean Air Act

Flaring is an engineering practice that provides for process equipment to immediately release gases to a device (a flare) where they can be quickly and safely incinerated. The proper use of flares is a good engineering practice because flares can prevent damages, fires and explosions, and injuries to employees. Flaring also converts noxious and odorous gases released in emergencies to less hazardous and objectionable emissions by the burning of the gases.

But EPA investigations suggest that flaring frequently occurs in routine, nonemergency situations or is used to bypass pollution control equipment. This results in unacceptably high releases of sulfur dioxide and other noxious pollutants and may violate the requirement that companies operate their facilities in a manner consistent with good air pollution practices for minimizing emissions. New "clean fuels" requirements will lead to the removal of even greater

Continued on page 2

Frequent and routine use of flares may not be good air pollution control practice for reducing emissions. (Photograph courtesy of Kaldair Inc.)

Editor's Note: To clarify sulfur dioxide reporting requirements, this issue contains slight revisions to the sections, "Diagnosing, Preventing Excess Flaring," located on page 3 and "EPCRA Reporting Requirements for Flaring Incidents" on page 4. Please disregard the earlier issue.

About Enforcement Alert

"*Enforcement Alert*" is published periodically by the Office of Regulatory Enforcement to inform and educate the public and regulated community of important environmental enforcement issues, recent trends and significant enforcement actions.

This information should help the regulated community anticipate and prevent violations of federal environmental law that could otherwise lead to enforcement action. Reproduction and wide dissemination of this publication are encouraged.

For information on obtaining additional copies of this publication, contact the editor listed below.

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(Please Email all address and name changes or subscription requests for this newsletter.)

Continued from page 1

amounts of sulfur from feed stocks. Companies should ensure they have adequate capacity to treat these pollutants without resorting to excess flaring.

Good pollution control practices include:

1. Procedures to diagnose and prevent malfunctions; and

2. Adequate capacity at the back end of the refinery to process acid gas.

At petroleum refineries, flares are used in a variety of process areas to prevent hydrocarbons and waste gases from being released directly to the atmosphere. Since hydrocarbons are the primary *product at refineries*, companies should make every effort to avoid sending their products up in flames. Flares, however, are also used to combust acid gas—a highly concentrated waste stream of hydrogen sulfide gas (up to 90 percent pure)—and sour water stripper gas (about 30 percent pure).

Sulfur Recovery Plants (SRPs) normally process hydrogen sulfide gas and sour water stripper gas. A sulfur recovery plant is a refinery process for producing elemental sulfur for sale but is also a part of the refinery's air pollution control systems. The process converts 95 percent or more of these hydrogen sulfide gases into elemental sulfur while reducing emissions to insignificant levels. Use of a flare for combusting acid gas instead of processing it in the SRP produces very large uncontrolled releases of sulfur dioxide (SO_2) and effectively bypasses the permitted and monitored SRP emission point. While the flare is designed to prevent the direct release of the very toxic and odoriferous hydrogen sulfide during malfunctions at the SRP, EPA [illegible] documented situations of regular or routine use of flares for acid gas incineration instead of the expected reliance on the flare only for emergencies.

One day of acid gas flaring can easily release more SO_2 than is released in a single year of permitted SRP activity. On numerous occasions, EPA has uncovered information on acid gas flaring incidents that shows that **100 tons or more of SO_2 can be released in such flaring within a 24-hour period.** A moderately sized Claus sulfur recovery plant (approximately 100 long tons of sulfur recovered per day capacity) that is subject to the New Source Performance Standards and properly operated with its pollution control device should emit no more than 250 parts per million of SO_2, **a rate that corresponds to a little less than 100 tons annually.**

Hydrocarbon Flaring Considered Fuel Gas Combustion Subject to NSPS

The NSPS defines "fuel gas" to be any gas generated and combusted at a refinery and identifies flares as NSPS affected facilities. EPA's letter to Koch Petroleum Company (Dec. 21, 1999) provides a detailed explanation of the various types of gases subject that are to NSPS requirements because they meet the definition of fuel gas (see *http://www.epa.gov/oeca/ore/aed*).

The NSPS exempts flaring of fuel gas from the standards for sulfur oxides and monitoring requirements only when there is a process upset or an emergency malfunction (40 C.F.R. Section 60.104(a)(1)). This "plain English" exemption applies only to true emergencies, and the Agency expects other *flaring to be monitored and comply with applicable emission* limits.

EPA believes that many affected facilities at petroleum refineries may not be in compliance with applicable NSPS requirements (fuel gas monitoring and emission limits for fuel gas combustion devices) because of their routine reliance on flaring to control releases of hydrocarbons. The Agency also believes that, as with acid gas flaring, good air pollution control practices include investigating the causes of flaring events and taking corrective action to avoid or reduce the probability of their recurrence. One way to address these potential compliance issues may be through the proper design, operation and maintenance of flare gas recovery systems.

Health Dangers From Sulfur Dioxide

Flaring H_2S can produce high ambient concentrations of SO_2. Short-term exposures to elevated SO_2 levels while at moderate exertion may result in reduced lung function accompanied by such symptoms as wheezing, chest tightness, or shortness of breath in asthmatic children and adults. Other effects associated with longer-term exposures to high concentrations of SO_2, combined with high levels of particulate matter, can result in respiratory illness, alterations in the lungs' defenses, and aggravation of existing cardiovascular disease. Those at risk include individuals with cardiovascular disease or chronic lung disease, as well as children and the elderly.

Acid Gas Flaring

Routine or nonemergency "flar

Continued on page 3

Continued from page 2

of acid gas" is directing that gas away from the recovery plant, combusting it at a flare and releasing sulfur dioxide to the atmosphere. Acid gas flaring is not a federally permitted operation and should typically only occur during a malfunction (a "sudden, infrequent, and not reasonably preventable failure of equipment or processes to operate in a normal or usual manner") (40 C.F.R. Section 60.2). In EPA's experience, frequent and repetitive acid gas flaring is often not due to malfunctions. Acid gas flaring that is routine or preventable violates the NSPS requirement for operating consistent with 'Good Air Pollution Control Practices' to minimize emissions at refineries with NSPS fuel gas combustion devices and affected facilities including SRPs (40 C.F.R.Section 60.11(d)).

Chain Reaction: Upstream Upsets May Result in Downstream Malfunctions

Properly designed, operated and maintained SRPs can typically receive and treat all acid gas produced at the refinery (most also are designed to treat sour water stripper gas). These gases should not be flared except under emergency or malfunction conditions.

Upsets in upstream process equipment may result in hydrocarbons or other contaminants entering the acid gas stream. Hydrocarbons can be very disruptive to the short- and long-term operation of the SRP. Historically, not much effort has been put into investigating and correcting the root cause of contamination or upsets. Instead, incidents have been simply reported as "malfunctions." EPA, believes that repeated malfunctions for the same cause, generally, could be predicted and prevented. If flaring results from a preventable upset, EPA believes that it does not represent good air pollution control practices and that it may violate the CAA.

The Agency also believes that, as with acid gas flaring, good air pollution control practices include investigating the causes of flaring events and taking corrective action to avoid or reduce the probability of their recurrence.

Diagnosing, Preventing Excess Flaring

Repeated or regularly occurring incidents of flaring can be anticipated and should not be classified as 'malfunctions.' For example, regularly switching between high and low sulfur crude may cause fluctuations of the acid gas feed to the SRP. This can create operational problems for the SRP and/or its pollution control equipment, resulting in a perceived need to flare. These upsets should be addressed through improved operational control systems, improved and frequent training of operators, and continued optimal performance of the SRP, ***not by bypassing or flaring acid gas and sour water stripper gas.***

Another cause of flaring is inadequate capacity of the SRP and its associated tail gas unit (TGU) to process all the acid gas at the refinery. Refineries should ensure that their units have the capacity and can handle variable volumes that may occur during different production levels.

Refineries should implement the following procedures to ensure that flaring results only from a true emergency or malfunction:

- Conduct a root-cause analysis of each flaring incident to identify if any equipment and/or operational changes are necessary to eliminate or minimize that cause so as to reduce or avoid future flaring events. As appropriate, corrective measures should be taken and implemented. If the analysis shows that the same cause has happened before, the incident should not be considered a malfunction and corrective measures should be taken to prevent future occurrences;

- Ensure there is adequate capacity at the SRP and TGU. Redundant units can prevent flaring by allow-

Continued on page 4

BP Amoco Reduces SO_2 Emissions from Flaring Nearly 75%

From 1993 to 1995, the BP Amoco facility in Oregon, Ohio, experienced an annual average of 16 flaring incidents and released approximately 180 tons of SO_2. Under the procedures outlined in a Consent Decree with EPA, BP Amoco has been able to reduce that amount to an insignificant number (three flaring events in 1999 released a total of 49 tons of SO_2) and each event was attributable to a true "malfunction" as defined in NSPS. This was accomplished through equipment and operational changes that eliminated the root causes of such flaring. The protocol in the consent decree (*http://www.epa.gov/oeca/ore/aed*) serves as a model in balancing the concerns of Good Engineering Practice and good Pollution Control Practices for any flaring of acid gas or sour water stripper gas.

EPA
United States
Environmental Protection Agency
Office of Regulatory Enforcement
(2248A)
1200 Pennsylvania Avenue, NW
Washington, DC 20460

'Enforcement Alert' newsletter

Continued from page 3

ing one unit to operate if the other needs to be shut down for maintenance or an upset; and

■ Prepare an accurate estimate of the total SO_2 released (using clear calculation procedures) for each acid gas flaring incident.

Identifying the root cause of the flaring incident gives the refinery the opportunity to fix the problem before it happens again. It also enables the facility to assess whether the flaring incident was caused by a true malfunction, which is considered acceptable engineering practices.

A reference procedure for evaluating if good air pollution practices are being used when future acid gas flaring events occur can be found in the Consent Decree, C.A. No. 3:97CV7790 N.D. Ohio, entered May 5, 1999 (*see http://www.epa.gov/oeca/ore/aed*).

For more information, contact Patric McCoy at U.S. EPA's Region 5 office in Chicago at (312) 886-6869, E-mail: mccoy.patric@epa.gov; and regarding federally permitted release questions, contact Ginny Phillips, Office of Regulatory Enforcement, Toxics and Pesticides Enforcement Division at (202) 564-6139,Em[illegible] phillips.ginny@epa.gov.

EPCRA Reporting Requirements for Flaring Incidents

EPCRA Section 304 requires that unpermitted releases of extremely hazardous substances in excess of their reportable quantity be reported immediately to the State Emergency Response Commission and Local Emergency Planning Committee. The flaring of hydrogen sulfide may require reporting if more than 500 pounds, the reportable quantity of SO_2, are released within a 24-hour period. The *Clean Air Act* recognizes that accidents, malfunctions, start-ups and shut downs may cause excess emissions even when the facility has implemented reasonable measures to avoid them. However, it is still important to alert emergency response personnel when these releases occur, as even short periods of flaring can emit large quantities of SO_2. For example, a medium-sized refinery with an SRP that processes 500 tons of acid gas each day could release as much as 40 tons of SO_2 at the flare in only one hour, more than 150 times the reportable quantity.

Useful Compliance Assistance Resources

CAA Applicability Determination Index:
http://www.epa.gov/oeca/eptdd/adi.html

Technology Transfer Network
http://www.epa.gov/ttn/

Office of Regulatory Enforcement:
http://www.epa.gov/oeca/ore/

RCRA Online:
http://www.epa.gov/rcraonline/

Compliance Assistance Centers:
http://www.epa.gov/oeca/mfcac.html

Audit Policy Information:
http://www.epa.gov/oeca/ore/apolguid.html

Small Business Gateway:
http://www.epa.gov/smallbusiness/

EXHIBIT F

COMMENTS

on

Regulation 12
Miscellaneous Standards of Performance
Rule 11
Flare Monitoring at Petroleum Refineries
Draft
(April 7, 2003)

Prepared by

J. Phyllis Fox, Ph.D., P.E., DEE
Consulting Engineer
Berkeley, CA

April 16, 2003

Table of Contents

Exhibits

Ex. 1: Excerpts from SBCAPCD, Flare Study, July 1991.

Ex. 2: BAAQMD Source Tests, Marine Vessel Loading Emissions

Ex. 3: T.R. Blackwood, An Evaluation of Flare Combustion Efficiency Using Open-Path Fourier Transform Infrared Technology, Journal of the Air &Waste Management Association, v. 50, October 2000.

Ex. 4: Texas Clean Air Act, Subchapter H: Highly-Reactive Volatile Organic Compounds, Division 1: Vent Gas Control

Ex. 5: Roxar RFM FGM 130 Flare Gas Meter Vendor Literature

Ex. 6: Panametrics GF868 Mass Flowmeter Vendor Literature

Ex. 7: K.S. Mylvaganam, Ultrasonic Gas Flowmeters, Measurements & Control, December 1989.

Ex. 8: The Norwegian Petroleum Directorate, Regulations Relating to Measurement of Petroleum For Fiscal Purposes and For Calculation of CO_2 Tax

Ex. 9:Utah Department of Environmental Quality, Monitoring of Operations

Ex. 10: A. Chambers, Well Test Plume Monitoring – Literature Review, December 21, 2001.

Ex. 11: Articles reporting the use of remote-sensing, open-path optical methods to measure flare emissions.

COMMENTS

The proposed flare monitoring rule, Regulation 12, Rule 11, is a step in the right direction. However, it contains a large number of exemptions which substantially limit its effectiveness. The rule exempts thermal oxidizers, purge gases, pilot gases, and flares that serve storage tanks, loading racks, marine terminals, wastewater treatment systems, pumps, sulfur recovery plants, ammonia services, and flexicokers. It also exempts releases that are less than certain time and volume triggers for ex-situ sampling, which effectively excludes up to 93% of the episodic flaring events. Finally, the rule, which purports to collect data to determine emissions, paradoxically does not require any actual monitoring of flare emissions themselves, but instead monitors only the input to the flares, crudely estimating emissions by assuming that all flares under all conditions will destroy 98% of the pollutants in the vented gases. These exemptions must be eliminated and the rule modified to require meaningful monitoring of actual flare emissions.

I. Exemptions Are Unreasonable (12-11-110)

I.A Thermal Oxidizers

The rule distinguishes "flares" and "thermal oxidizers," exempting the latter. The description of the rule in Section 101 notes that the "purpose of this rule is to require monitoring and recording of emission data for *flares* at petroleum refineries." (Emphasis added). Sections 112 and 113 exempt "thermal oxidizers" used to control emissions from wastewater treatment systems and pumps. The definitions in Section 200 distinguish flares and thermal oxidizers. The staff report notes that "the rule applies to the flares that are listed in this staff report and not to thermal oxidizers and other abatement devices." (Staff Report, p. 20.) The staff report also claims that the exempt thermal oxidizers have negligible emissions. (Staff Report, p. 20.) However, the staff report provides no justification for either this distinction or the assumed de minimus emissions.

A thermal oxidizer is a flare. In 1991, Santa Barbara County Air Pollution Control District ("SBCAPCD") prepared a flare study that distinguishes the various types of flares. (SBCAPCD 7/91.[1]) This study notes that there are two types of flares, open pipe flares and cascade flow controlled flares ("CFCFs"). The open pipe flare releases flared gases out of the end of a pipe into the air before combustion is commenced. The CFCF premixes vent gases with air in a bank of burners before combustion is initiated. The CFCF includes thermal

[1] Santa Barbara County Air Pollution Control District (SBCAPCD), Flare Study, Phase I Report, July 1991.

oxidizers and enclosed ground flares. The thermal oxidizer is distinguished from other CFCF systems by the use of a stack to funnel combustion gases produced inside the thermal oxidizer to above ground elevations. Excerpts from the Santa Barbara study that define these classes of flares are included in Ex. 1. The Santa Barbara definition is consistent with industry nomenclature, which likewise recognizes two classes of flares that include thermal oxidizers.[2] Thus, the District has exempted from regulation all thermal oxidizers, which are flares and should be covered by Regulation 12, Rule 11.

The draft Title V permits indicate that there are 21 thermal oxidizers at the five refineries that would be excluded from the flare regulation.

Refinery	Number of Thermal Oxidizers for Controlled Sources
Chevron[a]	–9 for compressor and pump seals –1 for wax deoiler
Shell Martinez[b]	–1 for marine terminal –3 for sulfur plant
Phillips 66[c]	–1 for marine terminal
Tesoro[d]	–1 for dissolved air flotation air stripper –4 for compressor and pump seals serving gasoline pipelines, alkylation unit, hydrocracker unit, etc.
Valero[e]	–1 for wastewater treatment plant

[a] Bay Area Air Quality Management District, Proposed Major Facility Review Permit, Chevron Products Company, Facility #A0010, http://www.baaqmd.gov/permit/t5/PERMITS/ PROPOSED/A0010.pdf, accessed April 15, 2003.

[b] Bay Area Air Quality Management District, Proposed Major Facility Review Permit, Shell Martinez Refinery, Shell Oil Products US, Facility # A0011, http://www.baaqmd.gov/ permit/t5/PERMITS/PROPOSED/A0011.pdf, accessed April 15, 2003.

[c] Bay Area Air Quality Management District, Proposed Major Facility Review Permit, Tesoro Refining and Marketing Company, Facility #B2758 & Facility #B2759, http:// www.baaqmd.gov/permit/t5/PERMITS/PROPOSED/b2758-b2759.pdf, accessed April 15, 2003.

[d] Bay Area Air Quality Management District, Proposed Major Facility Review Permit, Phillips 66 Company - San Francisco Refinery, Facility A0016, http://www.baaqmd.gov/ permit/t5/PERMITS/PROPOSED/A0016.pdf, accessed April 15, 2003.

[e] Bay Area Air Quality Management District, Proposed Major Facility Review Permit, Valero Refining Co. - California, Facility #B2626, http://www.baaqmd.gov/permit/t5/ PERMITS/PROPOSED/b2626.pdf, accessed April 15, 2003.

[2] K. Banerjee, N.P. Cheremisinoff, and P.N. Cheremisinoff, Flare Gas Systems Pocket Handbook. Methods, Formulas, and Guidelines for Flare System Design, Gulf Publishing Company, *Houston, TX*, 1985.

The blanket exemption for thermal oxidizers and the specific exemptions for wastewater treatment systems and pump thermal oxidizers (§112, 113) should be eliminated unless the District demonstrates that thermal oxidizers emit negligible amounts of hydrocarbons and SO_2.

I.B Organic Liquid Storage And Distribution (12-11-110)

Section 110 exempts "flares" used to control emissions exclusively from organic liquid storage vessels subject to Regulation 8, Rule 5 or exclusively from loading racks subject to Regulation 8, Rules 6, 33, or 39. The staff report claims that these flares control "relatively small and relatively clean gas streams. The devices do not have any potential for significant emissions." (Staff Report, p. 20.) The District's staff reports for these rules indicate that uncontrolled emissions from these sources are considerable and would remain considerable if vented to flare.[3]

The District's emission inventory,[4] which is incomplete, suggests emissions are high enough to warrant concern. The only refinery that reported storage and distribution emissions in 2001 was Shell,[5] even though the Title V permits indicate that other refineries have flares that process gases from storage and distribution systems. The emissions from the Shell tank flares were 1.2 ton/yr of VOCs and 0.1 ton/yr of SO_2. However, these emissions were likely estimated assuming a high and undocumented control efficiency. Further, BAAQMD inventories for the other refineries did not contain any data on storage and distribution flares. The requirements these sources are subject to Regulation 8, Rules 5, 6, 33 and 39 do not require flow and composition monitoring or emission reporting consistent with Regulation 12, Rule 11. Thus, the data required to accurately estimate emissions and develop future control strategies would not be collected, and monitoring is warranted.

Therefore, the exemption for organic liquid storage and distribution is not justified. This exemption should only be allowed on a case-by-case basis if a study demonstrates that there are no significant organics in any of the streams that would be vented to a subject flare under all plausible routine and emergency

[3] See, for example, Bay Area Air Quality Management District (BAAQMD), Rule Effectiveness Study, Storage Tanks for Organic Liquids (Regulation 8 Rule 5), January 16, 1992.

[4] 1993-2001 BAAQMD Emissions Inventory, Excel spreadsheets obtained from Adan Schwartz, BAAQMD, June 13, 2002.

[5] The Title V permits for Chevron, Phillips 66, Tesoro, and Valero refineries do not indicate the existence of any flares for the refineries' distribution and storage system; Tesoro has one thermal oxidizer that serves the pipeline.

operating conditions. If this exemption is retained based on such a study, the study conclusions should be periodically reconfirmed by unannounced District inspections and a minimum of two random samples of vent gases per year.

I.C Marine Vessel Loading Terminals (12-11-111)

Section 111 exempts "flares" used to control emissions exclusively from marine vessel loading terminals subject to Regulation 8, Rule 44. The staff report provides no justification for this exemption. The section labeled "Exemption, Marine Loading Terminals," discusses the wastewater treatment system exemption, not the marine vessel loading exemption.

Emissions from marine vessel loading terminals are very high,[6,7] which prompted the District to adopt Regulation 8, Rule 44 in 1989. A typical loading event of 250,000 barrels of fuel oil would release 0.2 tons of VOC; 250,000 barrels of light cycle oil would release 4.3 tons of VOCs; and ballasting, based on 10% of the capacity of a 2 million barrel vessel would release 2 to 18 tons of VOCs. (BAAQMD 12/02, p. 13[8]) The composition of vent gases from some typical loading events are documented in District source tests included in Exhibit 2, which demonstrate that emissions are significant. Many millions of barrels of these products are loaded every year at marine terminals serving Bay Area refineries. Therefore, the potential emissions, even when controlled by flares, are large and should not be exempted.

The current marine vessel loading terminal rule, Regulation 8, Rule 44, only requires that VOCs be reduced to 2 pounds of VOCs per 1000 barrels of organic liquid loaded or by 95%, significantly lower than the 98% tacitly assumed in the flare rule for estimating emissions. This rule also exempts certain classes of cargoes from regulation, which will likely be regulated in the future and thus potentially vented to flares. (BAAQMD 12/02.) Further, Regulation 8, Rule 44 does not require any of the monitoring and reporting required by Regulation 12, Rule 11, *e.g.*, continuous velocity, molecular weight, and composition data. This monitoring is essential to estimate emissions from flares and evaluate the need for controls. Finally, Regulation 8, Rule 44 does not even require that the 95% VOC control efficiency be demonstrated. The District

[6] Alyeska Pipeline Service Company, Report on Valdez Tanker Loading Vapor Emission Testing and Evaluation, October 22, 1990.

[7] Bay Area Air Quality Management District (BAAQMD), 8-31 Marine Emissions Study Final Report, 8-31 Technical Advisory Committee, December 1978.

[8] Bay Area Air Quality Management District (BAAQMD), Technical Assessment Document, Further Study of Measure 11 (FS-11), Regulation 8, Rules 44 and 46, Marine Loading Operations, Draft Revision 3, December 2002, p. 13.

recently discovered that its emission factors for unregulated cargos are not consistent with source tests and its emission inventory of marine terminal emissions underestimates emissions by assuming that 100% of unloading emissions are controlled to 95%, ignoring the exempted cargos. (BAAQMD 12/02, p. 2.) Thus, there is no reliable data to confirm that flares at marine vessel loading terminals have negligible emissions or would otherwise be in compliance with Regulation 12, Rule 11. Therefore, the exemption for flares that serve marine terminals in Section 12-11-112 should be eliminated.

I.D Wastewater Treatment Plant Flares (12-11-112)

Section 112 exempts thermal oxidizers used to control emissions exclusively from wastewater treatment systems subject to Regulation 8, Rule 8. Comment I.A notes that thermal oxidizers should not be exempted per se, because they are flares. Notwithstanding this issue, the staff report argues that thermal oxidizers used to control emissions from wastewater treatment systems should be exempt because they are used solely as control devices, and "there is no potential for significant emissions." (Staff Report, p. 20.). This is inconsistent with the District's emissions inventory,[9] which shows annual VOC emissions in 2001 of 2.0 tons from the wastewater treatment flare at Valero.

First, all flares are control devices. Thus, the designation of a flare as a control device is not a valid basis for exempting it from Regulation 12, Rule 11. Second, these flares are a potentially significant source of VOCs. The District estimates that wastewater treatment systems currently emit about 4 ton/day of VOCs. (BAAQMD 1/03,[10] p. 1.) The existing regulation allows the use of a vapor recovery system to control 95% of the emissions subject to regulation. Assuming that 100% of the current emissions of 4 ton/day were reduced by 95% using flares, daily emissions from wastewater treatment systems would be 0.2 ton/day or 73 ton/yr. Thus, these emissions are significant enough to warrant concern. Third, Regulation 8, Rule 8 does not require any of the monitoring and reporting required by Regulation 12, Rule 11, which is essential to estimate emissions from flares and evaluate the need for controls. Therefore, the exemption for wastewater treatment plant flares should be eliminated.

[9] 1993-2001 BAAQMD Emissions Inventory, Excel spreadsheets obtained from Adan Schwartz, BAAQMD, June 13, 2002.

[10] Bay Area Air Quality Management District (BAAQMD), Draft Technical Assessment Document: Potential Control Strategies to Reduce Emissions from Refinery Wastewater Collection and Treatment Systems, 3rd Draft, January 2003..

I.E Sulfur Recovery Plant Flares (12-11-114)

Section 114 exempts flares that exclusively serve a sulfur recovery plant from the monitoring and reporting of hydrocarbon and methane composition in Sections 401.2, 401.3, 401.5, and 502.3. Velocity monitoring and sulfur monitoring would be retained. The staff report indicates that vent gases to these flares contain no hydrocarbons. (Staff Report, p. 20.) However, the staff report presents no data to support this position. This is inconsistent with the District's emission inventory, which shows annual VOC emissions in 2001 of 0.6 tons from two of Shell's sulfur recovery plant thermal oxidizers. Similarly, an upset of Tesoro's sulfur plant in December 2002 released 0.4 ton of VOCs (including methane) and 0.3 ton of POCs (excluding methane).[11]

The tail gases in sulfur plants are typically incinerated in a thermal oxidizer, not flared, pointing to the District's inconsistent usage of the terms "flare" and "thermal oxidizer." Measurements of exhaust gases from two separate tail gas incinerators indicate that elevated concentrations of organic compounds are present, including benzene, ketones, and aldehydes. (Almega 1990;[12] Unocal 1991.[13]) Thus, the gases vented to the incinerator must contain organic compounds if they are present in the exhaust gases.

Alternatively, if a flare, in addition to a tail gas incinerator, were present at a sulfur recovery plant, it should also be covered by this rule. Several gas streams could be vented to such a flare in an emergency – acid gases entering the front end of the sulfur recovery plant and waste gases from various points in the sulfur recovery process up to and including the gases vented to the tail gas incinerator. Acid gas is the combined offgas stream from upstream processing units. Acid gas contains elevated concentrations of organics, including ketones, benzene, and other hydrocarbons. (Unocal 1991, Table 4-23.)

Thus, the exemption for sulfur plant flares (and thermal oxidizers) is not justified because the vent gases likely to be sent to such a flare may contain elevated concentrations of organic compounds. This exemption should only be allowed on a case-by-case basis if a study demonstrates that there are no organics in any of the streams that would be vented to a sulfur plant flare under all

[11] Letter from Alan A. Sasvage, III, Tesoro, to Christine Schaufelberger, BAAQMD, Re: December 2002 Flare Report, January 14, 2003.

[12] The Almega Corporation, AB2588 Pooled Source Emission Test Program, v. I, Summary Report, Prepared for Western States Petroleum Association, 1990, Table 16.

[13] Unocal, Environmental Monitoring Plan, Supplemental Environmental, v. I, Trip 2 Report, Prepared by J. Phyllis Fox for Unocal Energy Mining Division, October 1, 1991, Section 4.1.10, Upgrade Sulfur Plant.

plausible routine and emergency operating conditions. If this exemption is retained based on such a study, the study conclusions should be periodically reconfirmed by unannounced District inspections and a minimum of two random samples of vent gases per year.

I.F Flexicoker Flares (12-11-114)

Section 114 exempts flares that exclusively burn flexicoker gas with or without supplemental natural gas from the monitoring and reporting of hydrocarbon and methane composition in Sections 401.2, 401.3, 401.5, and 502.3. The staff report indicates that vent gases to these flares contain no hydrocarbons "aside from methane in the case of flexi-coker gas." (Staff Report, p. 20.) This is inconsistent with the District's emission inventory, which shows annual VOC emission in 2001 from Shell's OPC1 flexigas flare of 11 tons. Further, Shell's monthly flaring reports to the District indicate that 14 tons of VOCs were released from this flare over the period June 2002 through February 2003, based on a 99.5% control efficiency.

Methane is monitored in other vent gases (§502.3). Methane is also present at elevated concentrations in flexicoker gases at about 1% by volume.[14] It is inconsistent to monitor methane in other vent gases and exclude it from flexicoker vent gases. Further, trace amounts of other hydrocarbons may also be present including ethylene, ethane, propylene, and propane.[15] Finally, flexicoker vent gases are very low Btu gases, typically having a heat content less than 200 Btu/scf. Shell, for example, reports the heat content of its flexicoker gases as 120 Btu/scf. Thus, flares burning these gases without added fuel would not be in compliance with 40 CFR 60.18 unless fuel is added to raise the net heat content. If fuel were not added, the control efficiency of the flare would drop well below the assumed 98% control efficiency in Section 401.5. Combustion efficiencies as low as 55% have been reported when flaring gases with heating values similar to flexicoker gases.[16] Further, the proposed rule does not restrict the type of fuel that may be added, which could include refinery fuel gas, naphtha, or other fuels containing high concentrations of hydrocarbons.

Thus, the exemption for flexicoker flares is not justified because the vent gases may contain elevated concentrations of methane and other hydrocarbons

[14] Charles E. Baukal, Jr. (Ed.), The John Zink Combustion Handbook, CRC Press, Boca Raton, FL, 2000, Table 5.5.

[15] Robert A. Meyers, Handbook of Petroleum Refining Processes, 2nd Ed., McGrawHill, Boston, MA, 1996, Chapter 12.1

[16] Marc McDaniel, Flare Efficiency Study, U.S. EPA Report EPA-600/2-83-052, July 1983, Table 5.

originating from the flexicoking process itself plus added fuel required to comply with the heat content limits of 40 CFR 60.18. This exemption should only be allowed on a case-by-case basis if a study demonstrates that there are no organics in the flexicoker gas plus added fuel under all plausible emergency and routine operating conditions. If this exemption is retained based on such a study, the study conclusions should be periodically reconfirmed by unannounced District inspections and a minimum of two random samples of vent gases per year.

II. Definitions Are Inadequate (12-11-200)

II.A Flare (12-11-201)

A flare is defined as "a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. This term includes both ground and elevated flares." A flare is distinguished from a "thermal oxidizer," which is excluded from this rule, by defining it as "[a]n enclosed or partially enclosed combustion device that is used to oxidize combustible gases and that generally comes equipped with controls for combustion chamber temperature and often with controls for air/fuel mixture." § 208. This definition includes enclosed ground flares, which the District has arbitrarily included under its definition of "flares," creating a dichotomy that will likely lead to future disputes over the definition of these terms. Further, as discussed in Comment I.A, a thermal oxidizer is actually a cascade flow controlled flare, which is normally categorized as a flare. Further confusing the matter, "flaring" is defined as "[a] high-temperature combustion process used to burn vent gases." § 202. Thus, flaring includes the processes that occur in both "flares" and "thermal oxidizers," which the District attempted to distinguish. Thus, we recommend that the definition for thermal oxidizer be removed and included under the definition for flare.

II.B Vent Gas Exclusions (12-11-209)

Section 209 defines vent gases, which are monitored in this rule, as excluding assisting air or steam, flare pilot gas, and any continuous purge gases. The rule requires that volumetric flows of purge and pilot gases be monitored, but not their composition. § 504. Hydrocarbon-containing gases, such as refinery fuel gas or waste gases could be used for both the pilot gas and purge gas. Thus, the composition of the pilot gas and purge gas should be separately determined for each flare to provide data to assess whether controls are warranted on these potential emission sources.

III. Reporting Requirements Are Inadequate (12-11-401)

III.A Public Access To Reports And Supporting Data

Section 401 requires that monthly reports in electronic format be submitted to the APCO. The various subsections of this rule require summaries of volumetric flow rates of vent gas data, gas composition data, and mass emission rates. Due to the substantial delays the public has encountered in obtaining information from the District, we recommend that this rule be modified to facilitate public access to the resulting reports and supporting data as follows:

- The monthly reports should be posted on the District's website within 24 hours of receipt.
- A copy of the monthly reports should be placed in the District's library and the main library in each community that hosts a regulated flare.
- A CD should be prepared that contains all supporting data. A copy of this CD should be placed in the District's library and the library in each community that hosts a regulated flare. The CD should be distributed by the District's Public Information and Education Division and noticed on the District's website.

III.B Flare Efficiency Is Too High (12-11-401.5)

The reporting requirements allow calculations of mass emission rates to assume a flare control efficiency of 98%. § 401.5. However, flaring control efficiency depends on a number of factors, including heat content of the gas, exit velocity, flare operating conditions, flare design and wind speed, among others. The staff report reviews the literature, concluding "all of this research suggests that efficiency may be lower than 98% for low-Btu gases, high stack exit velocities, and high winds." (Staff Report, p. 7.) Nevertheless, the proposed rule tacitly assumes that all flares under all conditions will achieve a 98% control efficiency. The actual efficiency may be much lower, resulting in a substantial underestimate of flaring emissions. The District cannot accurately estimate flare emissions unless the control efficiency for each subject flare is measured under the full range of operating conditions.

The literature cited by the District indicates that flare efficiency ranges from 62% to over 98%. Only one of the studies reviewed by the District, Boden et al. (1996),[17] supports a *flaring efficiency of 98% or greater.* This study only measured C_1 thru C_6 alkanes in the flared gases, ignoring soot, CO, non-alkanes, and higher molecular weight alkanes, which are products of incomplete combustion. Thus, this study underestimated flaring efficiency by an indeterminate amount.

The other flare efficiency studies that the District reviewed report flaring efficiencies much less than 98% under some conditions. One recent study of Alberta oil field flares reported the average combustion efficiency for two flares (39 ft. high, 8 in. dia; 49 ft. high, 3 in. dia.) was below 70%.[18] Another study reported efficiencies of 62% (high flow rates) to 71% (low flow rates, controlled by knockout drum) when flare gases containing no H_2S and 82% to 84% when flaring sour, 23 wt% H_2S gases.[19] Similarly, the efficiency of oil field flares in Nigeria ranged from 80% to over 98%.[20] The Alberta studies suggested that entrainment of air into the region of combusting gases restricted flame sizes to less than optimum values. The resulting flames are too small to dissipate sufficient heat to result in high combustion efficiencies. This conclusion is consistent with wind tunnel experiments, which showed that a low exit velocity makes flames susceptible to wind effects and reduces flare efficiency.[21] These studies were analyzed to develop a model that predicts flare efficiency as a function of wind speed, stack exit velocity, flame temperature, stoichiometric mixing ratios, and other parameters.

The District dismisses the Alberta studies, which found the lowest efficiencies, because a subsequent study (Ex. 3: Blackwood 2000[22]) appeared to

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[17] J.C. Boden, K. Tjessem, A.G. Wotton, and J.T.M. Moncrieff, Elevated Flare Emissions Measured by Remote Sensing, Petroleum Review, November 1996, pp. 524-528.

[18] D.M. Leahey, K. Preston, and M. Strosher, Theoretical and Observational Assessments of Flare Efficiencies, Journal of the Air & Waste Management Association, v. 51, December 2001, pp. 1610-1616.

[19] M. Strosher, Investigations of Flare Gas Emissions in Alberta, Final Report to Environment Canada Conservation and Protection, the Alberta Energy and Utilities Board, and the Canadian Association of Petroleum Producers, November 1996.

[20] C.I. Ozumba and I.C. Okoro, Combustion Efficiency Measurements of Flares Operated by an Operating Company, Society of Petroleum Engineers Paper SPE 61025, SPE International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production, Stavanger, Norway, June 2000.

[21] M.R. Johnson, O. Zastavniuk, D.J. Wilson, and L.W. Kostiuk, Efficiency Measurements of Flares in a Cross Wind, Presented at Combustion Canada, Calgary, Alberta, May 26-28, 1999.

[22] Thomas R. Blackwood, An Evaluation of Flare Combustion Efficiency Using Open-Path Fourier Transform Infrared Technology, Journal of Air and Waste Management Association, v. 50, October 2000, pp. 1714-1722.

refute the wind velocity and air entrainment theory. (Staff Report, p. 7.) The District claims that Blackwood concluded that the efficiency of a large carbon monoxide flare was 95% while the Alberta wind model predicted only 30%. *Ibid.* However, the District does not fully disclose the conclusions of the Blackwood study. The Blackwood study used tracers and open-path Fourier transform infrared ("OP-FTIR") technology to measure flare control efficiency. This study actually reported that "[t]he average of all calculated values was 87%, with a range of 49-99%." The 95% efficiency cited by the District is only the most frequently observed frequency. (Ex. 3: Blackwood 10/00, p. 1718.) Elsewhere, Blackwood notes: "This study shows the efficiency of CO combustion for these flares is about 95% under the conditions discussed.... Since there were long periods of time when the efficiency was below the most frequently occurring efficiency, and due to the uncertainty of the tracer stability, the efficiency may be lower than what is reflected by this study. Until [the Alberta oil field model] can be revised to account for the factors that cause the variability, the combustion efficiency for gases containing primarily CO should be considered to be at least 80%." (Ex. 3: Blackwood, 10/00, pp. 1721-22.)

Thus, the available data is contradictory, incomplete, and inadequate to draw any blanket conclusions on flaring efficiency, such as the District has done. The Texas Natural Resources Conservation Commission ("TNRCC"), when confronted with this same dilemma in developing its vent gas control rule, took a two-pronged approach. The TNRCC vent gas rule (Ex. 4: TCAA[23]) requires that emissions be calculated "assuming a 98% destruction efficiency when the flare is in compliance with heating value and exit velocity requirements of 40 CFR §60.18. During periods when the flare is not in compliance with the heating value and exit velocity requirements of 40 CFR §60.18, a destruction efficiency of 93% shall be assumed to calculate HRVOC mass emission rates." TCAA §115.725(d)(6). The North Carolina Administrative Code ("NCAC") similarly only allows the use of a 98% destruction efficiency when the requirements of 40 CFR 60.18 are met. NCAC S 34 D-900-66.0944(f).

The 93% destruction efficiency in the TNRCC rule was based on the approximate median destruction efficiency from selected flare tests conducted during EPA flare studies in the 1980s. (TCEQ,[24] p. 82.) *In response to comments* from Environmental Defense, the Commission contracted for a study to determine flare destruction efficiency, scheduled to be completed by May 1, 2004, which "may be used to refine requirements for flares." *Ibid.*

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[23] Texas Clean Air Act (TCAA), Subchapter H: Highly-Reactive Volatile Organic Compounds, Division 1: Vent Gas Control.

[24] Texas Commission on Environmental Quality (TCEQ), Chapter 115 - Control of Air Pollution from Volatile Organic Compounds, Rule Log Numbers 2002-046b-115-AI and 2002-046d-115-AI.

Thus, the District's reliance on a single 98% destruction efficiency is not supported by the record nor the decisions of other agencies when confronted with similar facts. The rule should be modified to require each refinery to conduct a study to accurately determine the destruction efficiency of each flare subject to this rule for the range of conditions likely to be encountered during routine and emergency operation, including vent gas composition (including heat content), throughput, flare design and operation (steam injection, fuel gas), and ambient conditions. The study is further described in Comment V.D. The results of these studies should be used to revise Section 401.5.

We also recommend that Section 401.5 be amended to adopt the TNRCC approach to calculating flare emissions until the results of flare efficiency studies are available. An efficiency of 98% should only be allowed when the requirements of 40 CFR 60.18 are met. At all other times, the lowest reported efficiency in studies reviewed by the District for a large flare, or 80% (Ex. 3: Blackwood 2000), should be required until the efficiency studies are completed.

IV. Vent Gas Flow Monitoring Is Inadequate (12-11-501)

Section 501 requires that vent gas to the flare be continuously monitored for volumetric flow using a device that can detect a minimum velocity of 0.1 foot per second ("ft/sec"). § 501.1. However, this section does not contain adequate requirements to assure that the full range of flows will actually be measured. Further, it does not require measurements of related parameters required to estimate flows, nor does it specify the required accuracy of the velocity meter.

IV.A Flow Range (12-11-501.2)

Even though Section 12-11-501.2 requires that a meter be selected that is capable of measuring a minimum velocity of 0.1 ft/sec, it only requires that the flow monitoring device continuously measure flow in the range of 0.5 to 275 ft/sec. § 501.2. The lower and upper ends of this range are inadequate for several reasons.

The lower end of this range, 0.5 ft/sec, is too high. The staff report indicates 0.5 ft/sec was selected because the manufacturer only guarantees accuracy at 0.5 ft/sec and above. The staff report also argues that ultrasonic flow meters, the only ones that meet the requirements of the rule, are not as accurate at flow velocities below 1 ft/sec. (Staff Report, pp. 22-23.) This is incorrect.

We identified two U.S. vendors of ultrasonic flow meters for flares, Panametrics and Roxar. Both indicate that they will guarantee the accuracy of

their meters at 0.1 ft/sec. Roxar guarantees the accuracy of its flare gas meter,[25] as specified in its product literature, included in Exhibit 5. Parametrics reports "general" accuracy information in its product literature included in Exhibit 6, but will guarantee velocities as low as 0.1 ft/sec based on the specific installation and third party calibration. Good accuracy at low velocities can be obtained by using a two-channel installation, one channel for low velocity, another for higher velocities.[26]

Further, while it is true that accuracy is generally lower at flows below 1 ft/sec, the accuracy at flows of 0.1 ft/sec is still very high and more than adequate for the purposes of this rule. A review of accuracy achieved in practical operating conditions indicates an accuracy of 1% to 2% at flow velocities greater than 1 ft/sec and an accuracy of 0.03 ft/sec at velocities of less than 1 ft/sec.[27] This equates to an accuracy of 6% at 0.5 ft/sec and 30% at 0.1 ft/sec. Wind tunnel tests have demonstrated an overall accuracy of ± 5% over the entire velocity range of 0.1 ft/sec to 394 ft/sec for the Roxar meter. (Ex. 7: Mylvaganam 1989.[28]) The Norwegian Petroleum Directorate has established standards for flow meters used to monitor flare gases (for purposes of collecting CO_2 taxes). These standards require an accuracy of ± 5.0% over the flow range. (Ex. 8.[29]) It is preferable to have flow measurements accurate to 5% to 30% at 0.1 ft/sec than no data at all, particularly since these lower velocities comprise the majority of the flaring events experienced at Bay Area refinery flares.

Further, some meters can achieve even better accuracy than quoted in these articles. For example, the Panametrics GF868 Flare Gas Flowmeter measures flows of 0.1 ft/sec for a 1-path meter with an accuracy of 10% and for a 2-path meter with an accuracy of 7%. See Ex. 6. The Roxar Influenta Flare Gas Meter measures flows of less than 0.1 ft/sec with an accuracy of 2.5% at a 95% confidence level. Alternatively, a two-channel installation that uses separate channels for low and high velocities could be used to improve accuracy at the

[25] Personal communication, Warren Sneedon, Roxar, Stafford, TX, 714-482-6400, April 14 and 17, 2003.

[26] Personal communication, Rob Gold, Panametrics, Waltham, MA, 800-833-9438, April 14, 2003.

[27] M. Rychagov, S. Tereshchenko, B. Dean, and L. Lynnworth, Multipath Flowrate Measurements of Symmetric and Asymmetric Flows, 1st World Congress on Industrial Process Tomography, Buxton, Greater Manchester, April 14-17, 1999, pp. 438-443.

[28] K.S. Mylvaganam, Ultrasonic Gas Flowmeters. Novel Techniques of Transducer Orientation and Signal Processing Make High-Reliability Possible, Measurements & Controls, December 1989.

[29] The Norwegian Petroleum Directorate, Regulations Relating to Measurement of Petroleum for Fiscal Purposes and for Calculation of CO_2-Tax (The Measurement Regulations).

lower end of the range. This would only modestly increase cost, from about $25,000 for a 2-path ultrasonic meter to about *$30,000 for a 2-path, 2-channel* installation. Thus, there are flare gas flow meters in the market that are capable of making sufficiently accurate measurements of velocity at 0.1 ft/sec.

The upper end of the range, 275 ft/sec, may not be adequate in all instances. Emergency releases can have velocities well over 300 ft/sec. Some vendors offer meters that operate at higher velocities. See, for example, the Roxar Fluenta Flare Gas Meter, described in Ex. 5. The monitoring device should be sized to handle the maximum velocity expected for each flare, not an arbitrary value set by the District.

Thus, the language in Section 12-11-501.2 should be modified to read: "The device shall continuously measure velocity over the full potential range of operation of each covered flare, from a minimum velocity of 0.1 ft/sec to the maximum expected for each individual flare, but no lower than 275 ft/sec."

IV.B Accuracy

The rule is silent on the accuracy of the flow meter. The accuracy depends on the number of ultrasonic flow paths used to calculate velocity as well as the number of channels. The higher the number of paths and channels, the greater the accuracy. Panametric's meter uses one or two paths, Daniel's meter has four paths, Instromet's has five paths, and FMC's meter has six paths. The multipath meters achieve greater accuracy than single path meters, in the range of 0.5% or better, while the accuracy of single path meters is in the range of 1% to 2%.[30] An accuracy of 2% over the full range of flow conditions has been required and met in some applications.[31] The Roxar Influent Flare Gas Meter (Ex. 5) is accurate to 2.5% of the measured value in the range of 0 to 82 ft/sec and 5% of the measured value in the range of 82 to 328 ft/sec at the 95% confidence level. The Norwegian Petroleum Directorate requires an accuracy of 5.0% over the entire flow range. (Ex. 8.)

We recommend that the rule be revised to require a *minimum accuracy of* 5% over the entire flow range. This accuracy is available from flare gas meters provided by Panametrics and Roxar, among others. See Exs. 5-6.

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[30] Jesse Yoder, Ultrasonic Meters: A Natural Choice to Measure Gas Flow, Pipeline & Gas Journal, July 2000.

[31] Jonathan Miles, The Use of Flare Gas Metering after Kyoto – Metering Can Help Reduce Costs and Protect the Environment, Argo Environmental Engineering Limited.

IV.C Monitoring Location (12-11-501.4)

Section 501.4 requires that the flow monitoring device be installed at a location where measured volumetric flow is representative of flow to the flare or to the flare system in the case of a staged system consisting of more than one flare. This language is ambiguous and could result in the location of the monitor before the addition of any supplementary fuel. Thus, this language should be modified to require that the monitor be located "on the main flare header, after the knock-out pot and addition of any supplementary fuel" to assure that it measures the flow that is actually combusted.

IV.D Related Parameters Should Be Measured

The only related parameter that is measured is molecular weight of the gases. § 501. Section 401.1 requires that the total volumetric flow of vent gases be reported in standard cubic feet. Further, Section 401.5 requires that the data be used to estimate mass emissions, which are normally reported at standard conditions, a temperature of 70 F, and a pressure of 760 mm Hg. Flares, on the other hand, do not operate at standard conditions. Thus, the temperature and pressure in the main flare header must also be monitored continuously. Finally, compliance with 40 CFR 60.18, which we believe should be incorporated into Section 401.5, requires measurements of heat content, temperature and pressure, as well as actual exit velocity of the flare. Exit velocity, temperature, heat content, and pressure should be measured according to 40 CFR 60.18(f)(4).

We recommend that Section 501.3 be modified to read: "Molecular weight, temperature, and pressure shall also be continuously measured. The monitors shall be maintained according to vendor specifications and calibrated on an annual basis to meet the following accuracy specifications: the temperature monitor shall be $\pm$ 2.0% at absolute temperature and the pressure monitor shall be at $\pm$ 5 mm Hg." Heat content is discussed in Comment V.C. Alternatively, the accuracy for temperature, pressure, and molecular weight specified in Ex. 8 could be adopted. Many flow meters simultaneously measure all three of these parameters and automatically output both actual and standard flows rates. See Ex. 6.

V. Composition Monitoring Is Inadequate (12-11-502)

The purpose of Regulation 12, Rule 11 is to determine emissions from flares, in part to implement SIP Control Measure SS-15, Petroleum Refinery Flare Monitoring, in the 2001 *Bay Area Ozone Attainment Plan*. A related purpose is to determine emissions of sulfur compounds, which have long caused nuisance odors in surrounding communities. However, the proposed rule only requires monitoring of what goes into the flares, not what comes out. The emissions are blindly estimated assuming that only 2% of what goes in comes out. The balance or 98% is assumed to be combusted to carbon dioxide and water. However, as discussed in Comment III.B, the actual destruction efficiency depends on many variables that are poorly understood and cannot be reasonably captured in a single number, 98%, as proposed by the District. The only way to determine what comes out of flares is to monitor the actual flared gases. And the only way to determine the destruction efficiency is to monitor both the vent gases and the flared gases. Thus, we support the District's proposal to monitor vent gases, modified as described below. However, we recommend that vent gas monitoring be supplemented with flare gas monitoring, as detailed below in Comment V.D.

Section 502.3 allows the use of one of three methods to monitor vent gas composition: (1) manual or automatic sampling with ex-situ analysis; (2) continuous, in-situ analyzers other than gas chromatography; and (3) in-situ gas chromatography. The first of these, sampling and ex-situ analysis, is the most commonly used method in California and is the most likely to be used, particularly since the other two methods require some research and development work to address sample conditioning issues. (Staff Report, pp. 24-25.) However, both the triggers selected for initiation of ex-situ sampling and the subsequent sampling frequency are likely to omit most of the episodic and continuous flaring events. Further, manual sampling is dangerous and should be explicitly forbidden.

The following comments focus on periodic ex-situ sampling as outlined in Section 502.3.1 because this method is the most likely to be used. The other two methods require essentially continuous monitoring, within the limits of the chosen instrumentation, and are adequate as drafted. We suggest that periodic monitoring either be eliminated from the rule, or, if retained, modified to eliminate the volume and time triggers and to reduce the sampling frequency to every 15 minutes, consistent with the continuous in-situ methods in Section 502.3.2 and 502.3.3.

V.A Manual Sampling Should Not Be Allowed (12-11-502.3)

The staff report admits that the "disadvantage of manual sampling, is that great care must be taken to ensure the safety of refinery workers involved in sampling. In some cases, available sampling locations may have the potential to expose workers to dangerous heat if the vent gas flow rate is high." (Staff Report, p. 23.) The long history of accidents in refineries, coupled with the District's admission that such sampling poses worker safety issues, suggests that

the rule should explicitly eliminate manual sampling as an option. Thus, we suggest that the rule state that manual sampling may be not be used.

V.B Sampling Frequency Is Inadequate (12-11-502.3)

The rule sets a minimum sampling frequency of one sample per day. (Section 502.3.1.a) During flaring events, the first sample is taken 75 minutes (when an auto-sampler is used) to 90 minutes (when manual sampling is used) after the start of a flaring event in which the volume of vent gas exceeds 50,000 standard cubic feet ("scf") in 60 minutes. The sampling frequency thereafter is one sample every three hours until the volume of vent gas in any consecutive 60 minutes is 50,000 scf or less. § 502.3.1.b. This is an excessively high trigger and low sampling frequency, which combined, will result in minimal sampling of episodic and continuous flaring events.

V.B.1 Minimum Sampling Frequency Is Inadequate

Section 502.3.1.a establishes a minimum sampling frequency of one sample per day. Presumably, this frequency would apply to flares used routinely on a non-emergency basis that remain below the triggers in Section 502.3.1.b. Continuous flare release reports for Chevron that cover the period May 2001 through May 2002[32] indicate that 48% of the continuous releases would be exempted from continuous monitoring and be subject to only once per day sampling.

If a flare combusted just below 50,000 cfs in any consecutive 60 minutes all day long, over 1 million cubic feet of gases per day could be combusted in each flare without triggering periodic monitoring in Section 502.3.1.b, beyond once per day.[33] With 25 flares in the Bay Area subject to this rule, this adds up to about 30 million cubic feet per day of gases that could be flared, but sampled only once daily. This amount to 12 tons per day of VOCs[34] from the 25 flares that could be emitted with at most, one daily sample, at worst, none. The single

[32] Letter from Jeff Hartwig, Chevron, to James Guthrie, BAAQMD, Re: Information Request for Flaring – Historical Data, November 26, 2002, Continuous Release Report Flare Event Information (May 01 – May 02).

[33] If flows to each flare were maintained below the trigger of 50,000 cfs in any consecutive 60 minutes, the amount of unmonitored flow per flare would be up to: 49,999 ft^3 x 24 hours, =1,199,976 ft^3/day. Each refinery would be required to take one sample per day, unless it reduced the flow to near zero at the appointed time, eliminating sampling requirement.

[34] The amount of unmonitored VOCs, assuming 35 mole% propane and 98% control efficiency, would be up to: [(49,999 ft^3/hr)(24 hrs)/379 ft^3/lb-mole](0.35 hydrocarbon)(44 lb/lb-mole)(0.02) = 975 lb/day.

sample that is required by Section 502.3.1.a could be collected at any time, at the discretion of the facility, and thus could be selected to correspond to a time of zero flaring, or a time when natural gas is routed to the flare.

The District did not provide any justification for this trigger nor provide any data that would support it. Continuous, low-level flaring, below 50,000 cfs/hr, could result in significant emissions on an annual basis, depending upon the composition of the vent gas stream. Thus, the District should provide actual monitoring data that demonstrates that these emissions are de minimus and thus warrant only daily sampling or increase the sampling frequency to the same frequency required in 502.3.1.b.

V.B.2 The Monitoring Trigger Is Too High

Section 502.3.1.b establishes a trigger of 50,000 scf in 60 minutes when manual or automatic ex-situ sampling is used. This trigger is high enough to exclude a significant fraction of the flaring events that routinely occur at the Bay Area refineries. The episodic flaring reports submitted by two of the five Bay Area refineries, Shell and Chevron, are complete enough to evaluate whether this is a reasonable trigger. Flare reports submitted by the other refineries are not complete enough to evaluate this trigger as they typically lack information on event duration and/or flow rates.

Information submitted to the District by Shell indicates that 238 episodic flaring events occurred between January 2001 and February 2003.[35] Of these, 207, or 87% of the total, would be excluded from monitoring and reporting under the District's proposed trigger of 50,000 scf in 60 minutes. (While a minimum of daily monitoring is required by Section 502.3.1.a, the daily sample could be collected when no vent gases are routed to the flare.) These 207 flaring events released 15.3 million standard cubic feet ("MMscf") of vent gas and 25,057 pounds of SO_2. These quantities amount to 44% of the total gases and 42% of the total SO_2 that were episodically flared over this period by Shell's own accounting.

Similarly, information submitted by Chevron to the District indicates that for the 12 months from May 1, 2001 through May 31, 2002, 158 episodic flaring events occurred. Of these, 100 or 63%, would be excluded from monitoring and

[35] Letters from Teresa K. Makarewicz, Manager, Environmental Affairs Department, Shell Oil Products, to Bay Area Air Quality Management District, Re: Shell Martinez Refinery - BAASQMD Plant 11 - Flaring Reports for June 2002 through February 2003, Dated: July 15, 2002, August 14, 2002, September 12, 2002, October 14, 2002, November 15, 2002 (contains historic data for January 2001 through June 2002), December 13, 2002, January 15, 2003, and February 14, 2003.

reporting under the District's proposed trigger of 50,000 scf in 60 minutes.[36] (While a minimum of daily monitoring is required by Section 502.3.1.a, the daily sample could be collected when no vent gases are routed to the flare.) These 100 excluded events released 14.9 MMscf of vent gases and 33,232 pounds of SO_2. This amounts to 27% of the volume of total gases and 22% of the total SO_2 that were episodically flared by Chevron's own accounting over this 12 month period.

The District argued that the proposed trigger "would capture most of the flaring events of significance," based on an analysis of data collected during the District's flare study. (Staff Report, pp. 23-24.) However, our analysis of this data for the only two refineries with complete information indicate that the proposed trigger of 50,000 scf in 60 minutes is unacceptably high and would not capture the majority of the episodic flaring events or their associated emissions.

This trigger is based on a 1.0 ft/sec flow velocity in a 48 in. or larger flare header. The District argued that a lower trigger may indicate flow where none exists, resulting in sampling still gas in the header. (Staff Report, p. 23.) *However, this is based on the* presumption that ultrasonic flow meters are not accurate at flow velocities below 1 ft/sec. The information in Exs. 5 and 6 and discussion in Comment IV.A indicate that this is incorrect. Ultrasonic flow meters are able to measure flows down to 0.1 ft/sec at accuracies of 2.5% to 30%, depending upon the specific meter and configuration that are selected. Further, this is inconsistent with Section 501, in which the District requires the use of a flow meter capable of detecting a velocity of 0.1 ft/sec and requires monitoring at a velocity of 0.5 ft/sec.

Further, we are aware of three other agencies that have flare monitoring rules. These agencies do not rely on a trigger such as proposed here to initiate monitoring. SCAQMD Rule 1118 requires the use of an on/off flow indicator to trigger monitoring, with the first sample collected within 30 minutes of the start of each flare event. The TNRCC's vent gas rule (Ex. 4: TCAA § 115.725) requires monitoring at least once every 15 minutes with no trigger at all. The Utah Department of Environmental *Quality requires that the gas flow rate is* monitored at least once every 15 minutes. Ex. 9.

Thus, we recommend that the trigger of 50,000 scf in 60 minutes in Section 502.3.1.b be eliminated and replaced with a requirement that monitoring commence as soon as practical after flow is detected, but under no circumstances in more than 15 minutes, consistent with both the SCAQMD and TNRCC flare

[36] Letter from Jeff Hartwig, Chevron, to James Guthrie, BAAQMD, Re: Information Request for Flaring - Historical Data, November 26, 2002.

monitoring rules. The flow trigger may be any of the following: (a) first detection of 0.1 ft/sec velocity; (b) an on/off meter capable of detecting 0.1 ft/sec; or (c) detection of a flame at the flare stack using an infrared flare stack detection system, video images, or other similar device capable of detecting a flame.

V.B.3 Sample Start Time Is Too Long

This rule advocates the use of a data logger to record flare flow for 60 minutes. (Staff Report, p. 24.) If the flow over this period is greater than 50,000 scf, a sample must be collected within 15 minutes if an automatic sampler is used and within 30 minutes if manual sampling is used. Thus, Section 502.3.1.b does not require any sampling at all until 75 minutes (60 + 15) after the initiation of a flow event if an auto-sampler is used and 90 minutes (60 + 30) if manual sampling is used.

Starting sampling 90 minutes after a flaring event commences would further reduce the number of episodic flaring events that would be monitored. For Chevron, this would increase the number of excluded flaring events from 100 to 127, thus excluding 80% of all episodic flaring events before any samples at all are collected. Similarly, for Shell, starting sampling 90 minutes after a flaring event commences would increase the number of excluded flaring events from 207 to 222, excluding 93% of all episodic flaring events.

This excessively long start time is inconsistent with similar rules published by other agencies. SCAQMD Rule 1118 requires that the first sample be taken within 30 minutes of the start of each flare event. If the flare event is over in less than 30 minutes, flow rate may be estimated. The TNRCC vent gas rule requires composition monitoring at least once every 15 minutes, with no startup grace period.

The rule should be modified to require that sampling commence within 15 minutes of the detection of flow, as detected using the methods listed above in Comment V.B.2. If the event lasts less than 15 minutes, as many do, the flow rate should be estimated based on historic information and/or flame length as recorded by the video per API RP 521.[37]

[37] American Petroleum Institute, Guide for Pressure-Relieving and Depressuring Systems, API Recommended Practice 521, 3rd Edition, November 1990.

V.B.4 The Sampling Frequency Is Too Long

Once the flow volume (50,000 scf in 60 min) and sampling start time (75-90 min) are exceeded, samples need only be collected every 3 hours after the initial sample is collected. The flaring data submitted to the District indicates that this is far too long an interval to collect meaningful data. The episodic flaring data indicate that a second sample would be collected from only 15% of the Chevron flaring events and 3% of the Shell events. In comparison, the TNRCC vent gas rule requires that composition data be collected at least once every 15 minutes. Thus, we recommend that the rule be modified to require sampling a minimum of every 15 minutes.

V.C Monitored Parameters Are Inadequate (12-11-502.3)

Section 502 requires that total hydrocarbon, methane, and hydrogen sulfide or total reduced sulfur be analyzed in all samples. This is not adequate.

First, Section 401.5 requires that the data be used to estimate daily average and total monthly SO_2 mass emissions in pounds from each flare. All sulfur compounds, not just H_2S or reduced sulfur compounds, are converted to SO_2 during combustion. Vent gas streams also contain oxidized sulfur compounds, including carbonyl sulfide (COS), sulfate (SO_4), sulfur trioxide (SO_3), and SO_2. SCAQMD Rule 1118 requires that total sulfur be measured. A separate measurement of H_2S is required to determine compliance with 40 CFR, Subpart J, § 60.104(a)(1) and associated monitoring for routine flaring. Thus, the rule should be revised to require that both total sulfur and H_2S be measured.

Second, compliance with 40 CFR 60.18 requires that visible emissions and the heat content of the gas during flaring meet certain requirements. Flares must be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. Further, flares may only be used when the net heating value of the gas being combusted is 300 Btu/scf or greater if the flare is steam assisted or air assisted or 200 Btu/scf when the flare is unassisted. These conditions must also be met to assure that the control efficiency specified in Section 401.5 is actually met, as discussed in Comment III.B.

Thus, Section 502 should be modified to require that opacity and net heat content be monitored using the methods in 40 CFR 60.18. A calorimeter should be calibrated, installed, operated, and maintained, in accordance with manufacturer recommendations, to continuously measure and record the net heating value of the gas sent to the flare in Btu/scf. The net heating value of the gas combusted should be calculated according to the equation given in 40 CFR 60.18(f)(3).

V.D Flare Gas Monitoring

The proposed regulation seeks to collect data to estimate emissions, or what comes out of flares, but only proposes monitoring what goes into the flares, the vent gases. Emissions are then crudely estimated by applying a blanket 98% control efficiency to the flare input. This contravenes the purpose of the rule, which is to develop accurate estimates of flare emissions. The only reliable method to determine flare emissions is to directly measure flare emissions.

Elevated flare stacks cannot be monitored safely using standard stack source testing methods. However, they can be readily measured using remote-sensing, open-path optical techniques including differential absorption light detection and ranging ("DIAL"), Fourier transform infrared spectroscopy ("FTIR"), differential optical absorption spectroscopy ("DOAS"), a tunable diode laser, and light detection and ranging ("LIDAR"), among others. Most of these instruments are capable of measuring both SO_2 and hydrocarbons in the flare gases and most have been used to monitor flare stack gases and determine destruction efficiencies. These and other methods are reviewed and discussed in Exhibit 10.[38] These instruments have been widely used to monitor flare gas emissions and to estimate the efficiency of flares. A collection of some relevant papers supporting the feasibility of these technologies for flare gas monitoring are compiled in Exhibits 3 and 11. TNRCC is also currently using passive FTIR to determine the efficiency of large industrial flares.

Thus, we recommend that Regulation 12, Rule 11 be expanded to require that each refinery use an optical, remote-sensing instrument capable of measuring both SO_2 and hydrocarbons in flare exhaust gases. The equipment may be purchased or leased from a number of vendors, or contractors may be retained to perform the required monitoring. The equipment should be used to continuously monitor flare stack emissions from each flare where access is not limited for a period of not less than 3 months per flare. The study should be designed to determine SO_2 and hydrocarbon emissions as well as flare efficiency using tracers or other suitable methods. The instrument must be capable of detecting both SO_2 and hydrocarbons at the concentrations likely to be present in the flare gases.

[38] Allan Chambers, Alberta Research Council, Inc., Well Test Flare Plume Monitoring - Literature review, Prepared for Petroleum Technology Alliance Canada, December 21, 2001.

VI. General Monitoring Requirements Are Inadequate (12-11-506)

VI.A Allowed Monitor Downtime Is Excessive

Section 506.1 requires reporting of monitor inoperation greater than 24 continuous hours and allows periods of monitor inoperation up to 30 days per calendar year, or 92% of the time. The TNRCC vent gas rule requires that each monitoring system operate at least 95% of the time when the flare(s) are operational, averaged over a calendar year. Ex. 4. Further, the District's flare rule requires no reporting for downtime less than 24 hours, which would allow a facility to accumulate 29.99 days of inoperation, each such period lasting less than 24 hours, with no obligation to report or explain any of the downtime.

Thus, we recommend that Section 506.1 be modified to require recordkeeping of all periods of monitor inoperation and monthly reporting of the accumulated downtime for each monitor. An incident report should be prepared for any downtime in excess of 1 hour and submitted to the District within 24 hours of its occurrence. We also recommend that the allowed downtime of 30 days be revised to reflect *the language in the* TNRCC *vent gas rule, viz.,* "all monitors shall be continuously operated at least 95% of the time when the flare is operational, averaged over a calendar year, unless inoperable due to documented instrument malfunction." Ex. 4.

VI.B Sampling Frequency During Periods of Monitor Inoperation (12-11-506.2)

VI.B.1 Vent Gas Composition Monitoring

Section 506.2 requires that vent gas composition monitoring only be performed daily during periods when the continuous analyzers installed pursuant to Sections 502.3.2 and 502.3.3 are out of service. This is inadequate because it would fail to capture the substantial emissions that could be released. If an on-line analyzer is down, manual or auto-sampling could be performed at a frequency of one sample every three hours, as currently required in Section 502.3.1.b, or more *frequently, as discussed in Comment* V.B.1. The TNRCC vent gas rule requires monitoring every 4 hours during periods when the on-line analyzer is down. Ex. 4; §115.725(d)(4). The Commission stated this frequency "is necessary because of the potentially large emissions of HRVOC from flaring operations." (TCEQ, pp. 119-120.)

Thus, we recommend that Section 506.2 be modified to require that any facility electing to use a continuous analyzer must also obtain equipment to allow manual or auto-sampling when the continuous analyzer is down and use it to collect a minimum of one sample every three hours.

VI.B.2 Velocity Monitoring

The rule does not establish any procedures for estimating flow rates when the velocity meter is out of service. A new section should be added to Section 506 that requires that flow rate be estimated when the flow meter is out of service using either the methods in Section 602 and/or flame length as recorded by the video per API RP 521.

VI.C Calibration And Maintenance (12-11-506.3)

Section 506.3 requires that monitors are maintained and calibrated in accordance with manufacturer specifications. However, the manufacturers of ultrasonic velocity meters have no specific written requirements for meter calibration or maintenance after initial installation. The meters are factory calibrated and adjusted in the field. However, conversations with vendors and owners indicate that these meters should be field zeroed and the transducers cleaned annually. Thus, we recommend that Section 506.3 be modified to require annual maintenance and field zeroing of ultrasonic velocity meters.

EXHIBIT G

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April 13, 2005

Jack Broadbent
Air Pollution Control Officer
Bay Area Air Quality Management District
939 Ellis Street,
San Francisco, CA 94109

Attention Alex Ezersky,
Principal Air Quality Specialist
aezersky@baaqmd.gov

Re: **Comments on proposed BAAQMD Regulation 12, Rule12, Miscellaneous Operations, Flares at Petroleum Refineries**

Dear Mr. Broadbent,

On behalf of the Plumbers and Steamfitters Local 342, I am submitting the comments below to urge the BAAQMD to strengthen its proposed refinery flare regulation. (Regulations 12, Rule 12, Miscellaneous Operations, Flare at Petroleum Refineries). This long-awaited rule is a key step forward in emissions reductions and safety improvements for Bay Area oil refineries, and we commend the BAAQMD for proposing adoption of such a rule.

We propose clarification of definitions set forth in the proposed rule such that refineries will not be able to claim wholesale exemptions from the rule's provisions, allowing continued and widespread unnecessary flaring. Furthermore, we propose that the rule be amended to incorporate standards defining adequate flare minimization, and provisions for public input on flare minimization plans.

If strengthened, the flare rule would dramatically reduce flare emissions of sulfur oxides, hydrocarbons, and many other pollutants. Furthermore, a strong rule would result in inherently safer refinery operations by requiring root cause analysis and corrective actions following emergencies which result in flaring.

We recognize that the District's goal is to prevent flaring accidents and prohibit routine flaring, and we know the District is working to clarify the rule. We applaud these efforts and urge the District to add strengthening measures. Here is a summary of our findings and recommendations:

- Flares continue to be a significant source of air pollutant emissions;
- There are feasible methods to control flare emissions;
- Flaring prevention is an inherently safer practice;
- Repeated breakdowns and upsets cause unnecessary flaring;

- More recent voluntary flaring reductions demonstrate the feasibility of flare-minimization, which should be made permanent
- Definitions and standards in the BAAQMD draft rule need more clarity to prevent routine flaring;
- The flare minimization plan needs clear standards and public review provisions;
- The District should audit refineries for sufficient compressor capacity to prevent routine flaring;
- Flaring during planned start-ups and shutdowns should be minimized;
- The BAAQMD should amend the proposed rule to include sulfur limits at least as stringent as those proposed by the South Coast Air Quality Management District and adopted by the Santa Barbara Air Pollution Control District;

Flares Continue to be a Significant Source of Air Pollutant Emissions

Refinery flares continue to be a major source of air pollutant emissions in the Bay Area. Although flaring is generally episodic in nature, flaring in the Bay Area has been so frequent that its emissions approximate the emissions from a continuous source.

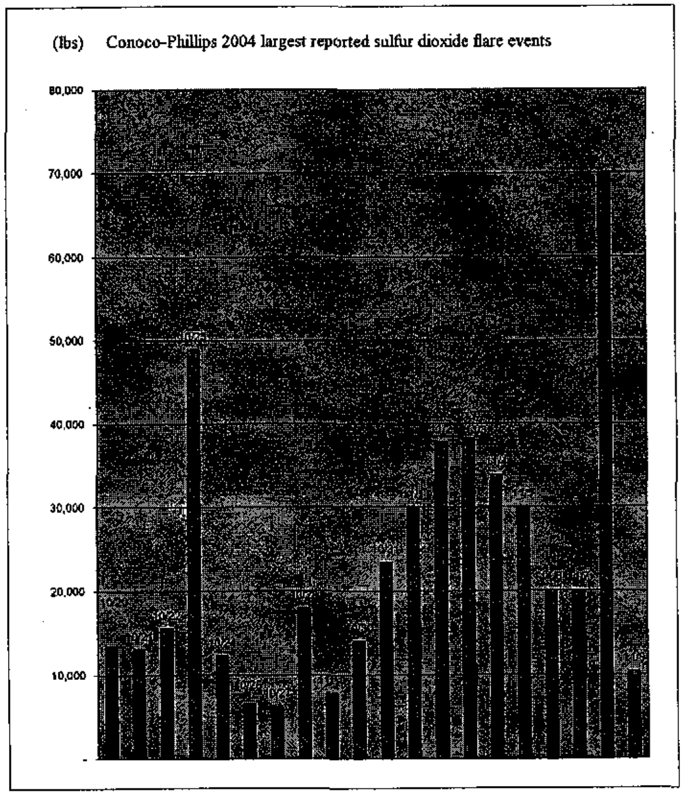
The 2001-2002 BAAQMD "Further Study" clearly demonstrates the problem. In refinery monthly reports to the District, the study accounted for hundreds of flaring events and demonstrated that the five oil refineries created maximum hydrocarbon emissions ranging from 11 to 134 tons per day and sulfur oxide emissions ranging from 11 to 27 tons per day.

It also appears that the "Further Study' may significantly underestimate emissions. The 134 ton hydrocarbon emission estimate from the Conoco-Phillips July (7/10/02) event was originally estimated by the District at 480-720 tons in one day, dwarfing the entire Bay Area hydrocarbon emission inventory from motor vehicles and all stationary sources (about 550 tons per day). The emissions estimate for that event was later reduced to 134 tons, after the District changed its emission calculation assumptions to include higher combustion efficiency. Even at this conservative estimate of 134 tons, however, it is clear that single flaring events can cause major impacts on the Bay Area daily hydrocarbon inventory.

Furthermore, flared gases often include high percentages of sulfur compounds. When sulfur compounds are combusted, sulfur compounds are released from the stack (sulfur oxides), no matter how efficient the flare. (Less efficient flares will also generate very hazardous hydrogen sulfide emissions.) Sulfur oxides can trigger asthma attacks and other respiratory ailments.

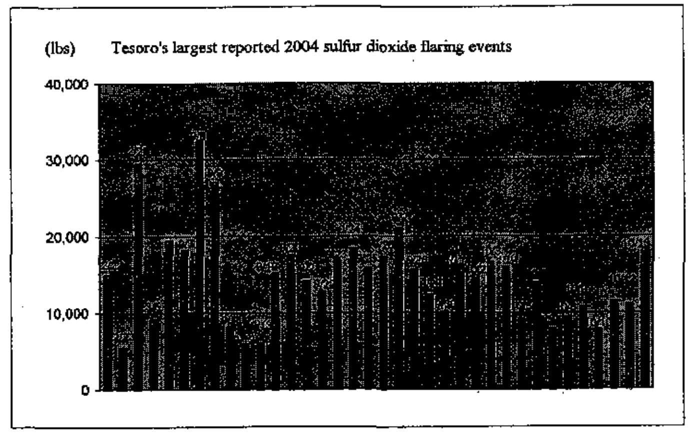
The new flare monitoring data required by the existing BAAQMD flare monitoring rule (http://www.baaqmd.gov/enf/flares/) includes updated data from January –

December, 2004. By compiling this data and graphing the larger flaring events reported by each refinery, we can compare refinery sulfur emissions during 2004. This comparison shows substantial sulfur emissions from the Conoco-Rodeo facility, the Tesoro facility, and the Valero-Benicia facility – reaching over 20,000 lbs per day for these three facilities. Chevron also had nine large events. Shell had no events comparable to those at other facilities. (Many dozens of additional smaller, but significant events are not graphed below.)

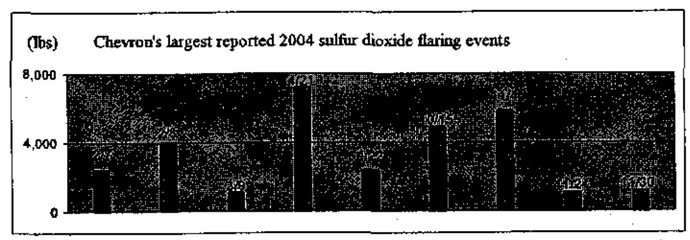


Conoco-Phillips in Rodeo reported the largest sulfur dioxide flaring events in 2004. 20

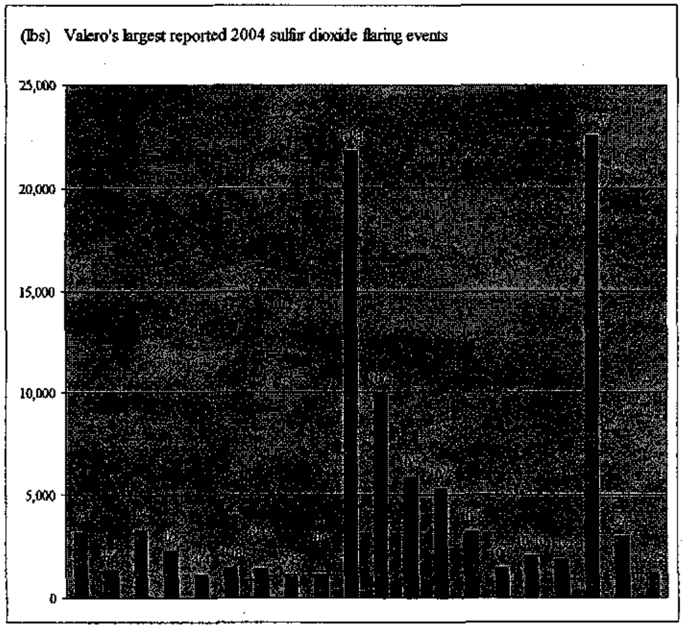
events generated more than 5,000 lbs. of sulfur dioxide and over 26 events generated over 1,000 lbs of sulfur dioxide each.



Tesoro in Avon had 36 flaring events that generated more than 5,000 lbs. of sulfur dioxide each.



Chevron in Richmond reported 9 flaring events that generated more than 1,000 lbs. of sulfur dioxide each (plus dozens of additional smaller events).



Valero in Benicia reported 20 flaring events with sulfur dioxide emissions of more than 1,000 lbs. each (plus dozens of additional smaller events).

→ **Shell in Martinez had by far the best record in 2004, with <u>no</u> flaring events with sulfur oxide emissions over 1,000 lbs, and only one event with greater than 500 lbs.** Shell did have many smaller flaring events, but these reported emissions were much smaller than the emissions reported by other refineries. Shell's much lower sulfur dioxide emissions demonstrate that it is feasible to reduce sulfur emissions from flares.

EPA has highlighted the importance of sulfur emissions from flaring:

> **"Frequent, Routine Flaring May Cause Excessive, Uncontrolled Sulfur Dioxide Releases, Practice Not Considered 'Good Pollution Control Practice,' May Violate Clean Air Act"** [1]

[1] EPA Enforcement Alert, Vol. 3, Number 9, October 2000, (The District is in possession of this document, submitted previously during the Clean Air Plan and during flare working group meetings.)

> "EPA investigations suggest that flaring frequently occurs in routine, nonemergency situations or is used to bypass pollution control equipment. This results in unacceptably high releases of sulfur dioxide and other noxious pollutants and may violate the requirement that companies operate their facilities in a manner consistent with good air pollution practices for minimizing emissions."

Analyzing the new flare monitoring data provided by the District website for Non-Methane Hydrocarbons (NMHC), we see that there is still frequent Bay Area flaring with very large hydrocarbon emissions. We have charted these events and once more find that Tesoro, Valero, and Conoco had dozens of particularly large flaring events reported in 2004. Chevron also had seven large events. Again, Shell had by far the best record, with <u>no</u> reported flaring event with non-methane hydrocarbon emissions greater than 300 lbs.

These charted hydrocarbon emissions do not include the methane component because the District considers this compound exempt. However, a Harvard study[2] found methane to be a powerful contributor to ground-level ozone. If we were to chart the total hydrocarbon emissions for all the facilities, these flaring emissions would be even more dramatic, sometimes doubling.

We do not consider the period of 2004 to reflect the full potential to emit for Bay Area refinery flares. The refineries appear to have been on their best behavior since monitoring equipment was required for flaring, and changes made are not all permanent. Despite this, the data still shows many large Bay Area flaring events with hydrocarbon emissions up to 20,000 lbs or more, and dozens of events with emissions over a thousand pounds per day.

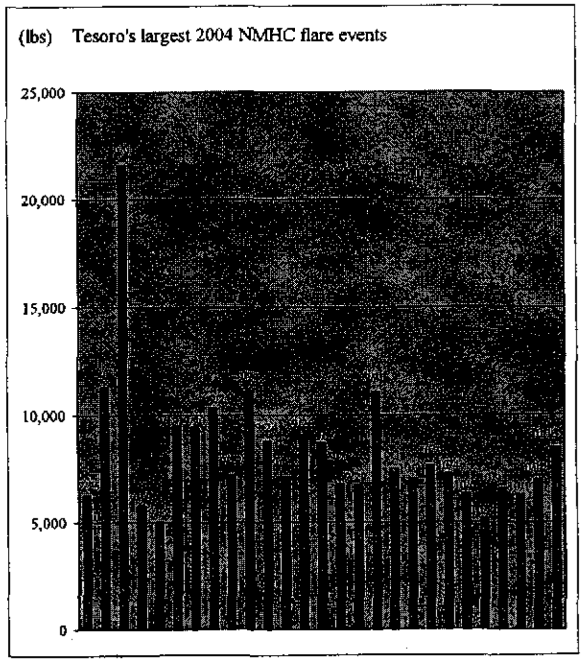
[2] *Linking ozone pollution and climate change: The case for controlling methane*, Fiore, et al, Harvard University, 2002, also summarized in Environmental Science & Technology, Dec. 1, 2002. (The District is in possession of this document, which was discussed during working group meetings on flares.)

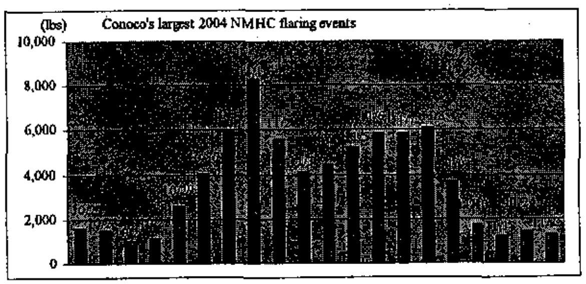
> The Harvard study found: *"Methane (CH4) emission controls are found to be a powerful lever for reducing both global warming and air pollution via decreases in background tropospheric ozone (O3)"*

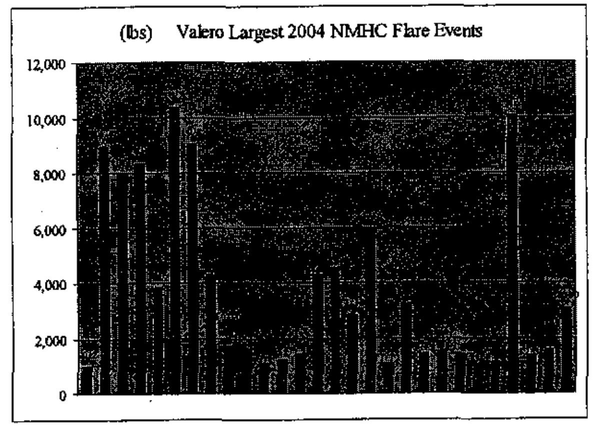
The Env. Science & Tech. article summarized the Harvard findings:

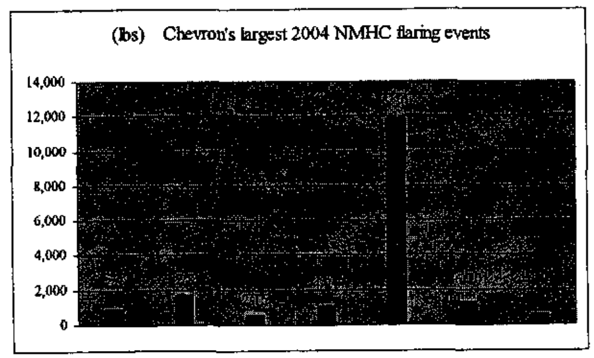
> *"Aggressive efforts to improve urban air quality could be undermined by rising levels of methane, a compound more closely linked to global warming than air pollution. Using a global model of tropospheric chemistry, researchers at Harvard University, Argonne National Laboratory, and the U.S. EPA determined that higher methane levels could increase ozone background levels worldwide, lead to a greater frequency of days with high ozone levels in the summer, and produce a longer "season of ozone pollution days."*

> "It is already known that methane is a major source of worldwide tropospheric ozone background concentrations, and this study supports that finding. However, the surprise is that a 50% reduction in anthropogenic methane in their scenario is as effective as a 50% drop in anthropogenic NOx concentrations at lowering summer afternoon ozone levels over the United States." (page 452A)









→ Shell's flaring events were not charted because Shell had no reported flaring events comparable to the other refineries.

There are Feasible Methods to Control Flare Emissions

There are feasible methods to control refinery flare emissions. The South Coast Air Quality Management District states in its report "Evaluation Report on Emissions from Flaring Operations at Refineries," (SCAQMD, Version 1, September 3, 2004 [3]):

> "Methods that have been employed to minimize flaring and reduce emissions include:
>
> - Installing a vapor recovery system at a facility without existing vapor recovery capability;
> - Increasing the vapor recovery system capacity;
> - Increasing the fuel gas treating system capacity; and
> - Implementing routine inspection and monitoring to detect leaking valves.
>
> Minimize the duration and volume of gas vented to the flares due to emergencies, planned start-ups and shutdowns, and turnaround activities. This may be accomplished by:
>
> - Improving operational and maintenance procedures to prevent upset conditions; and
> - Improving gas minimization plans for start-ups, shutdowns, and turnaround activities." (page 15)

A Santa Barbara Air Pollution Control District study[4] found that the need for flaring can be mostly eliminated by increasing gas recovery (except in the case of true emergencies). According to the study, total vapor recovery can be designed to largely eliminate flaring:

> "An example of a total vapor recovery system installed in a Canadian refinery is shown ... This system recovers flare manifold vapors into this refinery's fuel gas system. In this particular system, if the recovery vapor exceeds the refinery fuel gas demand, flaring still occurs. This is a rare occurrence at this facility, because fuel gas demand is much larger than all anticipated flaring events.
>
> "Various methods can be used to reduce the amount of flared gas including:
>
> - Partial vapor recovery systems
> - Better process control which may include the following:
>   - Pilot operated relief valves
>   - Equipment or process unit redundancy

[3] Available at: http://www.aqmd.gov/hb/attachments/2004/040933b.doc
[4] "Flare Study, Phase I Report," Santa Barbara Air Pollution Control District, July, 1991. This District is in possession of this document, submitted with comments on Clean Air Plans.

> - Automatic shutdown systems to prevent process unit over pressure and relief to the flares
> - Operational changes to reduce the frequency of inadvertent process vessel over-pressure episodes

Prevention of flaring is an inherently safer practice

Unfortunately, Bay Area refinery representatives have claimed during public workshops that flare controls will reduce safety and could confuse refinery operators during emergencies, who may become unsure whether to send gases to flares. The representatives have indicated this could cause refinery explosions. Exactly the opposite is true.

Repeated malfunctions and other errors at refineries cause unnecessary accidents that result in flaring, and reduce safety at refineries. During these events, refinery units are forced into emergency shutdown, and large volumes of gases are vented to flares. In addition to flaring, these same accidents can cause substantial emissions directly to the atmosphere from uncontrolled Pressure Relief Devices (District staff reports found emissions of nine tons per release on average and up to 150 tons per release of hydrocarbons, plus substantial emissions of hydrogen sulfide). Thus prevention of flaring can also prevent significant emissions from other sources. Emissions from flaring include hydrocarbons, sulfur oxides, hydrogen sulfide, nitrogen oxides, carbon dioxide, carbon monoxide, particulate matter, PAHs (polycyclic aromatic hydrocarbons) and potentially dioxins and heavy metals such as mercury and lead. Pressure Relief Devices can vent hydrogen sulfide, hydrocarbons and dozens of other pollutants.

Chemicals emitted during flaring have caused foul odors, breathing difficulties, and eye irritation in surrounding areas. These chemicals can also cause asthma attacks, chest pain and reduced ability to exercise for people with heart disease, and increased death rates in hospitals. They cause smog formation, and over the long term, can cause cancer, reproductive harm, immune system harm, and global climate change.

We will provide additional comments on the benefits of reducing impacts of flaring during the District's comment period on its CEQA analysis.

Root cause analysis of accidents will identify and prevent repeated malfunctions and upset conditions, thereby preventing substantial emissions from flaring and other refinery sources during upsets. It will also prevent dangerous conditions for workers that occur during emergencies, and prevent potential exposure of workers and neighbors to increased emissions.

We have stated during workshops that it is not <u>during</u> accidents that refineries should modify safety practices, it is <u>before and after</u> accidents that root cause analyses must be done to identify malfunctions and other problems, in order to prevent emergencies in the future. It is always up to the oil refining companies to ensure that operators have clear safety procedures and are not confused during emergencies. No part of the flare control regulation should be construed to induce refinery operators to modify safety procedures on the fly. Furthermore, the Bay Area draft flare control rule specifically exempts flaring associated with the safe operation of the refinery (Section 12-12-301). The District may want to further clarify to the refinery managers that they must operate their facility during emergencies according to procedures ensuring safety and should not unsafely modify safety practices during emergencies.

Furthermore, we urge the District to further clarify the rule to specifically prohibit repeated malfunctions not only by identifying them in the root cause analysis, but by requiring that they are corrected. These malfunctions otherwise continue to cause unnecessary emergencies, unsafe conditions, and unnecessary flaring.

Repeated breakdowns and upsets cause unnecessary flaring

EPA and other government agencies have often identified pollution prevention as the best way to reduce emissions and improve safety. The previously mentioned EPA Enforcement Alert specific to flaring found:

"Good pollution control practices include:
- Procedures to diagnose and prevent malfunctions; and
- Adequate capacity at the back end of the refinery to process acid gas."

Such good pollution control practices appear to have been repeatedly violated with regards to flaring events. Bay Area flaring from repeat equipment breakdowns, upsets or other conditions were reported by refineries including the following events, according to monthly reports to the BAAQMD during 2001-2002:

- **Flaring due to repeated equipment breakdowns, upsets, or other conditions:**
  - Chevron (Richmond) reported flaring associated with repeated compressor breakdowns on 47 separate days, including breakdowns associated events. (5/11/01, 5/12/01, 5/13/01, 5/14/01, 7/12/01, 6/10/02, 6/7/02, 6/4/02, 6/5/02, 6/6/02, 6/7/02, 6/8/02, 6/9/02, 6/10/02, 6/11/02, 6/15/02, 6/18/02, 6/25/02, 6/27/02, 6/28/02, 6/30/02, 7/01/02, 7/2/02, 7/02/02, 7/3/02, 7/4/02, 7/5/02, 7/6/02, 7/7/02, 7/8/02, 7/9/02, 7/10/02, 8/17/02, 8/18/02, 8/19/02, 8/20/02, 8/21/02, 8/22/02, 1/2/03, 1/3/03, 1/4/03, 1/5/03, 1/6/03, 1/7/03, 1/8/03, 1/9/03, 2/13/03);
  - Conoco-Phillips (Rodeo) reported repeated hydrogen-plant and hydrogen related upsets and associated shutdowns and startup. (1/19/2001, 4/04/2001, 6/22/2001, 6/23/2001, 7/17/2001, 7/18/2001, 9/26/2001, 11/13/2001, 11/15/2001, 7/13/02, 7/13/02, 7/24/02, 8/1/02);
  - Valero (Benicia) reported repeated flaring associated with alkylation systems (8/17/02, 9/5/02, 9/16/02, 9/18/02); and
  - Valero also reported hundreds of other flaring events that occurred without identifying a root cause.

- **Flaring due to power failures and recovery from the failures** (Chevron: 10/21/02, 10/22/02, 10/23/02, 10/24/02, 10/25/02, 10/26/02, 10/27/02, 10/28/02, 10/29/02; Conoco-Phillips: 7/10/02, 7/11/02; Shell: 12/16/02; Tesoro: 12/10/02, 12/11/02; Valero 6/4-6/10/02)

(The period of 2001 to 2002 is likely more representative of potential to emit than the more recent periods, because refineries have done voluntary reductions of flaring that are not necessarily permanent during the last two years. Also, root cause analysis information on the more recent monitored data was not available on the District website.)

More recent voluntary flaring reductions demonstrate the feasibility of flare-minimization, which should be made permanent

It appears that during the last two years, Bay Area refineries have voluntarily reduced flaring due to public pressure. Neighbors have noted, for instance, that Chevron's flaring events used to be very frequent. However, these same neighbors have found that during the last two years flaring at the Chevron refinery has been much less frequent. It appears that Chevron has voluntarily taken measures to prevent flaring, perhaps including addressing compressor problems.

Although these kinds of reductions are encouraging, voluntary reductions of this type are not necessarily permanent. The reduced flaring over the last two years demonstrates the feasibility of flare-prevention; but a strong Bay Area flare control rule is needed to make sure that no backsliding occurs and that further progress is made.

The District does not have a published analysis on methods that Bay Area refineries have used to accomplish these reductions, because the refineries have refused to provide information during flare control workshops on the methods they used. Except in the case where permanent equipment changes have been made, such as the compressor capacity added by Tesoro, we have no assurance that the reduced flaring will continue in the future.

A similar situation exists in the South Coast Air Basin (Los Angeles, Orange, San Bernardino and Riverside Counties). Refineries in the South Coast have also voluntary reduced flaring following public pressure to do so. In these cases, the South Coast Air Quality Management District analyzed some of the causes for reduced flaring. SCAQMD found that most of the reduction in flaring was not due to permanent changes, that additional reductions could be made, and recommended adoption of flare controls to permanently reduce emissions. The SCAQMD published its findings in a staff report ("Evaluation Report on Emissions from Flaring Operations at Refineries," SCAQMD, Version 1, September 3, 2004, attached):

> *SOx emission reductions from 2000 to 2001 can be partly explained by the addition of vapor recovery compressors in one of the flare systems at one refinery. Except for a sulfur treatment system installed at one facility to reduce sulfur content of process gas sold to a nearby facility in 2003, there have been no other physical modifications to the system to expand the gas vapor collection or gas treatment to*

> *account for lower emissions in 2002 and 2003.* ***In other words, emission reductions reported were not due to permanent installation of vapor recovery and treatment systems. Facilities indicated that the reduction in flare emissions resulted from the "best management practice".*** Page 13 [emphasis added]
>
> *Although efforts have been made by many facilities to minimize flare emissions since the start of the program, there are further emission reduction opportunities and emission reduction targets that should be explored by facilities subject to Rule 1118. . . .* ***Staff recommends that Rule 1118 be amended to set appropriate emission goals for facilities subject to the rule.*** *(page 14)*

Definitions and standards in the BAAQMD draft rule need more clarity to prevent routine flaring

Contrary to refinery representations, Bay Area and South Coast studies found that non-emergency, or routine flaring is widespread. The South Coast Air Quality Management District found in it's report "Evaluation Report on Emissions from Flaring Operations at Refineries," (SCAQMD, Version 1, September 3, 2004) that contrary to previous belief, flares in the South Coast District are mainly being used for non-emergency situations:

> *Although flares are designed to be used mainly during emergency releases, data reported to AQMD as shown in Table 4-1 shows that from the years 2000 to 2003, the total volume of gas flared due to emergencies ranged from only 2 to 14 percent of the total gas flared.* (page 34)

Routine flaring can make up a large percentage of flared gases, so clear definitions on prohibitions of routine flaring are crucial to flare minimization. While the definition of routine flaring begins well enough, the standard for routine flaring immediately opens the door to unintended exemptions:

> 12-12-200 **DEFINITIONS**
>
> 12-12-208 **Routine Flaring**: Flaring of vent gas produced during normal operation of a petroleum refinery that is not the result of malfunction, startup, or shutdown.
>
> 12-12-300 **STANDARDS**
>
> 12-12-301 **Routine Flaring:** Routine flaring is prohibited **except as necessary for the safe operation of the petroleum refinery or where, due to the quantity or quality of gas, it cannot reasonably be recovered, treated and used as fuel gas at the refinery.**
>
> [Emphasis added. Note: regarding startup and shutdown exemptions above, see later comments.]

While the concepts expressed in the definition are reasonable, the language is too vague, and there is no definition of what is "necessary for the safe operation of the petroleum refinery," nor any standard for what constitutes whether gases can "reasonably be recovered, treated and used as fuel gas." These determinations are left to refinery personnel. Refinery managers have stated publicly that they are already doing what is reasonable, and that their flaring is necessary. It is quite possible that after rule adoption refinery representatives will argue that their current operations define what is reasonably available, with no needed improvements.

Given these loose definitions, it is possible that the refinery with the worst capacity for capturing and recycling gases could be allowed to continue routine flaring unabated, while refineries with better facilities which invested in compressor capacity, sulfur controls, and flaring prevention would have stricter standards.

For example, Tesoro, the refinery which previously reported the largest and most frequent routine flaring in the Bay Area (Tesoro reported daily flaring to the District over the approximate two year study period of 20001-2002), could have been exempt from modifying practices or adding compressor capacity depending on the definition of what can be "reasonably" recovered. This facility had far less compressor capacity than other refineries, (and even after adding the compressors, continued to report higher volumes of gases venting to flares than the other refineries).

The flare minimization plan needs clear standards & public review provisions

The Flare Minimization Plan ("FMP") in Section 12-12-401 does not assure that flaring emissions are minimized, but rather allows business as usual. We recommend that the FMP be modified to: (1) set specific emission limits and a schedule for meeting them to assure reductions; (2) set monitoring requirements to assure the emission limits are met; (3) require that the plan be prepared and stamped by a registered professional chemical or mechanical engineer in California.

The information required in the FMP is important, but does not require refineries to minimize flaring, nor define what constitutes "minimization."

Clearly, the FMP leaves it up to the refineries simply to describe what they are planning to do. No standards are identified for determining whether flaring has been minimized, no emissions limits are proposed, no gas flow limit is proposed (such as that present in the Santa Barbara flare rule discussed later in this comment), no monitoring is required, and most importantly, no public review process is available to allow additional feasible flare minimization techniques to be proposed by the public. It appears that the District will be forced to secure voluntary agreements from the refineries through a negotiated process on the minimization plans later.

This approach to regulation is different from other District refinery regulations. Generally, the District audits a pollution source, describes available methods to reduce emissions, and proposes specific means that are available to achieve emission reductions. Flares represent more complex sources than other sources at refineries, and their use is more variable compared to sources like storage tanks or valves. However, that does not relieve the District from writing rules with clear standards, that allow the public to take part in a meaningful way in evaluating the effectiveness of these standards.

Flaring Standards Should Be Established

The proposed regulation does not require that any standards at all be met. The New Source Performance Standards ("NSPS") for refineries, developed in the early 1970ies, establish bare-bones flaring standards that are more rigorous than the proposed rule. Permits issued in Texas, noted for its lax environmental rules, have set more rigorous requirements on flares than proposed by the BAAQMD. The NSR permit for Premcor's Port Arthur facility requires the flare to meet the requirements of the NSPS, to be operated with a flame present at all times, and to operate without visible emissions. The permit also includes actual flare emission limits.[5] We recommend that NSPS for flares be adopted as the baseline and additional requirements be established to assure emissions reductions occur.

There are many options for setting standards. The District rule language above is highly subjective, leaving substantial discretion to District staff to determine what is a sufficient Flare Minimization Plan and whether enough has been done to minimize flaring. Standard methods the District normally uses for setting standards include the following potential options:

a. **Set emissions limits** – subject to discussion in pubic workgroup meetings and workshops based on health protective limits.
b. **Set a percent emission reduction starting from the current baseline.**
c. **Set flow limits** (limits in total volume vented to flares) with contingencies for true emergencies.
d. **Define poor practices more clearly so as to prohibit certain activities by definition**
e. **Make the Flare Minimization Plan subject to public review with a public hearing** where the public may advocate for additional measures to reduce flaring.

The FMP Should Be Subject To Public Review

An important method to ensure that all feasible measures are included in a flare minimization plan is to open the plan up for public review, allowing the proposal of additional feasible measures for flare minimization. This approach is similar to the EIR (Environmental Impact Report) process used by CEQA, where, because of the complexity and unique nature of different projects, the method for ensuring that all feasible measures are included to reduce impacts of a project is to allow the public to submit evidence of feasible pollution reduction methods.

[5] Texas Permit No. 6825A/PSD-TX-49 (available at http://webmail.tnrcc.state.tx.us/servlet/webpub).

The FMP Should Be Approved By A Registered Professional Engineer

Section 12-12-401 requires that the FMP be certified and signed by a Responsible Manager. We support this requirement. However, we recommend that the rule be modified to require that the FMP be prepared under the direction of and stamped by a Registered Professional Chemical or Mechanical Engineer in the State of California.

The BAAQMD should amend the proposed rule to include sulfur limits at least as stringent as those proposed by the South Coast Air Quality Management District and adopted by the Santa Barbara Air Pollution Control District

The SCAQMD draft flare rule currently includes a requirement strictly limiting sulfur *compounds in flare gases. This requirement is equivalent* to an existing federal standard for new or modified flares, but the South Coast draft rule applies this limit to existing flares, except for emergencies:

> **South Coast Proposed Amended Rule 1118,**
> **Control of Emissions from Refinery Flares, 3/10/05)**
>
> (c)(2)(C) Allow only vent gas with a total reduced sulfur concentration not to exceed 160 ppm or less, expressed as H2S, to be combusted in a flare, excluding any vent gas resulting from an emergency.

Other than measures to prevent flaring completely, the sulfur limit in the South Coast rule is the strongest means in the rule to reduce sulfur emissions. Because the concentration or percentage of sulfur in flares can be much higher than 160 ppm, this limit will result in a substantial reduction in flare emissions.

The previously mentioned South Coast flare report also found that sulfur oxide emissions from flaring can be large, and the majority of reported flaring was "dirty," that is, had high concentrations of sulfur compounds. This causes a particular hazard to neighbors, and especially to people with respiratory diseases.

> "Figure 4-1 shows the breakdown of reported sulfur concentrations by the number of event days. This figure indicates that the higher concentrations of sulfur compounds (greater than 40 PPM total sulfur) were present during the majority of event days. ... Figures 4-2 and 4-3 compares the recordable event days and flow amount between "dirty"[6] vent gases and "clean" vent gases for each year from 2000 to 2003, respectively. These figure shows that the majority of vent gases are dirty. ... This figure indicates that there are significant flows with sulfur concentrations exceeding 1,000 PPM and some vent gases contain sulfur *concentration in excess of* 100,000 PPM. Vent gases containing high concentrations of sulfur can generate a large amount of SOx emissions even under low flow conditions." (pages 37 - 38)

In addition to the South Coast draft rule, the Santa Barbara Air Pollution Control District has adopted a rule limiting sulfur compounds in flare gases for planned flaring to 239 ppm).

> **Santa Barbara Air Pollution Control District RULE 359, FLARES AND THERMAL OXIDIZERS.** (Adopted 6/28/1994)
>
> D. 1. Sulfur Content in Gaseous Fuels
>
> a. Effective June 28, 1994, any planned flaring shall not burn gaseous fuel which contains sulfur compounds in excess of 15 grains per 100 cubic feet (239 ppmv) in the Southern Zone of Santa Barbara County or 50 grains per 100 cubic feet (796 ppmv) in the Northern Zone of Santa Barbara County -- calculated as hydrogen sulfide at standard conditions (i.e., 1 atmosphere and 60°F)

The provision allows exemptions in the case where the facility can specifically prove to the District through a detailed analysis that it is infeasible to meet the limit. However, if the exemption is given, the facility must provide reductions of sulfur emissions from other sources at the facility to offset the sulfur emissions allowed by the exemption. While the Santa Barbara standard is not as stringent as the proposed South Coast limit, it would still result in significant reductions of sulfur emissions since the percentage of sulfur compounds in flare vent gas can far exceed 239 ppm in the Bay Area. The existence of the Santa Barbara rule demonstrates the feasibility of adopting such a sulfur limit.

We urge the District to add a provision to the rule limiting sulfur content in the flare gas to 160 ppm.

Refineries should be Audited by the District for Sufficient Compressor Capacity

A common cause of flaring events is lack of sufficient compressor and fuel gas recovery and treatment capacity to handle normal daily production of gases. Refineries need adequate capacity to reduce and capture large volumes of gases for use as fuels in the refinery.

An important example is the Tesoro refinery, which was highlighted earlier in this comment as a source of routine flaring listed every day of the review period of 2001 to 2002. (For these events, frequently "No Cause" was listed in the monthly reports, and "missing lab data.") Early in 2003, Tesoro added compressors. Tesoro flaring, which had been the highest in the District according to BAAQMD reports, dropped substantially.

There is a crucial need for independent detailed audits of refinery compressor and gas recovery systems to identify deficiencies which lead to routine flaring. The District should perform these audits before approving flare minimization plans to determine if refineries are including reasonably available compressor capacity for minimizing flaring.

Flaring During Planned Start-up and Shutdown should be Minimized

Many flaring events are the result of planned startup/shutdown and related maintenance. In the past, this has been associated with frequent and large amounts of flaring. Refineries were not required to control the flaring, but after more recent public scrutiny, it appears that refineries are making voluntary efforts to reduce this type of flaring. Methods for minimizing flaring during startup / shutdown include slowing vessel depressurization so as not to overwhelm gas recovery systems when individual units are being shutdown (though this does not work for refinery-wide shutdowns), having sufficient compressor capacity, and sometimes storing gases. Clear measures to minimize this large category of flaring need to be added to the rule.

Additional Key Measures are Needed to Strengthen the Rule

<u>The Rule Should Be Federally Enforceable</u>

The proposed rule is not enforceable because it does not contain any monitoring provisions to assure that emission reductions occur. The proposed water seal integrity monitoring in Sec. 12-12-501 does not assure that emissions are reduced.

The rule should be included in the BAAQMD's SIP to assure that its provisions are "applicable requirements" for Title V purposes and are thus federally enforceable. Unless the rule is federally enforceable and adequate monitoring is required in required in Title V permits, it is nearly impossible for affected parties to enforce the Clean Air Act under the Citizen Suit provisions or obtain any relief. Likewise, absent such monitoring, it is extremely difficult or impossible to track facilities' compliance and to accurately develop emission budgets and air pollution control plans.

<u>The Notification Provision Is Inadequate</u>

The proposed rule only requires notification of the APCO of certain large flaring events (Sec. 12-12-405). The proposed rule should be modified to require that any notifications under Section 12-12-405 be posted on the internet. Affected parties should also be notified.

<u>The FMP Update Provision Is Inadequate</u>

The proposed rule requires that the FMP be updated prior to installing or modifying any equipment under Sec. 12-12-401.3 or annually. The FMP should also be modified if upstream processing units are proposed to be modified or added that would increase the load on the flare.

The Definition Of "Flaring Event" Excludes Many Large Events

The definition of "flaring event" in Sec. 12-12-202 excludes events lasting 15 consecutive minutes or less and those relating one million standard cubic feet of gas or less. These provisions exclude many very significant flaring events that occurred in 2004. These exemptions should be either eliminated or reduced to levels that would exclude less than 0.1 percent of the annual emissions.

Thank you for your consideration of these comments, and for moving forward with an important rule that, if amended as suggested, will improve the health and safety of both workers and neighbors near refineries. We appreciate the District's efforts and look forward to discussing these issues with you.

Sincerely,

Julia May,
Environmental Consultant

EXHIBIT H

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

DRAFT STAFF REPORT FOR

PROPOSED AMENDED RULE 1118 - EMISSIONS FROM REFINERY FLARES

Dated: October 2005

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TABLE OF CONTENTS

Page

EXECUTIVE SUMMARY

Rule 1118 – Emissions from Refinery Flares was originally adopted by the South Coast Air Quality Management District (AQMD) on February 13, 1998, with the purpose of monitoring, recording and reporting data on petroleum refinery flaring and related operations. This represented Step I of Control Measure CMB-07 of the 1997 Air Quality Management Plan (AQMP) that targets emission reductions from refinery flares, also found in the 2003 AQMP. Pursuant to the AQMD Board's direction upon the adoption of the rule, staff analyzed the monitoring data submitted by refineries in the time period from October 1, 1999 through December 31, 2003 and compiled the "Evaluation Report on Emissions from Flaring Operations at Refineries".

Staff presented the report at the September 3, 2004 AQMD Board Meeting and concluded that emissions from refinery flares were significant enough to warrant the implementation of controls. The report suggests possible ways of reducing emissions through the prevention of flaring of excess fuel gas, the elimination of leaks from pressure relief devices and the reduction of emissions during routine flaring. These objectives can be achieved by installing flare gas recovery systems and gas treating systems, expanding current capacities of flare gas recovery and treatment systems already in place, and conducting surveys to detect leaking pressure relief devices. The report also recommended improvements in the measurement of flare vent gas flows and the installation of continuous monitoring systems to measure the total sulfur gas concentration and the higher heating value of the flared gas, as well as the standardization of methodologies for flow and emissions calculations and for missing data substitution. Following the report presentation, the AQMD Board directed staff to amend Rule 1118 – Emissions from Refinery Flares, and implement Step II of Control Measure CMB-07. Step II of the control measure aims to reduce emissions of criteria pollutants from refinery flares by identifying and requiring the most feasible and cost-effective control options available.

The air quality objective for the Proposed Amended Rule (PAR) 1118 is to help AQMD attain state and federal air quality standards by minimizing emissions of criteria air contaminants and their precursors from flaring activities at petroleum refineries. The proposed amendment would eliminate the flaring of vent gases except for those resulting from emergencies, shutdowns and startups, turnarounds and essential operational needs; establish operational requirements of diagnostic practices to minimize flaring.

The proposed amendment establishes refinery specific performance targets for flare-related total sulfur emissions, calculated as sulfur dioxide, at 1.5 tons per million barrels of crude processed in calendar year 2006, 1 ton per million barrels of crude processed in calendar year 2008, 0.7 tons per million barrels of crude processed in calendar year 2010, and 0.5 tons per million barrels of crude processed in calendar year 2012, respectively, based on the 2004 industry-wide throughput. Excess flare related total sulfur emissions would be subject to mitigation fees of $25,000, $50,000 or $100,000 per ton, depending on whether excess emissions are no more than ten percent, greater than twenty percent but less than twenty percent, or more than twenty percent, respectively, of the annual performance targets. Excess emissions would also trigger the submittal of a flare minimization plan by the refinery and a possible issuance of a Notice of Sulfur Dioxide Exceedance by the Executive Officer. Emissions resulting from external power curtailment, natural disasters or acts of war or terrorism will be exempt from being counted towards these limits.

The proposed amendment, in keeping with the recommendations from the "Evaluation Report on Emissions from Flaring Operations at Refineries", will also enhance monitoring requirements to

improve data reporting accuracy, primarily requiring the use of higher heating value analyzers and also total sulfur analyzers pending the result of a pilot test feasibility study taking place at one of the refineries. Until the analyzers are installed, but no later than July 1, 2007, the sampling frequency of flare events would be increased to daily from weekly. In addition, the rule will require the flare gas flow meters to be installed in a representative location or be upgraded with totalizing capability such that only an accurate flow to the flare is registered. The amended rule will also establish uniform missing data procedures and calculations for reporting emissions during monitors' downtime periods.

The amended rule will set new notification requirements for flaring events, as well as reporting, which will require quarterly reports to be submitted in an electronic format certified by the facility official and approved by the Executive Officer. Each petroleum refinery will submit a detailed technical description of the flare system, including an audit of vent gas recovery capacity, a summary of the flaring emissions reductions achieved to date and future planned flare emission reductions.

The emissions reductions associated with proposed amendments are estimated to be 1.18 tons per day of SO_2 and 1.44 tons per day overall for all criteria pollutants, excluding carbon monoxide, from the emissions baseline average (2002-2004) to 2012. The cost-effectiveness is estimated to be between $3,922 and $6,926 per ton of SO_2 reduced. When considering additional reductions in NOx, VOC and PM10, the cost effectiveness ranges between $3,112 and $5,675 per ton of pollutant reduced.

The proposed amended Rule 1118 is considered a "project" as defined by the California Environmental Quality Act (CEQA), and the AQMD is the designated lead agency. Pursuant to CEQA and AQMD Rule 110, the AQMD prepared an environmental assessment (EA) evaluating potential adverse significant impacts associated with implementing the proposed amended rule. The EA concluded that implementing PAR 1118 would have no significant impacts on the environment. An environmental impact is defined as an impact to the physical conditions that exist within the area which would be affected by the proposed project.

CHAPTER I

BACKGROUND

A. RULE HISTORY

The concept of reducing emissions from petroleum refinery operations was originally formalized in the 1982 Air Quality Management Plan (AQMP) as Measure A15. Measure A15 proposed increasing the use of blowdown and vapor recovery systems to reduce emissions from flares. Consideration of adoption in 1985 was postponed to provide additional time to collect background information regarding flaring operations and alternative control options. Measure A15 has been carried over through subsequent AQMPs and in the 2003 AQMP takes the form of Control Measure CMB-07.

In 1984, the Citizens for a Better Environment (CBE) petitioned the California Air Resources Board (CARB) to make a determination of the technological feasibility, availability and economic reasonableness of continuous emission monitors for refinery flares. CARB granted the CBE request and contracted a study with an engineering firm to evaluate the feasibility of continuously monitoring flaring operations at petroleum refineries. The study found that no refinery in California accurately monitored flow rates to its flares. Several types of flow meters had been installed on refinery flares, but the instrumentation could only provide relative flow information because the gas density varies and gas constituent data is necessary to calculate flow accurately. The study concluded that continuous monitoring of flare gas flow rates, gas composition and remote monitoring of flare plumes were practicable but would require substantial further development before they could be considered ready to use for accurate and precise measurements on flares at a reasonable cost.

Despite concluding that the aforementioned devices still required substantial development, the study found that devices which constantly monitored the on/off status of refinery flares were not only practicable, but were also ready to use at a relatively inexpensive cost. In 1986, CARB determined that monitoring devices were technologically feasible, available and economically reasonable for limited applications to identify and record continuously the on/off status of refinery flares in order to better quantify flare emissions. This finding was formalized and adopted by CARB as Resolution No. 86-60. CARB also encouraged local air pollution control districts to adopt rules requiring refineries to install on/off status monitors and collect flare gas composition data so that a suggested control measure for the control of emissions from refinery flares could be developed.

In 1987 through 1988, refineries in the South Coast Air Basin participated in a flare study resulting from CARB Resolution No. 86-60. The results of this study met with limited success. Staff's review of the available data has determined that the results of the study are insufficient to quantify the emissions from petroleum refineries, especially in light of the recent refinery modifications to produce clean fuels. In addition, the previous monitoring equipment used in this study was found to be maintenance intensive and is no longer used by the refineries.

Since 1988, staff has tracked the development of available technology that could accurately monitor gas flare parameters which would result in sufficient data to quantify emissions. Recent advances in technology have resulted in devices that can now accurately monitor gas flare parameters. Staff has found that these monitoring devices are currently being used in various industries that use gas flares with favorable results.

In 1993 and 1994, staff required two refineries to conduct flare system studies as a result of frequent complaints of odor from emissions associated with their gas flaring operations. Recommendations based on these studies were implemented and resulted in a significant reduction in violations of Rule 402 – Public Nuisance. These studies and subsequent

implementation of recommendations showed that each refinery flare system is complex and unique, but that opportunities do exist to reduce nuisance problems associated with refinery flare systems.

On February 13, 1998, the AQMD Board adopted Rule 1118 with the purpose of monitoring, recording and reporting data on refinery and related flaring operations. Upon rule adoption, the AQMD Board passed a resolution directing staff to a) collect and analyze the data submitted by subject refineries to determine if flare emissions are significant, and b) recommend whether further controls are needed.

After evaluating the data submitted to the AQMD from October 1, 1999 through December 31, 2003, staff compiled the "Evaluation Report on Emissions from Flaring Operations at Refineries", which was presented to the AQMD Board on September 3, 2004. The report recommended amending Rule 1118, concluding that, although refineries had made important progress in reducing emissions since Rule 1118 was originally adopted, flare emissions, especially oxides of sulfur (SOx), were still significant enough to warrant further controls. The report suggest various ways to reduce flare emissions, such as the elimination of leaks from pressure relief devices, the installation of flare gas recovery systems and gas treating systems. In addition to focus on minimization of flare emissions, the report emphasized the potential of the amendment to improve the monitoring, reporting and emission calculation methodology in order to increase the accuracy of the data collected.

B. OTHER CALIFORNIA DISTRICTS FLARE RULES

Several other air pollution control districts in California also have flare rules. The Bay Area Air Quality Management District's (BAAQMD) Rule 12-11, adopted in June 2003, is comparable to AQMD's current Rule 1118. Rule 12-11 – Flare Monitoring at Petroleum refineries applies to refineries in the San Francisco area. The rule requires the monitoring and recording of the vent gas and the composition as well as continuously recording digital video images of the flare tip for each flare. Refineries are required to submit monthly reports in electronic format, containing daily flows and gas composition and corresponding calculated emissions of methane, non-methane hydrocarbons and sulfur compounds resulting from combustion, as well as the archived video pictures of the flares. A complementary rule, Rule 12-12 which seeks to minimize flare emissions through the use of Flare Minimization Plans was adopted in June 2005, and is similar in some respects to PAR 1118.

The Santa Barbara Air Pollution Control District (SBAPCD) also regulates flares based upon its own Rule 359 - Flares and Thermal Oxidizers, adopted on June 28, 1994. This rule applies to oil and gas production, petroleum refineries and related sources, natural gas services and transportation sources and wholesale trade in petroleum/petroleum products that operate flares or thermal oxidizers. Rule 359 specifies sulfur content limits, technology-based standards for flares and thermal oxidizers, and emission standards for oxides of nitrogen (NOx) and reactive organic compounds (ROC) and operational limits. The rule also incorporates a Flare Minimization Plan, monitoring, recordkeeping, reporting and source test requirements for ground flares. However, a review of the staff report for Rule 359 indicates that there are no petroleum refinery operations in Santa Barbara similar to the petroleum refinery operations in the South Coast Air Basin and that Rule 359 applies to non-refinery petroleum operations such as oil and gas exploration and bulk loading terminals.

Ventura County Air Pollution Control District (VCAPCD) Rule 54 - Sulfur Compounds is similar to the SBAPCD Rule 359. While Rule 54 does apply to flares, as in the case with the SBAPCD rule, Rule 54 also applies to non-refinery petroleum operations and AQMD staff is not aware of any petroleum refinery operations in the jurisdiction of VCAPCD.

C. U.S. EPA REGULATIONS (EPA)

The EPA New Source Performance Standards (NSPS), under 40CFR 60.18 – General Control Device Requirements, contains provisions for flares that control vent gases from storage tanks built after July 23, 1984, subject to 40CFR 60 Subpart Kb and from piping components that were installed after January 4, 1983, subject to Subpart GGG. The federal regulation requires flares to operate without visible emissions, to maintain a pilot flame present at all times the flare is in operation and observe certain limits for the net heating value and exit velocity of the gases being combusted. The regulation also requires monitoring of the flares to ensure that they are operated in compliance with these requirements.

Another NSPS regulation, 40CFR 60 Subpart J – Standards of Performance for Petroleum Refineries, covers operation of combustion devices such as flares, that were built or modified after June 11, 1973 under 40CFR 60.104(a). This regulation limits the concentration of the hydrogen sulfide (H_2S) in the vent gases routed to flares to 160 ppm, averaged over three hours. However, vent gases that are combusted due to startup, shutdown, process upset or relief valve leakage are exempt from this requirement.

In 1998, EPA launched a program called "The Petroleum Refinery Initiative" consisting of a series of investigations at refineries under a multi-faceted compliance approach. One of the refinery activities targeted by the investigation was excessive flaring of acid gas (gas with high H_2S content generated during the oil refining process and from the sour water stripper) that results in large amounts of sulfur dioxide being released into the atmosphere. Also investigated was excessive hydrocarbon flaring. EPA's position, as stated in the Enforcement Alert newsletter of October 2000, is that routine or non-emergency flaring does not constitute good air pollution practice and may be a violation of the Clean Air Act. In the newsletter, EPA states that refineries should have adequate capacity to recover and treat sour gases routinely generated in their process without resorting to flaring. Good air pollution practices also include investigating the root cause of a flaring incident and taking corrective actions to prevent recurrence in the future. In the newsletter, EPA states that a properly designed, operated and maintained flare gas recovery system is one way to minimize or avoid flaring.

In an effort to reduce excessive flaring of acid gas and emissions of SOx and NOx, EPA, to date, has entered into 15 global settlements with petroleum refiners representing more than 65% od domestic refinery capacity. The settlements now cover 76 refineries and conferences are currently ongoing with 11 more petroleum refiners who represent an additional 24 refineries. Refineries effected by the global settlements are subject to a consent degree requiring them to prepare and submit plans to minimize hydrocarbon flaring, conduct root cause analyses of flaring events and implement control options such as installing flare gas recovery systems, rerouting hydrocarbon streams away from flares or making hydrocarbon flares compliant with the provisions of 40CFR 60.104(a). By stipulating to consent decrees with EPA, the refineries agreed to undertake certain remediation and mitigation actions, pay fines and provide affirmative relief by completing environmentally beneficial projects. These aforementioned requirements of

the consent decrees are, in part, the concepts on which the proposed amendment to Rule 1118 is based.

Four refineries within the AQMD's jurisdiction have entered consent decrees with EPA: Equilon Enterprises, BP West Coast Products, Chevron Products Company and Conoco Phillips. As a result of the settlements, these companies pledged to reduce SOx and other air contaminants emissions to the environment by minimizing acid gas and hydrocarbon flaring and by agreeing to subject their flares to the requirements of 40CFR 60.104 for combustion devices.

D. EQUIPMENT AND OPERATION

Flares are combustion devices used extensively in the petroleum industry to burn and dispose of excess combustible gases that are generated as part of the production processes or during a process upset. Flares are also used as safety devices to reduce the potential for fires and explosions due to unburned gaseous hydrocarbon releases. Blowdown systems are designed and installed at petroleum refineries to provide for safe containment or safe release of liquids and gases that must be disposed of in the refining process. Such systems generally consist of a series of venting manifolds which lead from the process equipment to a blowdown recovery system (i.e., storage tank, wastewater system, compressor) and flares.

Flares can be elevated like a stack where the combustion, or burn-off, takes place at the tip of the flare and the flames are visible from a distance. They can also be of the ground-flare type where the burners are concentrically located near the ground level in a shrouded, refractory lined enclosure. Both types of flares are capable of destruction of hydrocarbons and other combustible gases. However, as with any type of combustion equipment, they generate air pollutants such as NOx, SOx, carbon monoxide (CO), and particulate matter (PM), in addition to the release of reactive organic gases (ROG) which have not been completely combusted. Also, similar to any other combustion device, flares have the potential to generate toxic emissions depending on the type of gases burned and operating parameters.

Flares have a design capacity, usually expressed in pounds per hour, which represents the maximum design flow of a specific composition, temperature and pressure of vent gas that can be combusted in a particular flare. Due to federal and local regulations, most flares are designed for smokeless operation over a specified flow range, which is achieved by injecting steam or air at the flare tip to increase turbulence and allow ambient air to better mix with the hydrocarbons. The federal requirement allows refinery flare operators to operate a flare with visible emissions for up to five minutes in any two consecutive hour time period. The smokeless capacity of a flare is defined as the maximum flow to a flare that can be burned without smoke and is also expressed in pounds per hour of a specific gas composition, temperature and pressure. Typically, flares are operating in a smokeless manner in a range up to 20 percent of their maximum design flow; at higher flows the size of the pipe that would be required to provide adequate steam injection at the flare tip becomes a design challenge. Another factor contributing to visible emissions is the nature of the hydrocarbons being combusted. Paraffins have the least tendency to smoke, whereas unsaturated and aromatic hydrocarbons have a higher tendency to smoke.

A flare must have the pilot burners on at all times to ensure ignition of the vent gas generated in the process system it serves whenever it is in operation. A stream of combustible gas, called purge gas, is continuously flowing into the flare to prevent air from entering the flare header which can create an unsafe explosive mixture of air and hydrocarbons. Depending on the flare design and size, the amount of purge gas needed to keep the flare safe varies considerably. Although the quantities are relatively small, the burning of pilot and purge gases represent a continuous source of emissions.

In a refinery setting, a gas flare may be installed for only one process area or it can be used to serve a number of process units for a wide variety of purposes ranging from controlling a small stream of leaks or vent gas from a piece of equipment to the disposal of large quantities of gases during an emergency. Therefore, depending on how a flare is designed and used, in Rule 1118 flares are classified into three distinctive categories: clean service, emergency service, and general service.

A clean service flare is used to only burn natural gas, hydrogen, liquefied petroleum gas, or other gases with a fixed composition vented from specific equipment. These gases contain little or no sulfur, and the quality (i.e., heat content and sulfur content) of the gas is usually predictable regardless of the flaring situations. In the basin, there are four clean flares, which are associated with three liquefied propane and butane storage areas and a hydrogen generating plant each.

An emergency service flare is a flare that receives vent gas only during emergencies. The quality and volume of the vent gases vary depending on the source and duration of the emergency release. Nevertheless, an emergency flare is usually in a standby mode and does not create emissions except for those associated with pilot and purge gases, and during actual emergencies.

The most common and complicated flare configuration is the general service flare. In addition to the services described above, flares in a refinery are also used to dispose of gases from routine or non-routine operations including purged gas streams, non-emergency releases of excess pressures, venting of storage tanks or wastewater sumps and equipment leaks, startups and shutdowns, turnaround activities, etc.

E. *APPLICABLE RULES REVIEW*

In addition to Rule 1118, flares are also subject to general AQMD prohibitory rules, such as Rule 401 – Visible Emissions, Rule 402 – Public Nuisance and Rule 431.1 – Sulfur Content of Gaseous Fuels. Flares built after June 11, 1973, are subject to 40CFR 60 Subpart J - New Source Performance Standards (NSPS); flares may also be subject to 40CFR 60.18 – General Control Device Requirements if either vent gases from storage tanks subject to 40CFR 60 Subpart Kb or from components subject to 40CFR 60 Subpart GGG are routed to them.

In order to maintain a smokeless operation, flares at refineries are equipped with steam jets (steam assisted) to provide good mixing of the flare gas with air. Within the smokeless range of operation of a flare, if not enough steam is used during a flaring event, smoking may occur due to pockets of incomplete combustion that are formed in the combustion zone. Rule 401 prohibits visible emissions in excess of Ringelmann 1 or 20 percent opacity for periods exceeding more than three aggregate minutes within any hour. 40CFR 60.18 requires flares to have no visible emissions except for periods of time up to five minutes during two consecutive hours. The two standards are not identical, since they use different methods to determine visible emissions: Rule 401 uses USEPA Reference Method 9 and 40CFR 60.18 uses USEPA Reference Method 22.

If combustion is incomplete, as denoted by visible emissions, odorous materials may be emitted, affecting the area downwind of the flare and potentially resulting in a public nuisance. Odors could also be emitted if the heat content of the flared gas is very low resulting in the flame temperature not being hot enough to ensure complete destruction of odorous materials. The flare operator should supplement combustion with high BTU content gas to prevent this problem. A steam- or air-assisted flare should not be used for disposal of gases with less than 300 BTU/scf.

Although flares operate within refineries subject to Regulation XX - RECLAIM, they are not included in this program and their emissions do not count towards refineries' RECLAIM SOx and NOx allocations. The total sulfur content of the flare pilot gas and the purge gas, which maintain the flare operating continuously, is limited to a concentration of 40 ppm calculated as H_2S, averaged over a four hour period per Rule 431.1 – Sulfur Content of Gaseous Fuels. Most of the flares in the basin use natural gas for purge and pilots in order to comply with this requirement. The total sulfur content of the vent gas routed to a flare due to an emergency is exempt from the rule requirements. The federal regulation, 40CFR 60 Subpart J, has a limit of 160 ppm H_2S, averaged over a rolling three hour period, for purge and pilot gas combusted in a flare, whereas emergency vent gases and relief valve leakage are exempt from this requirement.

F. *AFFECTED FACILITIES*

The types of refinery operations subject to this rule are: petroleum refineries, sulfur recovery plants that recover sulfur compounds from acid gases and sour water generated by petroleum refineries, and hydrogen production plants that produce hydrogen from refinery gas and supply it for petroleum refinery operations. Presently, in the AQMD, there are seven operating petroleum refineries, one sulfur recovery plant and one hydrogen production plant, with a total of 10 distinct physical locations. The following facilities operate 27 flares subject to Rule 1118:

- Air Products (Hydrogen Production Plant)
- BP West Coast Products (Refinery)
- Chevron Products Company (Refinery)
- ConocoPhillips Company (Refinery – Carson Plant)
- ConocoPhillips Company (Refinery – Wilmington Plant)
- Equilon Enterprises, LLC, Shell Oil Products US (Los Angeles Refinery)
- Equilon Enterprises, LLC, Shell Oil Products US (Sulfur Recovery Plant)
- ExxonMobil Oil Corporation (Refinery)
- Paramount Petroleum Corporation (Refinery)
- Ultramar Inc. (Refinery)

Table I-1 shows the subject facilities and an inventory of their flares. Since ConocoPhillips and Equilon Shell Oil submit one quarterly Rule 1118 report for both their facilities (Carson

Plant/Wilmington Plant and L.A. Plant/SRU, respectively) the table shows eight reporting facilities.

Table I-1
Flare Inventory

Reporting Facility	Number of Flares	Type of flare	Type of Service	
			Clean	Emergency/ General Service
A	4	Elevated	1	3
B	1	Ground Flare	1	
C	2	Elevated		2
D	2	Elevated	1	1
E	5	Elevated		5
F	1	Elevated		1
G	6	Elevated		6
H	6	Elevated	1	5
8 Facilities	27 Flares		4	23

CHAPTER II

CONTROL TECHNOLOGY

A. CONTROL OPTIONS

At petroleum refineries, flares have historically been used to dispose of combustible gases resulting from emergency relief, overpressure, process upsets, startups, shutdowns and other operational and safety reasons to prevent direct release of toxic and /or odorous substances to the atmosphere. In recent years, U.S. Occupational Safety and Health Administration (OSHA) and U.S. EPA have become more concerned with refinery operation, resulting in tighter regulations on safety and emissions control and enforcement actions such as Consent Decrees, as shown before. Furthermore, smoke, noise, glare and odors sometimes associated with refinery operations may, and at times have impacted the surrounding communities, leading to an increase in the involvement of community and environmental groups in the regulatory process of controlling refinery flares.

There are two alternatives to control flare emissions: post-combustion and pre-combustion controls. Possible post-combustion controls could be selective catalytic reduction (SCR) units, Lo-NOx burners, scrubbers and bag houses. While post-combustion control technology exists, the unpredictability of the flare operation and the fact that combustion takes place at the tip of an flare 150 to 200 feet above the ground make such control devices impractical for elevated flares.

Controlling flue gases would be very costly under these circumstances and results would not be guaranteed. Therefore, the best way to control and minimize flare emissions is through the use of pre-combustion control, which prevents the formation and reduces the amount of vent gases routed to refinery flares, or recover the vent gases prior to combustion at the flare.

B. FLARE MINIMIZATION PLANS

Refineries can obtain meaningful results in their effort to minimize the volume of vent gases routed to the flare by setting up and implementing flare minimization plans. It is possible to achieve significant reductions in the volume of vent gas generated by process units at refineries. Listed below are several possible alternatives of minimizing flare emissions that could be incorporated in flare minimization plans:

- Better engineering and equipment design
  A reevaluation of existing process flow and equipment allowing changes in operating parameters such as temperature and pressure settings may result in reduced volumes of vent gas being generated.

- Diverting or eliminating streams vented to the flares
  Certain streams that routinely are directed to the flare may be rerouted and either treated for use as fuel gas or recycled back in the process.

- Installation of redundant equipment to increase reliability
  By installing redundant equipment, in case of a breakdown, the spare can be put on line, thus avoiding a process upset that results in gas being routed to the flare.

- Installation of flow monitors for vent gas generated at each process unit
  Installation of flow monitors on process units flare headers is a useful tool that allows the operator to quickly identify the origin of increased flare flows and take immediate corrective actions, potentially avoiding a flare event.

- Periodic monitoring maintenance programs of pressure relief valves that identify leaks to the blowdown system, such as acoustic or thermal surveys
  Pressure relief devices may develop leaks in time, due to the corrosive nature of the process, due to chattering or improper reseating. Given the extended periods of time between turnarounds, leaks may result in significant emissions, even at small rates. By conducting acoustical or thermal surveys of relief devices connected to the flare, the operators can identify and, with detection equipment currently available, even quantify the amount of leak-through gas that escapes to the flare. Upon identification of leaking relief devices, the operator can prioritize their maintenance and repair in order to reduce flare emissions. This program is especially valuable for those flares that are not equipped with flare gas recovery because these leaks end up being combusted in the flare for extended periods of time until the next scheduled turnaround.

- Conducting Specific Cause Analysis of significant flaring incidents
  This investigative procedure is used to identify the cause of significant flaring events and whether any equipment and/or operational changes are needed to prevent future reoccurrences. Once the investigation is completed, corrective measures need to be taken and implemented. It is important to communicate the findings to all parties involved and create a mechanism to track corrective actions in order to prevent future events. This analytical process enables a facility to shift the focus on preventing flaring events rather than reacting to them.

- Operator training for environmental awareness
  Making the operators aware of the impact of flare events on the environment and teaching them procedures that minimize venting to flares needs to be part of the facility's training program and should have full management support.

- Optimization of turnaround schedules
  Coordination of turnaround schedules for different units can result in reducing flaring activity and minimize emissions associated with these periodic maintenance activities.

- Developing startup and shutdown procedures that do not use flaring
  For certain units, it is possible to develop procedures that avoid flaring during shutdown and startup, such as using reduced loads, recycling feeds, better decontamination procedures, etc. Sometimes more time is necessary for a startup or shutdown, or physical modifications achieve this purpose.

C. FLARE GAS RECOVERY SYSTEMS

An alternative control option to minimizing the volume of vent gases routed to flares is to simply prevent the vent gases from being combusted in the flare by recovering them with a flare gas recovery system. In light of increasing environmental concerns, this flare gas recovery system control option is becoming popular, especially since there is an economic incentive due to recovery of valuable gas. The system usually consists of a set of compressors, a heat exchanger, a phase separator and associated pumps. The vent gas is compressed, cooled and routed to an amine scrubber for removal of sulfur compounds, and subsequently may be used as fuel gas or feed for refinery processes. A flare system generally consists of a header or manifold that collects the flare gases from various sources, a knockout drum, a liquid seal (usually water)

drum, and the flare itself. A flare gas recovery system unit connection is typically located between the knockout vessel and the flare water seal.

The primary control variable of the flare gas recovery system is the flare system pressure. As vent gases from various process units collect in the flare header, pressure reaches a predetermined pressure control set point, triggering the start up of the recovery compressor. The suction pressure of the compressor is set lower than that of the water seal, such that under normal operation, there is not enough pressure in the flare header to break through the liquid seal and all gas is recovered. During major upsets, if the flow exceeds the compressor capacity, the flare header pressure increases, breaking the liquid seal and the vent gases reach the flare, where they are combusted. Therefore, the safety function of the flare system is maintained in the event of process upset conditions.

In order to have a high recovery rate, the compressor station should be sized with a capacity two to three times the normal flare flow (Oil and Gas Journal, December 7, 1992). API Guideline 520 states that the normal flow rate is some average flare load or a frequently encountered maximum load and that the recovery system should be designed to operate over a wide range of dynamically changing loads. API 520 goes on to say that often these systems are installed to comply with local regulatory limits and therefore, must be sized to conform to any such limits.

CHAPTER III

PROPOSED RULE AMENDMENTS

PROPOSED AMENDMENTS

Staff proposes amending Rule 1118 as follows:

- Add, modify or delete definitions.
- Add new operational requirements for flares and establish diagnostic practices to minimize flaring.
- Prohibit the flaring of gases other than those resulting from emergencies, shutdowns, startups, turnarounds and essential operational needs and require minimization of such flaring.
- Establish refinery specific performance targets for minimizing flare emissions based on annual crude throughput.
- Require refineries to pay a mitigation fee for exceedances of a refinery specific performance target.
- Require a Flare Minimization Plan and possible issuance of a Notice of Sulfur Dioxide Exceedance when flare SOx emissions exceed the facility specific target for a given year.
- Add and modify requirements for the Flare Monitoring and Recording Plan.
- Add and modify requirements for the operation monitoring and recording.
- Modify the recordkeeping requirements.
- Add new notification and reporting requirements.
- Expand and update the test methods.
- Modify and add exemptions.
- Enhance and update monitoring specifications in Attachment A – Flare Monitoring System Requirements.
- Modify and enhance Attachment B – Guidelines for Calculating Flare Emissions which include missing data substitution procedures.

A. DEFINITIONS

The following definitions are new:

- Emergency - is defined as a condition that requires immediate attention to restore normal operation, caused by a sudden, infrequent and unavoidable event. An emergency may be caused by equipment breakdown, natural disaster or an act of war or terrorism. If a flare event is caused by poor maintenance or careless operation, it will not be deemed an emergency.
- Essential Operational Need – is defined as flare event caused by a specifically listed operational or maintenance related activity where due its quality or quantity, the vent gas cannot be reasonably recovered, treated, used or delivered for sale with existing equipment. Examples of Essential Operational needs are:

    Temporary fuel gas imbalances caused by inability of a customer to receive sales gas used for generation of electricity for a state grid or a third party contractual gas purchase agreement, or due to sudden shutdown of a combustion device for reasons other than operator error or poor maintenance;

    Leakage of relief valves due to malfunction;
    Venting of gas streams that are incompatible with the operation of the flare gas recovery equipment (e.g., molecular weight outside the design range) or that could pose a safety hazard to the fuel gas system (e.g., very low or very high BTU content that causes temperature swings in combustion devices, upsetting the process). Whenever the vent gas has a low BTU content a refinery may use supplemental natural gas or other clean gas that is compliant with Rule 431.1 to ensure high combustion efficiency;
    Venting of clean gas streams to either a clean service flare or a general service flare;
    Intermittent minor venting from sight glasses, compressor bottles, sampling equipment and pumps or compressors casings;
    Emergency situations when the pressure vessel operation pressure rises above the set point of the relief valve.

- Flare Gas Recovery System - is defined as any system designed to prevent or minimize the combustion of vent gases in a flare, composed of, but not limited to, compressors, heat exchangers, pumps, water seal drums, etc.
- Flare Minimization Plan is defined as a document that meets specific rule requirements in subdivision (e).
- Natural Gas - is defined as a mixture of gaseous hydrocarbons, with at least 80 percent methane (by volume), and of pipeline quality, such as the gas sold or distributed by any utility company regulated by the California Public Utilities Commission.
- Notice Of Sulfur Dioxide Exceedance – is defined as a notice that may be issued by the Executive Officer to a refinery in the event an annual performance target is exceeded and remains in its compliance record.
- Pilot - is defined as an auxiliary burner used to ignite the vent gas routed to a flare.
- Purge Gas - is defined as a continuous gas stream introduced in the flare header, flare stack and /or flare tip for the purpose of maintaining a positive flow that prevents that prevents the formation of an explosive mixture due to ambient air ingress.
- Sampling Flare Event – this definition replaces Recordable Flare Event and applies to flare events with a flow rate of at least 330 scfm for fifteen consecutive minutes or more, or any other flare event as approved in writing by the Executive Officer upon request from a facility, due to specific operational parameters of a flare.
- Shutdown - is defined as the procedure by which the operation of a process unit or piece of equipment is stopped at the end of a production run or for the purpose of performing maintenance, repair or replacement of equipment.
- Specific Cause Analysis - is defined as an investigation used to identify the cause of certain flare events with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of flared gas, provide corrective measure(s), and prevent recurrence of a similar event.
- Startup - is defined as the procedure by which a process unit or piece of equipment achieves operational status. The attainment of normal operational status may be substantiated by parameters such as temperature, pressure, feed rate and also by products meeting quality specifications.

- Turnaround - is defined as a planned activity involving shutdown and startup of one or several process units for the purpose of performing periodic maintenance, repair, replacement of equipment, or installation of new equipment.
- VOC – is defined as in Rule 102 of AQMD Rules and Regulations.

The following definitions were modified:

- Flare Event - clarifies that an event takes place when vent gas is combusted in a flare and ends when the vent gas velocity drops below 0.12 feet per second, or when no more vent gas is combusted as demonstrated by the water seal monitoring record or other parameters as approved by the Executive Officer in the Flare Monitoring and recording Plan.
- Flare Monitoring System - was expanded to include, in addition to the flow meter, a continuous higher heating value analyzer and a total sulfur analyzer.
- Gas Flare - was shortened by removing "Gas" since this rule addresses flares used to dispose of gases only.
- Hydrogen Plant - was expanded to include the processes used to generate hydrogen.
- Representative Sample - was modified by deleting part of the definition that no longer applies or was moved under monitoring requirements.
- Petroleum Refinery – was expanded, for the purpose of this rule, to clarify that all portions of the petroleum refining operation, including those at non-contiguous locations operating flares, shall be considered as one petroleum refinery.
- Sulfur Recovery Plant - was expanded to also include sour gases as process feed.
- Vent Gas - was redefined as any gas generated at a refinery that is routed to a flare excluding assisted air or steam injected directly into the stack or flare combustion zone via a line separate from the flare header.

The following definition was deleted:

- Recordable Flare Event - was removed due to the new monitoring requirements and was replaced with "sampling flare event".

B. REQUIREMENTS

Staff has added new requirements for flares, arranged by the date they become effective.

The following requirements become effective on January 1, 2006:

- A flare must have the pilot flames present any time the system it serves is in operation.
- All flares must operate without visible emissions, as determined by US EPA Method 22. The method allows for visible emissions for no longer than five minutes within a two consecutive hour period.
- All pressure relief devices (PRDs) connected directly to flares must have an annual inspection using acoustical or thermal surveys in order to detect leaks. The requirement applies only to PRDs venting directly to flares (gases that are not collected or controlled

with flare gas recovery and treatment. The inspection has to be conducted within 90 days prior to a scheduled turnaround, if one is scheduled for that calendar year.

- The owner or operator of a flare having a flaring event with emissions exceeding either 100 pounds of VOC or 500 pounds of sulfur dioxide, or 500,000 standard cubic feet of vent gas combusted is required to conduct a Specific Cause Analysis of the event. Flare events associated with shutdowns, startups, and turnarounds are exempt from this requirement since their cause is known and therefore no investigation is necessary.
- The owner or operator of a flare has to identify the cause, where feasible, of any flare event where at least 5,000 standard cubic feet of vent gas was released to the flare. For some smaller releases, the owner or operator may not have sufficient data to determine the cause of the flare event.

The following requirements are effective January 1, 2007:

- The owner or operator of a refinery subject to rule shall submit the technical detail of each flare system, including an audit of vent gas recovery capacity, an assessment of the flare gas reductions achieved since the adoption of Rule 1118 in 1998 and the planned future flare emission reductions.

The following requirements are effective January 1, 2007:

- Owners or operators have to operate flares such that only vent gases resulting from an emergency, shutdown, startup, turnaround or essential operational need are combusted and have to minimize flare emissions during these events.
- Staff acknowledges that some refineries will install gas recovery and treatment system(s) to comply with this requirement, and that the refineries will need time to connect and operate these systems. In recognition of this need staff proposes to establish a compliance date of no later than January 1, 2009, or January 1, 2010 if more than two flares are to be controlled, provided that those refinery operators submit an application to construct and operate the control equipment for approval by the Executive Officer prior to January 1, 2007.

The following requirement is effective on January 1, 2009:

- Any vent gas combusted in a flare, except for vent gas resulting from an emergency, shutdown, startup, process upset or relief valve leakage, cannot exceed 160 ppm H_2S concentration, averaged over three hours. Staff believes that by January 1, 2009, refineries will have sufficient vent gas recovery and treatment capacity to be able to comply with this requirement during essential operational needs, for which this requirement would essentially apply.

C. PERFORMANCE TARGETS

PAR 1118 prohibits flaring of gases other than those resulting from emergencies, shutdowns, startups, turnarounds, and essential operational needs. It also sets decreasing flare total sulfur performance targets for the allowed flaring activities, calculated and reported as sulfur dioxide (SO_2), for subject refineries, based on 2004 throughputs, with the purpose of capturing emission reductions achieved since the rule was adopted and to ensure that these and future emission reductions are enforceable, permanent, real, and verifiable. Total SO_2 reductions will be determined annually for each calendar year. To determine compliance with the SO_2 Performance

Targets, the annual emissions will be divided by the 2004 refinery throughput. The performance targets proposed and the corresponding milestones, starting with year 2006, are as shown in Table III - 1:

Table III- 1
SO_2 Performance Targets
(Tons per million barrels crude processed)

Year	2006	2008	2010	2012
SO_2 Performance Target	1.5	1	0.7	0.5

In the event that a refinery exceeds the specified performance target in any calendar year, it will have to pay a mitigation fee for each ton of sulfur dioxide over the limit based on the following levels of exceedance: $25,000 for each and every ton where the exceedance is up to ten percent over the performance target, $50,000 for each and every ton where the exceedance is greater than ten percent but no more than twenty percent over the annual performance target, or $100,000 for each and every ton where the exceedance is greater than twenty percent over the applicable performance target. The mitigation cannot exceed $4,000,000 dollars per each petroleum refinery in any one year. Any mitigation fees paid would be used to implement emission reduction projects in the area impacted by the excess emissions.

It is expected that refineries will implement the procedures and install the equipment necessary to achieve compliance with the annual sulfur dioxide performance targets. However, since the operation of flares is variable based upon periodic events, some of which may be unforeseeable, it is possible that a refinery could exceed a performance target in any one year. The mitigation fee provision offers the refinery an alternative compliance option in that circumstance and allows the opportunity for the refinery to take those actions necessary to ensure the performance targets are met in future years. For each year an annual performance target is exceeded, the Executive Officer may also issue a Notice of Sulfur Dioxide Exceedance that will become part of the petroleum refinery's compliance record.

In establishing the appropriate monetary amount for the mitigation fees, staff considered two larger petroleum refineries that currently have no or limited controls on their flares. Historical flare sulfur dioxide (SO_2) emissions and flare vent gas flows for the two facilities for the years 2002, 2003 and 2004 and the three year average are shown in Table III - 2.

Table III – 2

Historical Data

		2002	2003	2004	Average
Refinery 1	SO_2 (tons/year)	59	76	27	54
	Flow (million cubic feet per year)	804	804	657	755
Refinery 2	*SO_2 (tons/year)*	77	45	19	47
	Flow (million cubic feet per year)	308	324	289	307

As part of their 2004 Emissions Fee Billing (EFB) submittal, .Refinery 1 and Refinery 2 reported processing of approximately 95 and 51, million barrels of crude oil during the 2003-2004 fiscal year, respectively. Table III-3 is a summary of the permitted annual crude oil throughput (in million barrels of crude oil per year), the 2010 performance target for each petroleum refinery target (in tons SO_2) and the amount of SO_2 exceedance at twenty percent over the 2012 annual SO_2 performance target of 0.5 tons per million barrels of crude oil.

Table III – 3
Analysis

Facility	Annual Crude Oil Throughput (million barrels)	2010 Annual SO_2 Performance Target (tons)	20% SO_2 Exceedance (tons)
Refinery 1	93	47	10
Refinery 2	50	25	5

To estimate the vent gas flow associated with the 10 tons and 5 tons of sulfur dioxide excess emissions, staff will use the ratio of three year average of vent gas flow to SO2 emissions. Staff believes that the total flow and SO2 emissions for any year will average the high and low flows and SO2 emissions that will be used to determine the approximate vent gas flow for the sulfur dioxide excess emissions.

Therefore, the flow associated with the yearly exceedance, in million standard cubic feet per year (mmscfy) and calculated as daily, averaged over 365 days (mmscfd) is:

<u>Refinery 1</u>

$Flow_1$ = *10 tons * 755 mmscfy / 54 tons = 140 mmscfy = 0.38 mmscfd*

<u>Refinery 2</u>:

$Flow_2$ = 5 tons * 307 mmscfy / 47 tons = 33 mmscfy = 0.09 mmscfd

To prevent future exceedances, it is assumed that the two facilities would have to install flare gas recovery and treating systems to control this amount of vent gas associated with the SO_2 exceedance. The capacity of the control system should be two to three times the vent gas flow rate; staff has determined the cost of a flare gas recovery and treating system to be $2.17 million per million standard cubic feet per day (mmscfd) of vent gas recovery/treatment (see discussion in Chapter VI).

The cost to install vent gas recovery and treatment to control the incremental amount of sulfur dioxide that caused the exceedance of the annual performance target is:

<u>Refinery 1</u>

Control Cost = 0.38 mmscfd * 2 * $2.17 *million per mmscfd / 10 tons per day*

= $164,920 per ton SO_2 reduced

<u>Refinery 2</u>

Control Cost = 0..09 mmscfd * 2 * $2.17 million per mmscfd / 5 tons per day

= $78,120 per ton SO_2 reduced

The average cost to control the incremental amount of sulfur dioxide that caused the exceedance of the annual performance target is $121,520. As previously stated, the operation of flares and resultant emissions are variable based upon periodic events. Therefore, a mitigation fee of $100,000 per ton of SO_2 for annual exceedances of more than twenty percent of the annual performance target is appropriate. The mitigation fee for exceedances less than twenty percent are less than the cost of vent gas recovery and treatment and therefore would be considered reasonable.

D. FLARE MINIMIZATION PLAN REQUIREMENTS

Each refinery that exceeds an annual performance target must submit a Flare Minimization Plan to the AQMD for approval from the Executive Officer, along with appropriate fees pursuant to Rule 306 but no later than 90 days from the end of the calendar year when the performance target was exceeded that demonstrates the actions to be taken to achieve the performance targets. The main required elements of the plan are:

- A complete description and technical specifications for each flare at a facility;
- Detailed process flow diagrams of upstream equipment venting to each flare and an identification of all control equipment;
- Policies and procedures to be used to minimize vent gases during emergencies, shutdowns, startups and turnarounds and during essential operational needs; and
- A complete description of a flare gas recover and treatment system(s) to be installed to meet the performance target(s).

The AQMD will make available the Flare Mininimization Plans, less any confidential information, for public comments for a period of 60 days and respond to them prior to taking action on the plans. Any facility that exceeds it annual sulfur dioxide emission limit during a subsequent calendar year will have to submit to the AQMD a revised Flare Minimization Plan within 90 days from the end of the calendar year, in which it will detail additional measures for preventing future exceedance. If the Executive Officer deems the plan deficient, the facility has 45 days to correct and resubmit it. Failure to do so would cause the Executive Officer to deny the plan and issue the facility a Notice of Violation.

A facility may, without exceeding the performance targets and on a voluntary basis, submit a Flare Minimization Plan for approval to the Executive Officer. The plan would be subject to the same provisions as a mandatory plan, but if denied no Notice of Violation would be issued to the facility.

E. FLARE MONITORING AND RECORDING PLANS

Each existing facility currently in operation must submit a revised Flare Monitoring and Recording Plan by June 30, 2006 for approval by the AQMD, along with appropriate fees pursuant to Rule 306. Any new facility or non-operating facility that starts operating after the rule is amended will have to submit a Flare Monitoring and Recording Plan and appropriate fees

at least 180 days prior to initial start-up and notify the AQMD seven days prior to startup or resumption of operations. *The current monitoring plans submitted pursuant to Rule 1118,* adopted February 13, 1998 will be in effect until the revised plans are approved by the AQMD. The revised plans must provide, in addition to the existing information, details on installed heat content analyzers, total sulfur analyzers and upgraded flow meters, where applicable.

F. OPERATION MONITORING AND RECORDING

The proposed amendment has several new requirements for flare monitoring and recording. The new requirements will be phased in as follows:

Effective upon rule amendment:

- The presence of a flare pilot flame has to be monitored using a thermocouple or an equivalent device, such as infrared or ultraviolet cameras.
- Refineries will have to use video monitors equipped with date and time stamp to monitor the flares for visible emissions. The video recording will have to be maintained at the facility for a period of 90 days and submitted to AQMD personnel upon request.

Effective January 1, 2006:

- Facilities subject to this rule are required to take a daily representative sample. Only one representative sample is required each day for flare events that are not sampling flare events. A representative sample collected for a sampling flare event on that day may be used to satisfy this requirement. For flare events lasting 15 minutes or less, no representative sample is required. A sample shall not be required if the operator demonstrates vent gas is not routed to a flare based on verifiable records of flare water seal level and/or other parameters as approved by the Executive Officer in the Flare Monitoring and Recording Plan or the Revised Flare Monitoring and Recording Plan.

Within six months from approval of the Flare Monitoring and Recording Plan, but no later than July 1, 2007:

- Continuous higher heating value and semi-continuous total sulfur analyzers are required for emergency and general service flares to eliminate problems related to sampling and data accuracy, as recommended in the Evaluation Report on Emissions from Flaring *Operations at Refineries.* The use of analyzers will provide a more realistic picture of flare emissions by providing more data points for the heat content and total sulfur content of the vent gases, thus increasing the accuracy and reliability of emission reporting, that is currently achieved by using data from weekly samples. Refineries must begin monitoring within six months from approval of the Revised Flare Monitoring and Recording Plan by the AQMD. Until the analyzers are installed and certified by the Executive Officer, the refineries will be required to measure and sample for both higher heating value and total sulfur daily (an increase from the current weekly sampling requirement) in addition to collecting representative samples during a sampling flare event, using a step by step procedure outlined in Table 2 of the proposed amended rule. However, if no flare event takes place during the day, as demonstrated by water seal level records or other parameters as approved in the Flare Monitoring and Recording Plan, no sample is required. In the event that samples cannot be taken due to an exempt occurrence and emissions are estimated, the methods are those in the missing data procedures included in an appendix to the rule and estimated emissions have to be reported as such in the quarterly flare report.

Effective January 1, 2007:

- Flow meters are required for monitoring and recording the purge gas and pilot gas flow rates for all emergency and general service flares and have to be approved by the AQMD.
- All emergency and general service flare flow meters will have to be installed at a representative location to indicate an accurate flow to the flare. This requirement was necessary since there are flow meters located upstream of water seals at flares equipped with flare gas recovery systems that may indicate a flow that actually is recovered and not breaking the water seal. The operators monitor the water seal level to determine whether an actual flare event took place. There are also problems at low flows, when ambient heat creates a gas flow inside the large diameter flare headers, resulting in a "ghost" reading on the flow meter. In order to eliminate these problems, flow meters have to be installed downstream of water seals or, if this is not feasible due to physical constraints, they need to be equipped with totalizing capability that discounts reverse flows to a recovery compressor or due to turbulence created by ambient heat.
- Each emergency and general service flare that is not equipped with a total sulfur analyzer will have to be equipped with an automated sampling system capable of alerting the operator that a sampling event has started.

G. *RECORDKEEPING REQUIREMENTS*

The proposed amendment requires that video recordings of all flares be kept for 90 days and all other records mandated by the rule be kept for a period of five years.

H. *NOTIFICATION AND REPORTING*

The proposed amendment has new notification requirements and enhanced reporting requirements, as follows:

- Facilities subject to this rule will have to provide a 24 hour telephone service for access by the public for inquiries about flare events. The owner or operator shall provide the Executive Officer in writing the name and number of the initial contact and any contact update.
- Refineries will have to notify the AQMD by telephone within one hour of a flare event exceeding 100 pounds of VOC, 500 pounds of total sulfur emissions calculated as sulfur dioxide, or 500,000 standard cubic feet of vent gas. The one hour time requirement starts at the time the refinery operator facility knows or should have known that the aforementioned mass levels may have been emitted or the vent gas as measured by the flow meter is determined to exceed 500,000 standard cubic feet of vent gas. A "specific cause analysis", identifying the cause and duration of the event, mitigation and corrective actions taken, has to be submitted to the AQMD within 30 days.
- A 24-hour advance notice to the AQMD is required for scheduled planned flare events that have the potential to exceed 100 pounds of VOC or 500 pounds of total sulfur, calculated as sulfur dioxide or 500,000 standard cubic feet of vent gas.

- The quarterly reports will have to be submitted in an electronic format approved by the AQMD and certified in writing by a responsible facility official that the information is true and accurate. Emissions will have to be calculated or, in case of missing data, substituted using the guidelines in Attachment B to the rule. The refineries will also have to include in the quarterly report a categorization of flare events by cause and the associated emissions. Lastly, records of leak surveys done in the quarter for pressure relief devices connected to flares will have to be reported, including identification of the devices, dates of inspection and the person(s) conducting the surveys.

I. *TEST METHODS*

The following are additions and modifications to this section of the rule:

- The higher heating value of the flare vent gas has to be monitored with a semi-continuous analyzer meeting or exceeding the specifications in Attachment A to the rule.
- Total sulfur concentration calculated as sulfur dioxide may be monitored with a semi-continuous total sulfur analyzer meeting or exceeding the requirements in Attachment A to the rule. Until such time as the monitor is certified by the Executive Officer, the samples collected by the refinery operator shall be determined using AQMD Method 307-91 or updated ASTM Method 5504-01.
- The accuracy of the flare flow meters has to be verified annually according to manufacturer's procedures.
- For determining visible emissions from flares, refineries have to use procedures outlined in U.S. EPA Method 22, 40CFR Part 60 Appendix A.

J. *EXEMPTIONS*

An exemption was added for excluding the flare-related total sulfur emissions, calculated as sulfur dioxide, resulting from external power curtailments excluding interruptible service agreements, natural disasters and acts of war or terrorism, from the annual facility emissions established under Performance Targets since these events are beyond the reasonable control of the refinery operator. In addition, has added language to clarifying that sampling and analyses of representative samples for higher heating values and the concentration of total sulfur, expressed as sulfur dioxide, pursuant to paragraph (g)(3) may not be required for any flare event when collecting a sample is unfeasible or constitutes a safety hazard

K. *ATTACHMENT A*

Attachment A was enhanced by incorporating additional specifications for the continuous flow measuring device and adding new specifications for the heat content analyzer and the total sulfur analyzer.

L. *ATTACHMENT B – GUIDELINES FOR CALCULATING FLARE EMISSIONS*

Attachment B was modified to include equations and emission factors for calculating flare emissions for vent gas, natural gas, propane and butane, thus making reporting uniform among refineries, sulfur recovery plants and hydrogen production plants. Another addition provides the methodology to be used for data substitution during flow meter, sampling and analyzer down periods or when the representative samples are not measured and recorded pursuant to the rule requirements. Data substitution is not required if it can be demonstrated to the satisfaction of the Executive Officer that there was no flow to the flare during the flow meter and/or analyzer

outage or a sample was not taken and analyzed. Footnote 4 in Table 1 of Rule 1118 further explains that samples specified in Table 1 will not be required if the operator demonstrates that vent gas is not being routed to a flare based on verifiable records of flare water seal level and/or other parameters as approved by the Executive Officer in the Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan.

Once the methodology and parameters used to demonstrate that the vent gas is not being routed to a flare is included in the approved Flare Monitoring and Recording Plan or Revised Flare Monitoring and Recording Plan, it is considered to be to the satisfaction of the Executive Officer for the purpose of making the above demonstration. If there was flow, the method shown in equation (1) shall be used to calculate the substituted data, unless an alternate method using recorded and verifiable operational parameters and/or process data is approved by the Executive Officer to be representative of the missing parameters. The goal of the data substitution methodology was to provide a conservative estimate based on the operational history of the flare.

$$MP = P_{Max} - 0.5 \times \left(P_{Max} - P_{Avg}\right) \qquad \text{Equation (1)}$$

where:

MP = The missing parameter for which data was not recorded.

P_{Max} = Maximum measured and recorded value of the missing parameter over a 5 year period.

P_{Avg} = Average measured and recorded value of the missing parameter over a 5 year period.

This methodology was developed based on the reported flare event data for refineries operating in the South Coast Air Basin (including a sulfur plant) between October 1, 1999 through June 30, 2005. The data reported by the refineries and utilized in the analysis included:

- The duration of each individual flare event;
- The total volume of gas released during the flare event;
- The higher heating value of the flared gas;
- Basis for which the higher heating value (HHV) of the flared gas was determined (lab measurement, average of previous events, etc.);
- The sulfur content of the flared gas; and
- Basis for which the concentration of total sulfur, expressed as sulfur dioxide, of the flared gas was determined (lab measurement, average of previous events, etc.).

Data whose origin was not based on a discrete measurement was discarded. It was discarded so the entirety of the data being analyzed would be representative of actual flare events. This would prevent variability in the data being attenuated through the introduction of substitute data based on an average.

The data for each recorded flare event between October 1999 and June 2005 for each flare were plotted as a function of time. These plots revealed:

- The concentration of total sulfur, expressed as sulfur dioxide, in the flared gas showed a high degree of data scatter that varied randomly over a potential range of 200,000 ppm.
- The volume of gas flared in terms of rate and total volume released showed a high degree of data scatter which varied randomly over a potential range of 39,000 MSCF.
- The HHV of the flared gas exhibited the lowest degree of data scatter, but still varied randomly. The magnitude of the variation was over a potential range of 5000 Btu/scf.

The large range and randomness exhibited by the population of data posed the following difficulties in creating a methodology for estimating substitute data:

- Requiring the facility to report substitute data based on the single highest historical measured value would result in the facility grossly over-estimating their emissions. The emission would be grossly over-estimated as a result of the majority of the flares having a single point outlier for each data set that was orders of magnitude greater that the majority of the population.
- Requiring the facility to report an average value would result in a significant portion of the data falling above the mean value. There would be a large portion of data above the mean value due to the high degree of data scatter exhibited by the population of data.
- A methodology based on a short term sample of data could result in substitute data being under-estimated. The data would be under-estimated if the short term sample happened to be taken from a period where the values of the short term population were on a down-trend. There were flares in the analyzed data set, which included 23 consecutive quarters (5 years, 9 months) of reported data that demonstrated cyclic behavior. Coincidently, the refineries have stated that they turnaround their units every five years. This behavior showed surges in the value of a given parameter, followed by a lull. Any data that were estimated based on the lull period would provide under-estimated results during the surge, which is contrary to the goal of the substitution methodology.

The method shown in Equation (1) accounted for the problems listed above. This method accounts for the average value of the population with respect to the deviation from the mean. The use of a five year (20 quarters) averaging period also eliminates the potential of under-estimating substitute data due to basing it's value on a short term period where the value of the population could be in a lull. The 0.5 multiplier in equation (1) was empirically determined by fitting the equation to the population of data. The equation was fit multiple times with the multiplier incrementally increased between a range of 0.4 and 0.7. The 0.5 multiplier provided the desired result. This value provided a result that generally captured 98% of the population of data, but was sufficiently less than the single point outliers that were present in some populations of data.

CHAPTER IV

EMISSION INVENTORY

A. CONTRIBUTING SOURCES

As shown in Chapter I, in the AQMD there are seven petroleum refineries, one sulfur plant and one hydrogen generating plant accounting for 27 flares categorized as emergency flares, clean flares and general purpose flares. The breakdown by flare, as reported in the September 2004 Evaluation Report, including flare system design and flare gas recovery capacities, is shown below in Table IV – 1.

Table IV – 1
Flare Inventory

Flare ID	Capacity (lbs/hr)	Vapor Recovery Capacity (MMscfd)	Notes
Flare No. 1	41,000	0.36	
Flare No. 2	232,281	6.96*	
Flare No. 3	1,120,000	1.4*	
Flare No. 4	600,000	None	
Flare No. 5	343,900	None	Clean Flare
Flare No. 6	1,300,000	2	
Flare No. 7	250,000	None	
Flare No. 8	1,040,000	4.8	
Flare No. 9	956,000	None	
Flare No. 10	133,950	6.96*	
Flare No. 11	825,000	None	
Flare No. 12	6,000	None	Clean Flare
Flare No. 13	1,300,000	6	
Flare No. 14	26,718	None	Clean Flare
Flare No. 15	3,540,000	9.8	
Flare No. 16	176,000	None	
Flare No. 17	960,000	6	
Flare No. 18	1,400,000	6	
Flare No. 19	173,000	None	
Flare No. 20	188,000	None	
Flare No. 21	1,220,000	1.25	
Flare No. 22	655,000	1.4*	
Flare No. 23	26,000	None	
Flare No. 24	335,847	6.96*	
Flare No. 25	498,000	None	
Flare No. 26	1,407,000	6	
Flare No. 27	70,000	0.06	Clean Flare

* These flares share a flare gas recovery system

B. EMISSION INVENTORY

According to the 2003 AQMP, the SO_2 emissions inventory for refinery flares, based on the 1997 annual reports for emissions fee billing (EFB), is 4.14 tons per day (the initial number, based on unaudited data at the time the AQMP was published, was 4.4 tons per day). For 2006 and 2010, this inventory is projected to be reduced by 50 percent through the implementation of Step II of control measure CMB-07, and the AQMP assumes concurrent emission reductions for the other criteria pollutants. The proposed amendment of Rule 1118 will implement Step II of the control measure and further reduce emissions to the extent feasible.

Flare emissions are reported on a quarterly basis per current requirements in Rule 1118, and are calculated based on flare vent gas flows and weekly samples that are analyzed to determine the concentration of total sulfur, expressed as sulfur dioxide, and the higher heating value (HHV) of the vent gas. It has to be noted that these emissions are different from the annual emissions reported under EFB program, where reported flare emissions are calculated based on crude throughput and the amount of elemental sulfur produced at each facility, using appropriate emission factors.

A summary of the quarterly reports, showing Rule 1118 annual flare emissions, from 2001 *through 2003, extracted from the September 2004 report presented to the Governing Board* and the reported flare emissions for 2004 is shown in Table IV – 2.

Table IV – 2
Rule 1118 Reported Annual Flare Emissions (Tons)

Year	Flow (mmscf)	NOx	VOC	CO	PM10	SOx	Total
2000	4,085	136	125	733	43	2,633	3,670
2001	8,324	380	456	2,058	87	1,793	4,774
2002	2,440	83	78	450	25	754	1,390
2003	2,235	79	75	423	23	735	1,335
2004	2,392	93	70	364	27	352	906

The data in the table shows that flare emissions have decreased in the years following the adoption of the rule in 1998, as the refineries became more sensitive to flaring issues and implemented voluntary measures to reduce the vent gas flow combusted in the flares and better managed flare operations. It is important to note that these voluntary reductions in flare gas flow and associated emission reductions were generally not achieved through the installation or modification of gas recovery capacity or flare gas treatment systems. Since 1998, only one local refinery has installed control equipment in 2001; a flare gas recovery system for one of its flares that resulted in significantly reduced emissions from that flare.

Another reason for the drop in emissions was found to be the correct measurement of flare flows. A *refinery* discovered it had erroneous flare flow readings that led to reporting inflated emissions. An investigation of the problem concluded that the flow meter located before the water seal was counting both the flow towards the flare and the reverse flow to a recovery compressor, although no actual vent gas was going past the water seal and combusted in the flare. The refinery relocated the flow meter in the flare stack and eliminated the problem. Therefore, in order to get reliable emission data, it is necessary that the flow meters be located in a representative location after the water seals to ensure that a true flow to the flare is registered, or they must be equipped with totalizing capability to subtract any reverse flows to flare gas recovery systems.

The rest of the reductions resulted primarily from voluntary changes in operations, such as extending the time for shutting down or starting up units to minimize flaring, training operators to avoid routine flaring, as well as a commitment from management to minimize flaring. However, none of these measures are required by the current rule and as such, are not considered enforceable and permanent.

An analysis of the flare flow, events, and emissions data submitted to the AQMD since 1999 clearly shows a downward trend, it also shows variability from year to year. This variability is due in large part to emergencies, the specific unit(s) that undergo turnaround(s) in that year, other startups and shutdowns, and essential operational needs. Since these events can vary year to year, so will the number and type of flare events and the flare emissions. Therefore, it is appropriate to average the annual flare emissions to develop a representative baseline emissions inventory for emissions reductions and cost analysis calculations. Based on an analysis of the data submitted and discussions with refinery representatives, staff concluded that the 2000 data may not be very reliable due to compliance issues and because of problems related to the implementation of this recently adopted flare monitoring rule. Also, one refinery installed additional vent gas recovery in 2001; this installation would result in permanent emissions reductions from 2002 and beyond. Therefore, staff has determined that the most representative data for these variable flare operations and future releases are from years 2002, 2003 and 2004.

Table IV - 3
Flare Emissions Average 2002-2004

Year	NO_X	NMHC	CO	PM10	SO_2	Total
Average Emissions (TPY)	85	74	412	25	613	1,209
Average Emissions (TPD)	0.23	0.20	1.13	0.07	1.68	3.31

Based on emissions data from Table IV – 2, Table IV – 3 shows the flare emissions average for the period 2001 through 2004. The Rule 1118 average reported SO_2 emissions is 613 tons or 1.68 tons per day, while the average emissions total for all the criteria pollutants is 1,209 tons, or 3.31 tons per day. This inventory will be used as the baseline for calculating the emission reductions associated with the proposed amended rule and its cost effectiveness.

CHAPTER V

EMISSION REDUCTIONS

As shown in the previous chapter, flare emissions have trended lower since the rule was first adopted in 1998. As monitoring of flare flows was initiated to comply with the rule, refinery operators became aware of the high amounts of vent gas routed to flares and implemented procedures to minimize emissions. Although the reductions are substantial, staff believes that further emission reductions are feasible for the industry. In September 2004, after staff presented the "Evaluation Report on Emissions from Flaring Operations at Refineries", the AQMD Governing Board directed staff to initiate the amendment of Rule 1118. The performance targets in this rule amendment will result the installation of additional controls for flaring operations, as recommended in the Evaluation Report, to prevent backsliding in the emissions that have been reduced over the last several years.

The proposed amended rule requires refineries to gradually lower their annual sulfur dioxide emissions from a baseline average of approximately 1.68 tons per million barrels of crude processed to 1.5 tons per million barrels of crude processed in calendar year 2006, 1.0 ton per million barrels of crude processed in calendar year 2008, 0.7 ton per million barrels of crude processed in calendar year 2010 and 0.5 ton per million barrels of crude processed in calendar year 2012. The total processing capacity of the refineries in the basin, based on industry data, is approximately 1 mmbbl/day, therefore projected annual sulfur dioxide emissions for 2012 are 430.7 tons.

These reductions can be achieved by establishing a requirement that limits the use of flares only for emergencies, shutdowns and startups and certain essential operational needs and elimination of routine flaring. To ensure that total industry emissions will stay below the limit and prevent backsliding, the proposed amended rule has a mitigation fee provision in place. However, staff believes that by year 2012, flare sulfur dioxide emissions will be well below 0.5 ton per day and does not expect that any facility will have to pay mitigation fees, based on the current downtrend in emissions and the effect of the controls in the proposed rule amendment.

As the refineries minimize the amount of vent gas sent to flares, there will be concurrent emission reductions of other criteria pollutants. This is due to the fact that concurrent emissions are calculated as a function of the flare vent gas volume and the heating value of the flare gas. It is assumed that, since the average heating value of the vent gas is expected to stay constant, the lower vent gas volume will translate into proportionally lower emissions of NOx, CO, ROG and PM10.

Refineries E and H have reported significantly higher flare flows when compared to other refineries since the rule was adopted. During the interviews staff had conducted with all refineries subject to PAR 1118, Refinery H has informed staff that it has completed a flare gas optimization project in 2004 and that an additional flare gas recovery system will also be installed by 2008; moreover, Refinery E has also committed to the AQMD to increase its vapor recovery and gas treating capacity and to install flare gas recovery systems to significantly reduce flare emissions.

Staff has calculated the average total flare flow and a breakdown of the reasons for venting for 2001 through 2003, which can be found in Table V – 1. This information was based on data from the September 2004 "Evaluation Report on Flares at Petroleum Refineries." For the same reason as explained before, the data for year 2000 was not included in the calculation of the average flow since it was determined to be unreliable.

Table V – 1
Average Flare Flows and Reasons for Flaring 2002-2003

Reasons for Flaring			Flow (mscf/year)	% of Total
Emergency Recordable			276,544.5	11.755
Non- Emergency	Non-Recordable		1,126,875	48.15
	Recordable Events	Unknown	113474.5	4.775
		Maintenance	130,738	5.615
		Planned Startup/Shutdown	289,115	12.425
		Process Vent	50,985.5	2.155
		Turnaround Activities	240,031	10.37
		Fuel Gas Imbalance	109,730.5	4.76
Total Average Flow			2,337,493	**100.00**

As stated in Table V – 1, emergencies, maintenance, start-ups and shutdowns, turnaround activities, process vent and fuel gas imbalances represent approximately 53 percent of the total flow. The remaining 43 percent represents the volume of non-recordable and unknown non-emergency events that has a potential to be recovered/minimized.

Based on an analysis of the reported flare data and discussions with two "larger" of the three facilities that have been identified in the staff report as needing additional gas recovery and treatment system capacity to comply with PAR 1118, staff has determined that Refineries E, F and H will install flare vent gas recovery and treatment systems with a maximum capacity of 13.3 million standard cubic feet per day (mmscfd). The average capacity of 9 mmscfd is equivalent to 3,285,000 mscf per year (see Chapter VI – Cost and Cost Effectiveness for additional discussion and analysis of these vent gas recovery and treatment systems). This average recovery and treatment capacity represents more than 100 percent of the average annual flare flow, as found in Table V-1. Staff anticipates other refineries will initiate additional measure to minimize vent gases being sent to the flares. Therefore, with the increase in vent gas recovery and treatment capacity and additional voluntary flare minimization measures to be implemented, staff has determined that the baseline (three year average) emissions of criteria air contaminants other that sulfur dioxide will be reduced by 75 percent or more. Sulfur dioxide emissions will be reduced from the baseline of 1.68 tons per year to 0.5 ton per year by year 2012.

From the baseline emissions inventory representing the 2001-2004 annual emissions averages and using the emissions reduction analysis above, the projected 2010 flare emissions are as shown in Table V – 2. Although actual sulfur dioxide emission reductions are anticipated to be significantly higher than what it is assumed in this table, for the purpose of this analysis, emission reduction estimates were based on the 2010 annual sulfur dioxide performance target of 0.7 ton per million barrels of crude processed for PAR 1118.

Table V-2

Summary of AQMD Emission Reductions (Tons per Year)

Pollutant	Year		Emissions Reductions
	Baseline	2012	
SO_2	613	183	430
NOx	85	38	47
PM10	25	10	15
VOC	74	41	33
CO	412	198	214
Total	**1,209**	**470**	**739**

CHAPTER VI

COST AND COST-EFFECTIVENESS

A. COSTS

The proposed amendment seeks to implement the most feasible and cost-effective control options in order to reduce flare emissions. This chapter presents an overview of the costs refineries will have to incur in order to comply with the new requirements and the cost-effectiveness of implementing these requirements.

Since the proposed rule will only allow venting of vent gases during an emergency, shutdown, startup, turnaround or essential operational need and to minimize flaring, it is assumed that some refineries will need to install new flare gas recovery and gas treating systems, whereas other refineries may have to increase their existing flare gas recovery and treating capacity in order to comply with this proposed rule requirement. These are technologically feasible pre-combustion controls that were suggested in the conclusion of the "Evaluation Report on Emissions from Flaring Operations at Refineries" presented to the AQMD Board on September 3, 2004.

As shown in Table IV-1, of the seven oil refineries subject to the rule, three do not have any flare gas recovery for their flares. Staff expects these three refineries to install flare gas recovery systems and additional gas treating capacity. Based on the last four years, the other four refineries have adequate flare gas recovery capacity and are not expected to incur significant control equipment costs to comply with the proposed amended rule.

In order to meet the monitoring requirements, the refineries where the flow meters are located before the water seals at flares equipped with flare gas recovery compressors will need to upgrade the flow meters with totalizing and low flow measurement capability to accurately indicate the actual vent gas flow to the flare. Also, flow meters will need to be installed on all flares for the measurement of the purge and pilot gas flow. All refineries will have to equip their emergency and general purpose flares with heat content analyzers and total sulfur analyzers.

Until the analyzers are certified by the Executive Officer, refinery operators will be required to conduct sampling for both higher heating value and total sulfur daily. If the total sulfur analyzer pilot program to be conducted in 2006 demonstrates that the current sulfur monitoring technology is not feasible, an additional cost for automated sampling systems and the processing of samples for total sulfur content must be included in the costs to implement PAR 1118.

Staff will calculate the costs associated with the proposed amendment; two scenarios will be considered. Costs common to both scenarios include additional vent gas recovery and treatment systems (capacity), upgrade flare gas flow meters, install purge/pilot gas flow meters, and annual costs associated with the newly installed equipment (parts and maintenance), surveys of pressure relief devices, conducting flow meter tests and Specific Cause Analyses. In Scenario 1, it will be assumed that all of refineries will install heat content and total sulfur analyzers. In Scenario 2, it will be assumed that only heat content analyzers are installed along with automated sampling systems and that the concentration of total sulfur, expressed as sulfur dioxide, of the vent gas will be determined by laboratory analysis.

Scenario 1

Capital Costs

Under the first scenario, it will be assumed that:

- The three refineries that currently do not have flare gas recovery systems (for eight flares) will install a total of four flare gas recovery and gas treating systems. Staff assumes that

at the first refinery, two systems will be installed; one system will control three flares and the other two flares. Another system serving a pair of flares will be installed at the second refinery. The third refinery will install one control system for its one flare.

- Refineries will install 23 heat content analyzers for the emergency/general service flares;
- Refineries will install 23 total sulfur analyzers for the emergency/general service flares;
- Refineries will install 50 purge/pilot gas flow meters (one for each emergency/general service flare); and
- Refineries will upgrade the emergency/general service flare flow meters with totalizing and low flow capability.

A synopsis of the projected rule required changes for emergency and general service flares is shown in Table VI-1.

Table VI – 1
Scenario 1 Rule Required Modifications

Flare ID	Flare Gas Recovery	Gas Treatment	Higher Heating Value Analyzer	Total Sulfur Analyzer	Flow Meter Upgrade	Purge/Pilot Flow Meter
1			1	1	1	2
2			1	1	1	2
3			1	1	1	2
4	0.5*	0.5*	1	1	1	2
6			1	1	1	2
7	0.5*	0.5*	1	1	1	2
8			1	1	1	4***
9	0.5*	0.5*	1	1	1	2
10			1	1	1	2
11	1	1	1	1	1	2
13			1	1	1	2
15			1	1	1	4***
16	0.5*	0.5*	1	1	1	2
17			1	1	1	2
18			1	1	1	2
19	0.33**	0.33**	1	1	1	2
20	0.33**	0.33**	1	1	1	2
21			1	1	1	2
22			1	1	1	2
23			1	1	1	2
24			1	1	1	2
25	0.33**	0.33**	1	1	1	2
26			1	1	1	2
Total	**4**	**4**	**23**	**23**	**23**	**50**

* Common flare gas recover and treatment system serving two flares
** Common flare gas recover and treatment system serving three flares
*** System consisting of two flares in cascade (common flow meter)

The cost for a flare recovery and gas treating system will be estimated based on data submitted to the AQMD by two local refineries as part of an application for permits to construct and operate, and data obtained from the Montana Department of Environmental Quality (DEQ) for a petroleum refinery located in Billings, Montana.

One local refinery installed a 10 million standard cubic feet per day (mmscfd) flare gas recovery system in 1993 for $10 million and a 48 mmscfd gas treating system for $23.2 million. The other local refinery installed in 2001 a flare gas recovery system with a capacity of 6 mmscfd for $9.2 million. The Billings, Montana refinery installed a flare gas recovery and gas treating system with a design capacity of 4 mmscfd for $7.7 million in 2003. Staff will determine the average normalized cost of the three examples studied to calculate the cost of flare gas recovery and gas treating systems needed to comply with the requirements and annual emission targets of PAR 1118.

Based on the first case study, installed in 1993, the cost for a flare recovery system and gas treating unit, normalized per one mmscfd, was $1.48 million ($1 million and $0.483 million respectively). In 2005 dollars, based on the Nelson Farrar Index published in the Oil and Gas Journal, the cost would be $1.43 million and $0.734 million respectively, for a total of <u>$2.16 million per mmscfd</u>.

Based on the second case study, installed in 2003, the normalized cost of the flare gas recovery system and corresponding gas treating system per one mmscfd was $1.93 million, of which $1.52 million was for flare gas recovery and $0.41 million was for the gas treating system. In 2005 dollars, based on the Nelson-Farrar Index, the cost would be $1.6 million and $0.48 million, respectively, or <u>$2.08 million per mmscfd</u>.

Based on the third case study, installed in 2001, the normalized cost for a flare gas recovery compressor per one mmscfd was $1.53 million. In 2005, this cost, based on the Nelson Farrar Index, would be $1.645 million. No gas treating system was installed in conjunction with this flare gas recovery system. However, based on the two other case studies, the cost of a flare gas recovery system is approximately 72 percent of the cost of a system consisting of both flare gas recovery and gas treating which is calculated as $0.635 million. Therefore, the total cost of a complete system would be <u>$2.28 million per mmscfd</u>.

Based on the above case studies, the average cost to install a flare gas recovery and treating system, based on three different system capacities of 4 mmscfd, 6, mmscfd and 10 mmscfd, is $2.17 million per mmscfd (2005 dollars).

Staff reviewed the Rule 1118 quarterly reports for the year 2003 and selected the quarters with the highest flows for the eight flares without flare gas recovery systems, then calculated the daily average flows for those quarters. API 521 guidelines recommends that the capacity of a flare gas recovery system be able to handle a wide variation in flow rates, and an Oil and Gas Journal article published on December 7, 1992, recommends the recovery capacity to be 2-3 times the average flow rate.

Based on this information, staff has estimated that for the first refinery, one system with a maximum capacity of 6 mmscfd, serving three flares, and a second system serving two flares with a maximum capacity of 4 mmscfd would be adequate. For the second refinery, staff projected that a system with a capacity of 3 mmscfd serving two flares would be adequate. For the third refinery staff estimated that a system with a capacity of 0.3 mmscfd for its flare would be adequate.

The costs to install the flare gas recovery and treating systems are estimated by using the average $2.17 million per mmscfd factor times the projected capacities needed by the refineries with no control on their emergency/general service flares to comply with PAR 1118. The costs are summarized in Table VI – 2:

Table VI – 2
Total Installed Cost for Flare Gas Recovery and Gas Treatment

Flare ID	Maximum Capacity(mmscfd)	Total Installed Cost ($)
19, 20 and 25	6	13,020,000
9 and 16	4	8,680,000
4 and 7	3	6,510,000
11	0.3	651,000
Total	13.3	$28,861,000

The breakdown by flares of the projected installations, with the highest average daily flows and maximum capacities is shown in Table VI-3

Table VI – 3
2003 Highest Quarterly Flows and Daily Average Flows

Flare ID		Highest 2003 Quarterly Flow (mmscf)	Daily Average Flow (mmscfd)	Projected Treatment Capacity (mmscf)	
				Min.	Max.
25	Common System	87.03	0.97	2.25	6
20		59.6	0.66		
19		55.98	0.62		
16	Common System	32.27	0.36	1.49	4
9		101.61	1.13		
4	Common System	49.43	0.55	1.09	3
7		48.53	0.54		
11		9.01	0.1	0.1	0.3
	Total		4.93	4.93	13.3

The cost of installing flow meters for purge gas and pilot gas is estimated by assuming that these devices would be connected to computerized control systems and therefore, will need data transmitters. An orifice plate flow meter and transmitter combination was quoted at $2,280 by a parts supplier, and labor is estimated at 10 hours at a rate of $35 per hour each. The total installed cost, assuming an additional 10 percent for software, instrumentation, and taxes is therefore estimated at $2,858 per flow meter and for 50 flow meters the total cost will be $142,900.

The proposed rule requires the flare gas flow meters to be upgraded with totalizing and low flow capability. This upgrade was quoted at $10,000 per flow meter by GE Panametrics, therefore the total cost for 23 flow meters will be $230,000.

The cost of the heat content analyzers was quoted at $70,775 each by Cosa Instruments. Assuming that the total installed cost, including a sample conditioning unit, shelter, piping, electrical, taxes, permitting and certification will be $150,000, the total installed cost for 23 analyzers is estimated at $3,450,000.

The cost of a total sulfur analyzer, including taxes, shipping, startup/commissioning was quoted by ThermoElectron at $79,308. The additional cost of installation for the total sulfur analyzer to the heat content analyzer and sample conditioning system is estimated at $5,000. Therefore the total installed cost is estimated at $84,308 each and $ 1,939,084 for 23 analyzers.

In order to calculate the cost effectiveness of the rule, the capital costs of the proposed amendment will need to be determined. It will be assumed that the flare gas recovery systems, gas treating systems and flow meters have an equipment life of 25 years, whereas the heat content analyzers and total sulfur analyzers have a 10 year equipment life. In order to have a common basis for equipment life to calculate the cost effectiveness, the cost of the analyzers will be referenced to a 25 year equipment life. For this purpose, it is assumed that during a 25 year period three sets of analyzers will have to be purchased. The cost of this expenditure is calculated below:

$$C_{analyzers} = C1 + C2 + C3$$

1st Set Cost is at current cost:

C1 = $3,450,000 + $1,939,084 = $5,389,084

The 2nd set is to be purchased after 10 years. Its cost in today's dollars is calculated assuming a 4% real interest rate at ten years using the corresponding present worth factor of 0.6756 will be:

C2 = $5,389,084 * 0.66756 = $3,640,865

The 3rd set of analyzers is to be purchased after 20 years. The cost in today's dollars, at 4% real interest rate at twenty years using the corresponding a present value factor of 0.4564 will be:

C3 = $5,389,084 * 0.4564 = $2,459,578

The total cost of the analyzers will therefore be, over a 25 year period:

$C_{analyzers}$ = C1 + C2 + C3 = $11,489,527

The flare gas recovery and gas treatment systems will require a permit to construct and operate from the AQMD. The permit application evaluation fee for one system is $7,233. As previously stated, the staff has determined that four control systems will need to be installed and operated to meet the annual sulfur dioxide performance targets in PAR 1118. Therefore, the permit application fees/cost to the refineries is $28,932.

A one-time CEMS certification fee is also required. The certification fee includes the initial application approval, approval of the test protocol and approval of the performance test results. The maximum fee is $7,693 for a monitoring system consisting of up to four components. The system required to comply with PAR 1118 consists of three (flow, higher heating value and total sulfur). The industry will install 23 higher heating value and total sulfur analyzer systems to comply with the monitoring requirements in PAR 1118. Therefore, the cost to certify the analyzer systems will be $176,939.

Under Scenario 1, the total estimated capital costs associated with the rule, based on the assumptions stated above, are summarized in Table VI-4.

Table VI – 4
Total Capital Costs Scenario 1

Equipment	Cost ($)
Flare Gas Recovery/Treatment Systems	28,861,000
Higher Heating Value/Total Sulfur Analyzers (Initial + 2 replacements)	11,489,527
Pilot/Purge Gas Meters	142,900
Flow Meter Upgrades	230,000
Permit Processing Fees	28,932
Analyzer (CEMS) Certification Fees	176,939
Total Capital Cost	$40,929,298

Annual Costs

The refineries will also incur annual costs associated with the newly installed equipment (parts and maintenance), surveys of pressure relief devices, conducting flow meter tests and Specific Cause Analyses.

Assuming that annual cost, such as for parts, maintenance, repairs, calibration gases, taxes, insurance and power represent 10 percent of the capital cost (including only the initial purchase of analyzers), the annual cost is estimated as $3,482,886.

Another annual cost will be for conducting surveys of the pressure relief devices connected to flares. These surveys can be conducted concurrently with the Rule 1173 quarterly inspections and it is estimated that on average an additional 200 hours per refinery and 100 hours for the hydrogen plant will be spent per year for this task. At $25 per hour, for seven refineries and a hydrogen plant, the annual cost will be $37,500.

Another annual cost will be for verifying the accuracy of flow meters. Flow verification costs were quoted at $1,500 per day for up to two flares. The annual cost for flow verification is estimated as $25,000 as shown below:

Table VI – 5
Annual Cost for Flow Meter Verification

Facility	No. of Flares	Estimated Annual Cost ($)
A	4	3,000
B	1	1,500
C	3	3,000
D	3	3,000
E	5	4,500
F	1	1,500
G	6	4,500
H	5	4,500
Total	27	$25,500

The proposed rule will require refineries to conduct Specific Cause Analyses (SCA) for flaring events exceeding 500 pounds of sulfur dioxide, 100 pounds of VOC or 500,000 scf of vent gas. The investigation of flaring events exceeding 500 pounds of sulfur dioxide would not represent an additional cost since this is a requirement under federal law.

A review of the 2003 flaring events meeting these criteria stated in the previous paragraph found 980 flare events that had less than 500 pounds of sulfur dioxide emissions. However, these flaring events, representing 80 percent of the vent gas flow, included shutdowns and startups, turnaround activities or fuel gas balancing. The facilities subject to PAR 1118 are not required to submit an SCA for these categories of vent gas release under the proposed rule. Therefore, assuming that a corresponding 80 percent of these 980 events would not be required to submit an SCA, approximately 200 additional events would need to be investigated. The local refineries have estimated that the time needed to complete an SCA ranges from 40 to 200 hours. Based on this information, staff has estimated that a refinery would spend an average of 80 hours conducting SCA investigations, at an average rate of $50 per hour. The total annual cost of conducting an additional 200 SCA investigations that may be required as part of the proposed amended rule is therefore estimated at $800,000. The total annual costs associated under Scenario 1, as calculated above, are summarized in Table VI - 6:

Table VI -6
Total Annual Costs Scenario 1

Item	Annual Cost ($)
Maintenance/Parts for Controls Equipment, Flow Meters, and Higher Heating Value and Total Sulfur Analyzers	3,482,886
Leak Surveys	37,500
Flow Meter Verification	25,500
Specific Cause Analyses	800,000
Control Equipment Annual Operating Fee	2,951
Total	$4,348,836

Scenario 2

For scenario 2, the estimated capital costs will be identical to Scenario 1, except that it will not include the installation and operation of total sulfur analyzers but will include the addition of 23 automated sampling devices. A summary of the proposed rule requirements is shown in Table VI -7:

Table VI – 7
Scenario 2 Rule Required Modifications

Flare ID	Flare Gas Recovery	Gas Treating	HHV Analyzer	Automated Sampler	Flow Meter Upgrade	Purge/Pilot Flow Meter
1			1	1	1	2
2			1	1	1	2
3			1	1	1	2
4	0.5*	0.5*	1	1	1	2
6			1	1	1	2
7	0.5*	0.5*	1	1	1	2
8			1	1	1	4**
9	0.5*	0.5*	1	1	1	2
10			1	1	1	2
11	1	1	1	1	1	2
13			1	1	1	2
15			1	1	1	4**
16	0.5*	0.5*	1	1	1	2
17			1	1	1	2
18			1	1	1	2
19			1	1	1	2
20	0.5*	0.5*	1	1	1	2
21			1	1	1	2
22			1	1	1	2
23			1	1	1	2
24			1	1	1	2
25	0.5*	0.5*	1	1	1	2
26			1	1	1	2
Total	4	4	23	23	23	50

* Common system serving two flares
** System consisting of two flares in cascade (common flow meter)

The total installed cost of the automated sampling system is estimated at $5,000, and for 23 flares the cost will be $115,000.

As in Scenario 1, the cost of the 23 heat content analyzers will have to be referenced to a 25 year equipment life cycle; therefore it is assumed that 3 sets of analyzers have to be purchased during this period of time.

The cost for the initial set will be;

C1 = $150,000 * 23 = $3,450,000

After 10 years, in today's dollars, the cost of the second set in today's dollars will be:

C2 = $3,450,000 * 0.6756 = $2,330,820

After 20 years the cost of the third set of analyzers in today's dollars will be:

C3 = $3,450,000 * 0.4564 = $1,574,580

The total cost of the analyzers, assuming a 25 years life, will be:

$C_{analyzers}$ = C1 + C2 + C3 = $7,355,400

The capital costs under Scenario 2 are summarized in Table VI-8:

Table VI – 8
Total Capital Costs Scenario 2

Equipment	Cost ($)
FGRS/Amine Scrubbers	28,861,000
Heat Content Analyzers	7,355,400
Pilot/Purge Gas Meter	142,900
Flow Meter Upgrade	230,000
Automated Sampling System	115,000
Permit Processing Fees	28,932
Analyzer (CEMS) Certification Fees	176,939
Total Capital Cost	**$36,910,171**

Under Scenario 2, all refineries will be required to take six additional daily samples for total sulfur per flare during the week, incurring additional annual costs. Assuming that the cost of processing a sample will average $350, the annual cost of sampling will be:

Annual Sampling Cost = 23 flares * 6 samples /wk * 52 wks * $350/sample

= $2,511,600

The cost of maintenance, parts, power, insurance and taxes for equipment is assumed to be 10 percent of the total capital cost (including only the initial purchase of analyzers). Therefore, the total annual cost for the equipment and analyzers will be $3,300,477.

A summary of the annual costs under Scenario 2 is presented in Table VI – 9.

Table VI – 9
Total Annual Costs Scenario 2

Item	Annual Cost ($)
Maintenance/Parts for Equipment	3,300,477
Leak Surveys	37,500
Flow Meter Verification	25,500
Specific Cause Analysis	800,000
Daily Sampling	2,511,600
Control Equipment Annual Operating Fee	2,951
Total	$6,678,028

Recovered Vent Gas - Cost Savings

The flare gas recovery systems will recover vent gases that otherwise would be combusted in the flares. The recovered gas, after treatment, can be used as fuel gas or process feed, thus reducing operating costs for the refineries. Additional savings are realized by using less steam for the flare operations and extended flare tip life, minimizing repair costs; for this calculation, only the payback value of the recovered gas to be used as fuel gas or process feed is considered. This would represent annual savings that can lower the annual costs.

The following assumptions will be made:

- The annual average recovered gas volume is 3,285 mmscf (see Chapter V – Emission Reductions)
- On average, only 60 percent of the recovered gas volume is valuable product (based on review of recovered gas samples from a local refinery)
- The value of recovered gas is estimated at $2 per mmBtu (www.johnzink.com – Flare Gas Recovery payback analysis)
- The average heat content of the recovered gas is 1,000 Btu/scf

Annual Savings = 3,258 * 10^6 scf * 0.6 * 1,000 Btu/scf * $2/$10^6$ Btu = $3,909,600

As emissions will decrease, the refineries will pay reduced annual emission fees to the AQMD, reducing their annual costs. Table VI – 10 lists the estimated annual emission fees savings by pollutant and the total savings for the industry.

Table VI – 10
Estimated Annual Emission Fees Savings

Pollutant	Fees* ($/ton)	Projected Reduction (tons)	Estimated Savings ($)
ROG	944.16	33	31,157
NO_x	543.73	47	25,555
CO	4.64	214	993
PM10	720.72	15	10,811
SO_x	653.98	356	232,817
Total			**$290,439**

*Rule 301 – Table III-Emission Fees (June 3, 2005)

The total annual costs will then be:

For Scenario 1:

Total Annual Cost = $4,285,398 – $3,909,600 – $290,439 = $85,359

For Scenario 2:

Total Annual Cost = $6,614,59 – $3,909,600 – $290,439 = $2,414,551

B. COST-EFFECTIVENESS

In order to calculate the cost effectiveness of the proposed amendment, the present value of the capital cost and operating cost during the useful life of the control equipment and/or program must be calculated, using the following formula:

$$PV = C + A * PVF$$

where:

PV = Present Value to implement the proposed new rule requirements

C = Capital costs to implement proposed new rule requirements

A = Annual costs to implement proposed new rule requirements

PVF = Present Value Factor, Equal Series

= 15.62 (25 years equipment life and 4% real interest rate).

Cost Effectiveness – SOx Emission Reductions Only

Scenario 1:

C = \$40,929,298

A = \$85,359

PV1 = \$40,929,298 + \$85,359 * 15.62 = \$42,262,606

The cost effectiveness is calculated with the discount cash flow (DCF) method:

CE1 = PV1 / (ER * EL)

where:

CE1 = Cost Effectiveness for Scenario 1

ER = Emission Reduction for SO_2, 431 tons per year

EL = Equipment life, 25 years

CE1 = \$42,262,606 / (431 tons * 25) = \$3,922 per ton of SO_2 reduced

Scenario 2

C = \$36,910,171

A = \$2,414,551

PV2 = \$36,910,171 + \$2,414,551 * 15.62 = \$74,625,458

CE2 = \$74,625,458 / (431 tons * 25) = \$6,926 per ton SO_2 reduced

Therefore, the cost effectiveness for this proposed amendment is estimated to be between \$3,922 and \$6,926 per ton of SOx reduced.

Cost Effectiveness – Total Emissions Reductions (Excluding CO)

If reductions in the other pollutants were to be considered, the cost effectiveness would be:

CE = PV / (TER * EL)

where:

PV = Present Value to implement the proposed new rule requirements

TER = Total emission reduction for the other criteria pollutants less CO, tons per year

EL = Equipment life, 25 years

From Table V - 2:

TER = 431 tons + 47 tons + 33 tons + 15 tons = 526 tons

Scenario 1

CE1 = \$40,929,298 / (526 * 25) = \$3,112 per ton of pollutant reduced

Scenario 2

CE2 = \$74,625,458 / (526 * 25) = \$5,675 per ton of pollutant reduced

Therefore, if reductions for the other criteria pollutants, less CO, are included in calculations, the cost effectiveness of the proposed amendments ranges between \$3,112 and \$5,675 per ton of pollutant reduced, excluding CO.

C. *INCREMENTAL COST-EFFECTIVENESS*

Staff is required under state law to determine an incremental cost effectiveness of the most stringent control scenario. Staff believes that the most stringent control scenario would require petroleum refineries to control all vent gases excluding off specification gas and vent gases resulting from emergencies.

An analysis of the reported flare gas flow and emissions data for years 2002, 2003, and 2004 and vent gas recovery and treatment capacity associated with flares is summarized as follows:

Flare gas recovery and treatment system capacity

Current:	51 mmscfd
Future implementing PAR1118 requirements:	64.5 mmscfd
Additional capacity to treat maximum daily flow recorded: (excluding off spec gas and emergencies)	119 mmscfd

PAR 1118 - 2012 Emissions

SO_2 performance target:	0.50 TPD
Total emissions, less SO_2 and CO:	0.24 TPD
Reported non-emergency, SO_2:	94% (based on 2002 and 2003 data)
Reported non-emergency, other	68% (based on 2002 and 2003 data)

Capital cost of the additional flare gas recovery and treatment system capacity

Estimate cost of system based on a previously determined cost of \$2.17 million per million standard cubic feet per day treatment capacity (mmscfd)

\$2.17 million/mmscfd * 119 mmscfd = \$258,227,362

Annual cost is estimated to be 10 percent of the capital cost

\$258,227,362 *0.10 = \$25,822,362

SO_2 Emission Reductions Only

PV = \$258,227,362 + \$25,822,362 * 15.62 = \$661,578,503

CE = PV / (Incremental ER * EL)

CE = \$661,578,503 / [0.5 tons/day * 0.93 * 25 yrs * 365 days/yr]

= \$155,918 per ton of SO_2 reduced

Total Emissions Reductions, Less CO

PV = \$258,227,362 + \$25,822,362 * 15.62 = \$661,578,503

CE = \$661,578,503 / {[0.5 ton/day * 0.93 + 0.24 ton/day * 0.68] * 25 yrs * 365 days}

= \$115,412 per ton of air contaminant reduced

Therefore, the incremental cost effectiveness for this proposed amendment is estimated to be between \$115,412 and \$155,918 per ton of air contaminant reduced.

CHAPTER VII

COMPARATIVE ANALYSIS

[illegible]	[illegible]
– Applicability	
– *Flares at refineries, sulfur recovery plants and hydrogen* production plants	– *Flares built or modified after June 11, 1973, subject to 40CFR 60* Subpart J – Flares controlling vents from piping components subject to 40CFR 60 Subpart GGG, from storage tanks subject to 40CFR 60 Subpart K_a, or from wastewater systems subject to 40CFR 60 Subpart QQQ
– Requirements	
– Flares to be operated with no visible emissions – Flares to be operated with a pilot flame present at all times – Annual acoustical or thermal surveys of PRD's directly connected to flares – Specific Cause Analysis of flare events exceeding: o 500 lbs SO_2 o 100 lbs VOC o 500,000 scf vent gas combusted – Cause of flare events where at least 5,000 scf of vent gas are combusted – Effective September 1, 2006, submit the following information: o Technical specifications on flare systems including an *audit of gas recovery* and treating system capacity and storage capacity for excess vent gases o A description of equipment installed and procedures implemented within the last 5 years to minimize flaring o A description of equipment to be installed or procedures to be implemented to minimize or eliminate flaring – Effective January 1, 2007, operate flares in such a manner as to minimize flaring and only combust vent gas during emergencies, shutdowns, startups, turnarounds or essential operational needs	– Flares to be operated with no visible emissions – Flares to be operated with a pilot flame present at all times – Air or steam assisted flares shall only combust gases with a heat content of 300 BTU/scf or more – The exit velocity of the vent gas is limited by the net heating value of the vent gas – Flares shall not be used to combust gases containing more than 0.1 *gr/dscf* (160 ppm) H_2S, averaged over 3 hours

[illegible]	[illegible]
Effective January 1, 2009, combustion in flares of gases with hydrogen sulfide concentration exceeding 160 ppm, averaged over 3 hours, is prohibited, unless in an emergency, shutdown, startup or PRD leakage	
– Performance Targets	
– Specific annual performance targets for subject facilities based on their crude throughput – Mitigation fees assessed for exceedance of performance targets	– N/A
–. Flare Minimization Plans	
– Triggered by exceedance of performance target, or – To include policies and procedures and process and equipment upgrades implemented to prevent future exceedances – Subject to public review and comment	– N/A
– Monitoring and Recording	
– Until July 1, 2007, continuous monitoring of vent gas flow, sample daily and during sampling events for vent gas higher heat content and total sulfur as SO_2 or install continuous or semi-continuous analyzers – After July 1, 2007, continuous monitoring of vent gas flow, higher heat content and semi-continuously *for total sulfur as* SO_2 – The presence of pilot flames monitored with thermocouples or equivalent devices – Effective July 1, 2006, video monitors with date and time stamp must be used to determine visible emissions – Effective January 1, 2007: o automated sampling system required for vent gas sampling	– The presence of pilot flames monitored with thermocouples or equivalent devices

[illegible]	[illegible]
o Pilot and purge gas flow must be monitored	
– Recordkeeping	
– Video monitoring records to be kept for 90 days – Other records to be kept for five years	– Records to be kept at least two years – Records to be kept at least five years for Title V facilities
– Notification and Reporting	
– 1 hour notification of events exceeding: o 500 lbs SO_2 o 100 lbs VOC o 500,000 scf vent gas combusted – 24 hour notification of planned events exceeding: o 500 lbs SO_2 o 100 lbs VOC o 500,000 scf vent gas combusted – Submittal of Specific Cause Analysis of qualifying flare events within 30 days or 60 days upon request – Quarterly reports in electronic format certified for accuracy by responsible facility official, to include: o Daily and quarterly flare emissions o Causes of flare events o Records of annual PRD o Monitoring system down times – Copies of notifications required by 40CFR 355 pertaining to reportable air releases	– Semiannual reports – Notifications required by 40CFR Subchapter 355 Emergency Planning and Community Right to Know Act (EPCRA) pertaining to reportable air releases
– Testing and Monitoring	
– Visible Emissions determined with U.S. EPA Method 22, Appendix A, 40CFR 60 – Vent Gas higher heating value determined: o By ASTM Method D2382-88, ASTM Method D3588-	– Visible Emissions determined with U.S. EPA Method 22, Appendix A, 40CFR 60 – Net heating value of the vent gas determined with ASTM Method D2382-88 or D 4809-95

[illegible]	[illegible]
91 or ASTM Method D4891-89 o Effective July 1, 2007 with continuous analyzer – Vent Gas total sulfur expressed as SO_2 determined: o By ASTM Method D5504-01 or District Method 307-91 o *Effective July 1, 2007, with a semi-continuous* analyzer – Flow monitored with a continuous flow measuring device requiring annual accuracy verification	–
– Exemptions	
– Sampling not required if: o There is a catastrophic event, or o Safety of sampling personnel is at issue – Emissions from flaring events due to force majeure or circumstances beyond the operators' control do not count towards annual performance targets	– Emergency or upset vent gas and relief valve leakage due to malfunctions may exceed a H_2S concentration exceeding 160 ppm

Facilities subject to PAR 1118 are also subject to the following AQMD rules:

Rule 401 – Visible Emissions

Rule 402 – Nuisance

Rule 431.1 – Sulfur Content of Gaseous Fuels

CHAPTER VIII

DRAFT FINDINGS

DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE

Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing a rule or regulation, the AQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the hearing. The draft findings are as follows:

Necessity - The AQMD Governing Board has determined that a need exists to amend Rule 1118 – Emissions from Refinery Flares, to make current emission reductions permanent and enforceable, and to achieve emission reductions to meet the federal and state ambient air quality standard for PM 10 and PM 2.5 and to clarify rule language.

Authority - The AQMD Governing Board obtains its authority to adopt, amend, or repeal rules and regulations from Health and Safety Code Sections 39002, 40000, 40001, 40440, 40702, and 41508.

Clarity - The AQMD Governing Board has determined that the proposed amendments to Rule 1118 - Emissions from Refinery Flares, are written and displayed so that the meaning can be easily understood by persons directly affected by them.

Consistency - The AQMD Governing Board has determined that Proposed Amended Rule 1118 - Emissions from Refinery Flares, is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, federal or state regulations.

Non-Duplication - The AQMD Governing Board has determined that the proposed amendments to Rule 1118 - Emissions from Refinery Flares, do not impose the same requirement as any existing state or federal regulation, and the proposed amendments are necessary and proper to execute the powers and duties granted to, and imposed upon, the AQMD.

Reference - In adopting these amendments, the AQMD Governing Board references the following statutes which the AQMD hereby implements, interprets or makes specific: Health and Safety Code Sections 40001 (rules to achieve ambient air quality standards), 40440(a) (rules to carry out the Air Quality Management Plan), and 40440(c) (cost-effectiveness), 40725 through 40728.

CHAPTER IX

COMMENTS AND RESPONSES

ARB

Comment 1: Although the phrase "Flare Management (*Minimization*) Plan" is a central concept of the PAR 1118, the phrase is not included in the list of definitions. Staff recommends its inclusion.

Response 1: *PAR 1118 has been revised using the phrase "Flare Minimization Plan" (FMP). The latest proposal put greater emphasis on the minimizing flare events and emissions through the annual performance targets, which are significantly lower than previously presented at the June 29, 2005 Public Workshop. The latest proposal only requires an FMP from those refineries that exceed the annual performance targets. The required elements to be submitted as part of the FMP are listed under paragraph (e)(1), which effectively defines what an FMP is.*

Comment 2: Staff recommends that the definition of "Essential Operational Needs" be clarified so as to be limited to only those events clearly identified in an approved "Flare Management (*Minimization*) Plan".

Response 2: *PAR 1118 has been revised to include a definition of Essential Operational Needs.*

Comment 3: PAR 1118 ought to explicitly require that any pressure relief devices found to be defective or leaking be expeditiously repaired.

Response 3: *Pressure relief devices (PRDs), in particular PRDs that are connected directly to the flare gas header, can not be repaired without shutting down the process unit which they serve. Therefore, refineries typically repair defective or leaking PRDs during the process unit turnaround. To facilitate expeditious repair, PAR 1118 requires the refineries to conduct the PRD survey within 90 days prior to a turnaround.*

Comment 4: The district should include a mechanism to allow for public comment on the proposed Flare Management (*Minimization*) Plan [FMP] prior to each FMPs approval. The lack of specific quantifiable standards for an FMP to attain approval, as well as the fact that each FMP will be unique, make it imperative that a forum for public comment is included to provide all interested parties with the opportunity to provide critical input.

Response 4: *PAR 1118 has been revised to incorporate a provision that requires a 60 day public comment period for each Flare Minimization Plan (FMP) that has been reviewed and recommended for approval by the AQMD.*

Comment 5: Flare Management (*Minimization*) Plans should be required to be updated on an annual basis to incorporate improvements in flare management. Additionally, the district ought to include in the rule amendment a future commitment to evaluating Rule 1118 and making future recommendations to improve its effectiveness.

Response 5: *PAR 1118 has been revised to require submittal of a FMP or revised FMP whenever a refinery exceeds the annual SO_2 performance target. Staff will continue to analyze data that will be submitted to the AQMD as required by PAR 1118. As with other rules, staff will also assess the effectiveness of PAR 1118 to determine if future technologically feasible and cost effective amendments are necessary to achieve and maintain ambient air quality standards.*

Comment 6: In the preliminary draft staff report, the emission reduction calculation for sulfur compounds was made using a different methodology than was used to calculate the reduction of other criteria pollutants. This discrepancy in methods should be corrected.

Response 6 *The emission reduction for total sulfur, expressed as sulfur dioxide is based on the performance target in the rule, whereas the concurrent emission reductions for other combustion pollutants was based on the assumption that the flare vent gas flow will be reduced with the installation of additional flare gas recovery and treatment system(s).*

Minimization

Comment 7: The language in section (c) Requirements (2) (A) is extremely ambiguous. The lack of specificity in the language, "take steps to minimize emissions during such events", could provide a loophole for facilities operating flares, and could lead to disputes over enforcement.

Response 7: *PAR 1118 has been revised to include the requirement to minimize all flaring.*

Public Input and Involvement

Comment 8: The district should hold a public hearing and provide the opportunity for public comment prior to approving any FMP.

Response 8: *PAR 1118 has been revised to incorporate a provision that requires a 60 day public comment period for each flare minimization plan (FMP) that has been reviewed and recommended for approval by the AQMD.*

Comment 9: The public should be provided with quarterly flare reports online. The public has a right to emissions information and providing it online will allow the public to bypass the often long delays inherent in the public records request process.

Response 9: *Staff will post a summary of the quarterly flare emission reports on the AQMD web site.*

Mitigation Fees

Comment 10: Individual facility mitigation fees are preferable to mitigation fees based on industry-wide thresholds. Requiring mitigation fees to be paid based upon an industry-wide threshold is not an equitable arrangement for individual facilities, nor is it in keeping with environmental justice principles.

Response 10: *PAR1118 has been revised to establish facility-specific performance targets and mitigation fees will only be assessed for emissions exceeding the annual SO_2 performance target.*

Comment 11: The PAR 1118 indicates that a mitigation fee of $25,000 per ton will be charged for all emissions. The applicability of that mitigation fee should be changed so that it pertains only to those emissions above the prescribed target.

Response 11: *PAR 1118 has been revised such that mitigation fees will only be assessed for emissions exceeding the annual SO_2 performance target.*

Comment 12: The cost of $25,000 per ton is excessive given previous fees of $10,000 per ton or the RECLAIM backstop ceiling of $15,000 per ton. Furthermore, these mitigation fees are being charged on top of an existing fee (AER). The rule should offer the ability for a facility to propose a local community project for which their mitigation fee payments could be used.

Response 12: *PAR has been revised such that any refinery exceeding the specified performance target in any calendar year, it will have to pay a mitigation fee of $25,000, $50,000 or $100,000 per each ton of sulfur dioxide over the limit, depending on whether excess emissions are no more than ten percent, greater than ten percent but no more than twenty percent or greater than twenty percent of the applicable performance target, respectively. The mitigation fee is capped at $4,000,000 dollars in any year that the performance target is exceeded.*

Any mitigation fees paid would be used to implement emission reduction projects in the area impacted by the excess emissions. The amount of the

mitigation fee is based upon the current and future expected costs of vent gas recovery and treatment equipment needed to mitigate the exceedance of the final annual performance target. It is expected that refineries will implement the procedures and install the equipment necessary to achieve compliance with the performance targets

Comment 13: There should be no exemptions from mitigation fee payments. High emissions can still result even from facilities that are in compliance with the requirements to be exempted from paying mitigation fees.

Response 13: *PAR 1118 has been revised such that no facility is exempt from paying mitigation fees for emissions exceeding the annual SO_2 performance targets.*

Comment 14: In order to be exempt from mitigation fee payments, a facility must meet emissions standards of 0.25 tons or less of SOx per 1 million barrels of crude throughput. This standard is too low and based on a one-time best achieved emissions level by a refinery.

Response 14: *Under the revised staff proposal, this compliance option is no longer necessary and, therefore, staff has removed this compliance option from PAR 1118.*

Comment 15: The rationale behind calculating the emission level of SOx as a two-year average needs to be explained.

Response 15: *Staff has removed this compliance option from PAR 1118. However, for clarification, calculating emissions for compliance purposes using a two-year average was based on the fact that the frequency of flare events (and emissions) do not constant; they can vary from year to year. An average would smooth out any anomalies.*

Flare Minimization Plan

Comment 16: The Flare Management Plan requirement could be a stand alone rule. The requirement simply duplicates the emission reductions already imposed by limitations on causes of flaring, the performance goals, and the 160 ppm vent gas H2S limit.

Response 16: *PAR 1118 has been revised to only require a flare minimization plan (FMP) from refineries that exceed the annual SO_2 performance targets. The FMP requirement is a tool to ensure refineries that take appropriate measures to stay below the annual performance targets. Therefore, staff believes the FMP needs to be a part of PAR 1118.*

Comment 17: The requirement to provide in the FMP application a list of all valves, components, or any equipment at any process units venting directly to the flares is extremely punitive and burdensome and serves no apparent useful purpose.

Response 17: *PAR 1118 has been revised to only require P&IDs for each flare system in the FMP. Secondly, staff believes refineries will take the necessary steps, including the installation or modification of vapor recovery and gas treatment system(s) to ensure compliance with the annual performance standards. Therefore, staff believe that submittal of an FMP (with required data and information) is not likely.*

Comment 18: An explanation of policies and procedures to minimize flaring emissions during emergencies, shutdown and startup of *each* process unit should not be required in the FMP application. Since many policies and procedures are not unit-specific and instead have broad applicability, refineries ought to be able to respond to this requirement in a form and manner appropriate to their situation.

Response 18: *PAR 1118 has been revised to require an FMP only from refineries that exceed the annual SO2 performance targets. Also, the information required under a FMP submittal has been streamlined to only include refinery policy and procedures to be used and vapor recovery and gas treatment capacity that will be installed to minimize flaring.*

Comment 19: The district should provide more specific startup/shutdown requirements in order to provide better direction to refineries which will in turn help ensure compliance.

Response 19: *Because of the differences in the way refineries in the Basin are designed and operated and the associated complexities of these operations, as well as safety implications, staff believes that it is best to leave the election of specific procedures relative to shutdown and startup to the refinery operators. It is more appropriate, as PAR 1118 does, to establish a regulatory framework that requires refineries to minimize emissions.*

Comment 20: It is not practical to include in a FMP an estimate of the quantity of vent gas emitted during each occurrence, the duration of each occurrence, the number of occurrences each quarter, and maximum total volume of vent gas being routed to the flares each year is an impractical request. There is concern over the potential negative ramifications for refineries who cannot accurately predict the various aspects related to their future occurrences.

Response 20: *PAR 1118 has been revised to require from refineries that exceed the annual SO_2 performance target to include in their FMP application the policies and procedures as well as gas recovery and treatment systems that will be utilized to minimize flaring and related emissions.*

Comment 21: There should be no exemption for developing an FMP. Instead, both the strict emissions targets of .25 tons of SOx per 1 million barrels of crude processed and an FMP should be required of all refineries.

Response 21: *The latest proposal of PAR 1118 puts greater emphasis on minimizing flare events and emissions through the annual performance targets, which are significantly lower than previously presented at the June 29, 2005 Public Workshop. The 2010 annual SO_2 performance target of 0.7 tons per million barrels of crude oil processed is much lower than the 2.1 tons per year target stated in the 2003 AQMP. Staff believes the proposed performance targets are real, quantifiable, enforceable, and permanent (with the requirement of a mitigation fee for annual exceedances) and are technologically feasible and cost effective. A FMP will only be required from refineries that exceed the annual SO_2 performance targets.*

Comment 22: The level of emissions .25 tons of SOx per 1 million barrels of crude processed is too low to be practicable for refineries to meet. At such a low level, reducing emissions is no longer a viable alternative to submitting an FMP. This emission limit of 0.25 tons/MMBbl is based on the very lowest emissions data from two refineries. The district should take into consideration that even at the refineries that did achieve the aforementioned limit, there will always be year to year fluctuations in emissions.

Response 22: *The version of PAR 1118 presented at the Public Workshop provided refineries a compliance option to request a permit limit of 0.25 ton of SOx per 1 million barrels of crude processed; refineries accepting the permit limit would not be required to submit a FMP. Based on public comment and discussion with the Refinery Working Group, PAR 1118 has been revised to remove this compliance option. PAR 1118 was revised to now require refineries to meet declining performance targets over time and, beginning calendar yea, 2010, to emit no more than 0.7 ton SO_2 per million barrels of crude oil processed per year.*

Specific (Root) Cause Analysis

Comment 23: The 100,000 scf of vent gas or 500 lbs of sulfur dioxide emissions as a threshold for root cause analysis is too low. 500,000scf or 1000 lbs of sulfur dioxide emissions is suggested as a more practical threshold level.

Response 23: *PAR 1118 has been revised to now require a Specific Cause Analysis (SCA) when flare emissions or flow rate exceed any one of the following: 100 lbs of VOC; 500 lbs of SO_x emitted or flaring of 500,000 standard cubic feet of vent gas. Under federal requirements, refineries are required to analyze and report SOx emissions exceeding 500 pounds per release.*

Essential Operational Needs

Comment 24: It is impossible for an operator to foresee in detail all possible essential operational needs. Therefore, the rule should provide pre-defined EON categories with the provision that if a facility encounters a new scenario, the facility has the prerogative to analyze the event, determine if it is and EON and then submit it to AQMD for approval.

Response 24: *Staff has revised the definition of Essential Operational Need in PAR 1118 to now list specific operational or maintenance related activities where due to the quality or quantity, the vent gas cannot be reasonably recovered, treated, used or delivered for sale with existing equipment*

Comment 25: The current definition of Essential Operational Needs disqualifies many scenarios that a refinery could actually identify as an EON. The district, in deciding whether a scenario qualifies as an EON ought to examine not just the technical feasibility of a measure, but also the practicality, cost, and cost-effectiveness. The definition of EON should include such scenarios as fuel gas system imbalances, PRV leakage, and adding fuel gas to vent gas to support its combustion.

Response 25: *In developing standards and requirements, staff conducts technological feasibility and cost effectiveness analyses. The definition Essential Operational Needs in PAR 1118 has been revised to include such scenarios as fuel gas system imbalances, PRV leakage, and venting clean service streams to a clean service flare or a general service flare, and adding fuel gas to vent gas to support combustion.*

Visible Emissions

Comment 26: PAR 1118s provision to require a visual emissions evaluation within five minutes of observing visual emissions on the video monitor is impractical at best, and at worst, dangerous. During emergencies the focus of trained personnel should be on responding to the emergency, not on conducting a visual emissions evaluation.

Response 26: *Staff agrees with the recommendation. PAR 1118 has been revised to require video monitoring with a date and time stamp to determine and record visible emissions from refinery flares*

Comment 27: The requirement to visually monitor is vague and could imply around the clock monitoring. Such a requirement would mean that a facility could be out of compliance if a video monitor appeared to be "unattended" by refinery personnel.

Response 27: *PAR 1118 has been revised to remove that requirement that a refinery visually monitor visible emissions from flares. See Response 26.*

Comment 28: The requirement to operate all flares in a smokeless manner constitutes double jeopardy, as visible emissions are already regulated under Rule 401.

Response 28: *Staff disagrees. Although both PAR 1118 and Rule 401 address visible emissions, they are different standards with different requirements and measurement methods. PAR 1118 requires that flares be operated in a smokeless manner, which is defined as <u>no visible emissions</u> except for periods not to exceed a total of five minutes during two consecutive hours, based on USEPA Method 22. Rule 401 <u>limits the visible emissions</u> into the atmosphere from any single source of air contaminant for a period or periods not to exceed more than three minutes in any one hour to as dark or darker in shade as that designated No. 1 on the Ringelmann Chart or an equivalent opacity, based on USEPA Method 9. Therefore this does not constitute double jeopardy.*

Comment 29: The requirement to operate all flares in a manner with no visible emissions ignores the basic flare design principles such as smokeless capacity vs. ultimate capacity.

Response 29: *Staff understands that vent gas flow exceeding the smokeless capacity may result in visible emissions. PAR allows visible emissions for periods not to exceed a total of five minutes during two consecutive hours flare will cause visible emissions. Any visible emissions due to exceedances of the flares smokeless capacity are typically due to emergencies and breakdowns. Such visible emissions caused by the incident would be covered by Rule 430 – Breakdown.*

Comment 30: Some threshold Ringelmann number must be specified for visible emissions. If it is not, the smallest wisps of smoke could trigger an NOV or the smallest wisps of smoke could require a "reader" to go out into the field and conduct a visible emissions evaluation.

Response 30: *PAR 1118 allows visible emissions for periods not to exceed a total of five minutes during two consecutive hours. Staff has deleted the requirement that a certified "smoke" reader monitor visible emissions. See Responses 27 and 30.*

Comment 31: The requirement for a PRD survey to be conducted within 90 days prior to a scheduled turnaround is not adequate for turnaround planning purposes. Instead of specifying timing, the rule should specify that the scheduling of any PRD survey should be consistent with the turnaround planning timetable.

Response 31: *Staff disagrees. Maintenance, repair or replacement of defective PRDs is necessary to minimize flare emissions and often can only be corrected during a turnaround. It is now common practice to conduct unit turnarounds every five years. Conducting the PRD survey too far in advance of a scheduled turnaround may not provide the refinery with the knowledge that a PRD is now leaking and in need of corrective action. Staff believes that conducting the PRD survey within 90 days of the turnaround provides the refinery with sufficient time to adjust their turnaround timetable and gives the surrounding community a reasonable expectation that they will not have to experience flare emissions from leaking PRDs for the next five years waiting for the next scheduled turnaround.*

Clean Service Flares

Comment 32: Clean service flares should be exempted from the various requirements of PAR 1118. Their emissions are insignificant and they are already regulated to a certain extent under current Rule 1118.

Response 32: *Staff disagrees. All emissions should be considered in determining whether the facility meets its performance targets. In recognition, however, clean service flares may have a more consistent and typically lower SO2 concentration compared to other flares and are exempt from the daily sampling requirements.*

H2S Limits

Comment 33: The 160ppm H_2S limit for flaring is duplicative of limitations on causes of flaring, the requirements for FMPs, and the performance goals. Furthermore, this limit is an attempt to apply the EPA Subpart J (NSPS) limit to all flaring, an unnecessary rule element as industry has already achieved the emissions reductions contemplated by the AQMP measure. Additionally, Subpart J specifies a 3 hour rolling average, while PAR 1118 specifies no time limit. The AQMD has not demonstrated the feasibility of universal compliance with the 160ppm H_2S limit NSPS-based requirement that is not currently applicable to all flares.

Response 33: *Local refineries currently operate several "NSPS" flares that comply with proposed 160ppm H_2S limit. Staff has determined that three refineries will need to install flare gas recovery and treating systems and other refineries may consider expansion of flare gas recovery and treating systems to comply with the annual SO_2 performance targets, which can also be designed to comply with the proposed 160ppm H_2S limit. Staff has concluded that these systems are technologically feasible, achieved in practice and are cost effective (as part of the monitoring and control proposal for PAR 1118. PAR 1118 has been revised to allow averaging over a period of three hours rather than an instantaneous limit. Also, this proposed requirement does not include vent gases resulting from emergencies, shutdown, startup or relief valve leakage. Staff believes that other possible vent gas can be controlled to comply with the H_2S limit as part of the new and expanded recovery and treatment systems*

Comment 34: Because the H_2S limit applies to Essential Operational Needs, refineries needing to install flare gas vapor recovery and treatment systems could be out of compliance with this standard until the control systems are installed.

Response 34: *Staff has revised PAR 1118 to exclude relief valve leakage (due to a malfunction) when determining compliance with the H_2S limit. Staff believe all other essential operational needs, as defined in paragraph (b)(4), can be collected and treated to compliant levels. To allow time to install or expand needed control system(s), staff has revised the compliance date to January 1, 2009.*

Operation Monitoring and Recording Requirements

Comment 35: Six months after Flare Monitoring and Recording Plan approval may be insufficient time to install a calorimeter to analyze emissions.

Response 35: *Staff has revised PAR 1118 to require the installation and operation of a continuous higher heating value analyzer by July 1, 2007.*

Comment 36: The requirement to take a sample within the first fifteen minutes of each sampling flare event presents significant logistical hurdles, and in some cases it is an impossibility.

Response 36: *PAR 1118 requires the use of automated sampler to collect gases to be analyzed for higher heating value and total sulfur. Staff has determined that automated samplers are currently available and are in operation at most local refineries. These automated samplers can be programmed to take a sample 15 minutes after the start of a flare event.*

Comment 37: The requirement for daily sampling is a burdensome and expensive proposition which serves no purpose. There are millions of data points that could be used to develop statistically reliable averages.

Response 37: *Staff believes that increased sampling frequency will greatly increase the accuracy of emission data until the continuous monitors are installed. Many data submitted by the refineries was not measured but rather substituted data based on calculations. The cost of daily sampling and analysis has been included in the cost effectiveness determination for PAR 1118. Staff has determined that PAR 1118, which includes daily sampling, is technologically feasible and cost effective.*

Comment 38: Sampling during a Sampling Flare Event ought to suffice as the daily required sample.

Response 38: *Staff believes that increased sampling frequency will greatly increase the accuracy of emission data until the continuous monitors are installed. Furthermore, the use of data collected during a sampling flare event, such as an emergency, has in most instances, been documented as a value greater than the values measured during a smaller, non-sampling event. However, staff has revised PAR 1118 to allow the use data collected during a sampling event for the required daily sample.*

Comment 39: The time limit on breakdowns and unplanned flare monitoring system maintenance of 48 hours per quarter is not feasible. Often, more time is needed because vendors must be called out for repairs. 160 hours annually has been suggested as a viable option to the 48 hours per quarter limit.

Response 39: *PAR 1118 has been revised to allow flare monitoring system maintenance and repair of up to 96 hours per quarter, which is at least as stringent as Rule 218 – Continuous Emission Monitoring.*

Comment 40: There is no way to determine whether the 14 day per 18 month limit on planned maintenance is feasible, especially given the fact that monitoring systems will now include more components than before and will be more complex. Instead of the aforementioned limit, Rule 218 to should be used to deal with the issues of monitoring system downtime.

Response 40: *Data collected by AQMD on continuous emission monitoring systems (CEMS) does not suggest additional time will be needed. However, staff acknowledges that information on the operation of CEMS for flares is less robust. If the pilot study on the total sulfur analyzer shows a potential need for more than 14 days per 18 months, staff can revisit this provision of PAR 1118.*

Comment 41: PAR 1118 allows the refinery operator to monitor the presence of a pilot flame using a thermocouple or any other equivalent device approved by the Executive Officer. Providing examples of equivalent devices to a thermocouple, such as an IR camera, would be helpful for both facility operators and District engineers.

Response 41: *Staff has determined that thermocouples and video cameras are currently being used successfully to monitor the presence of the pilot flame on flares. However, staff did not want to limit a refinery's ability to propose an alternate measurement technique it believes equivalent. Any alternative(s) by the refinery can be proposed to and analyzed by AQMD staff.*

Comment 42: The requirement to install a flow meter to monitor and record the purge gas and pilot gas flow to each flare has no greater air quality benefit than using engineering estimates. Furthermore the installation of the proposed flow monitoring devices are far more expensive than engineering estimates and may require that the flare involved be out of service.

Response 42: *Staff believes that it is important to establish an accurate emission inventory. Installing flow meters on pilot and purge gas lines will is needed to obtain an accurate measurement of pilot and purge gas to the flares. Flow measuring devices are relatively inexpensive; the cost of this requirement was used in concluding that PAR 1118 is technologically feasible and cost effective.*

Comment 43: The language in (g)(5)(B)(i) is unclear. Does the district mean, "all the gases that are delivered to the flares for combustion must be measured and recorded."? Furthermore, the requirement should specify "vent gases" because there is a need to specifically exclude any assist air or steam for the purpose of insuring clarity.

Response 43: *Yes, Clause (g)(5)(B)(i) clearly states "A flare monitoring system may be used to measure and record the operating parameters required in paragraph (g)(3) of this rule for more than one flare provided that: All the gases that are delivered to the flares for combustion must be measured and recovered". To exclude "assist air or steam" from the gas(e) being directed to the flare(s), the refinery will need to demonstrate to the satisfaction of the Executive Officer that assist air or steam does not contain anything that will result in the emission of air contaminant(s). However, the revised definition of Vent Gas excludes assist air or steam injected directly into the flare combustion zone or flare stack via a separate line (not the flare header).*

Comment 44: The requirement for flow monitoring instrumentation placement in *(g)(5)(E)(i)* cannot be justified on the basis of an air quality benefit.

Response 44: *Accurate emission data, which includes flow measure to the flares, is paramount to determining the amount of air contaminants released to the atmosphere. Staff can not determine the air quality benefit without accurate flow data. The AQMD Governing Board, on September 3, 2004, directed staff to proceed with rule development to evaluate the recommendations stated in "Evaluation Report on Emissions from Flaring Operations at Refineries", which included a recommendation to improve the measurement of flare vent gas flows. Staff believes that it is important to establish an accurate emission inventory; installing flow meters in representative locations will do just that. As an alternative to relocation, an owner or operator may upgrade the meter with a totalizer to subtract any reverse flow to a flare gas recovery system.*

Comment 45: There is no air quality benefit associated with the requirement in (g)(5)(E)(iii) to install an automated flare gas sampling system, a costly and unnecessary investment. Such a sampling system will cost $50,000 to $100,000 according to estimates.

Response 45: *Accurate emission data, which includes higher heating value and total concentration of total sulfur, expressed as sulfur dioxide, of gases directed to the flares, is paramount to determining the amount of air contaminants released to the atmosphere. The AQMD Governing Board, on September 3, 2004, directed staff to proceed with rule development to evaluate the recommendations stated in "Evaluation Report on Emissions from Flaring Operations at Refineries", which included a recommended the installation of continuous monitoring systems to measure the higher heating value and the total sulfur gas concentration of the flared gas. Several local refineries have already installed and operate automated flare gas sampling systems. Staff believes that this equipment will improve the logistics of taking samples, especially during an emergency when refinery personnel are not available to manually collect the required sample(s). Staff has determined the installed cost of the automated flare gas sampling system to be approximately $5,000 based on cost information provided by an engineering general contractor who has installed sampling systems at refineries and the AQMD.*

Comment 46: The requirement of installation of Higher Heating Value (HHV) technology is problematic. It is requested that they be pilot tested before they are considered as a requirement for flare system monitoring.

Response 46: *Staff has contacted several petrochemical facilities in Texas and Louisiana where continuous calorimeters have been used for a number of years on flare headers for compliance with USEPA 40CFR 60.18 or Texas regulations. Staff believes, based on those testimonials, that a pilot program is not necessary.*

Comment 47: Procedures to prevent flaring events caused by recurring equipment breakdowns, detailing the adequacy of maintenance schedules for equipment, process and control instrumentation are not necessary and are a requirement that should be dropped. The issue is already addressed by the requirements for Root Cause Analysis. Furthermore, what constitutes a definition of recurring is unclear and no guarantee can ever be made that there will not be recurring breakdowns. The term "adequacy" used in the requirement is also subjective and should be replaced.

Response 47: *PAR 1118 has been revised to streamline the requirements of the FMP and eliminate any redundancy with the "Specific Cause Analysis" (SCA), which replaces the Root Cause Analysis. An SCA is an investigation of the cause of the flare vent where the facility operator also identifies corrective measures to prevent a recurrence of a similar flare event.*

Comment 48: There appears to be a misconception that fuel system imbalances only occur as a result of a temporary interruption of pipeline gas sales. Rather, the interruption of pipeline gas sales is probably one of the least common reasons for fuel system imbalances. There is concern that the fact that fuel gas imbalances are specifically addressed implies that they cannot be claimed as an Essential Operational Need, which they are.

Response 48: *Staff understands that an interruption in pipeline gas sales is not the only situation that may cause a temporary fuel gas imbalance; the loss of a combustion device such as a heater or boiler may also cause this temporary situation. Staff recognizes that there are essential operational needs that must be directed to the flare. The definition of Essential Operational Needs has been revised to include vent gas resulting from temporary fuel gas system imbalance.*

Comment 49: The requirement to specify the schedule and resources that will be used to conduct acoustic and temperature surveys of pressure relief devices is impractical. First, specifying schedules that far in advance, is difficult at best. Furthermore, specifying resources so far in advance serves no useful purpose as resources that complete a particular job at the same high quality are often interchangeable. For instance, contractor A could be replaced by contractor B and the job could be done in the same manner.

Response 49: *PAR 1118 has been revised to remove this requirement.*

Comment 50: The requirement to provide a list of equipment breakdowns during the previous five years that resulted in vent gas being directed to the flare cannot be guaranteed to be met since refineries have not been required to keep records going back five years.

Response 50: *PAR 1118 has been revised to remove this requirement.*

Comment 51: The provision requiring that actions be taken to prevent future breakdown is problematic because "prevent" is an absolute term and there cannot be any assurance that future breakdowns will not occur.

Response 51: *PAR 1118 has been revised to remove this requirement.*

Notification and Reporting Requirements

Comment 52: When an unplanned flare event exceeds a threshold of 100,000 scf of combusted vent gas or 500 lbs of sulfur dioxide emissions, the operator is required to contact the Executive Officer within one hour of the event. This extremely low threshold will result in an excessive number of phone calls to the District. There is also concern that any late, or missed calls could result in NOVs, despite the fact that there are no negative air quality implications.

Response 52: *PAR 1118 has been revised to require the refinery to notify the AQMD within one hour, by telephone, of the unplanned release of 100 pounds of VOC, 500 pounds of* SO_x *or 500,000 standard cubic feet of vent gas from a flare. The one hour notification requirement is consistent with Rule 430 – Breakdown Provisions and staff believes it is appropriate in order to conduct timely investigations of flaring events and possible public complaints. The AQMD issues NOVs only after careful consideration of the facts and merits of the failure to meet its' rule requirements promulgated to protect public health.*

Comment 53: The requirement to submit a follow-up report to the Executive Officer within 30 days carries with it the implication that a Root Cause Analysis should also be completed within this time frame, which is an unreasonable request. Furthermore, the requirement will result in resources being re-distributed from areas that have a greater potential for achieving air quality benefits to writing these reports that have no immediate air quality impact.

Response 53: *Staff made the requirement for submittal of the Specific Cause Analysis (SCA) consistent with the deadlines in Rule 430 or Regulation XX Rule*

2004 (h) for breakdown reports. If needed, a facility may request an extension of up to 30 additional days for submitting the SCA.

Comment 54: The term mitigation used in the requirement for Root Cause Analysis implies that mitigation of emissions is a requirement. Clarification is needed on this point to prevent the consequences of the subjective nature of the term.

Response 54: *PAR 1118 requires minimization of flaring during flaring events and any actions taken by the operator with this purpose should be reported in the SCA.*

Comment 55: Facilities are not always able to accurately predict the exact time period of even a planned flaring event, thus making the requirement to notify the district 24 hours prior to such an event difficult at best.

Response 55: *Staff understands that emissions reported as part of notification of such schedule changes are estimated at best in which case the facility should notify the AQMD of the revised planned event date and/or time. However, the facility will have the opportunity to refine these estimates once more information about the events become available.*

Comment 56: There should be clarification provided that demonstrates that the quarterly report required for submittal within 30 days after the end of each quarter is consistent with "standard" certifications such as other District requirements, EPA requirements etc.

Response 56: *PAR 1118 language was revised to be consistent with the certification requirements for quarterly reports in other AQMD rules.*

Comment 57: Because of the low thresholds that define a flare event, 500 pounds sulfur dioxide and 100,000 cubic feet of flare gas, many flare events are likely to be nearly continuous, making the requirement to provide an analysis of each flare event difficult.

Response 57: *PAR 1118 language has been revised to require a more comprehensive Specific Cause Analysis (SCA) for larger flare events 500 pounds sulfur dioxide, 100 pounds VOC or 500,000 cubic feet of flare gas is combusted and a basic investigation to determine the relative cause (emergency, shutdown, startup, turnaround, specific essential operational need, or unknown if undeterminable) where more than 5,000 cubic feet of flare gas is combusted by the flare. Staff believes that these thresholds are necessary to reduce emissions from flares since they will in effect provide operators useful information regarding the use of flares at their facilities.*

Comment 58: Requiring the name of the person who conducted the inspection to be part of the annual acoustical or temperature leak survey for pressure relief devices (PRDs) is not justifiable in any way. Furthermore, the clause, "but not limited to", which is part of the description of what the report should include ought to be deleted because it is too open ended and will result in confusion and problems later in terms of enforcement.

Response 58: *For the AQMD to effectively review and verify measured and reported data, it is critical that the name of the person(s) conducting the annual inspection of PRDs be recorded. Staff has revised PAR 1118 to remove all "but not limited to" language in the proposed amended rule.*

Testing and Monitoring Methods

Comment 59: Neither calorimeters nor sulfur analyzers have been demonstrated to be viable for flare service and both must be tested in a pilot program before PAR 1118 can include a provision requiring the use of semi-continuous heat content analyzer. Furthermore, the District has not justified the cost in terms of air quality benefits of installing these analyzers systems.

Response 59: *Staff has contacted several petrochemical facilities in Texas and Louisiana where continuous higher heating value analyzers (calorimeters) have been used for a number of years on flare headers for compliance with USEPA 40CFR 60.18 or Texas Commission of Environmental Quality (TCEQ) regulations. Staff believes, based on those testimonials, that a pilot program is not necessary for this type of analyzer. A local refinery will be install and operate a total sulfur (TS) analyzer in March 2006. Staff believes that sufficient data will be collected to demonstrate the effective operation of the TS analyzer well in advance of the July 1, 2007 date when petroleum refineries are required to install and operate this type of analyzer. Staff will make a commitment in the PAR 1118 adopting Resolution to conduct a study of the TS analyzer at the local refinery prior to the requirement going into effect. Accurate emission data, which includes total heating value and concentration of total sulfur, expressed as sulfur dioxide,, is paramount to determining the amount of air contaminants released to the atmosphere. Staff can not determine the air quality benefit without accurate emissions data. The AQMD Governing Board, on September 3, 2004, directed staff to proceed with rule development to evaluate the recommendations stated in "Evaluation Report on Emissions from Flaring Operations at Refineries", which included a recommendation to improve the measurement of flare vent gas. The requirement of continuous monitoring implements that recommendation.*

Comment 60: In subdivision (j) Testing and Monitoring Methods (B), the sulfur content of vent gas should be expressed as a reduced sulfur compound rather than as sulfur dioxide.

Response 60: *The 2003 AQMP Control Measure CMB-07 requires a reduction in the sulfur dioxide emissions from flares operated at petroleum refineries and related facilities. Therefore, staff has determined that it is appropriate to calculate and report concentration of total sulfur, expressed as sulfur dioxide, in the vent gas as sulfur dioxide.*

Comment 61: There is absolutely no justification for the provision that samples be analyzed by a third-party. It should be acceptable for the sample to be analyzed in a refinery lab that meets District operating standards.

Response 61: *PAR 1118 has been revised to allow AQMD approved laboratories to analyze for higher heating value and concentration of total sulfur, expressed as sulfur dioxide, (reported as sulfur dioxide).*

Comment 62: Under subdivision (k) exemptions, the terms "catastrophic" and "major" are subjective and the language ought to be clarified.

Response 62: *Subparagraph (k)(1)(A) relieves a facility from collecting "grab" samples for higher heating value and concentration of total sulfur, expressed as sulfur dioxide, during a flare event resulting from a catastrophic event including a major fire or an explosion at a facility. Staff agrees with petroleum refineries that safety is paramount; only the facility experiencing a significant flare event and the specific circumstances pertaining to that event knows if it is safe to send in personnel to collect a sample. PAR 1118 has been revised to better define circumstances during which sampling is infeasible or considered a safety hazard.*

Comment 63: Requiring facilities to submit a written document to explain flaring events caused by natural disasters or acts of war or terrorism is pointless, because the District would already be well aware of such events.

Response 63: *Staff believes that, in order to maintain an accurate record, this requirement is appropriate.*

Comment 64: The exemption in paragraph (k)(2) should also include flare sulfur dioxide emissions resulting from interruptions of power supply beyond the refinery's control.

Response 64: *PAR 1118 language has been revised to exclude emissions from power outages, other than due to an interruptible power agreement, from the annual performance target.*

Attachment A:

Comment 65: The District should refrain from specifying the materials of construction, or considering area classifications in a rule. Facilities must always be in control of the aforementioned issues as they are the ones that specify, purchase and operate equipment. This general provision extends to specifics in Attachment A such as installation issues like hot-taps.

Response: 65 *The goals of analytic and monitoring requirements are to ensure that complete, accurate meaningful and verifiable data are collected. In that this requirement contributes to ensuring that an analyzer will not have temperature changes that may compromise its ability to accurately measure flare gas parameters, it is both necessary and within AQMD's purvey. Area classification requirements were selected for harmony with building requirements in the region and to ensure safety of monitoring staff.*

Comment 66: The lower threshold of 0.1 in the velocity range is possibly unrealistic and can certainly not be justified based on any air quality benefits.

Response 66: *The manufacturer of the flow meters used by facilities subject to PAR 1118 has stated that the meters can accurately measure flow as low as 0.1 feet per second. However, staff will include a twenty percent margin to account for any fluctuations due to transient flow. PAR 1118 has been revised to raise the threshold to define a flare event as 0.12 feet per second or greater. As previously stated in Response 46, accurate flow data is necessary to determine emissions and air quality benefit as well as air quality detriment.*

Comment 67: It is assumed that data recorded will be transferred to a Data Collection System (DCS) and stored there.

Response 67: *The assumption is correct and all required records have to be kept by the facility for a period of five years.*

Attachment B:

Comment 68: Assuming that the flow rate is the maximum design capacity of the flare when the maximum range of the flow meter is exceeded is an overly

pessimistic assumption which will quickly cause emissions performance goals specified in (d)(1) to be exceeded.

Response 68: *Staff has revised PAR 1118 to allow the operators of facilities subject to this rule to substitute flow data that was not measured using both the maximum and the average flow measured during the previous 20 quarters. Based on flow data collected from 2000 through June 2005, the proposed methodology would capture approximately 97 percent of flow data previously reported. Operators also have the option to demonstrate to the AQMD that no flow occurred during the time when the flow meter was non operational through the monitoring of the water seal level associated with the flare or through any other operational parameters and/or other process data. Furthermore, the provisions applicable to the non-sampling events have been revised to allow these facilities to rely on previously measured events rather than relying on data substitution procedures.*

Comment 69: Defining the flow rate at the lower range when the flow rate is below the valid lower range of the flow meter means that a refinery could never use "zero". Without a designation of zero a "Flare Event" as defined would never actually end. This applies to both flow meters and to a combination of flow meters and on/off flow indicator switches.

Response 69: *Flow meters are capable of measuring flows as low as 0.1 feet per second. PAR 1118 has been revised to establish a flare event at 0.12 feet per second or greater. The twenty percent difference between the lower limit capability of the flow meter and what constitutes a flare event is adequate for an operator to discern flow from no flow.*

Comment 70: Using the maximum range of the meter as the assumed flow rate for any missing data is not acceptable. Nothing justifies this use of worst-case assumptions, especially in light of the mitigation fees that would apply if emissions performance goals are exceeded. Instead of just using worst-case assumptions, there should be a provision that considers other factors such as water seals that remained intact.

Response 70: *PAR has been revised to allow facility operators to demonstrate to the AQMD that operational records, such as water seal level or other approved parameters in the Flare Monitoring and Reporting Plan, that a flare event did not occur. Furthermore, the data substitution provisions of PAR 1118 have been revised and the worst case assumptions are no longer applicable.*

Comment 71: The requirement to fill in any missing data with the measurement of the highest sulfur concentration in the vent gas from the previous year is exceedingly harsh and based on unrealistic assumptions. First, it is unlikely that the peak value from the previous year would always exceed

any estimate based on engineering knowledge. Secondly, this requirement could lead to a situation in which the payment of the mitigation fee would be based on fictitious emissions instead of real ones. Instead of this worst-case data use, facilities ought to be able to use another appropriate estimate if the facility provides adequate justification for that estimate's use.

Response 71: *Staff has revised PAR 1118 to allow the operators of facilities subject to this rule to substitute concentration of total sulfur, expressed as sulfur dioxide, data that was not measured using both the maximum and the average concentration of total sulfur measured during the previous 20 quarters. Based on concentration of total sulfur, expressed as sulfur dioxide, data collected from 2000 through June 2005, the proposed methodology would capture approximately 97 percent of total sulfur concentration data previously reported. After the continuous total sulfur analyzers are certified by the AQMD, facility operators also have the option to collect a "grab" sample during the flare event and use that analysis to substitute data for time when the total sulfur analyzer was non operational. PAR 1118 also allows the facility operator the option to demonstrate to the AQMD that total sulfur can be estimated through alternative methods using recorded and verifiable operational parameters and/or process data to be representative of the total sulfur concentration.*

Comment 72: There is no reason why the single highest measurement of concentration of sulfur or heat content in the previous 365 days should be used when it would be more equitable to use an average of the values from the previous year.

Response 72: *See Response 72.*

Definitions

Comment 73: The very low velocity threshold of 0.1 ft/sec that helps define a flare event is problematic because it means that facilities are very likely to have continuous flare events. Part of the problem is that in some flare configurations, vent gases may enter the flare header, pass by the meter and then be recovered by the vapor recovery system before breaking through the water seal. This typically results in flow meter reading greater than .1 ft/sec to as high as about 1.5 ft/sec with no vent gas released to the flare. Therefore, a flare event defined by the presence of flow at a velocity of 0.1 ft/sec would force a recording of a continuous flare even when there is no flow to the flare. Furthermore, flare events indicated by flow monitor signals, which are not verified by on/off meters, water seal monitors, or video monitoring, must be excluded from flare events, as defined. A better definition of flare event is, "FLARE EVENT is any intentional or unintentional release of vent gas to a flare based on positive indications or other instrumentation including, but not limited to, water seal breakthrough, on/off indicators, or video monitoring.

Response 73: *The definition of Flare Event has been revised to address the situations where vent gas is measured by the flow meter but through the use of the water seal, the vent gas is processed by the gas recovery system. The revised definition includes the following language: "the owner or operator can demonstrate that no more vent gas was combusted based upon the monitoring records of the flare water seal level and/or other parameters as approved by the Executive Officer in the Flare Monitoring and Recording Plan."*

Comment 74: The definition of an emergency should include operational upsets to be consistent with federal rules. A better definition would be: "Emergency, for this rule, means a condition beyond the reasonable control of the owner or operator of a refinery requiring immediate corrective action to restore normal and safe operation, which is caused by any sudden, infrequent, and not reasonably, preventable failure of equipment or of a process to operate in a normal or usual manner, force majeure, act of war or terrorism, or external events beyond the control of the operator. Failures that are caused in part by poor maintenance or careless operation are not emergencies." (Reference: Based on 40 CFR 60, Subpart A 60.2 - Malfunctions) In addition, the current definition of Emergency Service Flare in Rule 1118 includes "emergency process upset condition."

Response 74: *The definition of Emergency was revised to include "not reasonably preventable". However, staff does not believe "process upset" should be included in this definition; specific situations will be listed in the definition of Essential Operational Need". The definitions of Emergency and Emergency Service Flare can not be identical in application since clean service flares and general service flares also process vent gases from emergencies.*

Comment 75: A better definition for "FLARE" is the one in the draft BAAQMD rule (definition 12-12-203).

Response 75: *PAR 1118 language was modified to incorporate elements from the BAAQMD in the definition.*

Comment 76: The definition of "FLARE GAS RECOVERY SYSTEM" would not apply in all cases. The following definition should be used instead. "Flare Gas Recovery System is a system consisting of permitted equipment used to prevent or minimize the combustion of vent gas in a flare."

Response76: *Staff believes the suggested definition is too vague and open-ended.*

Comment 77: The definition of "FLARE MONITORING SYSTEM" is inappropriate with the phrase "including but not limited to." There needs to be a clear understanding between the AQMD and industry of what a flare monitoring system consists of.

Response 77: *PAR 1118 was revised to delete the phrase "but not limited to." The definition of Flare Monitoring System includes higher heating value and total sulfur analyzers, flow meters, and on/off flow indicators.*

Comment 78: The definition of "GENERAL SERVICE FLARE" includes activities, such as tank vapor displacement, blowdowns, and "clean up" which should be included in other definitions and/or in the listing of allowable flaring at Rule 1118 (c)(2)(A).

Response 78: *Staff believes that these activities are within the scope of essential operational need(s) or qualify as startups, shutdowns and turnarounds.*

Comment 79: The definition of "HYDROGEN PRODUCTION PLANT" is overly specific.

Response 79: *Staff believes this definition is appropriate.*

Comment 80: Instead of using the current definition of "NATURAL GAS" the District should consider using an existing definition of "pipeline quality natural gas" from either CPUC or EPA.

Response 80: *Staff believes the current definition of Natural Gas is appropriate.*

Comment 81: The following definition of "PURGE GAS" is better than the current version. "PURGE GAS is a continuous gas stream introduced into a flare header, flare stack, and/or, flare tip, for the purpose of maintaining a positive flow and to prevent the formation of an explosive mixture due to ambient air ingress."

Response 81: *The definition of Purge Gas has been revised based on your suggestion.*

Comment 82: The definition of a REPRESENTATIVE SAMPLE ought to be consistent with other requirements such as the specifications for Higher Heating Value and Total Sulfur analyzers.

Response 82: *The proposed amended definition for Representative Sample was modified for consistency with requirements for analyzers.*

Comment 83: In the definition of SAMPLING FLARE EVENT it must be made clear that the refinery must initiate the request.

Response 83: *PAR 1118 language was modified to reflect that a facility is to propose a different Sampling Flare Event threshold for the Executive Officer's approval.*

Comment 84: The definition of SHUTDOWN does not take into account that shutdowns occur for reasons other than maintenance, repair, or replacement of equipment. The following definition is more complete. "Shutdown is the process of stopping the operation of a process unit or piece of equipment for any reason, including preparations necessary for maintenance work."

Response 84: *Staff believes that the suggested definition is too vague and may become a loophole to allow routine flaring.*

Comment 85: A more complete definition for STARTUP is the following. "Startup is the process of initiating and achieving normal operation of a process unit or piece of equipment.

Response 85: *PAR 1118 has been revised to include an expanded definition for startup that takes into account parameters, such as pressure, temperature, feed rate, etc. to characterize normal operation.*

Comment 86: In the definition of TURNAROUND it would be helpful to add language regarding installation of new equipment.

Response 86: Staff *has revised the definition of Turnaround to include "installation of new equipment."*

Comment 87: The definition of VENT GAS does not specifically exclude "assisting air or steam, flare pilot gas and any continuous purge gases." These exclusions must be included in the proposed definition. A more complete definition is the following. "Vent gas is any gas generated at a facility subject to this rule that is routed to, and combusted in a flare, excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

Response 87: *Staff has revised definition of Vent Gas to exclude assist air or steam injected directly into the flare combustion zone or flare stack via a separate line (not the flare header). However, any gas that is generated at a facility subject to PAR 1118 and is directed a flare is considered vent gas.*

MISCELLANEOUS

Comment 88: A flare designed for smokeless flaring at full capacity and designated for emergency use only should not be required to have a video monitor installed for it.

Response 88: *Staff is not aware of any flare that is smokeless over the whole operating range up to maximum design. Even if this existed, there is always the possibility of losing steam injection that could result in visible emission, therefore having a video record is appropriate.*

Comment 89: All current activities and uses of the flare should be considered essential operational needs. Without such designation, facilities planning to install complete vapor recovery and treatment systems in the next few years would face challenges relating to certain requirements prior to their installation of the vapor recovery system.

Response 89: *Staff disagrees with this statement that would effectively allow any flaring to take place and make the rule amendment futile. However, the rule language has been revised to allow more time for these facilities that intend to install additional vapor recover treatment capacity and have affirmed steps toward that goal.*

PRELIMINARY STAFF REPORT COMMENTS

Comment 90: The suggestion that a flare gas recovery and treatment system can prevent temporary fuel gas imbalances is incorrect; such systems are not effective for that purpose.

Response 90: *Staff agrees that such a system would not prevent a fuel gas imbalance, but rather flare emissions may be minimized by the use of this equipment.*

Comment 91: The rule is not necessary since the AQMD Basin is in attainment with the federal SOx standards and flare emissions have already been reduced by 80%.

Response 91: *Staff disagrees. SOx emissions are precursors to particulate matter (PM) emissions and the AQMD is not in attainment for PM 10 (particulate matter less than 10 microns aerodynamic diameter) and PM 2.5 (particulate matter less time 2.5 microns aerodynamic diameter). The reductions achieved to date were voluntary and were achieved primarily through operation procedural changes implemented by the refineries. Furthermore, a close look at the current differences of the recovery and* *treatment capacity of the various facilities indicates that additional capacity for some facilities is feasible to further minimize flaring and associated emissions. There is no mechanism in place that prevents backsliding to previous emission levels. PAR 1118 will make these reductions permanent, real, quantifiable and enforceable and will establish a framework for further reductions.*

Comment 92: It is not fair to assess mitigation fees based on an industry-wide performance, where an individual facility has no control on emissions from a competitor. Also, the standard for an "ultra-clean facility" is not attainable.

Response 92: *PAR 1118 has been revised to require petroleum refineries to achieve a facility-specific declining annual sulfur dioxide performance target. Facilities that exceed the annual performance target are subject to mitigation fees and must also submit a Flare Minimization Plan for public comment and Executive Officer approval. PAR 1118 no longer contains an "ultra-clean" facility compliance option.*

Comment 93: The estimated emission reductions based on 2003 emissions inventory is not appropriate since it does not take into consideration further reductions realized in 2004. Further, the use by the District of the DCF method yields a lower number for cost effectiveness.

Response 93: *Staff acknowledges that flare emissions have trended down and that 2004 emissions are lower than the previous stated baseline year 2003. Since emissions may vary significantly from year to year due to turnarounds and other unforeseen events in petroleum refinery operations, it is appropriate to use a multiple year average as an emissions baseline. The staff report has been revised to average sulfur dioxide emissions and vent gas flow rates for the years 2001, 2002, 2003 and 2004 to establish the baseline for calculating emission reductions and the cost effectiveness of PAR 1118.*

Cost effectiveness analysis is a tool to generate a cost effectiveness factor for a control measure. By comparing the cost effectiveness factors of several control measures with each others, one can acquire knowledge about the costs of each control measure relating to their effectiveness in controlling a particular pollutant. It is necessary to compare cost effectiveness factors of different control measures derived using the same methodology and the same assumptions. The AQMD has been using Discounted Cash Flow Method (with a 4% real interest rate) to determine the cost effectiveness factor for numerous proposed rules since 1995.

Comment 94: The Staff Report should include the CARB Resolution 86-60 for reference.

Response 94: *CARB Resolution 86-60 is included as an attachment to this staff report.*

Comment 95: In contrast with the Bay Area Air Quality Management District (BAAQMD) flare rule, PAR 1118 is far more complex and has duplicative requirements.

Response 95: *BAAQMD has two flare rules: one for monitoring and one for control of flare emissions, whereas PAR 1118 has one rule that includes both these aspects. Moreover, the approach of the two Districts to flares is different. BAAQMD is requiring Flare Minimization Plans while AQMD's PAR 1118 establishes performance targets for controlling and minimizing flare emissions.*

Comment 96: The Staff Report needs to explain the applicability of New Source performance Standards (NSPS) requirements to flares with respect to effective dates.

Response 96: *Staff has clarified in the Staff Report all applicable dates that trigger NSPS requirements for flares (40CFR Subparts A and J).*

Comment 97: Acid gas in the Preliminary Draft Staff Report (PDSR) should be described as "a highly concentrated waste stream of hydrogen sulfide gas (up to 90 percent pure) and sour water stripper gas (about 30 percent pure)" The PDSR incorrectly states EPA's position in the October 2000 Enforcement Letter, which is…"refineries should have adequate capacity at the back end of the refinery to process acid gas".

Response 97: *The description of acid gas was enhanced as suggested. Staff believes that the title of the October 2000 Enforcement Letter summarizes EPA's position that routine flaring is not considered "Good Pollution Control Practice" and it "May violate the Clean Air Act".*

Comment 98: The use of the same concepts in the Consent Decrees that EPA has entered with some refiners used in the amendment of Rule 1118 may represent a duplication of a federal regulations and the AQMD Board must recognize it in its findings upon rule adoption.

Response 98: *Staff disagrees. The Consent Decrees are not federal regulations and they may sunset according to specific clauses in each of them, based on each refinery's compliance record for a certain period of time following the signing of the Consent Decree.*

Comment 99: *The statement in the Staff Report that refineries burn "waste gases" in* flares is a false assumption.

Response 99: *Staff has revise the staff report and the word "waste" was removed.*

Comment 100: Stating that visible emissions are caused by insufficient steam is inconsistent with the smokeless capacity of a flare, since there are limits to how much steam can be used. The staff report should mention that a facility with a flare smoking for 5 minutes within 1 hour could receive two Notices of Violations, one for violating Rule 401 and one for violating Rule 1118.

Response 100: *Staff agrees that when the smokeless capacity is exceeded there is not enough steam to accommodate the high vent gas flow, but acknowledges that this is due to the limitations in the flare design and a clarification was made in the staff report.*

Assuming that a flare was found having visible emissions in excess of Ringelmann 1 or 20 percent opacity for 5 minutes within 1 hour due to a situation other than a valid breakdown, force majeure or power curtailment beyond the operator's control, only one NOV would be issued with two counts of violating Rule 401 and Rule 1118, respectively. If visible emissions were in excess of Ringelmann 2 or 40% opacity, there would be an additional count for violation of California Health and Safety Code 41701.

Comment 101: The operational status of a flare does not involve having just the pilot lights on and the amount of purge gas used depends on other variables than just the flare design.

Response 101: *The Staff Report has been revised to clarify these issues as suggested.*

Comment 102: Clean Service Flares should be exempt from all requirements except for monitoring and recording as specified in Table 1.

Response 102: *Staff disagrees. All flares have emissions potential and all significant flare events need to be accounted for in the form of a Specific Cause Analysis or a relative cause analysis, as required in PAR 1118. However, a Clean Service Flares is defined as a flare that is designed and configured by installation to combust only natural gas, hydrogen gas and /or liquefied petroleum gas, or any other gas(es) with a fixed composition vented from specific equipment which has been determined to be equivalent and approved in writing by the Executive Officer. Therefore, based on this definition, a Clean Service Flare would have very low sulfur dioxide emissions, and as such would contribute very little to the annual sulfur dioxide performance target. Clean Service Flares are not required*

to be monitored with higher heating value or total sulfur analyzers and are not required to have daily vent gas "grab" samples taken. However, the operator must collect grab samples for all sampling flare vents.

Comment 103 The staff report acknowledges that flares are used as control devices that prevent the release of VOC to the atmosphere, but the rule would prohibit this type of use.

Response 103: *Staff acknowledges that there are flares being used as control devices for VOCs. These flares were granted far in the past and would not be allowed for such use if requested by facilities today since the destruction efficiency for flares varies widely from 70 to 97 percent depending on atmospheric conditions and the quality of vent gas combusted. By contrast, thermal oxidizers are designed with a specific residence time, are able to maintain stable combustion temperatures, which results in destruction efficiencies in excess of 99%, are therefore more suited as control devices for VOCs.*

Comment 104: Excessive steam may lead to incomplete combustion and odors downwind. Adding high BTU gases to a flare to improve the combustion efficiency would be prohibited by the rule.

Response 104: *Staff believes that use of excessive steam may extinguish the flame and result in potentially high volumes of odorous and/or toxic substances being released from a flare. Boosting the BTU content of a vent gas with low HHV to ensure appropriate combustion efficiency is allowed as an Essential Operational Need in PAR 1118.*

Comment 105: Federal Regulation 40CFR60.104 has a 160 ppm limit for H_2S, averaged over 3 hours. There should be mention of AQMD Rules 1123 and 1176 and federal regulations requiring control of VOCs.

Response 105: *The staff report was expanded to include the clarification on the H_2S limit. The other rules mentioned do not apply to the operation of a flare, only to control of VOCs, and therefore will not be discussed.*

Comment 106: The report should clarify that flares prevent the release of raw VOCs to the atmosphere. The report should substantiate any "concerns" that OSHA and EPA have regarding the petroleum industry and any claims made by EJ groups.

Response 106: *The staff report has been revised to clarify these issues.*

Comment 107: Most of the "possible alternatives" suggested for minimizing flaring that are listed in the staff report are speculative and lack any foundation.

Response 107: *The suggested possible alternatives are taken form the "Episodic Release Reduction Initiative" document, issued by EPA on July 5, 2001 as a collaborative effort of EPA, the (Texas Commission of Environmental Quality (TCEQ), the Louisiana Department of Environmental Quality (LA-DEQ) in cooperation with 13 petroleum refineries.*

Comment 108: There is an economic incentive besides the environmental benefit for flare gas recovery (FGR), as long as the refinery has adequate storage for the recovered gas, or else it would have to flare it.

Response 108: *Staff agrees and the clarification was made in the staff report.*

Comment 109: Staff seems to have relied on an article in the Oil &Gas Journal to determine the necessary capacity of a flare gas recovery system. The article represents the author's opinion, not necessarily universally applicable guidelines.

Response 109: *Staff has expanded the staff report to include guidelines as stated in API 521 for flare gas recovery system sizing, where it is recommended that the system be sized such that it is able to operate over a "wide" range of dynamically changing flow rates. Thus the opinion expressed in the Oil & Gas Journal article is in agreement with the API guidelines.*

Comment 110: The significant emission reductions already realized suggest that there are limited benefits for amending the rule.

Response 110: *PAR 1118 implements the recommendation of the Governing Board regarding improved monitoring, recordkeeping and recording as well as establishing annual sulfur dioxide, already realized performance targets which will ensure that emission reductions already realized are permanent, real, quantifiable and enforceable and that further reductions are achieved in the future.*

Comment 111: The concept of an alternative to a Flare Minimization Plan is worthwhile; the District should encourage refineries to opt for SOx performance targets.

Response 111: *PAR 1118 has been revised to require petroleum refineries to comply with a declining annual sulfur dioxide performance target of 1.5, 1.0 and 0.7 ton per year for calendar years, 2006, 2008 and 2010, respectively. A*

Flare Minimization Plan will only be required for petroleum refineries exceeding the annual performance targets.

Comment 112: There is no need to require continuous HHV analyzers since on average this parameter is expected to be constant.

Response 112: *The fact that, on average, the HHV will be constant was an assumption used to estimate emission reductions. For calculating the emissions of each flare event with accuracy, a continuous monitor is the best option to use.*

Comment 113: The statements by staff regarding the cause of flare events are misleading, are based on tabulated data from the September 2004 "Flare Report" that are inconclusive. In addition, please explain your assumptions in calculating emission reductions that are used for cost analysis and cost effectiveness calculations.

Response 113: *Staff disagrees. The data presented in the Preliminary Draft Staff Report was based on 2003 obtained from the "Evaluation Report on Emissions from Flaring Operations at Refineries" (September 2004), which is a summary of data submitted by facilities to comply with monitoring and reporting requirements of the Rule 1118. The Staff Report has been updated to include data for calendar years 2001 through 2004 to calculate average vent gas flow and emissions from flares. Staff has determined that the average flow and emissions data is most representative data for the random, cyclical operation of the flares. Staff believes that emergencies, startup, shutdown, turnaround and fuel gas balancing events are a significant and determinant event/operation that should have been easily identified and reported to the AQMD. The total vent gas flow and calculated emissions other that sulfur dioxide and the measured total sulfur emissions, calculated as sulfur dioxide are accurate based on flow measurement, sampling, analytical, and published emission factors. Staff has met with two of the three facilities that have been identified in the staff report as needing (projected) additional gas recovery and treatment system capacity. These two "larger" facilities confirmed the need to install four systems totaling 13 mmscf capacity. Staff has determined that the third facility would install a system with 0.3 mmscf capacity. Staff has estimated the size of the systems based on historical vent gas flow. These systems will minimize vent gas directed to the flares which will reduce sulfur dioxide and other criteria air contaminants.*

Comment 114: Some suggested flare controls might have been considered technically feasible; however, practicality, costs and cost effectiveness were not necessarily considered.

Response 114: *The staff report language was modified to clarify that these controls were technologically feasible.*

Comment 115: Refineries that may not have to install flare controls will still incur significant costs for monitoring and other requirements of PAR 1118; in aggregate, complying with the rule will be a significant expenditure.

Response 115: *Monitoring and other requirement costs were included by staff in the cost-effectiveness analysis of the proposed rule. Staff has determined that PAR 1118 is both technologically feasible and cost effective.*

Comment 116: The assumptions made in the staff report for determining cost-effectiveness will need to be evaluated by individual facilities and commented upon. It is unclear whether three or four flare gas recovery and treatment systems are proposed and the number of flow meters for pilots may be triple than that indicated in the staff report.

Response 116: *Staff has estimated that four flare gas recovery and treatment systems would have to be installed at three petroleum refineries: The four systems will minimize vent gases to eight flares that currently are not connected to any gas recovery and treatment systems. Staff's analysis is discussed in Chapter VI - Cost and Cost Effectiveness. The number of flow meters for the pilot gas was assumed to be one meter per flare, located on the natural gas line before it splits in individual lines for each pilot.*

Comment 117: The case study used in the staff report to determine the cost of a flare gas recovery system was related to acid gas flaring. It would not be unreasonable for staff to contact each of the eight facilities subject to the rule to evaluate the cost of necessary expenditures required by the rule.

Response 117: *Staff has conducted interviews with subject facilities to assess compliance with future proposed rule requirements. For better accuracy in estimating costs, staff has expanded its analysis to two additional case studies from the data submitted by two local refineries for the installation and subsequent operation of two flare gas recovery and/or treatment system in 1993 and 2001.*

Comment 118: Staff needs to explain how the necessary size of a recovery system was determined.

Response 118: *The staff report states that for the flare considered for upgrade with a recovery system, the quarters with the highest flow between 2000 and 2003 were selected; then an average daily flow for those quarters was*

calculated. Based on a review of technical literature on flare design, the capacity of the recovery system was estimated at 2-3 times the daily flow rate.

Comment 119: It appears that staff may have underestimated some equipment and labor costs; refineries could provide some data in this respect.

Response 119: *Staff used cost information supplied by the refinery in Billings, Montana, as well as the cost data from two local refineries that installed control equipment in 1993 and 2001. Although the systems installed varied in scope and size, the cost of the flare gas treatment capacity was consistent, ranging from \$8.32 to \$8.77 million per four million cubic feet of gas recovered/treated. Staff will review any cost data supplied by refineries.*

Comment 120: The quoted prices for different pieces of equipment should be provided to refineries for evaluation.

Response 120: *Chapter VI - Cost and Cost Effectiveness lists the cost of control, monitoring and labor. The PAR 1118 Administrative Record contains the actual quotes and facility-specific cost information. Some of this information is considered confidential. Any non-confidential information can be provided to interested parties upon written request.*

Comment 121: When calculating the cost of equipment over time, staff did not factor in adjustments for inflation.

Response 121: *Staff disagrees. The cost of future expenditures was adjusted for inflation.*

Comment 122: Annual costs should include taxes and insurance.

Response 122: *The total installed cost includes taxes and insurance.*

Comment 123: The annual estimated savings due to recovered gas should be based not on the maximum capacity of the compressors but rather on the average flow rate of the gas recovered. Staff needs to explain the assumptions made in calculating the savings.

Response 123: *Staff has revised its analysis to use the annual average flow rate of vent gas recovered through the installation of additional vent gas recovery and treatment systems. Please refer to Chapter VI – Cost and Cost Effectiveness for a discussion on the assumptions used in calculating the cost savings.*

Comment 124: Staff has not clarified the necessity of the rule for ozone attainment.

Response 124: *The proposed rule amendment is necessary since oxides of sulfur (SOx) are precursors to PM10 and PM2.5. Since the rule is designed to minimize flaring and associated emissions, in addition to the SOx reductions, the rule will result in concurrent reductions of other criteria pollutants such as hydrocarbons, oxides of nitrogen and carbon monoxide, all of which are precursors to ozone.*

APPENDIX A

REFERENCES

Staff Report for Rule 1118 – Emissions From Refinery Flares, SCAQMD, December 1997

Evaluation of Refinery Flare Emissions at Petroleum Refineries, SCAQMD, September 2004

2003 Air Quality Management Plan, SCAQMD, 2003

U.S. EPA, Petroleum Refinery Initiative

U.S. EPA Enforcement Alert, Volume 3, Number 9 EPA300-N-00-014, October 2000

U.S. EPA, The Episodic Release Reduction Initiative, July 5, 2001

Hydrocarbon Processing, August 2002, pp76 – 80

Oil and Gas Journal, November 23, 1992, pp 70-76

Oil and Gas Journal, December 7, 1992, pp 68-72

Chevron Texaco Letter to William Norton, BAAQMD, February 6, 20030

APPENDIX B

CALIFORNIA AIR RESOURCES BOARD RESOLUTION 86-60

State of California
AIR RESOURCES BOARD

Resolution 86-60

June 19, 1986

RECEIVED
1 8 1990
STATIONARY SOURCE COMPLIANCE
REFINERY, ENERGY & OCS TEAM

Agenda Item No.: 86-7-2

WHEREAS, Health and Safety Code Section 42701 requires the Air Resources Board (the "Board") to determine the availability, technological feasibility, and economic reasonableness of monitoring devices to measure and record continuously emissions from larger stationary sources; and Section 42702 requires the Board to specify the types of stationary sources, the processes, and the contaminants for which a monitoring device is available, technologically feasible, and economically reasonable;

WHEREAS, pursuant to the Board's direction following consideration of a 1984 petition from Citizens for a Better Environment ("CBE"), the staff has evaluated the availability, technological feasibility and economic reasonableness of continuous emission monitors for all refinery flares;

WHEREAS, based on its evaluation the staff has recommended that the Board determine that devices which monitor the on/off status of refinery flares are technologically feasible, available, and economically reasonable;

WHEREAS, the Board staff has further recommended that the Board:

Encourage local air pollution control districts in which refinery flares are located to adopt rules requiring refiners to install refinery flare on/off monitors;

Direct the staff to work, as necessary, with industry and the districts to develop rules requiring the use of these devices with workable but standardized definitions of "on" and "off";

Encourage the districts to require, pursuant to Health and Safety Code Section 42303, refiners to provide grab sample composition analyses of flare feed stream gases;

Direct the staff, after sufficient on/off data and coordinated composition data have been collected, to evaluate such data and develop recommendations regarding the development of a Suggested Control Measure for the control of refinery flare emissions if the staff's evaluation indicates that such control is reasonable;

WHEREAS, pursuant to Health and Safety Code Sections 39002 and 40000, the districts have the primary responsibility in California for control of air pollution from nonvehicular sources;

WHEREAS, Health and Safety Code Section 41511 authorizes a district, for the purpose of carrying out its duties, to adopt rules requiring the owner or operator of any emission source to take such action, including installation of continuous emission monitors, as the district finds to be reasonable for determining the amount of emissions from the source;

WHEREAS, Health and Safety Code Section 42303 authorizes a district air pollution control officer at any time to require from a permit holder information which will disclose the nature, extent, quantity, or degree of air contaminants which are discharged by the source for which the permit was granted;

WHEREAS, the California Environmental Quality Act and Board regulations require that no project having significant adverse environmental impacts be adopted as originally proposed if feasible alternatives or mitigation measures are available;

WHEREAS, the Board finds that:

Pressure sensors, optical radiation sensors, and hot wire thermistors have been used at refineries in California to monitor the on/off status of refinery flares to the satisfaction of refinery personnel;

Refinery flare on/off status monitors are presently available in California from commercial vendors and would cost approximately $800 to $2000 for each installation;

Emissions of oxides of nitrogen and oxides of sulfur from refinery flares are currently not being routinely monitored in California, and the magnitude of flare emissions has not been determined accurately because of the technical problems associated with flare emission monitoring;

Records of the frequency and duration of flare operations made by flare on/off monitoring devices, coupled with composition data from analysis of grab samples of refinery flare gas streams, can be combined with existing information about refinery processes and flares to yield improved emissions estimates;

Standardized definitions of "on" and "off" for refinery flare on/off status monitors would enhance the usefulness of the data from such monitors;

The actions recommended by the staff will have no adverse environmental impact;

WHEREAS, the Board has conducted a public meeting to consider the staff recommendations and has received and considered written and oral presentations from any members of the public wishing to comment.

NOW, THEREFORE, BE IT RESOLVED that the Board determines that monitoring devices are technologically feasible, available, and economically reasonable to identify and record continuously the on/off status of refinery flares for the purpose of determining refinery flare emissions.

BE IT FURTHER RESOLVED that the Board encourages local air pollution control districts in which refinery flares are located to adopt rules requiring refiners to install refinery flare on/off monitors.

BE IT FURTHER RESOLVED that the Board directs the staff to work, as necessary, with industry and the districts to develop rules requiring the use of these devices with workable but standardized definitions of "on" and "off."

BE IT FURTHER RESOLVED that the Board encourages districts to require, pursuant to Health and Safety Code Section 42303, refiners to provide grab sample composition analyses of flare feed stream gases.

BE IT FURTHER RESOLVED that the Board directs the staff to report to the Board in six months on the progress of the districts in developing and adopting rules requiring refiners to use on/off status flare monitors and to submit grab sample composition analyses of flare feed stream gases, and directs the staff to report thereafter as appropriate on the implementation and results of flare monitoring requirements.

BE IT FURTHER RESOLVED that the Board directs the staff, after sufficient on/off data and coordinated composition data have been collected, to evaluate such data and develop recommendations regarding the development of a Suggested Control Measure for the control of refinery flare emissions if the staff's evaluation indicates that such control is reasonable.

I hereby certify that the above is a true and correct copy of Resolution 86-60, as adopted by the Air Resources Board.

Harold Holmes

Harold Holmes, Board Secretary

EXHIBIT I

Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Staff Report

Proposed Regulation
Regulation 12, Miscellaneous Standards of Performance
Rule 12, Flares at Petroleum Refineries

July 8, 2005

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TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

Emissions from flaring at petroleum refineries have been an ongoing concern to the Bay Area Air Quality Management District and residents of the communities in the neighborhoods surrounding the refineries. Because flares are first and foremost a safety device that must be available for use in emergencies to prevent accident, hazard or release of refinery gas directly to the atmosphere, development of an appropriate regulatory mechanism to address flaring emissions has been a challenge. Through a broad participatory process involving District staff, refinery representatives, community representatives, representatives of local, state and federal public agencies, and other members of the interested public, however, the District has formulated a regulation that will reduce flaring emissions while providing refineries with flexibility to address their unique flare systems without compromising the safety of workers and the public, or the refineries.

Refinery flares are necessary for the safe disposal of gases generated during the refining process. These gases are collected by the refinery blowdown system, which gathers relief flow from process units throughout the refinery, separates liquid from vapors, recovers any condensable oil and water, and recovers gases for use in the refinery fuel system. When the heating value of the gas stream is insufficient for use as refinery fuel, when the stream is intermittent or when it exceeds the refinery's capacity to recover and use the gas for use as a fuel, the blowdown system directs the vapors to the flare, which combusts the gases and prevents their direct uncontrolled release to the atmosphere.

The Bay Area Air Quality Management District (District) discussed the need to study the feasibility of implementing controls on refinery flaring as part of the San Francisco Bay Area 2001 Ozone Attainment Plan for the 1-Hour National Ozone Standard. Analysis of Further Study Measure 8 (FSM-8) for flares, blowdown systems and pressure relief devices was initiated in January of 2002. A draft Technical Assessment Document (TAD) for flares was released in December 2002. The TAD presented information on refinery flares and emission estimates, and was the foundation for the flare monitoring rule. The District's flare monitoring rule, Regulation 12, Rule 11, was adopted by the District Board of Directors on June 4, 2003. Information obtained from the required monitoring was used to develop the proposed control strategies. The result is a proposed new rule, Regulation 12, Rule 12: Flares at Petroleum Refineries.

Emissions from flare operations at each Bay Area refinery have decreased since the District began work on development of the flare monitoring rule in 2002. Reports from refiners and analysis by staff have shown a reduction of total organics of approximately 85% since the time period covered by the TAD. These reductions are primarily due to adding flare gas compressor capacity and better management practices.

Emissions from refinery flares are currently estimated at 2 tons per day of total organic compounds (TOC) and 4 tons per day of sulfur dioxide (SO_2). These emission levels reflect the reductions realized as a result of actions taken by Bay Area refiners in recent years. The proposed regulation will capture these reductions to ensure no backsliding to flaring practices of the past. These emissions levels are expressed as daily averages, however; actual emissions on any given day range from 0 to 12 tons TOC and 0 to 61 tons of SO_2. The proposed rule calls for refiners to develop flare minimization plans to further reduce these emissions.

Staff investigated a variety of options for addressing emissions from refinery flares. The proposed regulation uses an approach that requires each refinery to develop a comprehensive plan to minimize flare use. Significant differences in refinery configurations and capacities to process and use gas in other processes require the rule to provide flexibility to implement the most appropriate flaring prevention measures for each refinery. The minimization plans will be developed in active consultation with District staff and will require annual updates to ensure that new technologies and practices will be identified and implemented in a process of continuous improvement. The plans will be made available for public review and written comment. A plan will only be approved if the APCO determines that all feasible flaring prevention measures have been considered and incorporated.

An Environmental Impact Report (EIR) was prepared to investigate and discuss elements of the proposed regulation that could result in environmental impacts. The EIR concludes that the proposed regulation would have no adverse environmental impact. A socioeconomic analysis mandated by Section 40728.5 of the Health and Safety Code was prepared by Applied Economic Development, Berkeley, California. The analysis concludes that the affected refineries should be able to absorb the costs of compliance with the rule without significant economic dislocation or loss of jobs.

As part of the technical assessment and rule development process a working group was formed that included representatives from the Bay Area petroleum refineries, the Western States Petroleum Association (WSPA), Communities for a Better Environment (CBE), the California Air Resources Board, and District staff. The workgroup met routinely to discuss technical issues including legal requirements of rule development, emission control strategies, monitoring techniques, standard definitions and investigation procedures. Summaries of these meetings are contained in Section IX of this report.

Additionally, staff hosted two evening public workshops in Martinez on March 24, 2005 and Richmond on, March 16, 2005, to receive input from the public on a proposed draft rule. The core issues raised at these meetings were: due consideration of safety, enforceability of the standards, clarity in definitions, the need for public input into the development of flare minimization plans, adequacy of the breadth of flaring scenarios covered by the rule, and the need for a limit on the hydrogen sulfide content of the vent gas. The proposed rule includes revisions to the rule language presented at the workshops as necessary and appropriate to address these issues.

II. BACKGROUND

A. Process Description

Flares are first and foremost devices to ensure the safety of refinery operations and personnel. They also serve as emission control mechanisms for refinery blowdown systems. Blowdown systems collect and separate liquid and gaseous discharges from various process units and equipment throughout the refinery. They also collect gases that are the normal byproducts of a process unit or vessel depressurization, or that may result from an upset in a process unit, or that come from refinery process units during startup and shutdown, or when the balance between gas generation and the combustion of that gas for process heat is disrupted.

Blowdown systems generally recover liquids and send gases to the fuel gas system for use in refinery combustion. However, when the heating value of the gas stream is insufficient, when the stream is intermittent, or when the stream exceeds the refinery's capacity to safely use the gas stream to satisfy refinery combustion needs, and the refinery does not have available storage capacity, the flare is used to combust these gases and prevent their direct uncontrolled release to the atmosphere.

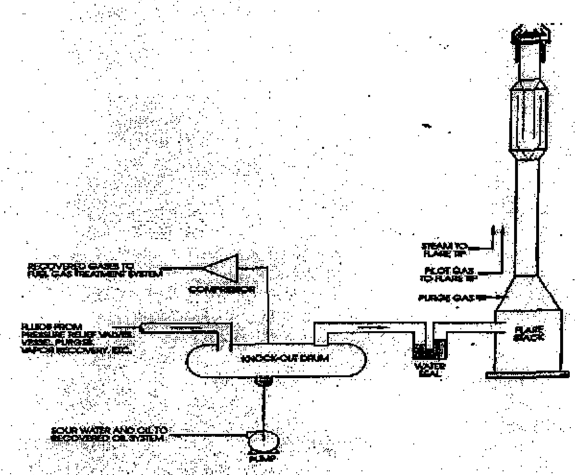

Figure 1. Typical Flare System

The diagram above illustrates a typical flare system. The system is a component of the refinery blowdown system, which delivers gases and liquids to a knockout drum that captures liquids and directs them to the oil recovery stream. The gases are routed to the fuel gas system. The extent to which these gases can be captured depends upon the capacity of the compressors and the energy demand throughout the refinery. A refinery is said to be operating in good balance when gas generation during normal operation is consumed by demand,requirements in the refining processes. As a general rule a refinery should be able to capture all of the gases delivered to the blowdown system during normal operations.

B. Bay Area Air Quality Management District Regulations Applicable to Flares

Several District rules apply to Bay Area refinery flare emissions, varying from the general to source specific requirements. The most recent is Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries, which was adopted on June 4,

2003. This rule requires refineries to accurately monitor the flow and composition of vent gases combusted in a flare, to calculate total organic (methane and non-methane organic compounds) and sulfur dioxide emissions, to identify reasons for and corrective actions taken to prevent major flaring events, to continuously video record flares subject to the rule, and to report this information to the District in a timely manner.

There are several other District regulations applicable to flare emissions. Regulation 1, Section 301: Public Nuisance, is derived from California Health and Safety Code Section 41700. It prohibits discharges that cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property. Regulation 6: Particulate Matter and Visible Emissions, limits the quantity of particulate matter in the atmosphere through limitations on *emission rates, concentration,* visible emissions and opacity. Regulation 7: Odorous Compounds, places general limitations on odorous substances and specific emission limitations on certain odorous compounds. Regulation 9, Rule 1 and Rule 2: Inorganic Gaseous Pollutants for Sulfur Dioxide and Hydrogen Sulfide, limit ground level concentrations of these pollutants. Regulation 10 - Standards of Performance for New Stationary Sources, incorporates Federal standards for petroleum refineries adopted by reference.

Regulation 8, Rule 2 contains controls for organic compounds from miscellaneous operations. Although this regulation was not intended to apply to refinery flares and has not been enforced against these sources by the District, some confusion regarding the scope of this regulation exists. Staff proposes an amendment to Regulation 8, Rule 2, to clarify that this standard does not apply to refinery flares. This modification *will resolve the existing confusion and will avoid* any overlap or duplication of requirements applicable to refinery flares once Regulation 12-12 takes effect.

C. Applicable Federal Regulations

Federal New Source Performance Standards (NSPS) in 40 CFR Part 60, Subpart A, Section 60.18 applies to flares that are used as general control devices. Subpart A specifies design and operational criteria for new and modified flares. The requirements include monitoring to ensure that flares are operated and maintained in conformance with their designs. Flares are required to be monitored for the presence of a pilot flame using a thermocouple or equivalent device, to meet visible emissions standards, to maintain a minimum exit velocity *and to meet a net heat content of the gas being combusted by the flare.*

In addition, the NSPS limits sulfur oxides from combustion devices installed after June 11, 1973 (40 CFR Part 60, Subpart J, Section 60.104). Flaring of gases released due to upset conditions or as a result of relief valve leakage, startup/shutdown, or other emergency malfunctions is exempt from this standard.

Since 1998, EPA has pursued a coordinated, integrated compliance and enforcement strategy to address Clean Air Act compliance issues at the nation's petroleum refineries.

The National Petroleum Refinery Initiative[1] addresses four compliance and enforcement issues under the federal Clean Air Act based on EPA's determination that these concerns affect the petroleum refining industry nationwide:

- Prevention of Significant Deterioration/New Source Review (NSR);
- New Source Performance Standards (NSPS) for fuel gas combustion devices, including sulfur recovery plants, flares, heaters and boilers;
- Leak Detection and Repair requirements (LDAR); and
- Benzene National Emissions Standards for Hazardous Air Pollutants (BWON).

EPA has embarked on a series of multi-issue/multi-facility settlement negotiations with major petroleum refining companies. The settlements for the Bay Area refineries are specific to each refinery. In general, they include elements specific to catalytic cracking units, sulfur recovery plants and flares. One facility has entered into a settlement agreement that locks in the current status of flare operations. Other settlements seek to improve upon the current operating practices and require implementation schedules for application of the NSPS to all their flares. The details of these settlements are available on EPA's website.

III. POTENTIAL CONTROL STRATEGIES

Staff considered a variety of strategies to control emissions from flares. The traditional method of controlling emissions generally involves add-on devices that capture or reduce emissions, such as baghouses, scrubbers and low NOx burners. These devices are usually designed for a specific pollutant and emission source. They are not well suited for flares where combustion takes place in open air at the flare tip. Also, these control devices are designed for steady state operation making them inappropriate for a source like a flare that must go from burning only pilot gas to burning thousands of cubic feet of gas per second. Consequently, staff concluded that mandating the use of such devices to control emissions from flares generally is not a workable approach.

[1] EPA Website: http://www.epa.gov/compliance/civil/programs/caa/oil/index.html. October 6th, 2004

Equipment control strategies applicable to refinery flare systems include those that require the installation of new equipment or devices, or physical changes to the flare system. Strategies that might be applied to these systems include:

- additional flare gas compressors to collect gases and prevent flaring;
- addition of gas storage capacity to hold flare gas;
- increasing gas treatment capacities;
- installation of redundant equipment;
- improvement of the reliability of the existing flare gas compressors;
- improvement of flare tip designs.

Pollution prevention strategies are designed to reduce emissions through changes to the operation of the refinery, as opposed to controlling the emissions with add-on equipment. These include:

- balancing the use of combustion devices, flare gas and natural gas consumption;
- developing management practices to minimize vent gases directed to the flare.

Since the beginning of the District's technical assessment efforts in 2002, each refinery has implemented one or more of the strategies described above. The most significant of these involve installation of new flare gas recovery compressors at one refinery. Installation of additional compressor capacity and improvement of the reliability of the existing flare gas compressors at other refineries have also significantly reduced emissions. During the rule development process, refiners have presented trend charts to the District that show up to 60% reduction in emissions since 2002. Bay Area refiners and other participants in the work group meetings convened to assist in rule development generally concur with this assessment, but District staff as well as some members of the public have expressed concern over possible backsliding or failure to maintain those reductions. Staff concluded that the most workable strategy for reducing emissions from flaring is to require refiners to develop individual flare minimization plans. This strategy provides flexibility to maximize emission reductions among significantly different refinery process designs and has been crafted to maintain emission reductions from the practices already instituted by the refiners.

IV. REGULATORY PROPOSAL

PROPOSED NEW REGULATION 12, MISCELLANEOUS STANDARDS OF PERFORMANCE, RULE 12: FLARES AT PETROLEUM REFINERIES

A. THE STANDARD

The proposed regulation is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. The proposal

includes a standard that prohibits the use of a refinery flare unless the use is consistent with an approved flare minimization plan ("FMP" or "Plan"). The rule includes a requirement to conduct a causal analysis to evaluate a reportable flaring event, i.e., flaring more than 500,000 standard cubic feet per calendar day, to identify the cause (or causes) of the flaring and the means to avoid flaring from that cause in the future if possible. In addition, each facility is required to submit an annual report to the District that includes an evaluation of flaring at volumes less than 500,000 where the calculated sulfur dioxide emissions are greater than 500 pounds. This formal evaluation process will ensure that each refinery makes continuous improvement and progress toward the goal to minimize use of refinery flares.

The standard recognizes that flares are safety devices and includes a provision to allow flaring in an emergency if necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere. To ensure that this exemption is properly applied, the proposed rule relies on the causal analysis to confirm that only flaring necessary for the safe operation of the refinery due to an emergency is allowed under this provision.

While the proposal will not eliminate all non-emergency flaring immediately, it will maintain reductions achieved by Bay Area refiners over the past few years and help identify areas where additional reductions are possible. Refiners will be required to update the plan annually to incorporate newly identified preventive measures to ensure continuous improvement over time and progress toward the goal to minimize use of refinery flares.

Certain flares are exempt from the requirements of the proposed rule. These exemptions apply to any flare that functions as an abatement device used exclusively for the following sources: organic liquid storage and distribution, marine vessel loading terminals, wastewater treatment plants, and pumps. Standards for these sources are specified in other District regulations. They include, but are not limited to abatement efficiency, use of good engineering practices, and emission limits depending on the source operation. Emission data from these source-specific applications are submitted annually to the District. Monitoring and control of these systems are well managed within this existing structure.

B. ADMINISTRATIVE REQUIREMENTS

The proposal specifies the required elements of a flare minimization plan; lays out the process that the APCO will use to evaluate and approve the FMP and updates; identifies the criteria for submission of the initial FMP and FMP updates; requires investigation into the cause of flaring and timely notification to the APCO; and specifies the procedures for submittal and designation of confidential information.

The FMP is not intended to serve as a permit for a flare or to be included as part of the refinery permit; thus the plan is not subject to provisions of the Health and Safety Code or District rules related to permits. If the plan includes a commitment to install new equipment or to modify existing equipment or to take any other action that would trigger the requirement to obtain a permit from the District, the owner or operator must obtain the required permit in a separate process in accordance with applicable District permitting rules.

Refiners will be required to include all feasible prevention measures in the FMP with a schedule for expeditious implementation of those measures. The elements of a FMP include:

1) A description of and technical information for the refinery flare system and the upstream equipment and processes that send gas to the flare, including all associated monitoring and control equipment;
2) A description of the equipment, processes and procedures previously *installed or implemented by the owner or operator within* the last five years to reduce the flaring;
3) A description of any equipment, process or procedure to reduce flaring that is planned, but not yet installed or implemented and the schedule for completion;
4) A description and evaluation of prevention measures, including a schedule to expeditiously implement the following:
    - flaring during planned major maintenance activities including startup and shutdown;
    - flaring that may occur due to issues of gas quantity or quality;
    - flaring caused by the recurrent breakdown of equipment;
5) Any other information requested by the Air Pollution Control Officer as necessary *to enable determination of compliance with applicable provisions of* this rule.

The schedule for submitting a flare minimization plan requires the owner or operator of a flare subject to the rule to submit a complete plan within a year of rule adoption. The proposed rule also requires the refiner to demonstrate that it is making progress toward development and timely submission of a complete plan beginning three months after adoption of the rule and every three months thereafter. Ongoing consultation with the APCO will ensure that any problems are identified and addressed early in the process.

The review and approval process allows time for the APCO to make an administrative determination that *the FMP is complete and for facilities to make* any corrections to address any deficiencies identified by the APCO before the substantive review of the plan is initiated. Once the APCO determines that the plan addresses all the required elements, it will be made available for 60 days for public review and comment. In addition to the complete plans, the quarterly status reports are public records and will be available for review upon request. In providing a lengthy public review and comment period at the earliest stage of the

substantive review of the plans, the process ensures meaningful public participation at the point in time when it will be most informed and most effective.

The District's substantive review process will involve an analysis of the prevention measures *considered in the plan, including the completeness of the* universe of measures identified, the feasibility determination for those measures, and the reasonableness of implementation schedule for the feasible measures. Following this review, including consideration of written public comment, the APCO will approve the FMP if he determines that it complies with the procedural and substantive requirements of the rule.

The proposed regulation includes language allowing a refiner to use a flare consistent with a complete FMP pending final action by the APCO on the plan. This prohibition is necessary because the prohibition on flaring takes effect November 1, 2006. In the event that the APCO has not taken final action on a refiner's initial FMP submission, rather than further delay implementation of the standard, the *rule allows a refiner that has submitted a complete plan to flare in* accordance with that plan until the APCO takes final action to approve or disapprove the plan. This provision does not signify that the plan is or will be approved.

Updates of FMPs are required annually to incorporate any significant changes in process equipment or operational procedures related to flares. In addition, an update is required prior to installing or modifying any equipment associated with flare systems that would require a District Authority to Construct. This provision requires refineries to consider the impact on flaring when installing or modifying equipment. After the initial implementation phase of the flare control rule, experience may indicate that the frequency of updates may need adjustment. At that point, *District staff will reassess this requirement and may recommend to the* Board in a future rulemaking that the frequency of updates could be adjusted to enhance the regulation.

Refiners will also be required to submit an annual report covering less significant flaring with sulfur emissions of concern (greater than 500 pounds per day). This report must identify the reason for flaring and describe any prevention measures considered or implemented. Any prevention measure implemented must be included in the annual update of the FMP. Having refiners examine smaller flaring events serves the continuous improvement goal of the proposed rule.

The proposed rule includes a requirement to notify the District of flaring of gas in excess of *500,000 standard cubic feet per calendar day. This will provide the* District and the public with timely information about flare operations. Under current regulations, refiners do not have to notify the District of a flaring event unless there is an indicated excess on a ground level monitor (within 96 hours) or they are seeking breakdown relief under Regulation 1 (immediately, with due regard for safety), which is available for equipment failures but not operator error.

The new proposal would ensure that the District receives information regarding flaring in a timely manner (as soon as possible consistent with safe operation of the refinery) in all cases where the trigger level is exceeded.

The proposed rule requires the flare owner or operator to determine and report the cause of a reportable flaring event. The investigation must be sufficient to determine the primary cause and contributing factors that resulted in flaring. This level of investigation is necessary to ensure that sufficient information is available to develop prevention measures to eliminate the recurrence of avoidable flaring. Currently the flare monitoring rule, Regulation 12, Rule 11, requires reporting of the cause of flaring more than 1 million standard cubic feet of vent gas. Over the past two years, the District has worked closely with refinery personnel preparing those reports to ensure that the investigations conducted are sufficient to provide the information necessary to identify measures to reduce or eliminate such flaring, and that reporting of the results of those investigations is complete. The language of the proposed rule is intended to require that the same level of investigation and reporting is provided for flaring of 500,000 scf under the proposed rule.

C. MONITORING AND RECORDS

The proposed rule requires continuous monitoring of the water seal. The "knockout water seal drum" performs three functions. First, the drum provides final vapor-liquid disengaging ("knockout") to reduce the potential for liquid carryover up the flare stack. Second, the drum provides a positive barrier or "water seal" between the flare gas header and flare stack. This prevents air in the flare stack from back flowing into the flare gas header and potentially forming an explosive mixture with the hydrocarbon vapors. An inert gas purge (such as nitrogen) may also be added at the base of the flare stack as "sweep gas" to prevent air from back flowing from the flare tip into the flare gas header. Third, the drum provides backpressure on the flare gas header to operate a flare gas recovery compressor. The recovery compressor collects vapors in the flare gas header that would otherwise be combusted in the flare, and returns those vapors to the refinery fuel gas system.[2] The flare owner or operator must record and archive the monitoring data to verify the integrity, or proper operational status, of the flare's water seal. These data are indicators of actual flow to the flare and are measured by flow of makeup water, the water seal height or system pressure. Records of these measurements will assist in verification of calculated emissions and investigations into the cause of flaring.

D. PROPOSED AMENDMENT TO REGULATION 8, ORGANIC COMPOUNDS, RULE 2: MISCELLANEOUS OPERATIONS

Staff is also proposing to amend Regulation 8, Rule 2, to clarify that flares are not subject to that rule.

[2] Excerpt from Flare Control Workgroup meeting by Clark Hopper, Valero Refinery

V. EMISSIONS AND EMISSION REDUCTIONS

A. Emissions

Flares produce air pollutants through two primary mechanisms. The first mechanism is incomplete combustion of a gas stream. Like all combustion devices, flares do not combust all of the fuel directed to them. Combustion efficiency reflects the extent to which the oxidation reactions that occur in combustion are complete reactions converting the gases entering the flare into fully oxidized combustion products. Combustion efficiency may be stated in terms of the extent to which all gases entering the flare are combusted, typically called "overall combustion efficiency" or simply "combustion efficiency", or it may be stated as the efficiency of combustion for some constituent of the flare gas as, for example, "hydrocarbon destruction efficiency."

The second mechanism of pollutant generation is the oxidation of flare gases to form other pollutants. As an example, the gases that are burned in flares typically contain sulfur in varying amounts. Combustion oxidizes these sulfur compounds to form sulfur dioxide, a criteria pollutant. In addition, combustion also produces relatively minor amounts of nitrogen oxides through oxidation of the nitrogen in flare gas or atmospheric nitrogen in combustion air.

Unlike internal combustion devices like engines and turbines, flares combust fuel in the open air. Because combustion products are not contained and emitted through a stack, a duct, or an exhaust pipe, emission measurement is very problematic. Studies can be conducted on scale-model flares under a hood or in a wind tunnel where all combustion products can be captured. Any results for these small flares must be adjusted with scaling factors if they are to be applied to full-size flares. For full-size operating industrial flares, which can have a diameter of four feet or more and a stack height of 100 feet or more, all combustion products cannot be captured and measured. To study emissions from these flares, emissions can be sampled with test probes attached to the stack, a tower, or a crane. Emissions can also be studied using remote sensing technologies like open-path Fourier transform infrared (FTIR) or differential absorption lidar (DIAL). In applying the results of any particular study to a specific flare or flare type, it is important to note any differences in flare design and construction. For example, some flares are simply open pipes, while others, like most refinery flares, have flare tips that are engineered to promote flare vent gas mixing to maximize combustion efficiency. In addition, studies suggest that composition and BTU content of gas burned, gas flow rates, flare operating conditions, and environmental factors like wind speed can affect, to varying extents, the efficiency of flare combustion.

B. Emission Reductions

While the District staff was studying flare emissions during the TAD period, the Tesoro Refinery was in the process of installing a fuel gas compressor capital improvement project to recover hydrocarbons previously sent to the flare.

Tesoro added an additional 8 million standard cubic feet of recovery capacity to the flare system. *This project significantly reduced the volume of gases flared* and emissions from flaring. Additionally, all the refineries instituted programs to reduce flaring. Measures implemented include improvements in flare gas compressor reliability, prolonging the interval between major maintenance activities, better process controls during startup and shutdown, source reduction efforts and increased scrutiny of flare gas systems.

Characterizing Flare Emissions

When the District staff examines the emissions from an air pollution source category, the air pollution emission estimates are typically expressed on an annual average basis (usually tons per day) determined from reported annual process throughput or reported emissions. For large, intermittent emission sources such as refinery flares, this air pollution emission estimation process can be quite challenging. First, there is the cyclic nature of refinery process unit startups and shutdowns. Major refining units at a petroleum refinery typically go five years between turnaround events. Until recently, the District's inventory excluded episodic emissions and Bay Area refineries were not required to measure the quantities of vent gases sent to their flare systems. Therefore, engineering assumptions had to be made to estimate air pollution emissions with limited information. While daily emissions based on annual averages are consistent with standard emission inventory practices, on any given day, actual refinery flare emissions can vary significantly. The day-to-day variation for the period of June 1, 2001 through September 1, 2002, is shown in Figure 2.

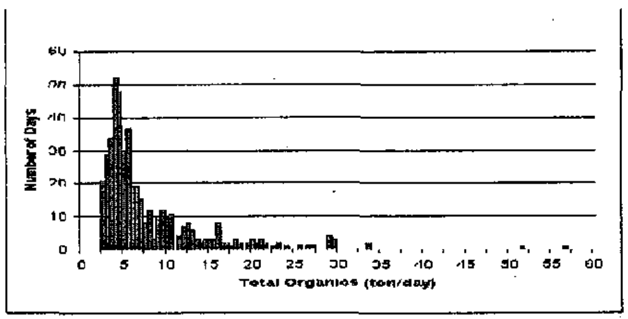

Figure 2. Distribution of Total Organics (tons per day) for the period of June 1, 2001 through September 1, 2002

Estimating Minimum Flow in Calculating Flare Emissions

In the past, there was a wide variation in the quality of flare monitoring instrumentation. The limit of detection of the instrumentation, the lower limit

where vent gas flows could be detected, was not state-of-the-art. Under typical operating situations, water seals prevent refinery gases from venting to a flare until a certain positive pressure is achieved. Once that positive pressure is exceeded, the refinery gases pass through the water seal and then are combusted in the flare.

The potential exists for refinery gases to travel through the water seal at some nominal flow less than the limit of detection for the monitoring instrumentation that was in place during the TAD period.[3] Pressure surging, percolation, inadequate or fluctuating water levels, or water seal design may allow refinery gases to reach the flare. To address concerns about minimum flows that could not be easily detected by the instrumentation, District staff investigated several methods to quantify these emissions. One method was to examine correlations between pressure and level indications at the water seal and the flow meter readings. This method presented limitations for some flare systems. In some *instances the pressure measuring* devices were located in different locations or at long distances from the water seal, possibly providing measurements that may not represent the actual water seal pressure. Where District staff identified proper installations of the water seal instrumentation, the readings were used to adjust minimum flow data.

Where the District staff identified issues with using water seal data, an alternative method was used. Staff considered the variation in flow meter technologies used during the TAD period, the limits of detection and reliability of the meters, refinery design and operational status that could generate flow to the flare, and then estimated minimum flow emissions at a value equal to 50% of the minimum limit of detection. The total contribution of this minimum flow emission estimate is approximately 1 ton per day of total organic emissions during the flare TAD study period.

The TAD Emission Estimates

The emission inventory for refinery flares prior to the Flare Monitoring Rule was included in the Draft December 2002 Technical Assessment Document (TAD). In order to develop emission information for the TAD, the District asked the refineries to submit flow and composition data on their flare systems for the period of January 1, 2001 to August 31, 2002. Some refineries had no monitoring, some used fairly new ultrasonic monitoring systems. To compensate for the wide-variation in the quality of information provided, staff used engineering assumptions and estimated from the information submitted that emissions from flares were approximately 22 tons/day[4] of total organic

[3] Uncertainties regarding minimum flows have been *greatly reduced due to improved* instrumentation requirements that specify much lower limits of detection. These requirements of Regulation 12, Rule 11 became effective in December 2003.

[4] Assumptions used for that estimate are: 1) emissions are averaged per day of flare use, 2) a flare gas composition of 75% hydrocarbon, and 3) a hydrocarbon molecular weight of 44.

compounds. As described below, subsequent efforts indicate that the TAD significantly overestimated flare emissions.

Updated TAD Emission Estimates

The initial emission estimate in the flare TAD caused the refineries to question District staff's analysis and the data submittals themselves. District staff spent considerable time working with each refinery to review the available data and replace the overall averages used in the TAD with refinery-specific information that is more representative of each refinery's flare emissions. Since the publishing of the TAD, the refineries have submitted several modifications to their original data submittals and have met with District staff on numerous occasions to clarify their data re-submittals. After evaluating the data re-submittals and developing refinery-specific gas composition and hydrocarbon molecular weight estimates, staff have revised the emission estimate from flares, on an annual average basis, to approximately 8 tons/day of total organic compounds (5 tons/day of non-methane organic compounds) during the TAD period. Additionally, staff now estimates flare emissions for the period of time covered by the TAD to include approximately 20 tons/day of SO_X for the time period June 1, 2001 through September 1, 2002. The daily emissions ranged from 2.5 to 55 tons/day of total organic compounds, and from 6 to 55 tons/day SO_X during the TAD data period.

Current Flare Emission Estimates

The data from the refineries that have been submitted since adoption of the monitoring rule indicates that flare flows have been reduced compared to flows during the TAD data period. Much of the reduction is due to the installation of additional compressors at the Tesoro refinery and better management practices at all of the refineries. Figure 3 illustrates the trend since implementation of the flow measuring requirement in the flare monitoring rule.

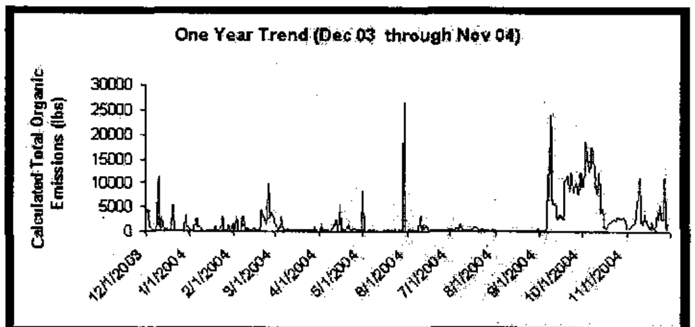

Figure 3. Total Organic Emission Trend

The graph illustrates four characteristics of refinery operations relative to flaring: 1) general operations through May 2004, 2) episodic emissions around June 2004, 3) general operations with emphasis on reductions during July 2004 to September 2004, and 4) major maintenance activities at several refineries from September through November 2004. The values represented in this figure are based on the assumption that no flow occurs when the water seal remains intact or the flow rate is less than 0.5 feet per second (lower limit of accuracy for ultrasonic flow meters).

Staff evaluated the reported data and characterized emissions using the assumption that any positive reading represents flow to the flare tip. Figure 3 illustrates the breakdown per facility for total organic emissions from vent, pilot and purge gas on an average daily basis for 2004.

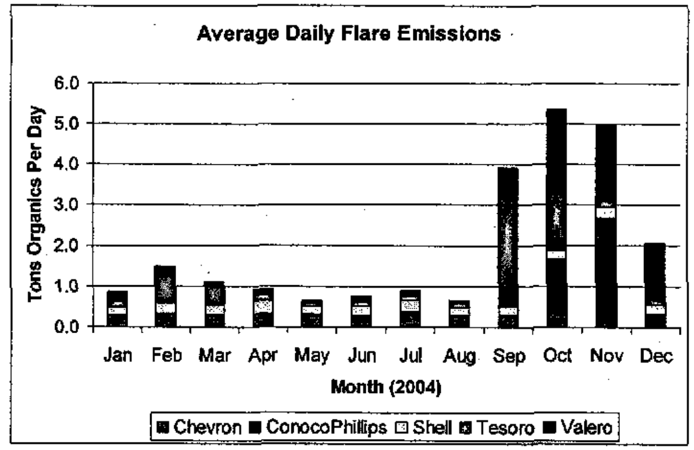

Figure 4. Average Daily Total Organic Emissions

The emission estimate from flares, on an average daily basis for all facilities in 2004, was approximately 2 tons/day of total organic compounds (approximately 1.5 tons/day of non-methane organic compounds). A monthly distribution for each facility is illustrated in Figure 4. The daily emissions ranged from 0 to 12 tons/day of total organic compounds. For sulfur dioxide, the average daily basis was approximately 4 tons/day and ranged from 0 to 61 tons/day.

VI. ECONOMIC IMPACTS

A. Introduction

This section discusses the estimated costs associated with the proposed rule. The California Health & Safety Code states, in part, that districts shall endeavor to achieve and maintain state ambient air quality standards for ozone, carbon monoxide, sulfur dioxide, and nitrogen dioxide by the earliest practicable date. In developing regulations to achieve this objective, districts shall consider the cost-effectiveness of their air quality programs, rules, regulations, and enforcement practices in addition to other relevant factors, and shall strive to achieve the most efficient methods of air pollution control. However, priority shall be placed upon expeditious progress toward the goal of healthful air.[5]

A number of unique factors come into play in the analysis of the cost of the proposed flare control rule. First, many of the benefits of the flare control rule, at *least those expected in the early years of implementation*, have already been achieved and the associated costs have been incurred by the refineries. Second, a number of the controls refineries will implement to reduce flaring will provide additional operational or economic benefits to the refinery operations, thus offsetting costs. For this reason, the costs of compliance presented below provide a very conservative picture.

Non-typical factors affect the cost-effectiveness analysis as well. For example, because emissions from flares are episodic, the use of annualized emissions provides a much less meaningful picture of cost effectiveness for the proposed flare control rule than for a standard control measure to control emissions from more stable sources or operations. In fact, the reduction or elimination of flaring *will have far more significant benefits during a day when flaring* would have occurred – particularly a day when the amount of gas flared is at the high end of the events that have occurred historically and can be expected to occur in the future – than during an hypothetical day with annualized flaring emissions.

Moreover, because the proposed rule requires refineries to develop the prevention measures they will implement to reduce flaring, the regulation ensures that the most cost effective means for achieving this goal will be implemented. That is, it is reasonable to expect that each refinery, given the flexibility provided by the structure of the rule, will include the most cost-effective prevention measures available for each iteration of the flare minimization plan, thus insuring the continuous improvement at the least cost.

B. Discussion of Elements

Development of a Flare Minimization Plan
Staff estimated the cost of developing the FMP document based on the workload

[5] California Health and Safety Code Section 40910

encountered during development of materials mandated by the Contra Costa County Safety Ordinance. The safety ordinance requires a hazard analysis for each process unit. This structure is nearly identical to the FMP, although the level of detail in the analysis would be substantially less under the proposed rule. The difference is due to the narrower focus of the *FMP*; it targets flare minimization while the hazard analysis required consideration of the "entire universe" of potential impacts. The approximate cost of a hazard analysis was $12,000 per process unit. This assumes 3.5 refinery staff at $35 per hour, a professional facilitator to assist in developing the analysis at $150 per hour, and 32 days[6] to develop the report. [7] Applying these values to a medium sized refinery, the cost for developing a FMP is approximately $100,000.

Implementation of Prevention Measures
The costs associated with implementing a flare minimization plan will vary depending on the status of the individual flare systems. Some systems may need only minor adjustments to existing operating procedures while others may need substantial modifications to incorporate design changes.

The precise costs for implementing a plan are difficult to determine prior to evaluating the specific elements of the plan. Refiners did not provide this level of detail during the workgroup process due to concerns over liability and trade secret information. Discussions with refiners regarding prevention measures already implemented or planned for study have lead to a general consensus that $20,000,000 represents a fair estimate of the high end of the range of costs.

To demonstrate the range of cost, staff considered alternatives to the high end, for example where a facility has already achieved the most feasible level of emission reductions. Staff estimated the range to be from $100,000 for minor modifications to potentially well over $20,000,000 for systems needing additional recovery and scrubbing capacities.

Notification of Flaring
The trigger level for this requirement is 500,000 standard cubic feet in any calendar day. The cost is dependant on the number of flaring days exceeding the volume trigger. The data from the flare monitoring monthly reports shows 243 occurrences where the volume of vent gas flared was greater than 500,000 standard cubic feet per day in 2004 for all facilities[8]. Based on this information and assuming 15 minutes per call at a rate of $30.00 per person hour, staff estimated the total cost for all facilities of notifying the District and providing the necessary information would be approximately $1,800 for all facilities per year. The cost for an individual refinery is expected to be much less, and in some cases zero cost.[9]

[6] Excludes administrative review and approval.
[7] Based on phone conversations with affected refineries.
[8] The majority, 88 occurrences, are from one flare with the same reported cause of flaring.
[9] Maintaining levels indicated in the 2004 Flare Monitoring Reports

Determination and Reporting of Cause

The cost for this requirement is dependant on the number of reportable flaring events and the complexity of the event. The data from the flare monitoring monthly reports shows 243 occurrences where the volume of vent gas flared was greater than 500,000 standard cubic feet per day (MMSCFD) in 2004 for all facilities. Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries requires investigation into and reporting of flaring events. The new requirement expands the scope of events requiring investigation because the trigger drops from 1,000,000 to 500,000, and it requires greater detail for all reportable events, including a thorough investigation into the cause and contributing factors, a description of prevention measures considered and justification for those not implemented, and identification of issues that require the use of a flare including safety considerations and regulatory mandates. To adjust for these differences, staff assumed an increase in the hourly rate to $50.00 per hour for 12 hours per event. The result was an estimate of approximately $145,800 for all facilities per year. Again the cost for an individual refinery will be much less. Moreover, staff expects this value to drop in time as facilities minimize the number of events and become more proficient in investigations.

Annual Reports and Updates

The proposed rule requires an annual report that summarizes flare usage when the flow rate is less than 500,000 standard cubic feet per day where the sulfur dioxide emissions are greater than 500 pounds. Flare monitoring data for 2004 indicates an additional 20 events for all facilities meeting the reporting criteria will occur. Additionally, the proposed rule requires the FMP to be updated annually to incorporate any new prevention measures identified as a result of the causal analysis and annual updates. Staff expects the complexity of these reports to be far less than the FMPs. Based on these factors staff estimates the annual reports and updates will cost less than one third of the cost of the FMP, or $30,000 for each.

Water Seal Integrity

The costs associated with this provision are dependant on the need to upgrade current monitoring systems on water seals. Several refineries have systems that are already configured for continuous monitoring and recording. Other systems would need upgrades, including water level and drum pressure measuring devices, hardwiring to data recording systems, and administrative procedures. For those systems that require upgrades, about half, the primary cost is hard-wiring to the control room and is a function of the distance. The cost might be reduced by choosing an alternative such as wireless, however, confidence in this technology is not known. Staff considered a system that would require only minor upgrades and arrived at an estimate of $100,000 for the first year. Annual costs thereafter include periodic maintenance and data handling. This cost was estimated at $3,000 per year.

C. Cost Analysis

The proposed rule is intended to reduce emissions from flares by minimizing the frequency and magnitude of flaring. This is accomplished by requiring each refinery to develop a flare minimization plan (FMP). The primary function of the plan is to set a schedule for implementing feasible flaring prevention measures. Refiners will be required to investigate the cause of all significant flaring and to update the FMP annually to incorporate the means identified to prevent recurrence. The initial FMP will prevent backsliding from those emission reductions that have already occurred by codifying those efforts as part of the plan.

Table 1 shows the costs associated with the proposed rule. Costs for individual refineries will vary significantly depending on the number and complexity of flares and flare systems and the amount of reduction already achieved. Following the table is a discussion of each provision. The provisions listed in the table include both one-time and recurring costs. The non-recurring costs are those associated with development of the FMP and the upgrades for water seal monitoring. About half of the monitoring systems would need an upgrade. The recurring costs in Table 1 are based on the scenario where significant flaring has occurred. These costs are likely to decrease in time as the level of flaring is minimized.

Table 1. Estimated Costs, First Year

Provision	Estimated Cost	Assumptions
FMP Development[a]	100,000	1/3 of an average hazard analysis[b] for a medium size facility
Prevention Measure (High End)	1,900,000	$20,000,000 project amortized over 20 year lifespan at 7%
FMP Updates	30,000	Approximately 1/3 of a full FMP
Notification of Flaring	500	67 notifications[c]
Causal Analysis	40,200	$50/hr for 12 hours per event for 67 events[d]
Annual Reports	30,000	Approximately1/3 of a full FMP
Water Seal Monitoring	9,000[e]	Partial upgrade; amortized over 20 year lifespan at 7%

[a] One time cost
[b] Hazop for the Contra Costa County Safety Ordinance
[c] Data from monthly reporting pursuant to the District's Flare Monitoring Rule
[d] Time based on pilot program during technical assessment, 2001
[e] Includes $3,000 for direct annual or recurring cost, and $6,000 non-recurring upgrade costs

Based on the example given in Table 1, the cost for a hypothetical refinery that must undertake a significant capital improvement project, such as the addition of compressor capacity, is approximately $2,100,000 for the first year. The total cost for the proposed rule would not be this calculated cost times the number of flare systems. Each flare system is unique and would have a unique set of feasible prevention measures at a variety of costs. However, this hypothetical provides an example approaching the upper bound of the cost range. Costs for a typical Bay Area flare is expected to be less.

As an alternative scenario staff considered a refinery that only implements an enhanced I&M program or other type of operational control, or is able to demonstrate no flare usage and therefore only needs to memorialize existing practices. Using Table 1 provisions for FMP updates, annual reports and recurring costs for monitoring, the recurring cost is approximately $63,000. This hypothetical provides the lower bound of the cost range.

COST EFFECTIVENESS ESTIMATE

Even though a traditional cost-effectiveness analysis is expected to be conservative due to various factors as discussed above, i.e., the use of average daily emissions, which tend to underestimate expected emission reductions from preventing a period of flaring, and the flexibility built into the proposed rule, which is expected to result in refiners selecting the most cost-effective means of reducing emissions from flaring, the following analysis – based on the traditional model – still supports a finding that the proposed rule is cost effective.

Case Studies

To demonstrate the cost effectiveness of equipment modifications, staff considered two scenarios that have already been implemented. Both involve modifications to the vent gas recovery compressors. The first involved a reliability study and implementation of measures used to improve performance of existing compressors. The second involved an increase in the recovery capacity of the compressors. Although the cost of implementation is similar – approximately $20,000,000 – the reductions achieved differ significantly. Table 2 shows the estimated emissions over the time period for these projects.

Table 2. Estimated Annualized Average Emissions[a]

Facility	Year	Organics[b] (tons/day)	SOx[c] (tons/day)	CO[d] (tons/day)	NOx[d] (tons/day)	PM[e] (tons/day)	Total
Case 1	2002	0.73	0.95	0.11	0.06	0.01	1.86
	2003	0.18	0.41	0.04	0.02	0.01	0.66
Case 2	2002	3.93	13.6	0.59	0.59	0.09	18.8
	2003	0.32	2.21	0.05	0.03	0.01	2.61

[a] Until the flare monitoring rule was adopted (June 2003) Bay Area refineries were not required to measure the quantities of vent gases sent to their flare systems. Therefore, engineering assumptions had to be made to estimate air pollution emissions with limited information.
[b] Total organics including vent, pilot and purge gas. Methane varies significantly; average content is ~ 30%
[c] Assumes all sulfur as hydrogen sulfide oxidized to sulfur dioxide
[d] Calculated using AP42 emission factors
[e] Calculated using AP42 emission factors assuming no visible emissions

For the first case, the total emissions as indicated in Table 2 decreased from a total of 1.86 tons per day prior to the reliability study, to a total of 0.66 tons per day, after implementing the reliability improvements. This represents a 65% reduction. For the second case, the total emissions decreased from 18.8 tpd to 2.61 tpd after the equipment upgrade. This represents approximately an 86% reduction.

At a twenty year amortized cost of 7%, equipment costs for each of the two case studies is $1,921,592 per year. The cost effectiveness for Case 1 is about $40,000 per ton for total organics, $9600 per ton for SOx, and $4,300 per ton for all pollutants combined. The cost effectiveness for Case 2 is about $1,580 per ton for total organics, $443 per ton for SOx, and $341 per ton for all pollutants combined. Despite the many factors that indicate these estimates are conservative, this analysis demonstrates that the proposed rule is cost effective for all pollutants and exceeds the range for hydrocarbon only in comparison to Best Available Control Technology guidelines.

Tables 3 and 4 include the cost of the administrative requirements of the rule with the equipment costs. Table 3 shows the estimated costs using as an example a facility that has performed a hazard analysis for Contra Costa County and has upgraded the flare gas recovery system. It is intended to represent a more costly prevention measure. Table 4 gives an example of a less costly measure in which startup and shutdown schedule adjustments result in a reduction of flaring and add lost production.

Table 3. Estimated Costs for High Cost Prevention Measure

Provision	Estimated Cost ($/year)	Assumptions
FMP Development	100,000	1/3 of an average hazard analysis for a medium size facility
Prevention Measure	1,921,592	Flare gas recovery compressor project; amortized over 20 years at 7%
FMP Updates	30,000	1/3 of a full FMP
Notification of Flaring	500	67 notifications
Causal Analysis	40,200	$50/hr for 12 hours per event for 67 events
Annual Reports	10,950	Enhanced daily log:1 hr/day at $30/hour for 365 days
Monitoring	9,000	Partial upgrade; amortized over 20 years at 7%

It is important to note that all items except the FMP development and the prevention measure are recurring costs that will decrease in time. The estimated cost of the prevention measure listed in Table 3 is for a specific system and would be substantially reduced after implementation. The cost could vary significantly for different systems and should not be assumed to be the same for any other system. However, recovery upgrade projects at other facilities were cited in this general price range.

Table 4. Estimated Costs for a Low Cost Prevention Measure

Provision	Estimated Cost ($/Year)	Assumptions
FMP Development	100,000	1/3 of an average hazard analysis for a medium size facility
Prevention Measure	121,945	Startup/Shutdown schedule adjustments including lost production costs; 5 year lifespan
FMP Updates	30,000	Approximately 1/3 of a full FMP
Notification of Flaring	50	7 notifications
Causal Analysis	4,200	$50/hr for 12 hours per event for 7 events
Annual Reports	10,950	Enhanced daily log:1 hr/day at $30/hour for 365 days
Monitoring	3,000	No upgrades

The cost effectiveness for the high cost prevention measure would be $1,603 per ton for the first year for all pollutants, $1,527 per ton thereafter. For the low cost prevention measure the cost effectiveness would be $1,298 per ton for all pollutants, and $818 per ton thereafter.

D. Socioeconomic Impacts

Section 40728.5 of the Health and Safety Code requires an air district to assess the socioeconomic impacts of the adoption, amendment, or repeal of a rule if the rule is one that "will significantly affect air quality or emissions limitations." Applied Economic Development, Berkeley, California, has prepared a socioeconomic analysis. The analysis concludes that the affected refineries should be able to absorb the costs of compliance with the proposed rule without significant economic dislocation or loss of jobs. The socioeconomic analysis is attached as Appendix A.

E. Incremental Costs

Under California Health and Safety Code Section 40920.6, the District is required to perform an incremental cost analysis for a proposed rule under certain circumstances. To perform this analysis, the District must (1) identify one or

more control options achieving the emission reduction objectives for the proposed rule, (2) determine the cost effectiveness for each option, and (3) calculate the incremental cost effectiveness for each option. To determine incremental costs, the District must "calculate the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressively more stringent potential control option as compared to the next less expensive control option."

To determine the incremental cost, staff used a case study (Case 2, Table 2) that considers reductions achieved since installation of capital equipment, and future implementation of a potential control option with a corresponding emission reduction based on historical reductions. The capital equipment installed was two new compressors rated at 4 MMSCFD each and was operational in the first quarter of 2003. The estimated cost was $20,000,000.[10] The emission inventory for NMHC[11] in tons per day, based on flare monitoring data received during the technical assessment and in accordance with the flare monitoring rule, indicated 3.07, 0.25 and 0.45 for 2002, 2003 and 2004, respectively.

The NMHC reduction in 2003 was 2.82 tons per day, or 92%. Assuming comparable reductions[12] and a potential control option with a cost of $40,000,000, the incremental cost is calculated at approximately $8,300,000. This is an example of a "most costly" scenario. For comparison, assuming the same reductions at a lower cost, for example $500,000[13], the incremental cost is calculated at approximately $207,500.

The proposed concept is to evaluate each flare system to identify where reductions may be available for that particular system, develop a plan most suited for that system, then operate in a manner consistent with the plan. It is dissimilar to traditional regulatory mandates due to the variation of the flare systems and the emission reduction potential for each of those systems. The incremental cost is specific to the individual system rather than applicable to the entire source category. This approach adds greater certainty to the selection of the most feasible measure.

F. District Staff Impacts

Implementing this rule will require a total of 1.5 FTE at an average staff level of a Senior Engineer. The actual personnel involved will likely include Senior and Supervising Inspectors assigned to refineries, a Principal Specialist and a Principal Engineer to coordinate review of flare minimization plans, and Source Test Engineers and Technicians to review water seal monitoring systems.

[10] This figure represents an estimate of the total project costs. A breakdown of costs was not provided, is likely to be less and is not applicable to any other project.
[11] Methane was approximately 22% of the total organic emissions.
[12] This assumption recognizes that flaring will not be eliminated.
[13] This value was stated during workgroup meetings and is an estimate for one day of loss in production, for example to extend a startup.

Causal analysis review should take no more than an hour for 90% of the flaring events, however, for the 10% of the events (24, based on 2004 flaring events) that are large, emergency events, a week of an inspector's time and several days of an engineer's time may be needed. A Senior Engineer level (top step) costs $149,000 at 1.5 FTE. In addition, management review, particularly for first year plans and major event analyses, will add to the costs. Management staff involvement would include personnel from the Enforcement, Engineering and Technical Divisions, with some oversight by the Deputy APCOs and the APCO. The total cost will exceed $250,000.

On June 15, the Board adopted a schedule of fees that shifted refinery flares from Schedule G1 to Schedule 3, which will result in approximately an additional $178,000 in revenue from these sources. The calculations above are only for the increase in costs for this proposal. Significant additional costs have been incurred over the last several years from investigation of complaints and implementation of the flare monitoring rule (Reg. 12, Rule 11). One Air Quality Specialist currently allocates 40% of his time to quality assurance of the monitoring reports and coordinating refinery work groups in the Enforcement Division, at a cost of $34,000.

VII. ENVIRONMENTAL IMPACTS

Pursuant to the California Environmental Quality Act, the District's environmental consultant, Environmental Audit, Inc., has prepared an Environmental Impact Report (EIR) for the proposed rule to determine whether it would result in any significant environmental impacts. The EIR concludes that the proposed rule would not have any adverse impacts. The EIR including comments and responses is attached as Appendix B.

VIII. REGULATORY IMPACTS

Section 40727.2 of the Health and Safety Code requires an air district, in adopting, amending, or repealing an air district regulation, to identify existing federal and district air pollution control requirements for the equipment or source type affected by the proposed change in district rules. The district must then note any differences between these existing requirements and the requirements imposed by the proposed change. Table 5 is a matrix of the proposed rule, existing Bay Area regulations, and federal requirements for flares.

Table 5. Regulatory Matrix

Agency	Regulation	Control/Performance Requirements	Monitoring Requirements	Emission Limitations
BAAQMD	Reg. 2, Rule 6 (Title V permit)	Specific to facility and source	Specific to facility and source	Throughput (lbs/hr vent gas), Visible emissions
BAAQMD	Proposed Reg. 12, Rule 12	Prohibits flaring without or not in accordance with a flare minimization plan.	Water seal pressure and level.	Minimize Flaring
EPA	*40 CFR 60.18* (applies to flares subject to NSPS)	*Pilot flame present at* all times, heat content, maximum tip velocity, composition	*Presence of* flame, heating value	*Smokeless* capacity
EPA	Subpart J	Limits on gases other than those due to malfunction, relief valve leakage and emergencies.	Hydrogen sulfide in fuel gas	Hydrogen sulfide in fuel gas

Federal Requirements

Federal New Source Performance Standards (NSPS) in 40 CFR Part 60, Subpart A, Section 60.18 apply to flares that are used as general control devices. They specify design and operational criteria for new and modified flares. The requirements include monitoring to ensure that flares are operated and maintained in conformance with their designs. *Flares are required to be* monitored for the presence of a pilot flame using a thermocouple or equivalent device. Other parameters to be monitored include visible emissions, exit velocity and net heat content of the gas being combusted by the flare.

In addition, the NSPS limit sulfur oxides in vent gases combusted in a flare installed after June 11, 1973 (40 CFR Part 60, Subpart J, Section 60.104). Upset gases or fuel gas that is flared as a result of relief valve leakage or other emergency malfunctions is exempt from the standard. As discussed above, EPA has entered into consent decrees with all Bay Area refineries. These decrees, among other requirements, contain increments of progress for the application of NSPS standards to all flares.

IX. RULE DEVELOPMENT PROCESS

As part of the development of this regulation staff have undertaken an extensive rule development process in order to receive input from all affected parties. These efforts included the formation of a technical working group, public meetings, workshops and presentations to the District Board Stationary Source Committee. The following is a discussion of these efforts.

A. Technical Working Group

To assist in the TAD and rule development process a technical working group was formed that included representatives from Industry, Communities for a Better Environment (CBE), California Air Resources Board, and District staff. This workgroup met routinely to discuss technical issues. The issues discussed include the significance of emission levels, potential control strategies, legal requirements for rule development and sharing of confidential information, current flare system monitoring, procedures to determine the cause of flaring, and the most effective means to distribute information to the public. The following is a summary of those meetings:

<u>August 7, December 10, and January 13, 2003</u>
The topics included the Technical Assessment Document (TAD) update, flare use categories and control strategies, and the rule development schedule. The discussion focused on the basis to update the District's initial assessment, how to identify the causes of flaring and how to develop appropriate control strategies.

<u>March 19, 2004</u>
The topics included technical assessment of emissions and flare control proposals. The discussion of the basis for updating the District's initial assessment, how to identify the cause of flaring and develop appropriate control strategies was continued from the previous meeting.

<u>June 11, 2004</u>
The topics included status update and timelines, final TAD revision, flare control proposals, definitions, and web casting. Staff presented a tentative schedule for rule development, an updated assessment of the flare TAD, proposals for controlling emissions from flares, definitions of various terms and text based web casting of flare monitoring data.

<u>November 4, 2004</u>
A professional facilitator was added to the workgroup for this and subsequent meetings. The topics included agenda review, flare control rule status, workgroup discussion ground rules, possible categories of flaring events, and definitions of terms. The discussion focused on meeting process, developing categories for the cause of flaring, and using terms consistently.

<u>December 2, 2004</u>
This meeting consisted of individual presentations by the Western States Petroleum Association, Communities for a Better Environment, and the District. The focus was on the procedure to evaluate the significance of flare events and the appropriate action to establish control strategies.

<u>December 14, 2004</u>
The topics included flaring information for determining cause, verification of low flow regimes, water seal integrity, and characterization of flare gas composition. The discussion focused on root cause analysis as the standard for investigating the reasons for flaring, monitoring devices on water seals, and current sampling protocols.

<u>January 11, 2005</u>
Workgroup members discussed the purpose, approach and essential elements of a flare control rule. A list of findings/issues was developed, with general agreement that a management plan for reducing emissions from flares is appropriate.

<u>February 8, 2005</u>
The meeting focused on two issues that had been developed at the prior meeting; thresholds for the casual analysis and expectations for a management plan.

The group reached consensus on the need to meet individually for future meetings. Subsequently, staff and District management met with representatives of the refineries, the Western States Petroleum Association, Communities for a Better Environment and the Plumbers and Steamfitters Local 342. In addition, numerous phone conversations between District staff and individual refineries occurred to gather information on the specific designs and operating practices for each flare system.

B. Stationary Source Committee Reports

At the flare monitoring rule adoption hearing, staff committed to provide an update to the Stationary Source Committee eighteen months after rule adoption. At the November 11, 2004 meeting, staff provided a report on the implementation of Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries, flare emissions information, and flare control rule development progress. In addition to staff's presentation, WSPA and CBE gave presentations. The minutes of that meeting can be found on the District's web site at (http://www.baaqmd.gov/brd/brddirectors/agendas_minutes_2004.asp).

Three additional presentations were given to the Stationary Source Committee: one on January 24, 2005, one on March 28, 2005, and one on May 23, 2005. The presentations provided progress reports regarding rule development and accomplishments since November 11, 2004, the last Stationary Source meeting.

The reports included background materials, an update on emission characterizations, workgroup progress, reports on the public workshops, response to public comments, and plans for finalizing this rule development process.

C. Public Meetings and Workshops

The staff of the Bay Area Air Quality Management District conducted public meetings in four different locations to discuss flare systems at petroleum refineries. The purpose of the meetings was to present information on the flare control measure and to receive input. These evening meetings were held on October 23, 2003 at the Crockett Community Center, October 29, 2003 at the Maple Hall Civic Center in San Pablo, November 5, 2003 at the Benicia City Council Chambers, and November 6, 2003 at the Martinez City Council Chambers. The input provided by the public was used in developing a draft rule.

A draft rule was presented at two public workshops held in Martinez on March 16, 2005 and in Richmond on March 24, 2005. Both meetings were held in the evening and combined were attended by over 200 people. The two core issues raised at the workshops concerned the perceived lack of clearly defined standards and the desire to have the rule provide an opportunity for public comment on the flare minimization plans. Staff made modifications to the proposed rule to address both of these concerns.

Written comments on the draft rule were received from the Western States Petroleum Association, Communities for a Better Environment, the Plumbers and Steamfitters Local 342, American Lung Association, Valero Refinery, EPA, ARB, Global Community Monitor, Clean Water Action and Community Labor Refinery Tracking Committee, Ohio Citizen Action, Louisiana Bucket Brigade, Inform Public Relations, Center for Environmental Health, Pamela Calvert, Bob Craft, Norma Wallace, Molly Boggs, and Peter Hendricks. In addition, one phone message was received from Shirley Butt. All were supportive of the District's effort to develop a flare control rule and made suggestions for improvement. Staff made modifications to the proposed rule to address the comments and suggestions.

This proposed rule was made available for public comment and posted on the District's web site. Staff has continued to meet with workgroup members to discuss the proposed rule. Written comments and staff responses will be contained in an addendum to this Staff Report (Appendix C), which will be prepared following the July 12, 2005 close of the public comment period on the regulatory proposals.

Appendix D contains a matrix of the timeline for the FMP submittal, public comment, and review and approval process.

X. CONCLUSION

The proposed rule, Regulation 12, Rule 12: Flares at Petroleum Refineries, is intended to limit the amount of emissions released from flares by limiting the frequency and magnitude of flaring events. Pursuant to Health and Safety Code Section 40727, new regulations must meet necessity, authority, clarity, consistency, non-duplicity and reference. The proposed regulation is:

- Necessary to protect public health by reducing ozone precursor emissions. The amendments also reduce exposures to toxic air contaminants, sulfur dioxide and particulate matter.

- Authorized by California Health and Safety Code Section 40702.

- Clear, in that the new regulation specifically delineates the affected industry, compliance options and administrative requirements for industry subject to this rule,

- Consistent with other District rules, and not in conflict with state or federal law,

- Non-duplicative of other statutes, rules or regulations, and

- The proposed regulation properly references the applicable District rules and test methods and does not reference other existing law.

An Environmental Impact Report prepared by Environmental Audit, Inc., concludes that there will be no adverse environmental impacts from adoption of the proposed rule. A socioeconomic analysis prepared by Applied Development Economics concludes that the affected refineries will be able to absorb the costs of compliance with the proposed rule without economic dislocation or loss of jobs.

Staff recommends the adoption of the proposed new Regulation 12: Miscellaneous Standards of Performance, Rule 12: Flares at Petroleum Refineries, the proposed amendment to Regulation 8: Organic Compounds, Rule 2: Miscellaneous Operations, and certification of the Final Environmental Impact Report.

REFERENCES

1. United States Environmental Protection Agency, "Refinery Initiative", EPA Website: http://www.epa.gov/compliance/civil/programs/caa/oil/index.html. Last updated on Wednesday, October 6th, 2004

2. Bay Area Air Quality Management District, "Draft Technical Assessment Document-Flares", December 2002

3. Bay Area Air Quality Management District, "Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries" Adopted June 4, 2003

4. California Health and Safety Code, CHAPTER 10, "District Plans To Attain State Ambient Air Quality Standards", Section 40910

EXHIBIT J

Shell Martinez Refinery

Regulation 12 Rule 12
FLARE MINIMIZATION PLAN
REDACTED VERSION

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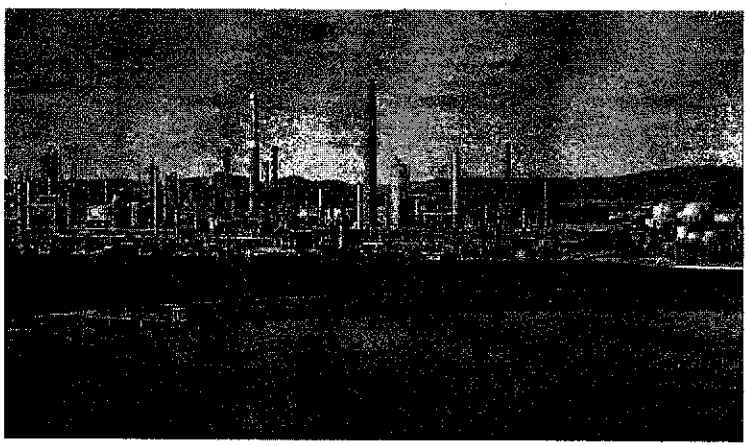
Submitted to:
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, California 94109

Shell Oil Products US
Martinez Refinery
Martinez, California 94553
BAAQMD Plant No. A0011



FLARE MINIMIZATION PLAN
SHELL MARTINEZ REFINERY
CONTENTS

LIST OF FIGURES

1.0 SUMMARY

The Shell Martinez refinery (SMR), a leader in minimizing flare emissions, has achieved significant reductions in flaring within the past few years. These reductions are the direct result of practices and procedures addressing source control and equipment reliability improvement.

In addition to the reductions achieved in the past, significant improvements to flare gas recovery recently occurred. With the OPCEN hydrocarbon flare gas recovery system starting up in late 2006, the average recovery efficiency for all process flares now exceeds 99.9%. This project's impact can best be evaluated *using average annual emissions* over the past two years, including emergency flaring. Using this as a basis, with the OPCEN hydrocarbon flare gas recovery system online, combined emissions from the four process flares at the Martinez refinery are expected to be less than 1.5 tons/year, contributing less than 0.2% of the refinery's total permitted emissions of non-methane hydrocarbon.

Finally, the plan evaluates a number of options for additional capital equipment and modifications to operating procedures to further reduce the volumes of gas flared. As the refinery already has very significant capital infrastructure for flare gas recovery in place, procedural modifications can be used to achieve much higher returns on a $/ton emissions reduction basis. New refinery procedures described in this Flare Minimization Plan address actions to further minimize flaring during process upsets and additional planning requirements for maintenance and turnaround activities. Careful planning of any activity with the potential for flaring is the most successful minimization approach that has been employed at SMR. Procedures for reporting and investigating all flaring provide a means to learn from unanticipated events. The result of this work will be further reductions in flaring.

2.0 INTRODUCTION

Shell's Flare Minimization Plan (FMP) is written to comply with the requirements of the Bay Area Air Quality Management District's Regulation 12 Rule 12. This Plan provides for continuous improvement in emission reductions from flares at Shell's Martinez refinery. This FMP describes prevention measures that have been implemented over the past five years and those that will be implemented to minimize flaring to the extent possible without compromising safety. Flares are essential refinery safety equipment. They provide a means to ensure the safe and efficient combustion of gases that would otherwise be released to the environment.

The Shell Martinez Refinery (SMR) has four process flares subject to Regulation 12 Rule 12. These flares are called:

- Light Oil Processing (LOP) flare (BAAQMD Source # 1471),
- Delayed Coking Unit (DCU) flare (Source # 4201),
- Operations Central (OPCEN) Hydrocarbon (HC) flare (Source # 1772)
- Flexigas (FXG) flare (Source # 1771).

These flares each serve specific processing units in the refinery and because they were constructed at different times and for different process units, each flare system is somewhat different.

SMR's four process flare systems are described in detail in this FMP. There are common Prevention Measures that are in place which help to reduce flaring at all four flares. These common Prevention Measures are described in the section titled Prevention Measures Common to All Process Flares. Following this section, each flare system is described individually providing technical data, flare reductions previously implemented, planned reductions and specific Prevention Measures for each flare. Historical flaring data was reviewed for each flare system and information from this review used to determine the feasibility of reducing flaring in the future by examining cost and benefits of potential equipment modifications.

A. Refinery and Flare System General Overview

SMR refines crude oil into gasoline, diesel fuel, jet fuel, asphalt, coke and liquefied petroleum gases (propane, butane and pentane). As part of the refining process, gases are produced that are typically routed to treaters to remove sulfur compounds and then routed to the refinery fuel gas system for use as fuel in refinery heaters and boilers. Natural gas is purchased to meet additional fuel requirements. SMR is designed and operated to balance fuel gas production with consumption. Natural gas is used to help keep the system in balance.

Each flare system at SMR has a header for collecting vapor streams from the process units it serves. The primary function of the flare header is to provide the process units with a controlled low pressure outlet for gases. Many of the processes operate at elevated temperatures and pressures and a critical element of safe design is the capability of releasing excess pressure in a controlled manner to the flare when necessary for safe operation. Flares are the safety device that allows this to happen and SMR strongly supports utilization of the flare where necessary for safe operation of the refinery. Flare use must be unrestricted for emergencies from any cause and to prevent accidents, hazards or release of vent gas directly to the atmosphere. Any flaring considered at any time to be necessary for the safe operation of the refinery must be allowed.

Two of SMR's flare systems (LOP and DCU) were constructed with vapor recovery to recover the gases in the flare header for use as a fuel. A project was recently implemented to provide vapor recovery for the OPCEN HC flare. The project was completed in December 2006. The Flexigas Flare is unique, and flare gas recovery on this flare is infeasible as will be discussed further in the FMP.

Flares are designed to promote good combustion over a broad range of gas flow rates and compositions. Flares have pilots that are kept burning at all times with natural gas to ensure that any gases that get to the tip of the flare are ignited for proper combustion. Flare headers must be purged to keep air out. Purge gas (typically nitrogen) is provided to prevent oxygen intrusion from the flare stack into flare headers at LOP, Delayed Coking and OPCEN Hydrocarbon flares. A minimum flow of Flexigas is used to prevent air intrusion at the Flexigas flare. Without these purges, oxygen can combine with hydrocarbon gas and cause combustion or detonation within the flare header. SMR flare systems each comply with the BAAQMD Regulation 12 Rule 11 Flare Monitoring requirements. As of 12/03, ultrasonic flare flow meters and automatic sampling systems were in place to monitor flare data.

3.0 PREVENTION MEASURES COMMON TO ALL PROCESS FLARES

This section describes measures implemented to minimize flaring that are common to all of SMR's process flare systems[1]. Measures include policy and procedural activities, as well as process and hardware measures. Additional prevention measures for specific flare systems are provided in sections specific for each flare.

A. COMMON PREVENTION MEASURES – POLICY, PROCEDURES AND OTHER RESOURCES TO MINIMIZE FLARING

Policy: The purpose of the four process flares serving the Shell Martinez refinery is to assure that process unit vent gases are safely burned to minimize the potential for explosion, fire, or other unsafe conditions. The refinery will not flare above the minimum amount necessary to assure the safety of our workers and nearby community, and provide for reliable operation of process equipment. We will adjust the operation of process units to minimize flaring when consistent with safe and reliable operation.

Procedures:

SMR believes that the key to flare minimization is careful planning to avoid flaring coupled with evaluation of any flaring events that do occur and incorporation of lessons learned back into the planning process to further reduce flaring. Four refinery procedures have been developed or revised as part of the FMP to implement this process. When these procedures are followed, any flaring is consistent with the FMP.

In no case do any of these procedures limit access to flares when such use is viewed necessary for personnel or equipment safety. SMR supports operator judgment in the use of the flares without hesitation where warranted for safety.

Following is a list of procedures describing flare use covered by the Flare Minimization Plan.

- Environmental Procedure 2.20: Environmental Procedure stating the Refinery Flaring Policy, describing the FMP and regulatory requirements for various categories of flaring, and defining document requirements and retention
- Administrative Requirements and Management Systems for General Operations C(F)20: Flaring Due to Process Upsets or Unanticipated Equipment Failure
- Administrative Requirements and Management Systems for General Operations C(F)21: Flaring Due to Unit Startup, Unit Shutdown, Major Maintenance or Turnaround Activities
- Administrative Requirements and Management Systems for General Operations C(F)22: Fuel System Management during Flare Events

[1] These preventions measures address requirements of section 12-12-401.4.

Summary Description of Procedures

1. **REFINERY FLARE MANAGEMENT AND REPORTING – EP 2.20**

This procedure describes the Shell Martinez refinery policy to minimize flaring from process flares serving Light Oil Processing, OPCEN, and Delayed Coking. When flaring occurs, it is subject to this procedure. In addition to stating this policy, this procedure includes the following:

- Requirements necessary to comply with BAAQMD Regulation 12 Rule 11 - Flare Monitoring at Petroleum Refineries, Regulation 12 Rule 12 – Flares at Petroleum Refineries, SMR Title V permit requirements regarding flaring, EPA requirements regarding flaring and the refinery Flare Minimization Plan
- Responsibilities of all groups and departments in the refinery with respect to flare management and reporting. Responsibilities are described for operations, maintenance, process engineering, control systems, quality assurance lab and environmental affairs
- A description of the related Field Requirements Manual operating procedures, C(F)20, C(F)21 and C(F)22, defining when they are triggered and who is responsible for implementation
- Recordkeeping and document control

2. **FLARING DUE TO PROCESS UPSETS OR EQUIPMENT FAILURE - C(F)20**

This procedure addresses flare events caused by process upsets, unplanned events or equipment and instrument failures that result in flaring. Any flaring that is not planned is covered by and must comply with this procedure.

By nature, the causes and options available to mitigate flaring due to upsets, unplanned events or unanticipated equipment failure, are unique. As a result, procedures to minimize specific events cannot reasonably be predefined in the plan. This procedure describes in general terms the nature and priority of actions to minimize flaring in the event of a process upset, unplanned event or equipment failure. It references the overarching Environmental Procedure and reiterates the policy to minimize flaring where this may safely be done.

- All flare activity must be reported to the Refinery Team Leader (RTL) and Environmental Affairs. This includes the likely source and probable cause.
- After a flaring event (defined as > 0.5 MMSCFD flared), an incident investigation and/or causal analysis will be conducted and documented.
- Actions taken to minimize flaring will be captured when personnel and process safety allow. The RTL is responsible to assure this activity has been resourced.

Following any flaring, information will be compiled and retained to show that the flaring was minimized. The compiled information will include:

- Description of the flaring event and any consideration or measures taken to reduce flaring during the event
- For flaring > 0.5 MMSCF, the incident investigation/causal analyses
- For flaring < 0.5 MMSCF, a description of any lessons learned

- Management activity to assure lessons learned and recommendations from the causal analysis will be compiled and retained and incorporated into future FMP updates

3. FLARING DUE TO PLANNED START UP, SHUTDOWN, MAJOR MAINTENANCE OR TURNAROUND – C(F)21

Because each turnaround is unique, it is impractical to develop specific flare mitigation plans for all turnarounds in advance. Instead, this procedure requires a specific plan in advance of each planned turnaround or major maintenance activity that includes a review of potential flaring and evaluation of possible mitigations to minimize any flaring. Steps taken to minimize flaring in the event that deviations from the plan are necessary would be included in the plan to the extent they can be anticipated.

This procedure represents an extension and formalization of the historical practice where environmental impacts are assessed, communicated, and managed. Specific plans will assure the potential for flaring during major maintenance, turnaround and startup and shutdown activities has been considered and all feasible steps taken to minimize flaring – including consideration of the impact of the activity on fuel balance.

The procedure requires that the Operating Department and Turnaround groups develop plans with input from the Planning Group and Environmental Affairs. Status and expected impacts are shared across the refinery. The overall environmental performance.is reviewed after the turnaround to develop "lessons learned" for subsequent turnarounds.

If unanticipated flaring occurs during any part of a turnaround, then Procedure C(F)20 is triggered to ensure that lessons learned and recommendations to minimize flaring from this activity in the future are captured.

4. FUEL SYSTEM MANAGEMENT DURING FLARING EVENTS – C(F)22

This procedure comprises a "Best Practice" for fuel system management in the event of flaring for any reason that impacts the fuel gas system balance. The procedure describes actions that should be taken as soon as it is safe to minimize flaring if it occurs due to a fuel gas system imbalance. The procedure requires that the actions taken be documented once the condition that resulted in flaring is under control. The documentation is made in the refinery's environmental incident tracking database (or its successor) and will be made available to the District upon their request. The documentation will address:

- Alternatives considered
- Constraints encountered which caused flaring to continue after the original condition that caused the flaring no longer exists

The documentation required by this procedure is directed as follows:

- Where the fuel gas imbalance results from planned maintenance, documentation will be included with the Startup/Shutdown/Major Maintenance documentation
- Where the imbalance is caused by process upset, unanticipated events that result in flaring or equipment failure, documentation will be included with the Process Upset documentation

Other Resources

WORK PROCESSES: Complimenting our flare procedures, a variety of work processes combine to effectively minimize potential flaring. These work processes are continually evolving and may not produce a documented record. They are mentioned to provide a perspective of how the refinery communicates to optimize refinery operations and minimize flaring.

System Teams: Several work groups, known as System Teams, work to minimize potential flaring by discussing volatiles (propane, butane, pentane) management and fuel balance for planned events and long-term strategy. In the event of unplanned events, these same teams work to minimize the magnitude and duration of flaring.

On-Shift Leadership: The Refinery Team Leader provides 24-hour coverage to integrate and manage operational events that may cause flaring. This position, supported by additional staff on and off-shift, provides the capability to intercept and deflect events that may otherwise cascade through process units in various parts of the plant. This work involves developing, coordinating and implementing plans to mitigate unexpected flaring.

Refinery Reliability and Maintenance Programs: The Shell Martinez Refinery utilizes several key work processes to keep our equipment and processes operating reliably. Reliable equipment and process operation minimizes flaring due to upset or unanticipated events. Preventative maintenance is the key technique to reduce the probability of equipment failure.

All flare gas recovery compressors in the refinery are normally running. Compressors are purposefully removed from service only when monitoring of the machine or its associated equipment indicates the need for maintenance or a more elaborate inspection that requires a shutdown. The need to remove compressors from service for maintenance is based on regular evaluation of the machine's condition such as vibration. This Performance or Risk-based approach has generally replaced specified maintenance intervals.

Shell global standards known as the Global Asset Management Excellence processes were specifically designed to improve reliability. The processes include:

- ***Maintenance Execution:*** This process covers the day-to-day execution of maintenance work including screening, assessment, planning, scheduling, execution and review of the maintenance work to optimize the reliability and availability of the assets.
- ***Reliability Centered Maintenance (RCM):*** RCM is the systematic improvement of equipment care through analysis of failure modes to identify optimum operator surveillance and planned maintenance tasks.
- ***Ensure Safe Production (ESP):*** The Ensure Safe Production (ESP) work process was developed by Shell to map, establish metrics and implement a suite of work processes designed to deliver superior results in the area of Process Safety Management. The overall objective is to substantially increase reliability by ensuring operation of facilities in a safe, environmentally sound and productive manner. In implementing the ESP work process, safe limits of operation are established, communicated, and maintained. The objective is to ensure operation within defined limits at all times.
- ***Instrument Protective Functions (IPF):*** An instrumented function whose purpose is to prevent or mitigate a hazardous situation. An IPF is intended to achieve or maintain a safe state for the process in the event of a specific hazardous event. IPFs are frequently referred to as emergency shutdowns,

protective instrument systems, safety trips, or interlocks. They bring a process or piece of process equipment to a safe condition in the event of a failure or an abnormal operating condition. In order for these systems to mitigate the risks for which they were designed, they must be as reliable as possible. For this reason, strict guidelines and procedures are followed to ensure their protection is not compromised.

- ***Equipment Integrity:*** – this process aims at an active reduction of unforeseen events by setting the boundaries of the Integrity Operating Windows to more accurately predict equipment life.
- ***Turnarounds:*** The objective of the turnaround process is to restore the plant to a physical state appropriate to meet its expected run length within the boundaries of our standards and regulatory requirements while optimizing plant delivery to meet production plans.

B. COMMON PREVENTION MEASURES - PROCESS EQUIPMENT AND HARDWARE TO MINIMIZE FLARING

Key to preventing flaring is reliable access to process and hardware to either avoid creating or effectively manage any excess of treated or untreated gas. The Shell refinery has several features that provide a high degree of flexibility in this area. These features are described below and additional details are provided in Appendix E.

- **Fuel System Control:** A robust refinery fuel system is required in order to minimize flaring. The Martinez Refinery has two independent fuel systems: the refinery fuel gas system (RFG) and the Flexigas system (FXG). These fuels have separate distribution systems comprised of independent piping and separate burners. Fuels are never directly combined. The separate fuel systems provide fuel to many of the same heaters. To maintain a constant heater duty, some amount of FXG can be removed from a heater to allow an increase in the amount of RFG to that heater.

  There is only one refinery fuel gas blend drum that blends the gasses that comprise the RFG fuel system. These gases include treated vent gases from various process units, propane, butane and purchased natural gas. The Flexigas fuel system is made up of just Flexigas and so there is no blending and no blend drum.

  A few of the factors contributing to the robustness of the combined fuel gas systems are listed below.

- **Pressure Control**: The capability to pressure-control the RFG system with purchased natural gas, own-produced fuel gas and propane streams helps reduce flaring, which may otherwise result from dynamic variations of non-elective fuel contributors. Fuel system supply pressure must be maintained steady for reliable operation of fired heaters. This stable operation is complicated by the nature of many of the flows that contribute to the fuel gas system. Having a range of streams available to provide pressure control minimizes the risk of fuel system pressures rising above target, which would otherwise result in flaring.
- **Heating Value and Specific Gravity**: The refinery fuel gas system is monitored for specific gravity and BTU content. BTU content and gravity of blended refinery fuel gas are maintained in an acceptable range by adjusting purchased natural gas, and moving individual component streams between the hydrogen plant feed system and fuel system. Specific Gravity is maintained between 0.5 and 0.83. The monitoring and adjustment helps maintain the stability of fired heaters and allows major heaters to anticipate changes in raw

fuel composition that would be required for stable operation of the process unit. The resulting flexibility is sufficient to prevent the need to flare individual fuel component streams, or recovered flare gas, due to their impact on blended fuel gravity or BTU value.

  Flexigas is produced by gasifying coke produced in the Flexicoker. The nature of the gasification reaction assures the composition and BTU content of Flexigas are extremely stable. Gasifier temperature is monitored to assure the BTU content of Flexigas is acceptable to be routed to process heaters.

- **Sulfur Content:** H2S content of the both fuel gas systems is monitored to ensure they meet all regulatory requirements. Alarms are set to provide early warning of H2S concentration changes which allow the cause to be identified and mitigated to avoid violation of the H2S limits.

  A variety of sulfur specifications are applicable to process heaters at the refinery. Details of these specifications are available in Shell's Title V permit. The H2S content of both blended RFG from the fuel gas blend drum and Flexigas is measured using on-line analyzers to assure compliance with applicable regulatory limits for consumers in LOP and OPCEN. Sulfur limits for process heaters constructed as part of the Clean Fuels Permit are generally lower than for the rest of the refinery, and include other sulfur species (see Title V permit for the limits). Analyzers continuously monitor sulfur species (H2S and total reduced sulfur) in fuel gas routed to Clean Fuels units.

  The Martinez Refinery does not flare untreated fuel component streams in either fuel gas system to avoid an exceedance of a sulfur limit.

- **Stability.** The number and size of process units at SMR provide a significant fuel demand even during large process unit turnarounds. Planned turnaround activity can usually be managed to leave enough of the fuel system in operation to absorb recovered vents generated during equipment depressuring and startup and shutdown activities. The combination of process units comprising a maintenance turnaround block takes into consideration the need for fuel demand for these gases. When it is not possible to completely avoid an excess of fuel, the sequence of startups and shutdowns is evaluated to minimize the duration and volume of flared gases
- **Cogeneration Plant:** The refinery Cogen unit has the ability to use fuel streams that may otherwise be flared to produce steam and electricity.
- **Railcar Loading of Excess Volatiles:** During periods where there is an excess of fuel suppliers over fuel consumers, reducing the amount of volatile liquids such as propane and butane in the fuel system minimizes the potential for flaring due to fuel gas imbalance. SMR has extensive ability to load volatile liquids for sale rather than route them to the fuel system. The refinery has an automated propane truck rack as well as the ability to load railroad tank cars with volatile liquids. The ability to ship volatile liquid products out by both truck and rail provides significant flexibility in the fuel gas system and results in the reduction of flaring that would otherwise be necessary during some fuel gas imbalance situations.
- **Wet Gas Compressor Modifications**: Major refinery conversion units (Cat Cracker, Delayed Coker, and Flexicoker) have wet gas compressors to route a gas stream containing volatile liquids (wet gas) to a gas plant for treating to remove condensable liquids and sulfur components. At Shell, hardware has been provided to assure wet gas compressors are available to recover gases to route to the fuel system without flaring during unit startup. These large compressors generally cannot operate reliably without adequate gas flow through the machine. To avoid operation without adequate gas flow, all wet gas compressors at the refinery are provided with recycle spill-back hardware to control surge

and reduce potential flaring. These facilities include piping and control valves that allow the discharge gas to return to the machine suction. By this method, the compressor has sufficient gas flow through the machine to prevent surge, even when the net gas production from the upstream conversion reaction may be low, for example during startups and shutdowns. If these recycle facilities were not available (e.g., because of a breakdown failure), it would be necessary to flare the gas until the conversion reaction provided the required minimum gas flow. This is a significant improvement from the original designs that generally called for flaring wet gas until process unit operation had fully stabilized.

4.0 INFORMATION FOR INDIVIDUAL FLARE SYSTEMS

A. FLARE SYSTEM: LIGHT OIL PROCESSING (LOP) FLARE

BAAQMD Source No. 1471

1. SYSTEM DESCRIPTION (12-12-401.1)

The LOP Flare system is comprised of collection headers, liquid knockout vessels, two flare vapor recovery compressors, piping to route recovered gas to fuel gas treaters, a water seal vessel, the flare header proper, and the flare stack. The flare is an elevated, steam-assisted flare with nitrogen purge to prevent air intrusion. Piping provides sufficient flexibility to operate in various configurations, allowing continuous and reliable operation during turnarounds, inspection and maintenance activities. A sketch of the LOP Flare system is provided in Figure 1. Technical details of the system are provided in Appendix A[2].

The process units in the LOP Area that are served by the LOP flare system include the Crude Unit, Vacuum Flasher, Straightrun and Catalytic Hydrotreaters, the Catalytic and Saturates gas plants, the Fluid Catalytic Cracker, Hydrocracker, Alkylation, Catalytic Reformer, Sulfur Recovery Units 1 and 2, Hydrogen Plant 1 and various Utilities systems.

Capacity of the two LOP flare gas recovery compressors is approximately 3.2 million standard cubic feet per day (MMSCFD) each for a total of 6.4 MMSCFD. Typical flare header gas flow, in the absence of relief events or unusual operation, is around 2.5 MMSCFD – well within the capacity of one compressor to recover. This normal base flow in the header is typically from many small sources including instrument purges, pump and compressor seal purges, sample station venting, and pressure control for refinery equipment. Because the LOP flare recovery compressors are both normally in operation except during maintenance, there is typically about 4 MMSCFD reserve capacity above the base load available to recover unexpected flows resulting from relief events, or increased vent flows associated with planned and unplanned events. When one of the two compressors is out of service for maintenance, the compressor remaining in service is able to recover the routine flare header flow.

The ability to take one compressor out of service for routine maintenance without flaring provides the ability for sufficient maintenance to ensure reliable compressor operation. Only one of the two compressors is scheduled for planned maintenance at any one time. Typical preventative maintenance involves a 'minor' (process-side) overhaul or a 'major' (process-side + running gear) overhaul. A process-side overhaul typically includes: replacing suction and discharge valves; overhauling suction valve unloaders; replacing piston rod packing; replacing piston rings and rider bands; and inspecting piston rods and cylinder liners. A running gear overhaul typically includes: inspecting crossheads and connecting rods; replacing connecting rod bushings and bearings; inspecting crankshaft and main bearings; cleaning lube oil system; and miscellaneous work on instrumentation and auxiliary equipment.

As discussed in Section 3, Shell's maintenance program utilizes a condition-based approach to balance the frequency for preventative maintenance of a flare compressor to ensure reliable operation with the risk of flaring due to operation with only one compressor while the other is being maintained. Past maintenance history and current condition are used to evaluate the risk of

[2] Information in this appendix meets requirements of section 401.1.

operation beyond 'typical' overhaul intervals. Compressor operation is monitored closely by both operations and maintenance to ensure the highest probability of reliable operation. Typical variables that are monitored are suction and discharge pressures and temperatures, process flow, lube oil pressure and temperature, and vibration.

Recovered flare gas is treated to remove hydrogen sulfide and condensable liquids. Treated gas is routed to the fuel gas system. The fuel gas treaters typically used for LOP recovered flare gas are located in the Catalytic Cracker Gas Plant (CGP). When this unit is unavailable for any reason, recovered gas may be routed to the Saturates Gas Plant (SGP). Sufficient capacity can be made available in both sets of treaters for the incremental flow up to the total capacity of both compressors of about 6.4 MMSCFD.

2. HISTORICAL FLARING REVIEW

Summary: Non-emergency flaring from the LOP flare during 2004 and 2005 averaged 0.1% of permitted emissions of non-methane hydrocarbon. *Efficiency of the existing flare gas recovery* system exceeds 99.90% for non-emergency flaring.

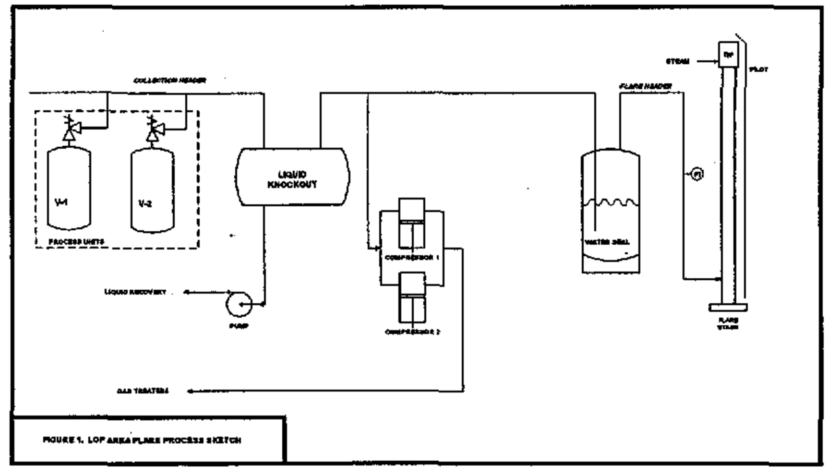


FIGURE 1. LOP AREA FLARE PROCESS SKETCH

There was one reportable flare event[3] on the LOP flare during 2004 and 2005. That single emergency flare event was an unplanned electrical power outage in December 2005 that resulted in almost half of the non-methane hydrocarbon emissions during the entire two-year period (0.5 tons). Total emissions for both years combined (including the emergency flaring) were 1.06 tons of non-methane hydrocarbon in 2004-2005. Even including the emergency flaring, recovery of gas from the collection header exceeded 99.78%. Emissions of non-methane hydrocarbon were less than 3 pounds per day, which is less than 0.2% of the refinery's permitted emissions.

Minor flare activity occurred on 40 occasions during 2004-2005. Most events lasted for less than 20 minutes, and typically less than 10 minutes. The distribution of these events offers no single focal area providing significant leverage for feasible prevention measures. The variety of causes, and the distribution of events among these causes, means preventative measures must consider a wide scope; including mechanical reliability, improved handling of startup and shutdowns without flaring, and reducing the impact of process upsets.

Historical Flaring Review Discussion: Historical flaring at the LOP flare was reviewed to identify opportunities for feasible prevention measures. The review addressed the past five-years' data and included both emergency and non-emergency flaring. Prior to January 2004 when ultrasonic flow meters became operational, flare flows were not accurately measured, making any thorough analysis impractical. For these earlier periods the review relied upon internal Environmental Incident reports, Operations' shift logs, reports and communications to the District and other regulatory agencies.

Flaring prior to January 2004. Review of flare events prior to January 2004 provided little usable information. Without flow meters, neither durations nor volumes could be accurately determined. In many cases, even the proximate cause of flaring could not be reliably determined due to the limited documentation and time elapsed since the event. With these qualifications, a breakdown as to general cause of LOP flare events for the previous five years is depicted in Figure 2. A description of the various categories listed is provided below:

Upset: Flaring attributed to process upsets.

Mechanical Failure: Flaring attributed to mechanical or instrument failure.

Power Outage: Flaring related to electrical outage (similar to process upset).

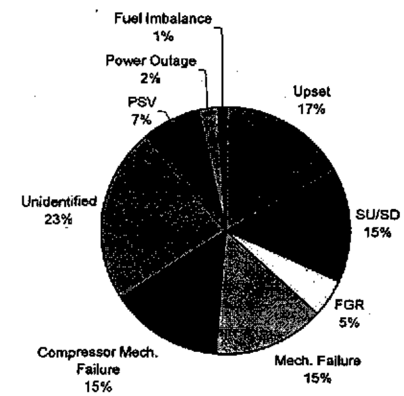
SU/SD: Flaring attributed to process start-up and shutdowns. Flare events due to startup and shutdown have generally been eliminated in recent years by procedural revisions. In some cases this includes use of temporary facilities for selected activities.

Fuel Imbalance: Flaring resulting from temporary imbalance in the fuel system. These events are typically very brief and are generally caused by a process upset at another unit that is a consumer of refinery fuel gas.

Based on these data, about 65% of the flare events occurring within the past five years are essentially evenly divided among the following categories: process upsets, process startup and shutdowns, mechanical failures of compressors and other equipment. Almost one quarter of the time the occurrences where the water seal was broken indicating that flaring occurred were so small, and of such brief duration, no cause could be reliably determined.

[3] Reportable Flare Event as defined in Regulation 12-12 Section 208 is any flaring where more than 500,000 standard cubic feet is flared or sulfur dioxide (SO_2) emissions > 500 lbs per day.

Figure 2. LOP Area Flare Events
(2000-2005)



There has been a significant decrease in the number of flare events caused by fuel system balance and startup/shutdown in recent years. This is a direct reflection of the increased emphasis on reducing flaring. Regardless of historical performance, major turnarounds in the recent past on units served by this flare have been performed without planned flaring. That this work was performed without flaring is evidence of careful review and planning. We commit to continue this careful review and planning prior to planned major maintenance and expect to perform turnarounds with little or no planned flaring. Therefore there is no predicted flaring resulting from planned major maintenance for which to evaluate prevention measures against. If during the maintenance planning and review process we find that *planned flaring is required, all* appropriate prevention measures will be considered and feasible measures will be implemented to reduce or eliminate the planned flaring.

Further reductions have been achieved through improvements in mechanical equipment reliability associated with changes in maintenance evaluation and practice.

Flaring during 2004 and 2005. The highest quality data are available for the period from January 2004 to January 2006. This generally coincides with installation of the ultrasonic flare flow meter and BAAQMD flare reporting required per Regulation 12 Rule 11. Available data for flare event volume, rates and durations are provided in Figures 3 through 5 below. This information will be used to evaluate environmental impacts and potential options to further reduce flaring.

Volumes flared: Figure 3 depicts the amount of material flared during the 25 events occurring in 2005. Each point on this plot represents the total flare volume of gas during that event. The vertical axis is relative magnitude of that event compared with all events in the period. Based on this figure, ninety percent of the events had volumes less than 100,000 standard cubic feet (SCF) per event. Approximately five percent had volumes between 100,000 and 200,000 SCF per event. A single emergency event resulted in flaring more than 500,000 SCF.

Therefore, if sufficient recovery compressor capacity could be installed to meet the flare flow rate that occurs during the flaring events, providing storage for the equivalent of 200,000 SCF of flare gas volume would be adequate to contain about 90% of the number of events[4]. To determine the recovery compressor capacity that would be needed requires information concerning the flaring event flow rates and duration. This is described below.

Flare flow rates: The amount of flare gas that can be recovered depends upon compressor capacity and gas properties. Compressor capacity is typically described in terms of gas at standard conditions, however compressors are forced to work with gas at actual conditions. At the elevated temperatures which often occur in flare events, this difference between actual gas volume *and the gas volume at standard conditions* may be significant. For example, a compressor with a capacity of 3.2 million standard cubic feet per day (MMSCFD) has a capacity of approximately 2.2 MMSCFD for gas at 300 F.

Figure 4 depicts the average rates of flow to the flare for events occurring in 2005. These data indicate that approximately 30% of the flare events had event-average flow rates of less than 3 million standard cubic feet per day. Actual instantaneous rates are generally higher – often significantly – than these average rates. This difference between the average rate for an event and instantaneous flare gas rate during an event is important because once the instantaneous rate exceeds the available compressor capacity the water seal is typically broken and flaring

[4] The elevated temperature of compressor discharge flows requires storage volumes greater than those required for gas at standard conditions. For a 300 Degree F gas, the required actual volume is approximately 50% greater than that calculated for standard conditions.

occurs. Once flaring begins, backpressure in the flare header provided by the water seal is significantly reduced. Due to the lower header pressure, flare gas recovery rates are typically significantly reduced from their rated capacity.

Data from Figure 4 were used to evaluate the leverage provided by additional flare gas recovery in LOP. As each increment of compressor capacity was added, the corresponding events with average flows within the newly-revised total capacity were considered to be recovered rather than flared. Similarly, the reported emissions for these events were presumed not to occur. This provided the basis for emissions reductions as a function of compressor capacity.

Flare event durations: The duration of a flare event affects both our ability to determine the cause of the flaring and the alternatives for flare gas recovery. Events that have a very short duration require the flare gas recovery equipment to operate continuously. Events lasting for several hours may allow some equipment to be shutdown under normal conditions and then started when an event occurs.

Figure 5 depicts the distribution of flare event durations for 2005, the year for which these data are available. Most flare events have very short durations with small volumes of gas flared. From Figure 5 it can be seen that half of the flare events had durations of less than 10 minutes. By combining event durations with additional data on the volume flared during each event, it can be shown that the 50% of events with durations less than 10 minutes contributed less than 10% to the total volume of gas flared. The 85% of events which lasted 15 minutes or less contributed less than 40% to the total volume flared. Only three of the flare events during this period lasted longer than one hour. All of the event durations were less than three hours.

This distribution of event durations affects how flare gas recovery compressors must be operated. One possibility to reduce flaring would be to make use of standby flare gas compressor capacity for higher than normal flare gas loads. During an unplanned event that produces significantly more flare gas than for average operating conditions, refinery operations would need at least 15 minutes from the time when higher than normal flow began before an additional recovery compressor could be brought online to handle the increased demand. The brief durations of the bulk of these flare events means that any additional recovery compressors would have to be operating continuously if they were to recover the gas from these events. A standby compressor that was only started after flare gas flowrates increased would miss much of the flare gas flow before it could be brought online. In addition this practice has been shown to create a distraction on operating personnel at the very time their assistance is more appropriately directed to controlling the conditions responsible for the process upset.

Electrical costs associated with running an additional compressor at the time of the event must be included *in the economic evaluation. This increases the cost* and therefore decreases the cost-effectiveness of emissions reductions.

An additional consideration is that the brief duration of many flare events makes it more difficult to determine their cause. Often excess flow to the flare gas header has stopped before significant troubleshooting activity can be undertaken to determine its source.

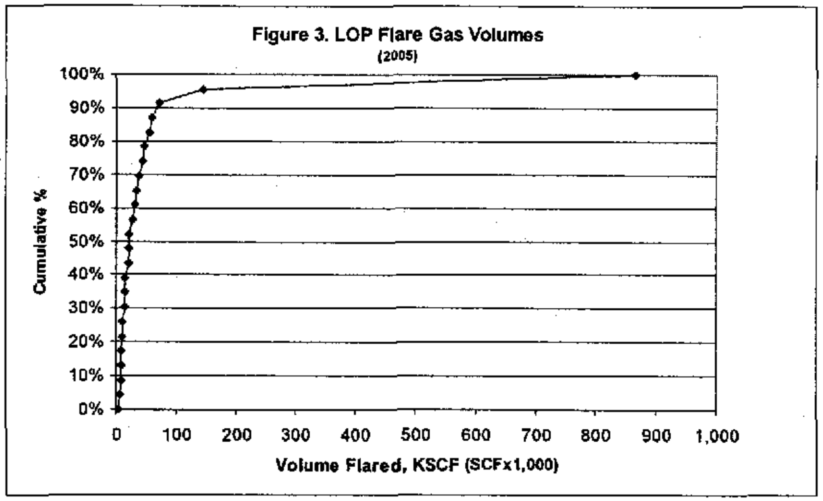


Figure 3. LOP Flare Gas Volumes
(2005)

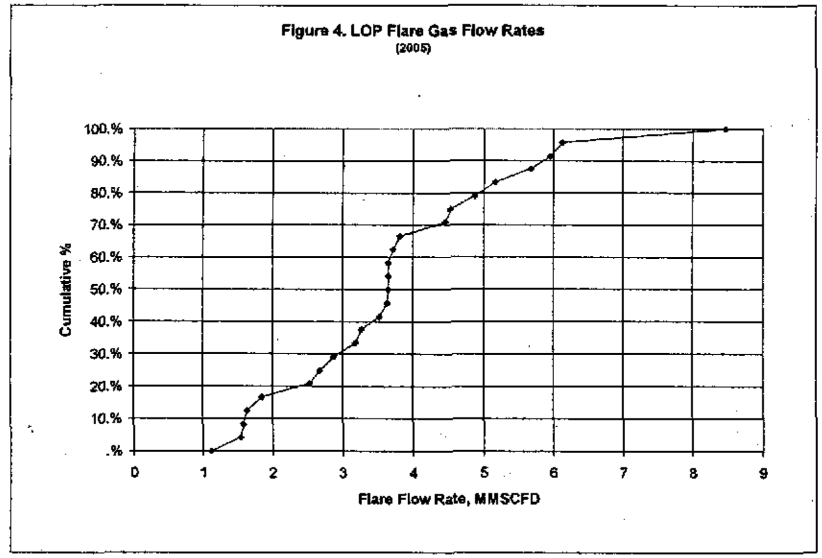
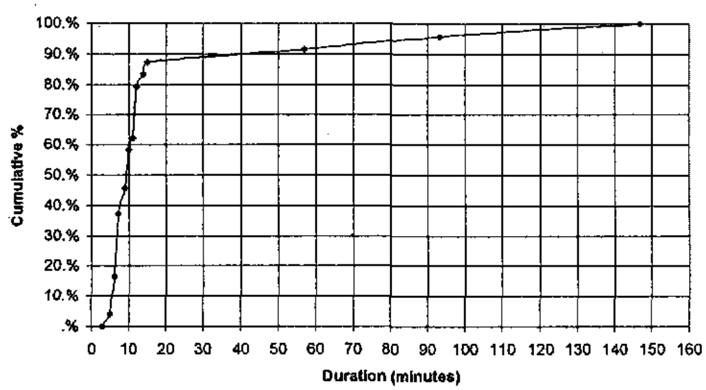


Figure 4. LOP Flare Gas Flow Rates
(2005)

Figure 5. LOP Flare Durations
(2005 - 25 Events)



3. REDUCTIONS PREVIOUSLY REALIZED (12-12-401.2)

Equipment, processes and procedures installed or implemented to reduce flaring at the LOP flare within the last five years are described below.

HARDWARE AND PROCESS REVISIONS

A variety of hardware modifications, and operational and procedural changes have been made in LOP that help to reduce flaring in some circumstances. These include:

(A) Following the December 2005 flaring event that was the result of a power outage due to a ground fault, electrical sub stations at the refinery were upgraded to further limit potential for water intrusion that may cause ground fault.

(B) Available flare gas recovery capacity in LOP was increased 0.3 MMSCFD by rerouting the Crude Unit overhead vent to the Delayed Coker main fractionator. When the Delayed Coker is shutdown, or this routing is unavailable for any reason, the vent flow is returned to its historical disposition. This additional flare gas compressor capacity was made available in 2005.

(C) The pressure control target for the Fuel Gas Blend Drum was adjusted in 2002 to assure a cushion of natural gas, when this stream is being used to pressure control the blend drum. This provides a greater dampening for operational swings in fuel gas supply or demand that may otherwise result in flaring. Several revisions were made to the fuel gas blend drum pressure control as part of the project. The previous control scheme relied on natural gas to pressure control the refinery fuel gas system. The capability to control pressure with other streams was extended to include a second natural gas control valve (to increase the control range) and vaporized propane or butane streams. This flexibility allows us to pressure control the blend drum over a wider range of operating conditions. In addition, operating guidelines were changed to assure that the fuel balance provided enough flexibility to absorb the return flows from tank vapor recovery as they cycle on and off during the day. Since these flows are driven by atmospheric conditions they cannot be accurately predicted or controlled.

These changes reduce flaring because the fuel component that is controlling blend drum pressure is present in a high enough volume so that the fluctuations in operating conditions can usually be accommodated without overpressuring the system.

(D) Over the past few years, the refinery has implemented a variety of operational strategies to consume fuel and minimize flaring during periods where fuel availability temporarily exceeds demand. These strategies are described in procedure C(F)22.

PROCEDURAL REVISIONS

The LOP Area Flare header is provided with vapor recovery. Operating personnel in process units served by this flare have extensive experience managing background flare header flow within the capacity limits of the compressors. These activities include: managing startups, shutdowns, vessel *depressuring and maintenance. Careful management* of these activities is an expectation to minimize or prevent flaring.

(A) Historical flaring in LOP shows strong dependence of flaring upon the reliability of rotating equipment, including flare gas recovery compressors. Compressors are required to increase the pressure of gases within the flare header to the pressure in the fuel system. If compressors are unavailable for any reason, gas in the flare header cannot be recovered. To maximize available compressor capacity, maintenance practices and schedules are regularly reviewed.

(B) The Environmental Impacts assessment practice for turnaround and maintenance work has been in place for several years. According to this practice, prior to each turnaround and major maintenance block, including the related shutdown and startups, the operating department and turnaround groups discuss ways to minimize flaring. This practice is formalized in new procedure C(F)21 described previously in this FMP.

4. PLANNED REDUCTIONS (12-12-401.3)

HARDWARE AND PROCESS REVISIONS

The causal analysis that was conducted for the flaring event that occurred in December 2005 due to the electrical power outage identified the following mitigation that is planned for implementation. Flaring occurred when a low-pressure vent gas compressor experienced a surging event due to the process conditions that resulted from the power outage. The flaring lasted longer than it might otherwise have lasted due to a problem with a control valve requiring manual operation from the field. Repairs to the control valve will be made to allow propane to be automatically added to the suction of the compressor. The repair requires a turnaround. Repair is scheduled for [redacted].

In light of the historical flaring review, the analysis of potential mitigation measures provided in section 401.4.2 (below), and the anticipated effect of the new policy and procedures described in addressing flaring, no further hardware or process revisions are planned at this time. The FMP will be updated at least annually with any revisions developed from the causal analysis of future flaring events.

PROCEDURAL REVISIONS

The four procedures described under the section Prevention Measures Common to All Flares, were implemented by November 1, 2006. As discussed in the historical flaring review, non-emergency flaring is rare for the LOP flare. Even including the emergency flaring, recovery of gas from the LOP collection header exceeded 99.78%. These procedures are expected to help us continue to find ways to minimize and reduce flaring where possible, but it is impossible to quantify the expected reduction in flaring. Any reduction in flaring, no matter how small, eliminates the emissions that would have occurred due to the flaring, including the emissions of non-methane hydrocarbon and sulfur dioxide.

5. PREVENTION MEASURES (12-12-401.4)

Figure 2 illustrates that there are a wide range of events that can cause flaring at LOP. The annual volume of gas flared could be reduced in two basic ways. One alternative is an increase in the capacity of the flare gas recovery system. The second is improved measures to limit the rate

and volume of gas discharged to the flare gas header so that it does not exceed the capacity of the existing recovery system. These two alternative approaches are discussed below.

Increasing the capacity of the flare gas recovery system would require additional equipment. Using the cost-effectiveness calculation methodology found in the BAAQMD BACT guidelines and the expected flare emission reductions, we can calculate the most that could be spent on this equipment and still be considered cost-effective. Based on the historical flaring review, the average annual non-methane hydrocarbon emissions from the LOP flare are approximately 0.55 tons. Using the BACT methodology and the BACT cost-effectiveness hurdle of $20,000 per ton of non-methane hydrocarbon emissions, the maximum annual expenditure for prevention measures, even if they could completely eliminate emissions from the LOP flare, would be $11,000. Consequently, for the LOP flare and associated process units, the maximum justifiable capital cost of project(s) that would completely eliminate this flaring is $44,000[5]. The analysis of potential projects later in this section shows that this amount does not buy much hardware.

An alternative approach to adding equipment is careful evaluation of current practices and procedures that can lead to flaring, and development of alternatives that are less likely to overwhelm the existing flare gas recovery system. Consideration of the factors and events that can lead to higher than normal flare gas flowrates can yield reductions in flaring that are far more cost-effective than can be achieved with additional equipment for flare gas recovery. We believe that flare minimization efforts are best achieved on this flare by maximizing the use of procedures, training, reliability improvement, and planning.

401.4.1 Prevention Measures for Flaring Due to Planned Major Maintenance

Figure 2 shows that activities that have occurred during startups and shutdowns have contributed to approximately 15% of the flare events that occurred at the LOP flare over the past five years. Insufficient data are available to determine whether this flaring may have been avoidable by changing operating practices, improved planning, or minor hardware revisions. However, the trend over the past two years indicates that startup, shutdowns and maintenance-related flaring can be significantly reduced and largely eliminated with careful planning. Regardless of historical performance, major turnarounds in the recent past on units served by the LOP flare have been performed without planned flaring. That this work was performed without flaring is evidence of careful review and planning. We commit to continue this careful review and planning prior to planned major maintenance and expect to perform turnarounds with little or no planned flaring. If during the maintenance planning and review process we find that planned flaring is required, all appropriate prevention measures will be considered and feasible measures will be implemented to reduce or eliminate the planned flaring.

In order to maintain equipment, it must be cleared of hydrocarbon before opening to the atmosphere for both safety and environmental reasons. Typically this is done by transferring as much of the hydrocarbon as possible to equipment that is still in service (e.g., pumping liquids to tanks) and then multiple steps of depressurization and purging of the equipment with nitrogen to the flare collection header since it is the lowest pressure system in the refinery and allows the most complete depressurization. Careful planning to limit the depressuring/purge rate and to maintain an acceptable gas temperature and composition in the flare header can reduce the potential for flaring.

[5] The maximum capital cost was determined using the 16.3% Capital recovery factor and additional costs referenced in the BAAQMD Best Available Control Technology guidelines.

Although it may not be possible in all circumstances, we have found that planned depressuring and purging of equipment to the LOP flare header can typically be controlled to stay within the capacity and capability of the LOP flare vapor recovery compressors for recovery of the gases to the refinery fuel gas system without flaring. Because of the robustness of the refinery fuel gas system described previously, the recovered purge gas from planned events can typically be absorbed in the fuel system without adverse impact on the refinery heaters and boilers.

The review required prior to turnarounds and major maintenance, including startup and shutdowns in procedure C(F)21 will continue to improve our ability to perform these planned activities without flaring.

There are occasions, typically due to equipment malfunction, when a decision has to be made to shut down a process unit or major piece of equipment within a period of hours or immediately. Although the refinery will review the impacts and attempt to minimize flaring as much as possible, it can be more difficult to eliminate flaring since it may not be possible in the limited time available to take actions to ensure the fuel gas system is balanced. Flaring due to these unexpected events will follow procedure C(F)20 and/or C(F)21 to ensure that flaring is minimized as much as possible and lessons learned are captured for the future. As long as we follow these procedures, any flaring that occurs, whether predicted or unexpected, will be minimized as much as possible and the flaring reviewed to determine if there are prevention measures that can be implemented to further reduce flaring.

401.4.2 – Prevention Measures for flaring due to issues of gas quantity and quality including review of existing vent gas recovery capacity of the LOP Flare System

Flaring can occur as a result of an imbalance between the quantity of vent gas produced and the rate at which it can be utilized as fuel gas. When refinery equipment that is either a producer or consumer of fuel gas is shut down for any reason, then adjustments must be made in the fuel gas system to bring it back in balance. Flaring can result if the change in fuel gas balance is large and adjustments cannot be made quickly enough (typically due to the potential for upsetting other units). Imbalance in the quantity of fuel gas can occur due to maintenance, upset, malfunction, emergencies, etc.

The range of gases that can be recovered by compressors depends on the flowrate, process conditions (e.g., temperature) and composition of the gases. The limits most often approached are gas temperature and the amount of condensable liquids. High temperature may cause the *compressor to shutdown if compressor inter-stage* heat exchangers cannot remove enough heat to maintain cylinder temperatures below 320 Degrees F. High concentrations of propane or butane may overwhelm the machine's ability to separate liquids. Neither of these limits are often approached for the small events which occur in the LOP area flare. High temperatures and relatively large amounts of condensable liquids that may limit the ability of flare gas compressors to recover some gases typically occur during large pressure relief events. Examples include process upsets and unplanned electrical power outages that result in a loss of cooling in the process equipment. When the hot gases cannot be cooled and condensed, pressure in the process equipment increases. To prevent equipment damage and catastrophic releases, the pressure is relieved to the flare header. The resulting relief events cannot generally be recovered by the flare gas recovery compressors – because of very large flow rates, high temperatures or large concentration of condensable vapor in the gas. If electrical power to the flare gas recovery compressors is lost, flare gases cannot be recovered regardless of the temperature or composition since the compressors cannot operate without power. These events cannot reasonably be predicted, occur very infrequently, and are characteristic of emergency flaring, which is not restricted by Regulation 12 Rule 12. During these events, flaring is minimized by

returning the unit to a stable condition as quickly as possible. This is the primary responsibility of Operating personnel and is described in Procedure C(F)-20 – Flaring Due To Process Upsets or Mechanical Equipment Failure.

The maximum capacity of a flare gas recovery system is no more than the total installed nameplate capacity of the flare gas compressors. However, flare gas compressor capacity does not fully define the total capacity of the system. In order to recover flare gas for use in the fuel gas system, four criteria must be met. First, there must be sufficient flare gas compressor capacity. Second, the compressors must act rapidly enough to prevent the water seal from being "broken"[6]. Third, there must be sufficient gas treating capacity. Finally there must either be available storage volume or a user (e.g., heater or boiler) with a need for the gas. If any of these conditions are not *met, then the gas cannot* be recovered into the fuel gas system.

SMR's vent gas recovery system does not include any capacity for storage of fuel gas or vent gas. On a continuous basis we optimize the refinery fuel gas system of producers and consumers to maximize the capacity available for treatment and reuse of recovered gases. This is accomplished as described previously in the FMP under the Prevention Measures common to all the refinery flares. These Prevention Measures include:

- Adjusting the sources of fuel that are made up to the fuel gas system including purchased natural gas and propane. Having a range of streams available to provide pressure control minimizes the risk of fuel system pressures rising above target, which would otherwise result in flaring.
- Adjusting the operation of units that produce fuel gas range materials to reduce fuel gas production as much as possible (consistent with safe operation) to avoid flaring.
- Adjusting the refinery profile for consumption of fuel gas by ensuring the cogeneration unit is at its maximum capacity.
- Shifting rotating equipment to turbine drivers where feasible to increase steam consumption from steam generated in the fuel gas fired boilers. Several functions provided by rotating equipment in the refinery may be powered by either electricity or steam. This ability to shift the load between the off-site electrical grid and refinery steam boilers provides additional flexibility to balance the fuel system when there is an excess of fuel. In periods where the fuel supply is limited, motor drives maximize use of electrical power. When the refinery has an excess of fuel this equipment may be powered by steam. When the cause of flaring is the result of a process unit upset or mechanical failure, changing between steam turbine and electrical motor drivers is may not be practical and must be evaluated on a case-by-case basis[7].

Procedure C(F)22 is in place to help manage the fuel system balance during periods of flaring.

[6] The water seal is considered to "break" when flare gas in the inlet pipe to the water seal drum first enters the water column. This is the onset of flaring.

[7] The use of steam drivers is less energy efficient than electricity. Regular use of steam driven equipment is evaluated considering both the reliability benefits with the increased operating costs, higher water demand, and greater emissions associated with steam production. If there is a fuel gas imbalance (for whatever reason) that results in flaring of excess fuel gas and some of that excess gas can be shifted to produce more steam, we won't have to flare that amount of fuel gas. This is how shifting to steam-driven equipment can reduce flaring in some circumstances.

The total gas scrubbing capacity is an integral part of the refinery fuel gas management system. The capacity available for recovered vent gas scrubbing will vary depending on the balance between fuel gas production and consumption; it will vary both on a seasonal basis and during the course of the day. Sufficient capacity can be made available in the LOP treaters for the incremental flow up to the total capacity of both flare recovery compressors.

LOP flare gas recovery system capacity:	
Total LOP flare gas recovery compressor capacity	= 6.4 MMSCFD
Total LOP flare gas storage capacity	= 0 SCF
LOP fuel gas treating available capacity can match recovery capacity.	

Average annual non-emergency flare emissions from the LOP flare during 2004 and 2005 amounted to less than 0.1% of the annual refinery permitted emissions for both non-methane hydrocarbon and sulfur dioxide. Efficiency of the existing flare gas recovery system exceeds 99.78%, including emergency flaring during that time. An evaluation of the feasibility of eliminating this flaring by increasing the recovery of flared gas by combination of additional compressors and storage vessels is provided below[8].

Prevention Measure Options Considered for Recovery, Storage and Treatment: Costs and potential benefits of improving gas recovery and reducing flare emissions from the current 99.78% recovery efficiency are addressed by considering the addition of flare gas recovery compression and flare gas storage. Gas treating capacity is expected to be adequate for all options evaluated. A sketch of the potential options is provided in Figure 6.

Normal operation of the revised system would have to involve continuous operation of one or more of the additional compressors to capture the short duration flare events typical on the LOP flare[9],[10]. A line from the common discharge of the flare gas recovery compressors is routed to a new gas storage vessel. The portion of the total compressor flow above that which can be treated and used in the fuel system during flare activity is routed to the storage vessel rather than being flared. Once conditions responsible for the high flare header flow have returned to normal, a valve would open directing flow from the storage vessel back to the recovery compressor inlet header. With the flare activity now over, the flow from compressor discharge would be treated and processed as fuel.

[8] These evaluations do not consider expansion of treating capacity since non-emergency flaring at the refinery has not resulted in the need to flare untreated gas due to limits on existing treater capacity. There is no incentive to provide increased treater capacity since it is not a bottleneck resulting in flaring. Additional storage and compression would reasonably be required to take advantage of additional treater capacity. Once these are provided it is more cost-effective in our case to reduce unit rates making room in existing treaters. This may not be the case if flaring occurred more often.

[9] The requirement for continuous compressor operation derives from actual data showing that most events in the LOP flare last less than 10 minutes. It is impractical to expect a compressor of this size to go from shutdown to full operation rapidly enough to capture such events.

[10] Presumes use of single stage liquid ring compressors. Power requirements are scaled from a nominal 2 MM SCFD machine provided with a 600 HP motor.

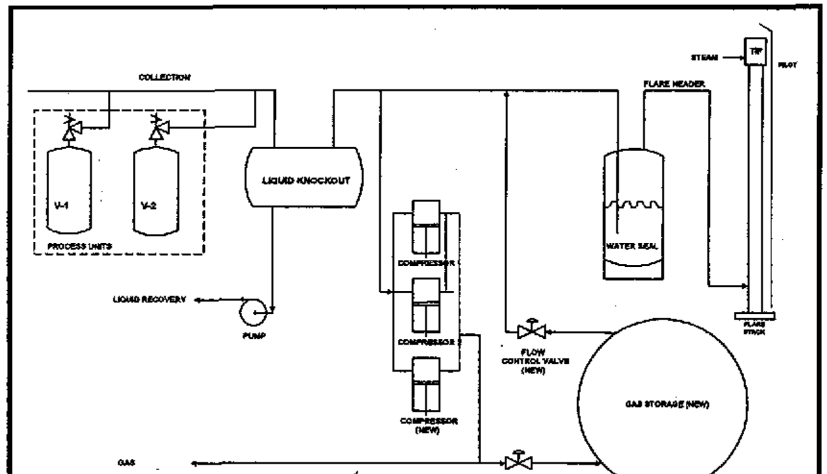


FIGURE 6. SKETCH OF OPTIONS FOR LOP AREA

Tables 1A and B depict the increased flare gas recovery and annual costs and benefits for the revised facilities considered. The evaluation makes use of data from actual flare events for calculation of potential benefits and conservatively assumes that all emissions can be eliminated, including those resulting from emergencies. Excluding the emergency emissions would result in even a higher cost per ton reduction. The evaluation below is calculated on the basis of emission reductions using the reported emissions from 2005. Even with the very conservative assumptions used in the calculations, the most cost-effective measure is still not feasible.

Table 1A considers the case of no storage, only additional compression. In this case, the emissions savings are realized only when there is sufficient purchased fuel (PG&E natural gas) in the fuel system that recovered gas can be fit in the fuel system by backing out purchased natural gas. For the purpose of this analysis, we have assumed that on average half of the recovered fuel *would fit in the fuel system.*

As depicted in Table 1A, increasing flare gas recovery efficiency from the current 99.78% by a further 0.05% would require doubling the current compressor capacity and a capital investment of approximately $10,000,000. The cost-effectiveness for non-methane hydrocarbon emissions for Option 1A, which does not provide storage, ranges between approximately $24 Million and $61 Million dollars per ton. (Refer to Appendix F for additional details of these calculations).

Including emissions of greenhouse gases and non-methane hydrocarbon associated with producing the required electrical power would significantly reduce the benefit of the project. A significant reduction in benefits would occur when recovered gas does not fit in the fuel system. For these cases, there is no alternative to flaring until operating conditions of units that produce fuel gas streams can be safely adjusted to compensate for the extra fuel. This significantly decreases the benefit, increasing the effective cost to benefit ratio.

Table 1B includes additional storage in the form of a 45' diameter sphere operating at up to 120 psig. The capital cost of the sphere significantly increases total cost, but the emissions reductions are higher since the potentially recoverable gas is presumed to always fit within the capacity of the fuel system and gas treaters[11].

Results presented in Table 1B indicate that it may be possible to increase the efficiency of recovering potentially flared gas by almost 0.1% (from 99.78% to 99.87%), provided the system *works perfectly.* Electrical costs for additional compressor capacity are unchanged from the earlier example. The effect of the additional capital investment in storage is to improve the range of cost-effectiveness to between $16 Million and $53 Million dollars per ton. Once again, including emissions of greenhouse gases and non-methane hydrocarbon associated with producing the required electrical power will further decrease the cost-effectiveness. Additionally, permitting a flare gas storage facility in Contra Costa County is not considered in this analysis.

[11] Estimated cost to construct and tie into the existing system is about $5,000,000. Storage limits the need for expanding treater capacity, and allows for capturing the fuel value and emissions savings of recovered gas. Without storage, recovered gas would most likely be burned in heaters running at lower than normal efficiency. In this event, the available non-methane hydrocarbon savings are simply the difference between the efficiency of combustion in a heater and in a flare – a number much, much, less than used for determination of estimated benefits

Table 1. Economic Justification for Additional Recovery Capacity at LOP Flare

A. No Gas Storage Provided

Additional Recovery Compressor Capacity	Overall Recovery Efficiency	Capital Cost	Combined Annual Cost[2,3]	Emissions Reductions by Species (lbs/year)					Cost Effectiveness of Reductions ($ Million/ton)				
(MMSCFD)[1]	(%)	($)	($/yr)	NMHC	SOx	NOx[6]	CO[6]	PM[6]	NMHC[4]	SOx[5]	NOx	CO	PM
0	99.78%	-	-	-	-	-	-	-	-	-	-	-	-
3	99.79%	$5,000,000	$1,745,000	57	158	28	150	4	$61	$22	$126	$23	$858
4	99.81%	$6,700,000	$2,335,300	203	961	98	535	14	$23	$8.3	$47	$8.7	$323
5	99.82%	$8,300,000	$2,899,700	235	652	114	621	17	$26	$8.9	$61	$9.3	$345
6	99.83%	$10,000,000	$3,490,000	294	816	143	778	21	$24	$8.6	$49	$9.0	$332

B. 400,000 SCF Gas Storage Provided

Additional Recovery Compressor Capacity	Overall Recovery Efficiency	Capital Cost	Combined Annual Cost[2,3]	Emissions Reductions by Species (lbs/year)					Cost Effectiveness of Reductions ($ Million/ton)				
(MMSCFD)[1]	(%)	($)	($/yr)	NMHC	SOx	NOx[6]	CO[6]	PM[6]	NMHC[4]	SOx[5]	NOx	CO	PM
0	99.78%	-	-	-	-	-	-	-	-	-	-	-	-
3	99.80%	$10,000,000	$3,040,000	114	315	55	301	8	$53	$19	$110	$20	$748
4	99.84%	$11,700,000	$3,630,300	405	1,122	197	1,070	29	$18	$6.5	$37	$5.6	$251
5	99.85%	$13,300,000	$4,194,700	470	1,303	228	1,243	34	$16	$6.4	$37	$6.8	$250
6	99.87%	$15,000,000	$4,785,000	589	1,632	288	1,557	42	$16	$5.9	$33	$6.1	$227

1) Capacity units are millions of standard cubic feet per day.

2) Indirect costs include Capital Recovery (10% interest over 10 yr), plus other costs described in the BACT implementation procedure

3) Direct costs include Electrical ($0.1/kw), plus other costs described in the BACT implementation procedure

4) Non Methane Hydrocarbon emissions reductions are based on 100% Recovery capturing the entire NMHC emissions for the base period, 2005 (0.7 tons)

5) SOx emissions reductions are based on 100% Recovery capturing the entire NMHC emissions for the base period, 2005 (1.94 tons)

6) NOx, CO and PM are estimated using AP-42 Emissions Factors

Based on this analysis, we conclude that further expansion of the LOP flare recovery or installation of storage facilities are not feasible options to reduce flaring. We believe more effective ways to reduce flaring include training, reliability improvement, and careful planning including adjustment of refinery operations. These actions will continue to occur as a result of the refinery flare procedures described previously.

401.4.3 Recurrent Failures

There have been no recurrent failures in equipment routed to the LOP flare in the period since July 2005.

B. FLARE SYSTEM: DELAYED COKING AREA FLARE

BAAQMD Source No. 4201 (also known as Clean Fuels Flare)

1. SYSTEM DESCRIPTION (12-12-401.2)

Process units in the Delayed Coking Area are served by a dedicated flare system. A sketch of this flare system is provided in Figure 7. This system is comprised of collection headers, liquid knockout vessel(s), two recovery compressors, piping to route recovered gas to gas treaters, water seal vessel(s), the flare header proper, and the flare field[12]. Piping provides sufficient flexibility to operate in various configurations, allowing continuous and reliable operation during turnarounds, inspection and maintenance activities. Technical details of the system are provided in Appendix B.

Process units in the Delayed Coking Area that are served by the DCU flare system include the Delayed Coker, Isomerization, Distillate and Heavy Gasoline Hydrotreaters, the Cat Gas Depentanizer, Sulfur Recovery Unit 4 and Hydrogen Plant 3.

Capacity of the two existing DCU flare recovery compressors is approximately 4 million standard cubic feet per day (MMSCFD) each, for a total of 8 MMSCFD. Typical header gas flow, in the absence of relief events or unusual operations, is around 2 MMSCFD – well within the capacity of one compressor. Since both compressors are normally in operation except during maintenance when one is out of service, there is typically about 6 MMSCFD reserve capacity available to recover unexpected flows during relief events, or increased vent flows associated with planned and unplanned events. When one of the two flare recovery compressors is out of service for maintenance, the compressor remaining in service is able to recover the routine flare header flow.

The ability to take one compressor out of service for routine maintenance without flaring provides the ability for sufficient maintenance to ensure reliable compressor operation. Only one of the two compressors is maintained at any one time. Typical preventative maintenance involves a 'minor' (process-side) overhaul or a 'major' (process-side + running gear) overhaul. A process-side overhaul typically includes: replacing suction and discharge valves, overhauling suction valve unloaders, replacing piston rod packing, replacing piston rings and rider bands, and inspecting piston rods and cylinder liners. A running gear overhaul typically includes: inspecting crossheads and connecting rods, replacing connecting rod bushings and bearings, inspecting crankshaft and main bearings, cleaning lube oil system, and miscellaneous work on instrumentation and auxiliary equipment.

As discussed in Section 3, Shell's maintenance program utilizes a risk-based approach to balance the frequency for preventative maintenance of a flare compressor to ensure reliable operation with the risk of flaring due to operation with only one compressor while the other is being maintained. Past maintenance history and current condition are used to evaluate the risk of operation beyond 'typical' overhaul intervals. Compressor operation is monitored closely by both operations and maintenance to ensure the highest probability of reliable operation. Typical variables that are monitored are suction and discharge pressures and temperatures, process flow, lube oil pressure

[12] The Delayed Coking Area flare uses an array of 160 separate tips instead of a single stack. This design allows smokeless combustion using very low rates of steam.

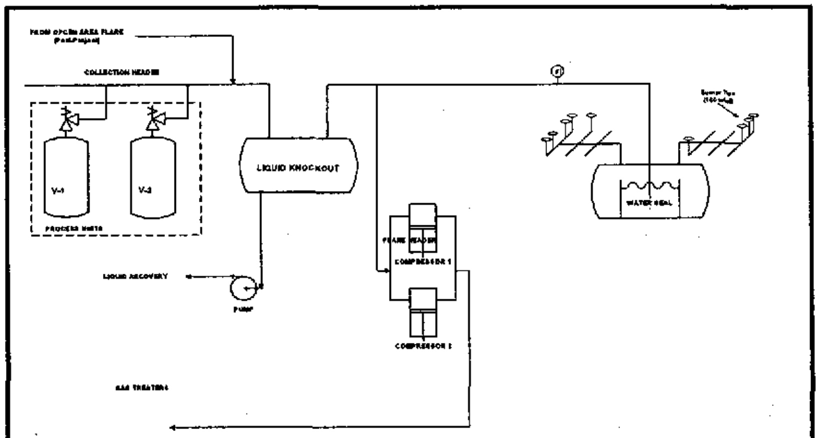


FIGURE 7. DELAYED COKING AREA FLARE PROCESS SKETCH

and temperature, and vibration.

Recovered gas from the Delayed Coking and OPCEN HC Flares is treated to remove sulfur in the Vent Gas Treater in Delayed Coking. Sufficient capacity is available in this gas treater for the incremental flow (up to the total capacity of about 8 MMSCFD). From the Vent Gas Treater, the treated gases may be routed to the refinery fuel gas blend drum for use as fuel in combustion devices throughout the refinery. In addition, the treated gas from the Vent Gas Treater may be used as feed to Hydrogen Plants 2 and 3. Having the option of using the treated fuel gas as feed to the hydrogen plants or fuel for heaters throughout the refinery increases the flexibility of the fuel gas system, reducing the potential for fuel gas imbalance that may cause flaring.

2. HISTORICAL FLARING REVIEW

Summary: There were no reportable flare events (flaring > 0.5 MMSCF) for the Delayed Coking Area flare during the two-year period between January 2004 and January 2006. Minor flare activity during this period accounted for less than 0.04% of permitted refinery emissions of non-methane hydrocarbon. Efficiency of the existing flare gas recovery system exceeds 99.90% for non-emergency flaring.

There were 25 occasions where minor flaring occurred at the DCU Flare during the two-year period. Most activity lasted for less than 20 minutes, and typically less than 10 minutes. Total emissions of non-methane hydrocarbon during this period were less than 0.8 pounds per day. The average annual emissions over the two-year period were approximately 0.13 ton/year.

Discussion: Historical flaring at the Delayed Coking area flare was reviewed to identify opportunities for potential mitigation. As a condition of SMR's Clean Fuels permit (Title V permit condition 12271), it has been necessary to track these events since the flare start-up and include the flare emissions in the total emissions under the Clean Fuels emissions cap. Accuracy of the measurements improved significantly once flare flow monitoring and sampling equipment was provided. For that reason, the data review based actual emissions on data collected between January 2004 and December 2005. Reports from 2000 through early 2005 were used to develop the distribution of the causes of flaring.

Flaring prior to January 2004. *Review of* flare events prior to January 2004 provided little usable information. Without flow meters, neither durations nor volumes may be determined with accuracy approaching that with flowmeters installed. In many cases, even the proximate cause of flaring could not be reliably determined due to the limited documentation and time elapsed since the event. With these qualifications, a breakdown for general cause of Delayed Coking flare events for the previous five years is depicted in Figure 8. A description of the various categories listed is provided below:

> **Process Upset:** Flaring attributed to Process Upsets.
>
> **Mechanical Failure:** Flaring attributed to mechanical or instrument failure, including Flare Gas Recovery compressors and trips of Hydrogen Plant #3.
>
> **SU/SD:** Flaring attributed to Process Start-Up and Shutdowns. Flare events due to Startup and Shutdown have generally been eliminated in recent years by procedural revisions. In some cases this includes use of temporary facilities for selected activities.

Process constraint addressed by procedure: This category identifies events where reevaluating process and equipment constraints has allowed procedure revisions to reduce or eliminate flaring.

Flaring during 2005. The highest quality data are available for the period from January 2005 to January 2006. Data is available during this period from flare flow meters and monthly BAAQMD flare reporting. Available data for flare event volumes and durations are provided in Figures 9 through 11 below.

Figure 9 depicts the amount of material flared during the reported incidents of flare activity in 2005. All flaring was below 500,000 scf. Approximately 70% of the incidents of reported flaring involved volumes of gas of 50,000 SCF or less. All were below 300,000 standard cubic feet.

Figure 10 depicts the average rates of flow to the flare for events occurring in 2005. These data indicate that approximately 80% of the flare events had event-average flow rates less than 3 million standard cubic feet per day. Actual instantaneous rates comprising the average are generally higher – often significantly – than these average rates.

Based on the reliable data collected since initiation of flare gas flowrate monitoring, non-methane hydrocarbon emissions from the Delayed Coking area flare during 2004 and 2005 corresponded to about 0.14 ton.

Figure 11 depicts the distribution of flare event durations for 2005 where these data are available. 50% of the events lasted less than 30 minutes. This is consistent with other data characterizing the bulk of flare events being very brief.

Figure 8. Delayed Coking Area Flare Events (2000 - 2005) 76 Events

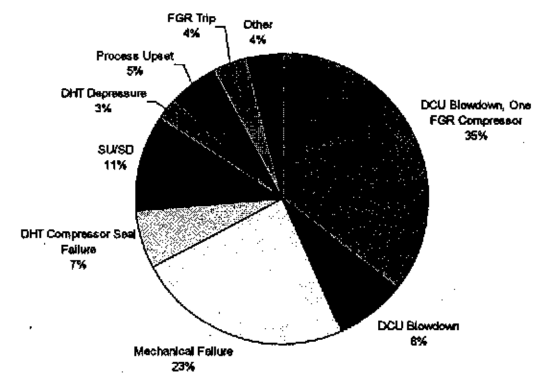


Figure 9. Delayed Coking Area Flare Gas Volumes (2005)

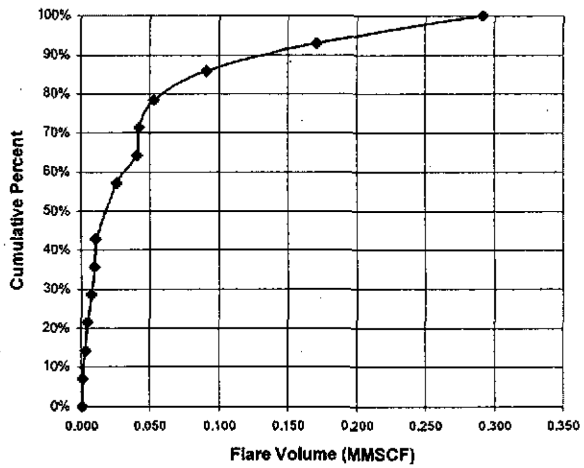


Figure 10. Delayed Coking Area Flare Gas Flow Rates (2005)

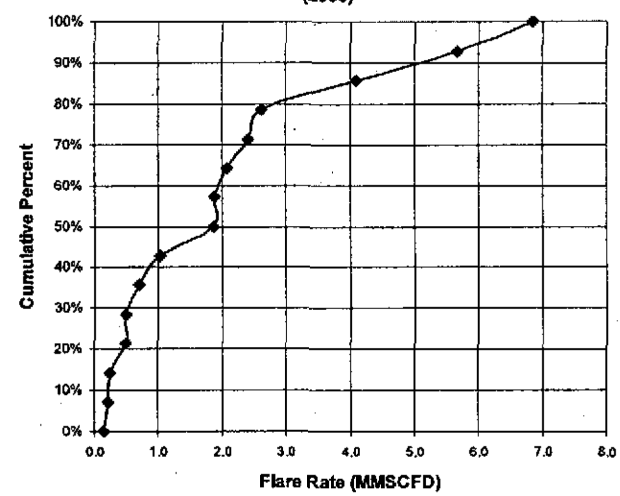
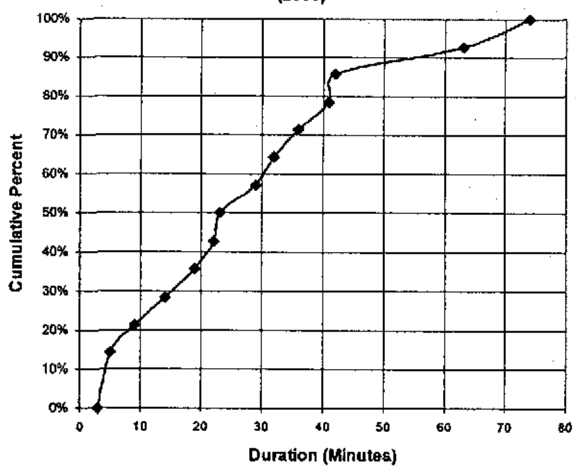


Figure 11. Delayed Coking Area Flare Event Durations (2005)



3. REDUCTIONS PREVIOUSLY REALIZED (12-12-401.2)

Equipment, processes and procedures installed or implemented with the last five years to reduce flaring are listed below.

HARDWARE AND PROCESS REVISIONS

A variety of hardware modifications, and operational and procedural changes have been made in the Delayed Coking Area to reduce flaring in some circumstances.

The single greatest reduction in flaring accompanied steps to improve reliability of the DHT recycle compressor. Prior to this work, the DHT was depressured to the flare when its recycle compressor stopped for any reason[13]. This occurred approximately once or twice each year. Hardware and process changes were implemented in 2001 following an extensive study to improve compressor reliability. The compressor currently meets the three-year run premise of the DHT. Hardware and Process revisions included;

i) Revisions to design of compressor seals.
ii) Addition of a dedicated seal gas coalescer and seal instrumentation revisions. Installed cost of this hardware exceeded $700,000.
iii) Removing DEA from the upstream contactor to prevent DEA reaching compressor seals.

PROCEDURAL REVISIONS

The Delayed Coking Area flare header is provided with vapor recovery. Operating personnel have extensive experience managing background flare header traffic within the capacity limits of the compressors. These activities include managing startups, shutdowns, vessel depressuring and maintenance.

(A) Occasionally, only one of the two Delayed Coking flare recovery compressors will be operating due to either planned maintenance or equipment breakdown. An operating procedure for switching coke drums when only one flare gas recovery compressor is online was developed in March 2004. Previously, entering the "blow-down" phase of the drum switch could create load requirements greater than the one available recovery compressor could consistently meet. Now, drum-stripping intervals have been increased to assure the vented vapors are reliably within the capacity of one machine. This procedure was adopted to ensure the load requirements during a drum switch are within the capacity of a single flare gas recovery compressor and is independent of which compressor is unavailable.

(B) Reliability of the cooling water supply in the Delayed Coking area was improved in 2004 by modifying procedures to operate with two cooling water supply pumps where conditions allow. This increases the reliability of overhead condensing on the DCU Main Fractionator and its Wet Gas Compressor. When the wet gas compressor shuts down for any reason, flaring will occur and the volume and temperature of vented gas far exceeds the capacity of any reasonable flare gas recovery compressor.

[13] The DHT (Distillate Hydrotreater (DHT) is a 2,000# hydrotreater. For process safety, this unit is automatically depressured to the flare system when recycle hydrogen stops for any reason. The high flow and temperatures of hydrogen to the flare during emergency depressuring make its recovery infeasible.

(C) The Environmental Impacts assessment practice for turnaround and maintenance work has been in place for several years.

Prior to each turnaround and major maintenance block, including the related startups and shutdowns, the operating department and turnaround group develop specific plans to minimize environmental impacts. The Operating Department and Turnaround groups develop the plans with input from the Planning Group and Environmental Affairs. Status and expected impacts are shared across the refinery before and during the turnaround. The overall environmental performance is reviewed after the turnaround to develop "lessons learned" for subsequent turnarounds. This practice is formalized in the new Maintenance/Turnaround procedure described previously.

4. PLANNED REDUCTIONS (12-12-401.3)

HARDWARE AND PROCESS REVISIONS

In light of the historical flaring review, and anticipated effect of the new policy and procedures addressing flaring, no further hardware or process revisions are planned at this time. The FMP will be updated at least annually with any revisions developed from the causal analysis of future flaring events.

PROCEDURAL REVISIONS

The four procedures described under the section Prevention Measures Common to All were implemented by November 1, 2006. These procedures address flaring.

PREVENTION MEASURES (12-12-401.4)

401.4.1 Prevention Measures for Flaring due to planned Major Maintenance

Based on the historical review of flaring incidents, planned major maintenance is not a significant contributor to overall flaring due to careful review and planning prior to major maintenance. The shutdown and startup reviews resulting from the new Maintenance/Turnaround procedure C(F)21 will further improve our ability to perform these planned activities without flaring. We commit to continue this careful review and planning prior to planned major maintenance and expect to *continue to perform turnarounds with little or no planned flaring.* Therefore there is no predicted flaring resulting from planned major maintenance for which to evaluate prevention measures against. If during the maintenance planning and review we find that planned flaring is required for some reason, all appropriate prevention measures will be considered and feasible measures will be implemented to reduce or eliminate the planned flaring.

In order to maintain equipment, it must be cleared of hydrocarbon before opening to the atmosphere for both safety and environmental reasons. Typically this is done by transferring as much of the hydrocarbon as possible to equipment that is still in service (e.g., pumping liquids to tankage) and then purging the equipment with nitrogen to a low-pressure closed system for recovery. The flare collection header is the lowest pressure closed system in the refinery. Careful planning to limit the depressuring/purge rate and to maintain an acceptable gas temperature and composition in the flare header can reduce the potential for flaring.

Although it may not be possible in all circumstances, we have found that planned depressuring and purging of equipment to the Delayed Coking flare header can typically be managed within the capacity and capability of the flare vapor recovery compressors for recovery of the gases to the refinery fuel gas system. Because of the robustness of the refinery fuel gas system described

previously, the recovered purge gas from planned events can typically be absorbed in the fuel system without adverse impact on the refinery heaters and boilers.

There are occasions, typically due to equipment malfunction, when a decision has to be made to shut down a process unit or major piece of equipment within a period of hours or immediately. Although the refinery will review the impacts and attempt to minimize flaring as much as possible, it can be more difficult to eliminate flaring since it may not be possible in the limited time available to take actions to ensure the fuel gas system is balanced. Flaring due to these unexpected events will follow procedure C(F)20 and/or C(F)21 to ensure that flaring is minimized as much as possible and lessons learned are captured for the future.

401.4.2 – Prevention Measures for flaring due to Issues of gas quantity and quality including review of existing vent gas recovery capacity

Flaring due to gas quantity: Non-emergency flaring from the Delayed Coking Area flare during 2004 and 2005 amounted to less than 0.04% of permitted emissions of non-methane hydrocarbon. Efficiency of the existing flare gas recovery system is about 99.9%. Actual data for this flare provided in figures 9 through 11. These data, together with knowledge of the various process units and hardware served by the flare, provide no new alternative mitigations beyond those already presented for the LOP Area flare.[14] Applying an analysis similar to that done on the LOP flare in the previous section, the capital and operating costs are essentially the same, but the lower frequency and volume of flare activity reduces the available emissions reductions. The reported 2005 NMHC emissions from the Delayed Coking flare were 0.16 tons (compared to 0.7 tons from the LOP flare). The combination of nearly identical costs and fewer emissions to eliminate produces significantly lower calculated cost-effectiveness. For the option where storage is not provided, the cost-effectiveness for NMHC emissions ranges between approximately $40 Million and $46 Million dollars per ton. For the option that includes storage, cost-effectiveness ranges between $32 Million and $35 Million dollars. (Refer to Appendix F for additional details of these calculations). In either case, including emissions of greenhouse gases and non-methane hydrocarbon associated with producing the required electrical power to operate recovery compressors further decreases the cost-effectiveness. The reported 2005 SO2 emissions from the DC flare were 1.6 tons. The ratio of SO2 emissions to NMHC emissions is 10:1 (1.6 tons of SO2 and 0.16 tons of NMHC). Basing the cost effectiveness on SO2 emission reductions instead of NMHC reductions improves the potential cost-effectiveness by a factor of 10. However, these prevention measures are still infeasible based on cost-effectiveness ($3.2 MM – $3.5 MM) for the option providing storage.

Flaring caused by gas quality: The reciprocating compressors used in Delayed Coking are fairly robust. Experience obtained over the past decade operating these compressors indicates they can effectively deliver their rated capacity over the range of normal operation and planned startup and shutdown activities – provided loads to the flare header are controlled. During relief events, high temperatures and/or the presence of condensable liquids may cause the compressors to stop or recycle discharge to suction, effectively stopping them from conveying flare header gas to the vent gas treaters.

Vent gas recovery capacity: The capacity of a flare gas recovery system is not more than the total installed nameplate capacity of the flare gas compressors. However, flare gas compressor capacity does not fully define the total capacity of the system. In order to recover flare gas for use in the fuel gas system, four criteria must be met. First, there must be sufficient flare gas compressor capacity. Second, the compressor capacity must be able to respond to the event so

[14] Refer to the LOP Area Flare section of this report for elaboration of the option and associated costs.

that it is available to recovery the increased flow. Third, there must be sufficient gas treating capacity. Finally there must either be available storage volume or a user (e.g., heater or boiler) with a need for the gas. If any of these conditions are not met, then the gas cannot be recovered into the fuel gas header.

SMR's vent gas recovery system does not include any dedicated capacity for storage of fuel gas or vent gas. On a continuous basis we optimize the refinery fuel gas system of producers and consumers to maximize the capacity available for treatment and reuse of recovered gases. This is accomplished as described previously in the FMP under the Prevention Measures common to all the refinery flares. These Prevention Measures include:

- Adjusting the sources of fuel that are made up to the fuel gas system including purchased natural gas and propane. Having a range of streams available to provide pressure control minimizes the risk of fuel system pressures rising above target, which would otherwise result in flaring.
- Adjusting the operation of units that produce fuel gas range materials to reduce fuel gas production as much as possible (consistent with safe operation) to avoid flaring.
- Adjusting the refinery profile for consumption of fuel gas by ensuring the cogeneration unit is at its maximum capacity.
- Shifting rotating equipment to turbine drivers where feasible to increase steam consumption from steam generated in the fuel gas fired boilers. Several functions provided by rotating equipment in the refinery may be powered by either electricity or steam. This ability to shift the load between the off-site electrical grid and refinery steam boilers provides additional flexibility to balance the fuel system when there is an excess of fuel. In periods where the fuel supply is limited, motor drives maximize use of electrical power. When the refinery has an excess of fuel this equipment may be powered by steam. When the cause of flaring is the result of a process unit upset or mechanical failure, changing between steam turbine and electrical motor drivers is may not be practical and must be evaluated on a case-by-case basis[15].

Procedure C(F)22 is in place to help manage the fuel system balance during periods of flaring.

The total gas scrubbing capacity is an integral part of the refinery fuel gas management system. The capacity available for recovered vent gas scrubbing will vary depending on the balance between fuel gas production and consumption; it will vary both on a seasonal basis and during the course of the day. Sufficient capacity can be made available at the Delayed Coking treaters for the incremental flow up to the total capacity of both flare recovery compressors.

[15] The use of steam drivers is less energy efficient than electricity. Regular use of steam driven equipment is evaluated considering both the reliability benefits with the increased operating costs, higher water demand, and greater emissions associated with steam production. If there is a fuel gas imbalance (for whatever reason) that results in flaring of excess fuel gas and some of that excess gas can be shifted to produce more steam, we won't have to flare that amount of fuel gas. This is how shifting to steam-driven equipment can reduce flaring in some circumstances.

Delayed Coking flare gas recovery system capacity:	
Total Delayed Coking flare gas recovery capacity	= 8 MMSCFD
Total DC flare gas storage capacity	= 0 SCF
DC fuel gas treating capacity- can match recovery capacity	

4.1.4.3 Recurrent Failures

There have been no recurrent failures in equipment routed to the Delayed Coking flare in the period since July 2005.

C. FLARE SYSTEM: OPCEN HYDROCARBON FLARE

BAAQMD Source No. 1772

1. SYSTEM DESCRIPTION (12-12-401.2)

Process units in the OPCEN area are served by a dedicated flare system. This flare was modified by a project to provide flare vapor recovery. The vapor recovery was operational by December 2006. A sketch of the flare system as it existed prior to December 2006 is provided in Figure 12 with modifications to the system shown as a clouded area. The flare system is comprised of collection headers, a liquid knockout vessel, a water seal vessel (new), piping to flare gas recovery compressors (new) and gas treating, the flare header proper, and the flare[16]. Additional details of the flare are provided in Appendix C.

The process units in the OPCEN area that are served by the OPCEN Hydrocarbon flare include the hydrocarbon streams from the Flexicoker (FXU), Hydrogen Plant 2, Sulfur Recovery Unit 3 and the Dimersol Unit.

Prior to December 2006, all flare gas generated in OPCEN was flared at the OPCEN hydrocarbon flare. Routine flare flow, excluding purges, was typically less than 0.2 MMSCFD. With the vapor recovery project in place, compressors in the Delayed Coking area recover this gas from the OPCEN flare header and route this gas to the Vent Gas Treater as described in the Delayed Coking Area Flare section of this report. These two compressors have a capacity of approximately 4 million standard cubic feet per day (MMSCFD) each. Typical combined flow of Delayed Coking Area vents and OPCEN flare header gas flow, is around 2 MMSCFD – well within the capacity of one compressor. Since both compressors are normally in operation except during maintenance, we expect about 6 MMSCFD reserve capacity available to recover unexpected flows during relief events, or increased vent flows associated with planned and unplanned events. See Section 4.B for more information concerning the DCU Flare Recovery Compressors.

Recovered gas from OPCEN is treated to remove H2S and routed to fuel and hydrogen plant feed along with the recovered gas from Delayed Coking. The normal routing for Delayed Coker Area *recovered* flare gas is the Vent Gas Treater. Sufficient capacity is available for the incremental flow (up to the total recovery compressor capacity of about 8 MMSCFD).

[16] This figure includes the flare gas recovery system with the modification. Due to the need for a general shutdown of process units in the OPCEN area, the system was not operable in time for the August 1 original submittal of this plan. Post-project facilities are used as the basis for system description. However, the historical performance of this flare obviously provides little basis for evaluating mitigation options beyond the implemented flare gas recovery.

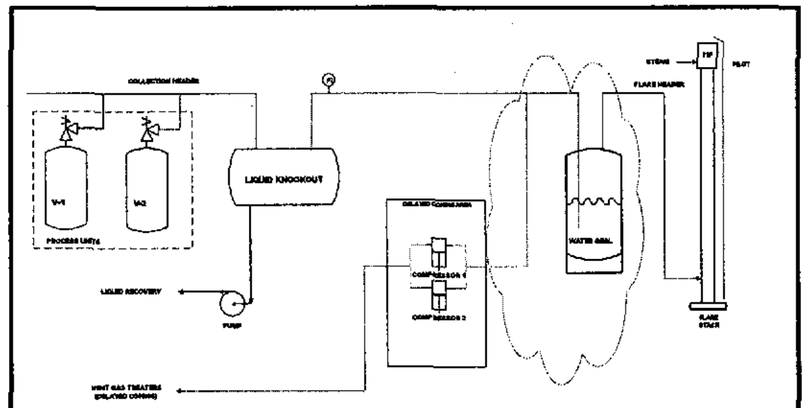


FIGURE 12. OPCEN HYDROCARBON FLARE AREA PROCESS SKETCH

2. HISTORICAL FLARING REVIEW

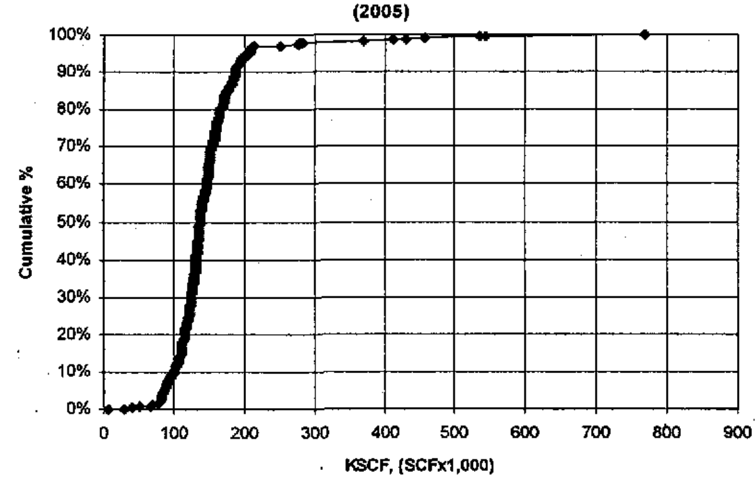
Because vent gas in the OPCEN Hydrocarbon flare had not been recoverable, even minor maintenance and depressuring caused measurable flaring. In consequence, statistics on flow rates and durations for operations and maintenance related flare activity don't merit further review here. This is because they were not constrained by the ability to manage flows within the capacity of recovery compressors.

The relevant measure is flared volumes. During the development of the flare gas recovery project, normal flows in the vent headers of the two flare systems were closely evaluated. This analysis indicates that the normal traffic in the OPCEN flare header is less than 0.2 million standard cubic feet per day (MMSCFD), with the header purges currently used to prevent air intrusion into the system removed[17]. In comparison, background traffic moved by the Delayed Coking Area flare gas recovery compressors is about 2 MMSCFD.

With historical performance profoundly biased by absence of flare gas recovery, this review concentrated on calendar year 2005. Flare data are depicted in Figure 13. Total emissions of non-methane hydrocarbon during 2005 were approximately 30 tons. Emissions of SO2 in 2005 were 0.3 tons.

[17] Purge gas (typically nitrogen) is provided to all flares to prevent oxygen intrusion from the flare stack into the flare header. Without this purge, oxygen can combine with hydrocarbon gas and cause combustion or detonation within the flare header. Where a water seal is present, the location of the purge is moved downstream of the water seal. However, the industry standard practice is to provide purge flows whether or not the seal is present (this will be discussed further in the section on the Flexigas flare). After the flare gas recovery project started up, the purge upstream of the water seal could be eliminated to not contribute a load on Delayed Coker flare gas recovery compressors. The relocated purge gas (nitrogen in this case) downstream of the water seal will not result in emissions of non-methane hydrocarbon or sulfur dioxide.

Figure 13. OPCEN Hydrocarbon Flare Gas Volumes (2005)



3. REDUCTIONS PREVIOUSLY REALIZED (12-12-401.2)

Equipment, processes and procedures installed or implemented within the last five years are listed below.

HARDWARE AND PROCESS REVISIONS

A. A project was installed in January 2006 to improve cooling for the Dimersol Unit reactor effluent. This revision is expected to allow the unit to more reliably meet expected run lengths between maintenance turnarounds. Before this change, fouling of the reactor effluent air cooler required a unit shut down once a year to clean the exchangers. During the shutdown it was necessary to temporarily flare unit feed, and de-inventory the unit to the flare. Since the Dimersol Unit converts propylene to gasoline components, propylene, in excess of that allowed in product, was put into the fuel system. This periodically contributed to flaring treated Flexigas during the maintenance turnaround because of a fuel gas imbalance.

B. Modifications were made to the Wet Gas Compressor (WGC) to allow for full recycle on FXU start-up and shutdown in September 2003. This change helps to keep the WGC out of surge and reduce the potential for flaring during Flexicoker Unit start-up and shutdown.

C. The potential for flaring from all sulfur plant regenerators (DEA Strippers and the Flexsorb stripper) has been virtually eliminated by providing automated reboiler steam cuts when pressures in the column approach relief. This steam cut prevents an overpressure of the system, which would result in venting to the flare through pressure relief valves on the Overhead Accumulator.

PROCEDURAL REVISIONS

The OPCEN Hydrocarbon flare was provided with Flare Gas Recovery in December 2006. Prior to this date, it had been impossible to safely prevent flaring during shutdowns and planned major maintenance or turnarounds since there was no vapor recovery. However, the refinery practice to minimize environmental impacts of planned shutdowns and major maintenance work has been in place for several years. Two activities are provided below.

A. Procedural modifications were made for loading the polysulfide vessel at the FXU (March 2004). The modifications were made to improve pressure control on the vessel, thereby minimizing the potential of flaring due to venting from the vessel. The procedure involved stopping the flow of nitrogen purge gas to the vessel (which is vented to the flare) when the vessel was being re-filled. This eliminated the contribution of the nitrogen purge to the flare header which prior to the flare vapor recovery project, would have been directly flared. With the start up of the OPCEN flare recovery project, the procedure to stop the nitrogen purge during vessel refilling is no longer necessary since the nitrogen purge is recovered by the flare compressors and no longer goes directly to the flare.

B. Each turnaround and major maintenance block, and the related shutdown and startups are *required to develop specific plans* to minimize environmental impacts. The Operating Department and Turnaround groups develop plans with input from the Planning Group and Environmental Affairs. Status and expected impacts are shared across the refinery during the turnaround. The overall environmental performance is reviewed after the turnaround to develop "lessons learned" for subsequent turnarounds.

4. PLANNED REDUCTIONS (12-12-401.3)

HARDWARE AND PROCESS REVISIONS

FLARE GAS RECOVERY: The OPCEN Hydrocarbon flare was provided with a water seal pot and process interconnection to allow use of the Delayed Coking area flare gas recovery compressors for recovery of vent gases that would normally be flared. The project was operational in December 2006. Project cost was approximately $2,700,000. Based on actual 2005 emissions of non-methane hydrocarbon (30 tons) the cost effectiveness of this project is approximately $12,800/ton. Compared to a cost-effectiveness trigger of $20,000 per ton of these emissions, the cost-benefit ratio for this project is approximately 0.6:1. This is a cost-effective project, in contrast to the LOP and DC flare gas recovery expansion projects considered earlier. Basing the cost effectiveness on SO2 reductions would have resulted in a non-feasible project since the ratio of SO2 emissions to NMHC emissions based on the 2005 reported monthly flare emissions is 1:100 (0.3 tons of SO2 emitted and 30 tons of NMHC)

PROCEDURAL REVISIONS

The four procedures described separately are applicable to this flare. These procedures were implemented by November 1, 2006.

5. PREVENTION MEASURES (12-12-401.4)

401.4.1 Prevention Measures for flaring due to planned Major Maintenance

Based on the historical review of flaring incidents, the OPCEN flare gas recovery project will provide sufficient capacity to allow Turnaround and Major Maintenance activities to be conducted without flaring. Until this project was started up, flaring continued when process units either relieved or had to be depressured to the flare. The project was implemented as rapidly as hardware could be acquired, necessary process connections provided, and operating personnel trained. The project was operational in December 2006.

401.4.2 – Prevention Measures for flaring due to issues of gas quantity and quality including review of existing vent gas recovery capacity

Flaring due to gas quantity: In the absence of flare gas recovery, issues of gas quantity and quality were not a factor. All gases entering the flare header were flared. This regular flare gas flow was eliminated by the flare vapor recovery project. Based on demonstrated performance of the other recovery systems at the refinery, the expected performance of the recovery system is greater than 99.8%.

Flaring due to gas quality: Performance of the Delayed Coking Area recovery system with respect to gas quality has been presented earlier. There are no unusual properties of the flare header gas in OPCEN that would affect the historical performance of the system.

Existing Vent Gas Recovery Capacity: With the recovery project complete, the vent gas recovery capacity and alternatives to increase recovery efficiency beyond the expected 99.8% are the same as those presented for the Delayed Coking Area flare and are presented in that section.

401.4.3 Recurrent Failures

There have been no recurrent failures in equipment routed to the OPCEN Hydrocarbon flare in the period since July 2005.

D. FLARE SYSTEM: OPCEN FLEXIGAS FLARE

BAAQMD Source No. 1771

1. SYSTEM DESCRIPTION (12-12-401.2)

The OPCEN Flexigas flare is a dedicated flare serving the Flexicoker Reactor/Heater/Gasifier. The Flexigas flare only combusts flexigas (FXG). This flare differs significantly from all other process flares serving Bay Area refineries for reasons described below. A simplified process sketch is provided in Figure 14. Details of the system are provided in Appendix D.

Low BTU fuel gas: Flexigas (FXG) is a low-BTU fuel gas produced by gasifying coke produced in a fluid-bed Coker. Due to the air used in the gasifying process, Flexigas is approximately half nitrogen. The bulk of the remaining components are hydrogen and carbon monoxide. The gas is produced and supplied at a relatively low pressure compared with the refinery fuel gas system. Compressors are not used because the volume of gas (210 MMSCFD) would result in tremendous and unnecessary cost.

All Flexigas is treated for sulfur removal: All of the Flexigas produced from the Flexicoker Reactor/Heater/Gasifier is cooled and routed to the Flexsorb Unit. Flexsorb removes H_2S down to a level typically lower than that of refinery fuel gas[18]. Control valves on Flexsorb column overhead piping provide the stable backpressure necessary to assure reliable operation of the Flexicoker. A separate control valve maintains the required minimum purge flow through the Flexigas flare header to prevent air intrusion into the header.

High recovery of Flexigas: There are approximately 19 heaters in the refinery that can use Flexigas as a fuel. Combusting Flexigas results in lower NOx emissions than combustion of either refinery fuel gas or natural gas and its use is an integral part of the refinery's NOx emission reduction program. The specific number and capacities of the individual heaters varies depending upon process unit turnarounds and refinery operation. The vast majority of the time there are more consumers than required to consume all Flexigas. This is why the Flexigas system has the highest effective "recovery" of all potentially flared gases. Of all Flexigas produced during 2005, only 0.08% ended up in the flare as the result of dynamic movement in the refinery fuel system.

All Flexigas emissions in permit cap: When a Flexigas user unexpectedly comes off-line, it can be difficult to rapidly take up the available gas. Because of the high flows involved, a volume of gas exceeding the Air District definition of flare "event" (0.5 MMSCF) may result before the Flexicoker can reduce production of this gas. In this case, treated Flexigas may be temporarily flared. Emissions from burning flexigas, whether in refinery heaters or the flare, are subject to the permit limits in our refinery emission cap.

2. HISTORICAL FLARING REVIEW

[18] Because of its low emissions of SOx, NOx and particulates, Flexigas is the fuel flared during those brief periods where a fuel system imbalance occurs as a result of process upset. This may increase the flaring at the Flexigas flare, but results in lower emissions than flaring any other fuel.

Historical flaring at the OPCEN Flexigas flare was reviewed to identify opportunities for potential mitigation. The highest quality data are available for the period from December 2003, to January 2006. This coincides with installation of the flare flow meter and BAAQMD flare reporting. Data for 2005 are plotted in Figure 15 and Figure 16.

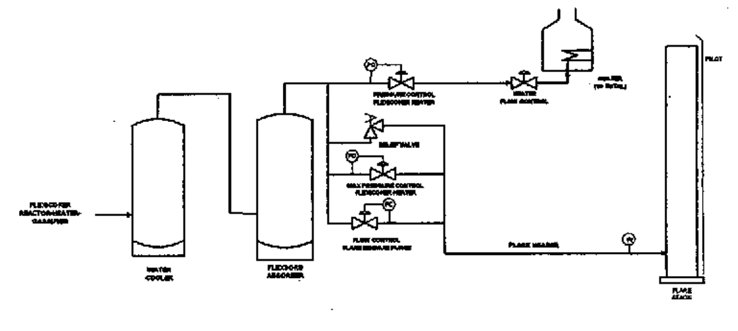


FIGURE 14. FLEXIGAS SUPPLY SYSTEM PROCESS SKETCH

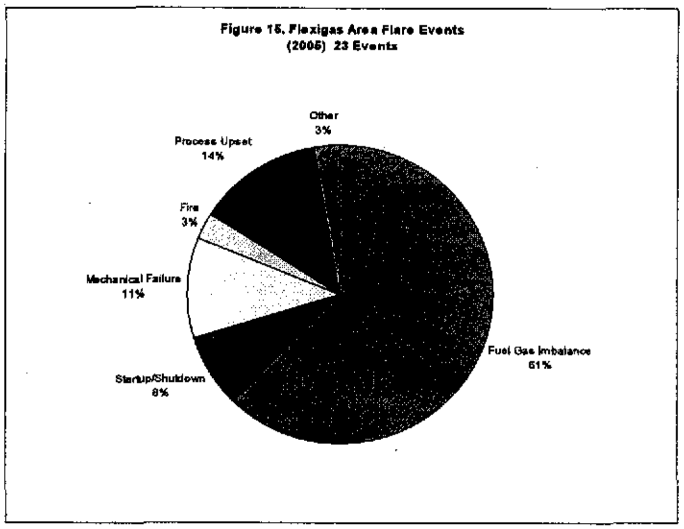


Figure 15. Flexigas Area Flare Events
(2005) 23 Events
Other
3%
Process Upset
14%
Fire
3%
Mechanical Failure
11%
Startup/Shutdown
8%
Fuel Gas Imbalance
61%

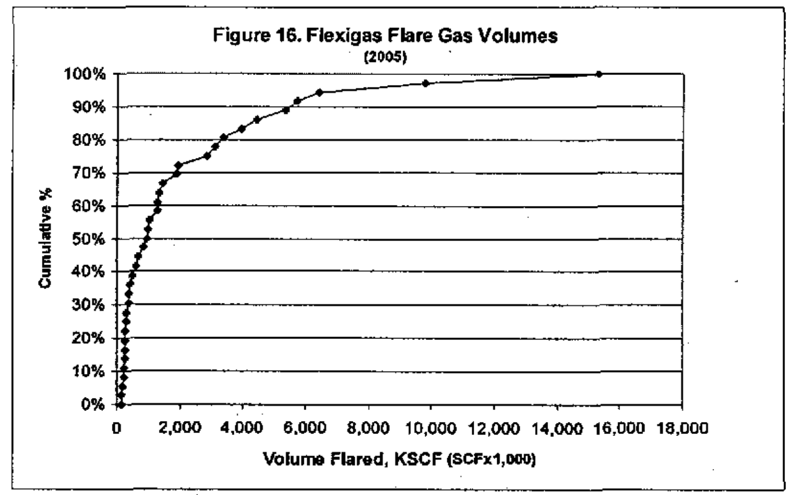


Figure 16. Flexigas Flare Gas Volumes
(2005)
Cumulative %
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
2,000
4,000
6,000
8,000
10,000
12,000
14,000
16,000
18,000
Volume Flared, KSCF (SCFx1,000)

3. REDUCTIONS PREVIOUSLY REALIZED (12-12-401.2)

Equipment, processes and procedures installed or implemented with the last five years to reduce flaring include:

HARDWARE AND PROCESS REVISIONS

A. The Stretford Unit was replaced with a Flexsorb unit in 2005. This project cost approximately $30,000,000. Sulfur levels in treated flexigas are significantly lower with the *Flexsorb process than the earlier* Stretford process. The Flexsorb process unit eliminated the problem of sulfur plugging that had occurred with the earlier Stretford process. This plugging had resulted in the need for a dilute caustic wash once or twice each year to remove elemental sulfur from the gas contacting tower. Each caustic wash resulted in the flaring of 6-10 MMSCF of flexigas. Since Flexsorb is not susceptible to plugging, the improved on-stream factor and operating stability result in both significantly less flaring, and lower SO_2 emissions, when flaring does occur.

B. The control system used to maintain a steady supply pressure of Flexigas to the distribution system has undergone continuous improvement. Revisions implemented during the last FXU turnaround simplified the control system to use standard Honeywell TDC control logic. This control logic is more easily understood by operating personnel. FXU Board operators are generally able to recognize and respond more quickly to upsets. The result is that the new control system has proven more responsive than the previous version which results in less FXG flaring due to upsets in the flexicoker system.

   On the Flexigas consumption side, furnace control limits related to FXG were examined and adjusted to allow maximum FXG consumption.

C. Flexicoker run length (time between shutdowns) has been increased to reduce the volume of untreated Flexigas which must be flared during startup conditions.[19] This change reduces flaring because there are less shutdowns and startups requiring flaring for the same time period of time.

D. Additional heaters have been converted to Flexigas over the years to increase the number of consumers for this clean burning low-NOx fuel.

E. Shutdown of the Catalytic Reforming Unit, a major flexigas consumer, resulted in a Flexigas flaring event in September 2005. The cause of *the shutdown was determined to be a* leaking flange on a heat exchanger that resulted in a fire. The flange leak was believed to have been caused by thermal-cycling of the equipment that occurred during a previous shutdown. Bellville washers were added to the bolting arrangement on the flange to provide more tolerance for thermal expansion. Bellville washers are specially designed using spring-tension to provide a more constant sealing force on equipment that undergoes temperature cycling. Having a more uniform sealing force is hoped to reduce the potential for an unexpected and rapid unit shutdown due to leaking flanges after reactor regeneration. The type of washer used in this application may change if future evaluation of these washers indicates that a different type of washer is needed to assure reliable and safe unit operation.

[19] Flexsorb is an Exxon/Mobil process. Due to the nature of the Flexsorb solvent, it may be degraded by oxygen that can be present in Flexigas during initial startup. Exxon/Mobil operating guidelines call for this gas to be flared until Flexicoker operation is stable.

F. PROCEDURAL REVISIONS

Due to the volume and composition of Flexigas, it cannot be captured and returned to the refinery fuel system. The balance between production and consumption of this gas must be managed in real time to avoid flaring above the minimum required to prevent oxygen entering the flare stack. Refinery work practices have been significantly affected by the desire to avoid flaring Flexigas. In particular, efforts relating to fuel system management have strict guidelines to minimize Flexigas flaring. These guidelines include direction to reduce Flexigas production and Flexicoker feed rate subject to prevailing requirements for safe and reliable operation of that unit.

4. PLANNED REDUCTIONS (12-12-401.3)

HARDWARE AND PROCESS REVISIONS

A) Flexigas flaring occurred when the Flexicoker elutriator feed line required inspection and repair due to discovery of a crack near a weld. To help prevent cracking, the elutriator feed line has been re-designed. The changes were implemented during the Flexicoker turnaround occurring through [redacted].

B) Flexigas flaring occurred due to slowdown of coke transfer in the Flexicoker Gasifier Return Line (GRL) due to refractory spalling in the line. During [redacted], the GRL will have a more robust refractory liner installed that should be less susceptible to flaring.

C) The Flexicoker heater/reactor differential pressure control scheme will be simplified and improved in [redacted] to help reduce flaring.

PROCEDURAL REVISIONS

The four procedures described separately are applicable to this flare. These procedures were implemented by November 1, 2006.

PREVENTION MEASURES (12-12-401.4)

Two options are presented to improve the efficiency of recovering Flexigas from the current 99.92%. These are presented in section 401.4.2.

401.4.1 Prevention Measures for flaring due to planned Major Maintenance

An important difference between the Flexigas flare and other process area flares is that it does not receive vent gases from maintenance sources such as vessel depressuring. Beyond the very limited windows where Flexigas *must be flared during Flexicoker startups and shutdowns to* protect the Flexsorb unit, untreated Flexigas is not flared.[20] However, turnarounds and major maintenance at other units may remove enough Flexigas consumers from the system that limited Flexigas flaring cannot be prevented. In these cases, flare minimization due to fuel balance procedure C(F)-22 is applicable as well as the minimization of flaring during turnaround and major maintenance in procedure C(A) -1.

401.4.2 – Prevention Measures for flaring due to issues of gas quantity and quality including review of existing vent gas recovery capacity

Gas Quantity: All Flexigas that is created is combusted somewhere, either in a process heater or the Flexigas flare. The minimum volume of Flexigas which must be made in order to operate the

[20] The Flexsorb Permit to Operate specifies periods where Flexigas may be flared. This permitted flaring is found in Shell's permit condition # 7618. As long as the permit conditions are met, this flaring is consistent with the Flare Minimization Plan.

Flexicoker is approximately 165 MM SCFD. When there are insufficient consumers to handle this volume, the remainder has to be flared. Because of the amount of time required to cut from the normal Flexigas production of approximately 210 MM SCFD, down to the minimum, the volume of Flexigas that can be flared even with best operating practices can exceed the current 500,000 SCF flare event threshold. As a result, two options are considered to reduce or eliminate Flexigas flaring.

OPTION 1: PROVIDE ADDITIONAL FLEXIGAS CONSUMER(S) (see Figure 17).

The objective of this project would be to provide an additional consumer that can rapidly pick up the Flexigas volumes made available by loss of another consumer (e.g., process heater) for any reason. Because excess Flexigas is available less than 10% of the time (based on the percent of days on which flaring occurred from Figure 16), and the current fuel system is roughly in balance, this consumer must essentially remain in hot standby until needed. This means it must be waiting to burn between 1 MMSCFD and 40 MMSCFD Flexigas when an existing consumer unexpectedly comes off line.

The only remaining consumer at the Martinez refinery not already converted to burn Flexigas that approaches the attributes described above is the Cogeneration Unit Steam Generator. If additional steam is not needed in the refinery, then adding Flexigas to the Cogeneration Steam Generator will produce steam that must subsequently be vented to atmosphere. For the sake of the analysis, we assume the steam produced by Flexigas burned in this boiler can be used in the refinery. In the event that the Cogeneration Steam Generator was only used to burn the Flexigas and the steam had to be vented, the emissions reductions amount to only the difference in combustion efficiencies of process heaters and flares. The project has an estimated cost of approximately $3,000,000.

Assuming this eliminates all Flexigas flaring, it would reduce emissions of non-methane hydrocarbon by much less than one ton per year[21]. The cost effectiveness of this project using accepted BAAQMD methods is approximately $19,000,000/ton for non-methane hydrocarbon, and $1,000,000 per ton for SOx. Details of these calculations are provided in Appendix F of this report. If the refinery fuel and steam systems are in balance prior to the flare event, the actual value of produced steam is small. This more realistic assumption results in an even less cost-effective project. In either case, this project is not cost effective for reduction of flaring.

[21] Cost-effectiveness based on 2005 reported emissions of NMHC from flaring of flexigas (0.04 tons for the entire year). The average ratio of SO2 to NMHC emissions over the same period (2005) from the reported monthly flare reports is 20:1 (0.81 tons of SO2 and 0.04 tons of NMHC emissions were reported). The project described as Option 1 is also not cost-effective based on the reduction of SO2 emissions ($950,000/ton of SO2 reductions).

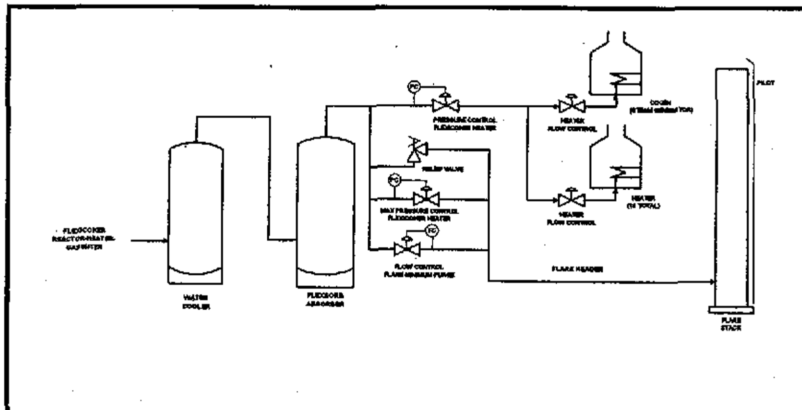


FIGURE 17. FLEXIGAS FLARE PROCESS SKETCH OPTION 1

OPTION 2: PROVIDE FLEXIGAS STORAGE.

Regulations in Contra Cost County require consideration of Inherently Safer Systems to proposed process revisions. Key strategies in making things inherently safer include: reducing both the amount of materials stored and their hazard classification, and making use of a simple processing scheme that is not reliant on active controls. Measured against this standard, the proposed active system of compressing, storing and reprocessing fuel gas, as an alternative to immediately flaring these gases, would not be preferred under the Contra Costa County Industrial Safety Ordinance. Regardless, for the purposes of this plan, our analysis considers two storage options.

Option 2A consists of a pressurized vessel that would require a compressor with capacity ranging between 1 MMSCFD and 10 MMSCFD. This option is depicted in Figure 18. Flexigas in excess of consumer demand is routed to storage via compressor(s). A controlled flow is returned to the distribution system when enough consumers are available to avoid flaring. Due to the limited capacity of this storage, it has no real capability to accommodate prolonged fuel system imbalances. As a result, the expected best-case emission reductions are about the same as those available in 2005. A rough capital cost for the storage and large compressors is about \$27,000,000[22]. Annual electrical costs for the required compressors add another \$600,000. The annualized capital plus electrical costs to eliminate a ton of non-methane hydrocarbon result in a cost-effectiveness of approximately \$190 Million dollars per ton. Therefore, Option 2A is even less cost-effective for reducing flaring than Option 1.

Option 2B uses low-pressure expandable gas storage. This option is depicted in Figure 19. This type of storage can be built significantly larger than the pressurized storage used in option 2A, and has the advantage of not requiring compressors in some cases. However, the concentration of carbon monoxide in the gas will likely require use of a water seal to limit leakage, restricting vessel height to a single lift. The requirement for a single lift, combined with low-pressure operation, significantly limits available storage volume[23]. In any event, the installed cost is approximately \$21,000,000, providing cost-effectiveness of approximately \$276 Million dollars per ton of NMHC. As was the case for Option 2A, this option is even less cost-effective for reducing flaring than Option 1.

Flaring due to gas quality: Flexigas may be flared during Flexicoker startup and shutdown to avoid poisoning the Flexsorb solution in the early stage of gasification. This is specified in Operating Procedures provided by the technology vendor, Exxon/Mobil, and is addressed in the Flexsorb unit Operating Permit. Shell staff are working with Exxon/Mobil to understand whether it is possible to reduce the volume flared by revising the procedure without poisoning the Flexsorb solution which would result in the inability to treat the flexigas. The permit condition currently allows flexigas flaring for a certain number of hours during startup and shutdown of the Flexicoker. Outside of this condition, Flexigas is not flared as a direct consequence of its quality.

[22] Based on a nominal 1 MMSCF sphere (60' diameter) at 120 psig, and two 4 MMSCFD compressors. This system would handle only minor imbalances while the Flexicoker cuts rate.
[23] The actual available storage volume is probably on the order of 1 MMSCFD, and will severely limit achievable emissions reductions. A 50% savings is premised for this analysis.

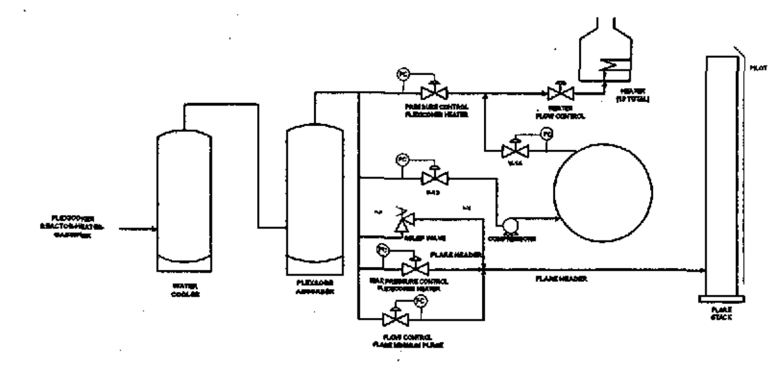


FIGURE 18. FLEXIGAS FLARE PROCESS SKETCH OPTION 2A

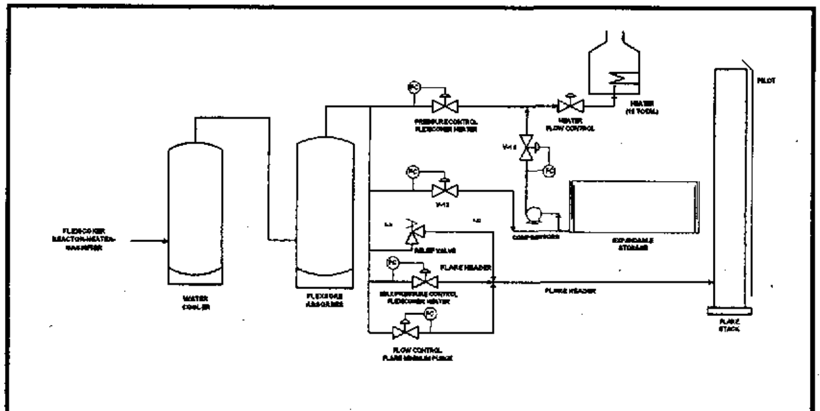


FIGURE 1[illegible], FLEXIGAS FLARE PROCESS SKETCH OPTION [illegible]

Review of existing vent gas recovery capacity: There is no vent gas recovery or storage capacity for Flexigas. The Flexsorb Unit is designed to be able to treat all Flexigas that can be produced for sulfur removal.

OPCEN Flexigas flare gas recovery system capacity:	
Total OPCEN Flexigas flare gas recovery capacity	= 0 MM SCFD
Total OPCEN Flexigas flare gas storage capacity	= 0 SCF
OPCEN Flexigas fuel gas treating capacity	= 250 MM SCFD

401.4.3 Recurrent Failures

There have been no recurrent failures in equipment routed to the OPCEN Flexigas flare in the period since July 2005.

APPENDIX A

LOP AREA FLARE TECHNICAL DATA

The information in this section has been redacted.

March 2007

APPENDIX B

DELAYED COKING AREA FLARE TECHNICAL DATA

The information in this section has been redacted.

APPENDIX C

OPCEN HYDROCARBON FLARE TECHNICAL DATA

The information in this section has been redacted.

APPENDIX D

FLEXIGAS FLARE TECHNICAL DATA

The information in this section has been redacted.

APPENDIX E

REFINERY FUEL GAS SYSTEM

The information in this section has been redacted.

APPENDIX F

DETAILED ECONOMICS FOR FLARE MITIGATION OPTIONS

The information in this section has been redacted.

EXHIBIT K

	Vent Gas Flow Volume (scf)	Methane (tpy)	NMHC (tpy)	Sulfur Dioxide (tpy)
Shell Clean Fuels Flare	157,458	0.02	0.03	0.10
Shell LOP Flare	973,317	0.16	0.19	0.56
Shell Opcen Flare	32,196,294	5.76	21.09	0.68
Shell Opcen Fxg Flare	297,115,292	6.43	0.06	1.46
Total	330,442,361	12.36	21.36	2.80
Total without Opcen	298,246,067	6.60	0.28	2.11
Total ratiod up to ConocoPhillips Wood River ratiod up from 98,500 to 385,000		48.3	83.5	10.9

Shell Martinez Refinery, California, Flare Data downloaded from Bay Area Air Quality Management Distric
http://www.baaqmd.gov/enf/flares/index_2006.htm

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Jan 1 2006 - Jar 2006
#

#Date (mo/dɛ	Vent Gas	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
1/1/2006	0	0	0	0
1/2/2006	0	0	0	0
1/3/2006	0	0	0	0
1/4/2006	0	0	0	0
1/5/2006	0	0	0	0
1/6/2006	0	0	0	0
1/7/2006	0	0	0	0
1/8/2006	0	0	0	0
1/9/2006	0	0	0	0
1/10/2006	0	0	0	0
1/11/2006	0	0	0	0
1/12/2006	0	0	0	0
1/13/2006	0	0	0	0
1/14/2006	0	0	0	0
1/15/2006	0	0	0	0
1/16/2006	0	0	0	0
1/17/2006	0	0	0	0
1/18/2006	0	0	0	0
1/19/2006	0	0	0	0
1/20/2006	0	0	0	0
1/21/2006	0	0	0	0
1/22/2006	0	0	0	0
1/23/2006	0	0	0	0
1/24/2006	0	0	0	0
1/25/2006	0	0	0	0
1/26/2006	0	0	0	0
1/27/2006	0	0	0	0
1/28/2006	0	0	0	0
1/29/2006	0	0	0	0
1/30/2006	0	0	0	0
1/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Feb 1 2006 - Fel 2006
#

#Date (mo/dɛ	Vent Gas	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
2/1/2006	0	0	0	0

2/2/2006	0	0	0	0
2/3/2006	0	0	0	0
2/4/2006	0	0	0	0
2/5/2006	0	0	0	0
2/6/2006	0	0	0	0
2/7/2006	0	0	0	0
2/8/2006	0	0	0	0
2/9/2006	0	0	0	0
2/10/2006	0	0	0	0
2/11/2006	13966	1.95	6.4	29.61
2/12/2006	0	0	0	0
2/13/2006	0	0	0	0
2/14/2006	0	0	0	0
2/15/2006	0	0	0	0
2/16/2006	0	0	0	0
2/17/2006	0	0	0	0
2/18/2006	0	0	0	0
2/19/2006	0	0	0	0
2/20/2006	0	0	0	0
2/21/2006	0	0	0	0
2/22/2006	0	0	0	0
2/23/2006	0	0	0	0
2/24/2006	0	0	0	0
2/25/2006	0	0	0	0
2/26/2006	0	0	0	0
2/27/2006	0	0	0	0
2/28/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Mar 1 2006 - Ma 2006
#

#Date (mo/d:	Vent Gas	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
3/1/2006	0	0	0	0
3/2/2006	36087	8.16	9.06	0
3/3/2006	0	0	0	0
3/4/2006	4640	0.65	2.13	9.84
3/5/2006	0	0	0	0
3/6/2006	0	0	0	0
3/7/2006	0	0	0	0
3/8/2006	0	0	0	0
3/9/2006	0	0	0	0
3/10/2006	0	0	0	0
3/11/2006	0	0	0	0
3/12/2006	0	0	0	0
3/13/2006	0	0	0	0
3/14/2006	0	0	0	0
3/15/2006	0	0	0	0
3/16/2006	0	0	0	0

3/17/2006	0	0	0	0
3/18/2006	0	0	0	0
3/19/2006	0	0	0	0
3/20/2006	0	0	0	0
3/21/2006	0	0	0	0
3/22/2006	0	0	0	0
3/23/2006	0	0	0	0
3/24/2006	0	0	0	0
3/25/2006	0	0	0	0
3/26/2006	0	0	0	0
3/27/2006	0	0	0	0
3/28/2006	0	0	0	0
3/29/2006	0	0	0	0
3/30/2006	0	0	0	0
3/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Apr 1 2006 - Apr 2006
#

#Date (mo/d	Vent Gas	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
4/1/2006	0	0	0	0
4/2/2006	0	0	0	0
4/3/2006	0	0	0	0
4/4/2006	0	0	0	0
4/5/2006	0	0	0	0
4/6/2006	0	0	0	0
4/7/2006	0	0	0	0
4/8/2006	0	0	0	0
4/9/2006	0	0	0	0
4/10/2006	0	0	0	0
4/11/2006	0	0	0	0
4/12/2006	0	0	0	0
4/13/2006	0	0	0	0
4/14/2006	0	0	0	0
4/15/2006	0	0	0	0
4/16/2006	0	0	0	0
4/17/2006	0	0	0	0
4/18/2006	1364	0.35	0.54	3.34
4/19/2006	4769	1.22	1.89	11.68
4/20/2006	0	0	0	0
4/21/2006	0	0	0	0
4/22/2006	0	0	0	0
4/23/2006	0	0	0	0
4/24/2006	295	0.08	0.12	0.72
4/25/2006	0	0	0	0
4/26/2006	0	0	0	0
4/27/2006	0	0	0	0
4/28/2006	0	0	0	0
4/29/2006	0	0	0	0
4/30/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#May 1 2006 - Ma 2006
#

#Date (mo/d	Vent Gas	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
5/1/2006	0	0	0	0
5/2/2006	0	0	0	0
5/3/2006	0	0	0	0
5/4/2006	0	0	0	0
5/5/2006	0	0	0	0
5/6/2006	17604	4.59	6.03	25.18
5/7/2006	0	0	0	0
5/8/2006	0	0	0	0
5/9/2006	0	0	0	0
5/10/2006	0	0	0	0
5/11/2006	0	0	0	0
5/12/2006	0	0	0	0
5/13/2006	0	0	0	0
5/14/2006	0	0	0	0
5/15/2006	61758	16.11	21.16	88.35
5/16/2006	0	0	0	0
5/17/2006	0	0	0	0
5/18/2006	0	0	0	0
5/19/2006	0	0	0	0
5/20/2006	0	0	0	0
5/21/2006	0	0	0	0
5/22/2006	0	0	0	0
5/23/2006	0	0	0	0
5/24/2006	0	0	0	0
5/25/2006	0	0	0	0
5/26/2006	0	0	0	0
5/27/2006	0	0	0	0
5/28/2006	0	0	0	0
5/29/2006	0	0	0	0
5/30/2006	0	0	0	0
5/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Jun 1 2006 - Jur 2006
#

#Date (mo/d	Vent Gas	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
6/1/2006	0	0	0	0
6/2/2006	0	0	0	0
6/3/2006	0	0	0	0
6/4/2006	0	0	0	0
6/5/2006	0	0	0	0

6/6/2006	0	0	0	0
6/7/2006	0	0	0	0
6/8/2006	0	0	0	0
6/9/2006	0	0	0	0
6/10/2006	0	0	0	0
6/11/2006	0	0	0	0
6/12/2006	0	0	0	0
6/13/2006	0	0	0	0
6/14/2006	0	0	0	0
6/15/2006	0	0	0	0
6/16/2006	0	0	0	0
6/17/2006	0	0	0	0
6/18/2006	0	0	0	0
6/19/2006	0	0	0	0
6/20/2006	0	0	0	0
6/21/2006	0	0	0	0
6/22/2006	0	0	0	0
6/23/2006	0	0	0	0
6/24/2006	0	0	0	0
6/25/2006	0	0	0	0
6/26/2006	0	0	0	0
6/27/2006	0	0	0	0
6/28/2006	0	0	0	0
6/29/2006	0	0	0	0
6/30/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Jul 1 2006 - Jul 2006
#

#Date (mo/d	Vent Gas I	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
7/1/2006	7903	2.06	2.71	11.31
7/2/2006	0	0	0	0
7/3/2006	0	0	0	0
7/4/2006	0	0	0	0
7/5/2006	0	0	0	0
7/6/2006	0	0	0	0
7/7/2006	0	0	0	0
7/8/2006	0	0	0	0
7/9/2006	0	0	0	0
7/10/2006	0	0	0	0
7/11/2006	0	0	0	0
7/12/2006	0	0	0	0
7/13/2006	0	0	0	0
7/14/2006	0	0	0	0
7/15/2006	0	0	0	0
7/16/2006	0	0	0	0
7/17/2006	0	0	0	0
7/18/2006	0	0	0	0

7/19/2006	0	0	0	0
7/20/2006	0	0	0	0
7/21/2006	0	0	0	0
7/22/2006	0	0	0	0
7/23/2006	0	0	0	0
7/24/2006	0	0	0	0
7/25/2006	0	0	0	0
7/26/2006	0	0	0	0
7/27/2006	0	0	0	0
7/28/2006	0	0	0	0
7/29/2006	0	0	0	0
7/30/2006	2123	0.55	0.73	3.04
7/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Aug 1 2006 - Au(2006
#

#Date (mo/d‹	Vent Gas I	Methane (	NMHC (lb‹	Sulfur Dioxide (lbs)
8/1/2006	0	0	0	0
8/2/2006	0	0	0	0
8/3/2006	3916	1.02	1.34	5.6
8/4/2006	0	0	0	0
8/5/2006	0	0	0	0
8/6/2006	0	0	0	0
8/7/2006	0	0	0	0
8/8/2006	0	0	0	0
8/9/2006	0	0	0	0
8/10/2006	0	0	0	0
8/11/2006	1859	0.48	0.64	2.66
8/12/2006	0	0	0	0
8/13/2006	0	0	0	0
8/14/2006	0	0	0	0
8/15/2006	0	0	0	0
8/16/2006	0	0	0	0
8/17/2006	0	0	0	0
8/18/2006	0	0	0	0
8/19/2006	0	0	0	0
8/20/2006	0	0	0	0
8/21/2006	0	0	0	0
8/22/2006	0	0	0	0
8/23/2006	0	0	0	0
8/24/2006	0	0	0	0
8/25/2006	0	0	0	0
8/26/2006	0	0	0	0
8/27/2006	0	0	0	0
8/28/2006	0	0	0	0
8/29/2006	0	0	0	0
8/30/2006	0	0	0	0
8/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Sep 1 2006 - Sep 2006
#

#Date (mo/d	Vent Gas	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
9/1/2006	0	0	0	0
9/2/2006	0	0	0	0
9/3/2006	0	0	0	0
9/4/2006	0	0	0	0
9/5/2006	0	0	0	0
9/6/2006	0	0	0	0
9/7/2006	0	0	0	0
9/8/2006	0	0	0	0
9/9/2006	0	0	0	0
9/10/2006	0	0	0	0
9/11/2006	0	0	0	0
9/12/2006	0	0	0	0
9/13/2006	0	0	0	0
9/14/2006	0	0	0	0
9/15/2006	0	0	0	0
9/16/2006	0	0	0	0
9/17/2006	0	0	0	0
9/18/2006	0	0	0	0
9/19/2006	0	0	0	0
9/20/2006	0	0	0	0
9/21/2006	0	0	0	0
9/22/2006	0	0	0	0
9/23/2006	0	0	0	0
9/24/2006	0	0	0	0
9/25/2006	0	0	0	0
9/26/2006	0	0	0	0
9/27/2006	0	0	0	0
9/28/2006	0	0	0	0
9/29/2006	0	0	0	0
9/30/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Oct 1 2006 - Oct 2006
#

#Date (mo/d	Vent Gas	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
10/1/2006	0	0	0	0
10/2/2006	0	0	0	0
10/3/2006	0	0	0	0
10/4/2006	0	0	0	0
10/5/2006	0	0	0	0
10/6/2006	0	0	0	0
10/7/2006	0	0	0	0

10/8/2006	0	0	0	0
10/9/2006	0	0	0	0
10/10/2006	0	0	0	0
10/11/2006	0	0	0	0
10/12/2006	0	0	0	0
10/13/2006	0	0	0	0
10/14/2006	0	0	0	0
10/15/2006	0	0	0	0
10/16/2006	0	0	0	0
10/17/2006	0	0	0	0
10/18/2006	0	0	0	0
10/19/2006	0	0	0	0
10/20/2006	0	0	0	0
10/21/2006	0	0	0	0
10/22/2006	0	0	0	0
10/23/2006	0	0	0	0
10/24/2006	0	0	0	0
10/25/2006	0	0	0	0
10/26/2006	0	0	0	0
10/27/2006	0	0	0	0
10/28/2006	0	0	0	0
10/29/2006	0	0	0	0
10/30/2006	0	0	0	0
10/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Nov 1 2006 - Nov 2006
#

#Date (mo/d	Vent Gas	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
11/1/2006	0	0	0	0
11/2/2006	0	0	0	0
11/3/2006	0	0	0	0
11/4/2006	0	0	0	0
11/5/2006	0	0	0	0
11/6/2006	0	0	0	0
11/7/2006	0	0	0	0
11/8/2006	0	0	0	0
11/9/2006	0	0	0	0
11/10/2006	0	0	0	0
11/11/2006	0	0	0	0
11/12/2006	0	0	0	0
11/13/2006	0	0	0	0
11/14/2006	0	0	0	0
11/15/2006	0	0	0	0
11/16/2006	0	0	0	0
11/17/2006	0	0	0	0
11/18/2006	0	0	0	0
11/19/2006	0	0	0	0
11/20/2006	0	0	0	0

11/21/2006	0	0	0	0
11/22/2006	0	0	0	0
11/23/2006	0	0	0	0
11/24/2006	0	0	0	0
11/25/2006	0	0	0	0
11/26/2006	0	0	0	0
11/27/2006	0	0	0	0
11/28/2006	0	0	0	0
11/29/2006	0	0	0	0
11/30/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Dec 1 2006 - Dec 2006
#

#Date (mo/d	Vent Gas	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
12/1/2006	0	0	0	0
12/2/2006	0	0	0	0
12/3/2006	0	0	0	0
12/4/2006	0	0	0	0
12/5/2006	1174	0.35	0.39	1.7
12/6/2006	0	0	0	0
12/7/2006	0	0	0	0
12/8/2006	0	0	0	0
12/9/2006	0	0	0	0
12/10/2006	0	0	0	0
12/11/2006	0	0	0	0
12/12/2006	0	0	0	0
12/13/2006	0	0	0	0
12/14/2006	0	0	0	0
12/15/2006	0	0	0	0
12/16/2006	0	0	0	0
12/17/2006	0	0	0	0
12/18/2006	0	0	0	0
12/19/2006	0	0	0	0
12/20/2006	0	0	0	0
12/21/2006	0	0	0	0
12/22/2006	0	0	0	0
12/23/2006	0	0	0	0
12/24/2006	0	0	0	0
12/25/2006	0	0	0	0
12/26/2006	0	0	0	0
12/27/2006	0	0	0	0
12/28/2006	0	0	0	0
12/29/2006	0	0	0	0
12/30/2006	0	0	0	0
12/31/2006	0	0	0	0

Total 2006	Vent Gas I	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
Clean Fuels Area Flare	157458	37.57	53.14	193.03
tons		0.0	0.0	0.1

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Jan 1 2006 - Jar 2006
#

#Date (mo/da	Vent Gas (	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
1/1/2006	0	0	0	0
1/2/2006	0	0	0	0
1/3/2006	0	0	0	0
1/4/2006	0	0	0	0
1/5/2006	0	0	0	0
1/6/2006	24009	8.42	11.72	66.35
1/7/2006	0	0	0	0
1/8/2006	80549	12.38	54.75	319.79
1/9/2006	0	0	0	0
1/10/2006	0	0	0	0
1/11/2006	27705	3.63	19.44	113.84
1/12/2006	0	0	0	0
1/13/2006	0	0	0	0
1/14/2006	0	0	0	0
1/15/2006	15336	6.89	6.01	33.09
1/16/2006	0	0	0	0
1/17/2006	0	0	0	0
1/18/2006	0	0	0	0
1/19/2006	14917	8.06	4.52	23.83
1/20/2006	0	0	0	0
1/21/2006	50421	5.83	36.14	211.96
1/22/2006	0	0	0	0
1/23/2006	15546	8.53	4.59	24.09
1/24/2006	0	0	0	0
1/25/2006	0	0	0	0
1/26/2006	0	0	0	0
1/27/2006	0	0	0	0
1/28/2006	0	0	0	0
1/29/2006	0	0	0	0
1/30/2006	0	0	0	0
1/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Feb 1 2006 - Fel 2006
#

#Date (mo/da	Vent Gas (	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
2/1/2006	0	0	0	0
2/2/2006	0	0	0	0
2/3/2006	0	0	0	0
2/4/2006	0	0	0	0
2/5/2006	0	0	0	0

2/6/2006	0	0	0	0
2/7/2006	0	0	0	0
2/8/2006	0	0	0	0
2/9/2006	0	0	0	0
2/10/2006	0	0	0	0
2/11/2006	0	0	0	0
2/12/2006	0	0	0	0
2/13/2006	0	0	0	0
2/14/2006	0	0	0	0
2/15/2006	0	0	0	0
2/16/2006	0	0	0	0
2/17/2006	0	0	0	0
2/18/2006	0	0	0	0
2/19/2006	0	0	0	0
2/20/2006	0	0	0	0
2/21/2006	0	0	0	0
2/22/2006	0	0	0	0
2/23/2006	0	0	0	0
2/24/2006	0	0	0	0
2/25/2006	0	0	0	0
2/26/2006	0	0	0	0
2/27/2006	0	0	0	0
2/28/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Mar 1 2006 - Ma 2006
#

#Date (mo/da	Vent Gas I	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
3/1/2006	0	0	0	0
3/2/2006	0	0	0	0
3/3/2006	0	0	0	0
3/4/2006	0	0	0	0
3/5/2006	0	0	0	0
3/6/2006	0	0	0	0
3/7/2006	0	0	0	0
3/8/2006	0	0	0	0
3/9/2006	0	0	0	0
3/10/2006	0	0	0	0
3/11/2006	0	0	0	0
3/12/2006	0	0	0	0
3/13/2006	0	0	0	0
3/14/2006	0	0	0	0
3/15/2006	0	0	0	0
3/16/2006	0	0	0	0
3/17/2006	0	0	0	0
3/18/2006	0	0	0	0
3/19/2006	276026	17.74	68.27	102.54
3/20/2006	0	0	0	0

3/21/2006	0	0	0	0
3/22/2006	0	0	0	0
3/23/2006	0	0	0	0
3/24/2006	0	0	0	0
3/25/2006	0	0	0	0
3/26/2006	0	0	0	0
3/27/2006	0	0	0	0
3/28/2006	0	0	0	0
3/29/2006	0	0	0	0
3/30/2006	0	0	0	0
3/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Apr 1 2006 - Apr 2006
#

#Date (mo/da	Vent Gas	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
4/1/2006	0	0	0	0
4/2/2006	0	0	0	0
4/3/2006	0	0	0	0
4/4/2006	0	0	0	0
4/5/2006	0	0	0	0
4/6/2006	0	0	0	0
4/7/2006	0	0	0	0
4/8/2006	0	0	0	0
4/9/2006	0	0	0	0
4/10/2006	0	0	0	0
4/11/2006	0	0	0	0
4/12/2006	0	0	0	0
4/13/2006	0	0	0	0
4/14/2006	0	0	0	0
4/15/2006	0	0	0	0
4/16/2006	0	0	0	0
4/17/2006	0	0	0	0
4/18/2006	0	0	0	0
4/19/2006	0	0	0	0
4/20/2006	0	0	0	0
4/21/2006	0	0	0	0
4/22/2006	0	0	0	0
4/23/2006	0	0	0	0
4/24/2006	0	0	0	0
4/25/2006	0	0	0	0
4/26/2006	0	0	0	0
4/27/2006	0	0	0	0
4/28/2006	0	0	0	0
4/29/2006	0	0	0	0
4/30/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#May 1 2006 - Ma 2006
#

#Date (mo/da	Vent Gas I	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
5/1/2006	0	0	0	0
5/2/2006	0	0	0	0
5/3/2006	0	0	0	0
5/4/2006	0	0	0	0
5/5/2006	0	0	0	0
5/6/2006	0	0	0	0
5/7/2006	0	0	0	0
5/8/2006	0	0	0	0
5/9/2006	0	0	0	0
5/10/2006	0	0	0	0
5/11/2006	0	0	0	0
5/12/2006	0	0	0	0
5/13/2006	0	0	0	0
5/14/2006	0	0	0	0
5/15/2006	0	0	0	0
5/16/2006	0	0	0	0
5/17/2006	0	0	0	0
5/18/2006	0	0	0	0
5/19/2006	0	0	0	0
5/20/2006	0	0	0	0
5/21/2006	0	0	0	0
5/22/2006	0	0	0	0
5/23/2006	0	0	0	0
5/24/2006	0	0	0	0
5/25/2006	0	0	0	0
5/26/2006	0	0	0	0
5/27/2006	0	0	0	0
5/28/2006	0	0	0	0
5/29/2006	0	0	0	0
5/30/2006	0	0	0	0
5/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Jun 1 2006 - Jur 2006
#

#Date (mo/da	Vent Gas I	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
6/1/2006	0	0	0	0
6/2/2006	0	0	0	0
6/3/2006	0	0	0	0
6/4/2006	0	0	0	0

6/5/2006	0	0	0	0
6/6/2006	0	0	0	0
6/7/2006	0	0	0	0
6/8/2006	0	0	0	0
6/9/2006	0	0	0	0
6/10/2006	0	0	0	0
6/11/2006	0	0	0	0
6/12/2006	0	0	0	0
6/13/2006	0	0	0	0
6/14/2006	0	0	0	0
6/15/2006	0	0	0	0
6/16/2006	0	0	0	0
6/17/2006	0	0	0	0
6/18/2006	0	0	0	0
6/19/2006	0	0	0	0
6/20/2006	0	0	0	0
6/21/2006	0	0	0	0
6/22/2006	0	0	0	0
6/23/2006	0	0	0	0
6/24/2006	0	0	0	0
6/25/2006	0	0	0	0
6/26/2006	0	0	0	0
6/27/2006	0	0	0	0
6/28/2006	0	0	0	0
6/29/2006	0	0	0	0
6/30/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Jul 1 2006 - Jul 2006
#

#Date (mo/da	Vent Gas I	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
7/1/2006	0	0	0	0
7/2/2006	0	0	0	0
7/3/2006	0	0	0	0
7/4/2006	0	0	0	0
7/5/2006	0	0	0	0
7/6/2006	0	0	0	0
7/7/2006	0	0	0	0
7/8/2006	0	0	0	0
7/9/2006	0	0	0	0
7/10/2006	0	0	0	0
7/11/2006	0	0	0	0
7/12/2006	0	0	0	0
7/13/2006	0	0	0	0
7/14/2006	0	0	0	0
7/15/2006	0	0	0	0
7/16/2006	0	0	0	0
7/17/2006	0	0	0	0
7/18/2006	0	0	0	0

7/19/2006	0	0	0	0
7/20/2006	0	0	0	0
7/21/2006	0	0	0	0
7/22/2006	0	0	0	0
7/23/2006	0	0	0	0
7/24/2006	19856	7.32	9.66	40.74
7/25/2006	0	0	0	0
7/26/2006	0	0	0	0
7/27/2006	0	0	0	0
7/28/2006	0	0	0	0
7/29/2006	0	0	0	0
7/30/2006	0	0	0	0
7/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Aug 1 2006 - Au(2006
#

#Date (mo/da	Vent Gas I	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
8/1/2006	0	0	0	0
8/2/2006	0	0	0	0
8/3/2006	0	0	0	0
8/4/2006	0	0	0	0
8/5/2006	0	0	0	0
8/6/2006	0	0	0	0
8/7/2006	0	0	0	0
8/8/2006	0	0	0	0
8/9/2006	0	0	0	0
8/10/2006	0	0	0	0
8/11/2006	0	0	0	0
8/12/2006	0	0	0	0
8/13/2006	0	0	0	0
8/14/2006	0	0	0	0
8/15/2006	0	0	0	0
8/16/2006	0	0	0	0
8/17/2006	0	0	0	0
8/18/2006	0	0	0	0
8/19/2006	0	0	0	0
8/20/2006	0	0	0	0
8/21/2006	0	0	0	0
8/22/2006	0	0	0	0
8/23/2006	0	0	0	0
8/24/2006	0	0	0	0
8/25/2006	0	0	0	0
8/26/2006	0	0	0	0
8/27/2006	0	0	0	0
8/28/2006	0	0	0	0
8/29/2006	0	0	0	0

8/30/2006	0	0	0	0
8/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Sep 1 . 2006 - Sep 2006
#

#Date (mo/da	Vent Gas I	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
9/1/2006	0	0	0	0
9/2/2006	0	0	0	0
9/3/2006	0	0	0	0
9/4/2006	0	0	0	0
9/5/2006	0	0	0	0
9/6/2006	0	0	0	0
9/7/2006	0	0	0	0
9/8/2006	0	0	0	0
9/9/2006	0	0	0	0
9/10/2006	0	0	0	0
9/11/2006	0	0	0	0
9/12/2006	0	0	0	0
9/13/2006	0	0	0	0
9/14/2006	0	0	0	0
9/15/2006	0	0	0	0
9/16/2006	0	0	0	0
9/17/2006	0	0	0	0
9/18/2006	0	0	0	0
9/19/2006	0	0	0	0
9/20/2006	0	0	0	0
9/21/2006	0	0	0	0
9/22/2006	0	0	0	0
9/23/2006	0	0	0	0
9/24/2006	0	0	0	0
9/25/2006	32158	18.5	4.45	2.72
9/26/2006	0	0	0	0
9/27/2006	83139	54.77	6.46	0
9/28/2006	0	0	0	0
9/29/2006	0	0	0	0
9/30/2006	0	0	0	0

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#Refinery: Shell Martinez
#Flare Name: LOP
#Oct 1 2006 - Oct 2006
#

#Date (mo/da	Vent Gas I	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
10/1/2006	0	0	0	0
10/2/2006	0	0	0	0
10/3/2006	0	0	0	0
10/4/2006	0	0	0	0

10/5/2006	0	0	0	0
10/6/2006	0	0	0	0
10/7/2006	0	0	0	0
10/8/2006	0	0	0	0
10/9/2006	0	0	0	0
10/10/2006	0	0	0	0
10/11/2006	0	0	0	0
10/12/2006	0	0	0	0
10/13/2006	0	0	0	0
10/14/2006	0	0	0	0
10/15/2006	0	0	0	0
10/16/2006	0	0	0	0
10/17/2006	0	0	0	0
10/18/2006	0	0	0	0
10/19/2006	0	0	0	0
10/20/2006	0	0	0	0
10/21/2006	0	0	0	0
10/22/2006	0	0	0	0
10/23/2006	0	0	0	0
10/24/2006	18493	7.14	8.35	30.31
10/25/2006	0	0	0	0
10/26/2006	0	0	0	0
10/27/2006	0	0	0	0
10/28/2006	0	0	0	0
10/29/2006	0	0	0	0
10/30/2006	0	0	0	0
10/31/2006	0	0	0	0

c
#Refinery: Shell Martinez
#Flare Name: LOP
#Nov 1 2006 - No\ 2006
#

#Date (mo/da	Vent Gas I	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
11/1/2006	0	0	0	0
11/2/2006	0	0	0	0
11/3/2006	0	0	0	0
11/4/2006	0	0	0	0
11/5/2006	0	0	0	0
11/6/2006	0	0	0	0
11/7/2006	0	0	0	0
11/8/2006	0	0	0	0
11/9/2006	0	0	0	0
11/10/2006	0	0	0	0
11/11/2006	0	0	0	0
11/12/2006	0	0	0	0
11/13/2006	0	0	0	0
11/14/2006	0	0	0	0
11/15/2006	0	0	0	0
11/16/2006	0	0	0	0
11/17/2006	0	0	0	0

11/18/2006	0	0	0	0
11/19/2006	0	0	0	0
11/20/2006	0	0	0	0
11/21/2006	0	0	0	0
11/22/2006	0	0	0	0
11/23/2006	0	0	0	0
11/24/2006	0	0	0	0
11/25/2006	0	0	0	0
11/26/2006	0	0	0	0
11/27/2006	0	0	0	0
11/28/2006	0	0	0	0
11/29/2006	0	0	0	0
11/30/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Dec 1 2006 - De(2006
#

#Date (mo/da	Vent Gas (	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
12/1/2006	0	0	0	0
12/2/2006	0	0	0	0
12/3/2006	0	0	0	0
12/4/2006	0	0	0	0
12/5/2006	197021	68.45	140.28	146.39
12/6/2006	0	0	0	0
12/7/2006	0	0	0	0
12/8/2006	0	0	0	0
12/9/2006	0	0	0	0
12/10/2006	0	0	0	0
12/11/2006	0	0	0	0
12/12/2006	0	0	0	0
12/13/2006	0	0	0	0
12/14/2006	0	0	0	0
12/15/2006	0	0	0	0
12/16/2006	0	0	0	0
12/17/2006	0	0	0	0
12/18/2006	0	0	0	0
12/19/2006	0	0	0	0
12/20/2006	0	0	0	0
12/21/2006	0	0	0	0
12/22/2006	0	0	0	0
12/23/2006	118141	82.7	13.36	0
12/24/2006	0	0	0	0
12/25/2006	0	0	0	0
12/26/2006	0	0	0	0
12/27/2006	0	0	0	0
12/28/2006	0	0	0	0
12/29/2006	0	0	0	0
12/30/2006	0	0	0	0
12/31/2006	0	0	0	0

shell--lop--20060101--20060131	Vent Gas	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
Total 2006	973317	310.36	388	1115.65
		0.2	0.2	0.6

c
#Refinery: Shell Martinez
#Flare Name: Opcen
#Jan 1 2006 - Jan : 2006
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#Date (mo/day/	Vent Gas Fl	Methane (lk	NMHC (lb:	Sulfur Dioxide (lbs)
1/1/2006	62687	28.05	96.65	0.91
1/2/2006	58652	27.34	94.22	0.89
1/3/2006	45728	25.07	86.41	0.82
1/4/2006	57694	27.17	93.64	0.88
1/5/2006	68291	29.03	100.04	0.95
1/6/2006	65952	28.62	98.63	0.93
1/7/2006	75961	30.38	104.68	0.99
1/8/2006	64711	28.4	97.88	0.93
1/9/2006	39916	24.06	82.89	0.78
1/10/2006	78190	30.77	106.02	1
1/11/2006	86001	32.14	110.74	1.05
1/12/2006	75964	30.38	104.68	0.99
1/13/2006	100275	34.64	119.37	1.13
1/14/2006	91041	33.02	113.79	1.08
1/15/2006	75574	30.31	104.44	0.99
1/16/2006	96006	33.89	116.79	1.1
1/17/2006	100065	34.6	119.24	1.13
1/18/2006	107308	35.87	123.62	1.17
1/19/2006	137760	41.21	142.02	1.34
1/20/2006	128194	39.54	136.24	1.29
1/21/2006	147823	42.98	148.1	1.4
1/22/2006	121011	38.28	131.9	1.25
1/23/2006	123638	38.74	133.49	1.26
1/24/2006	126333	39.21	135.11	1.28
1/25/2006	121952	39.09	134.69	1.27
1/26/2006	135905	40.89	140.9	1.33
1/27/2006	111642	36.63	126.24	1.19
1/28/2006	140945	41.77	143.95	1.36
1/29/2006	123787	38.76	133.58	1.26
1/30/2006	121065	38.29	131.93	1.25
1/31/2006	113289	36.92	127.23	1.2

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Feb 1 2006 - Feb : 2006
#

#Date (mo/day/	Vent Gas Fl	Methane (lk	NMHC (lb:	Sulfur Dioxide (lbs)
2/1/2006	135732	40.86	140.79	2.04
2/2/2006	136313	40.96	141.15	2.05
2/3/2006	127430	39.4	135.78	1.97
2/4/2006	105730	35.6	122.66	1.78
2/5/2006	115441	37.3	128.53	1.86

2/6/2006	108773	36.13	124.5	1.81
2/7/2006	123635	38.74	133.48	1.94
2/8/2006	109914	36.33	125.19	1.82
2/9/2006	100770	34.73	119.67	1.74
2/10/2006	105327	35.53	122.42	1.78
2/11/2006	107015	35.82	123.44	1.79
2/12/2006	112088	36.71	126.51	1.83
2/13/2006	108159	36.02	124.13	1.8
2/14/2006	126555	39.25	135.25	1.96
2/15/2006	149570	43.29	149.16	2.16
2/16/2006	161738	45.53	156.9	2.28
2/17/2006	173122	47.42	163.39	2.37
2/18/2006	158845	44.91	154.76	2.24
2/19/2006	163058	45.65	157.31	2.28
2/20/2006	150238	43.4	149.56	2.17
2/21/2006	149357	43.25	149.03	2.16
2/22/2006	153497	43.97	151.53	2.2
2/23/2006	156186	44.45	153.15	2.22
2/24/2006	139816	41.58	143.26	2.08
2/25/2006	153124	43.91	151.3	2.19
2/26/2006	199662	52.07	179.43	2.6
2/27/2006	215803	54.9	189.18	2.74
2/28/2006	118345	37.81	130.29	1.89

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Mar 1 2006 - Mar 2006
#

#Date (mo/day/	Vent Gas Fl	Methane (lt	NMHC (lb:	Sulfur Dioxide (lbs)
3/1/2006	148661	43.13	148.61	2.29
3/2/2006	166790	46.31	159.56	2.45
3/3/2006	163173	45.67	157.38	2.42
3/4/2006	153444	43.97	151.5	2.33
3/5/2006	201322	52.36	180.43	2.78
3/6/2006	170962	47.04	162.08	2.49
3/7/2006	145891	42.64	146.93	2.26
3/8/2006	160192	45.15	155.58	2.39
3/9/2006	184398	51.19	167.73	2.62
3/10/2006	151143	43.56	150.11	2.31
3/11/2006	147070	42.85	147.65	2.27
3/12/2006	170256	46.91	161.66	2.49
3/13/2006	158635	44.88	154.63	2.38
3/14/2006	183252	49.19	169.51	2.61
3/15/2006	177902	48.25	166.28	2.56
3/16/2006	192264	50.77	174.96	2.69
3/17/2006	163108	45.66	157.34	2.42
3/18/2006	154994	44.24	152.43	2.34
3/19/2006	179841	47.81	164.75	2.58

3/20/2006	203052	52.66	181.48	2.79
3/21/2006	168023	46.52	160.31	2.47
3/22/2006	116165	37.43	128.97	1.98
3/23/2006	84522	31.88	109.85	1.69
3/24/2006	141233	41.82	144.12	2.22
3/25/2006	122276	38.5	132.66	2.04
3/26/2006	74048	30.04	103.52	1.59
3/27/2006	118893	37.91	130.62	2.01
3/28/2006	85768	32.1	110.6	1.7
3/29/2006	147930	43	148.17	2.28
3/30/2006	138823	41.4	142.66	2.19
3/31/2006	112919	36.86	127.01	1.95

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Apr 1 2006 - Apr : 2006
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#Date (mo/day/	Vent Gas Fl	Methane (lt	NMHC (lbs	Sulfur Dioxide (lbs)
4/1/2006	114175	33.73	126.08	1.34
4/2/2006	169561	50.09	187.24	1.98
4/3/2006	157985	46.67	174.45	1.85
4/4/2006	145887	43.1	161.1	1.71
4/5/2006	97707	28.86	107.89	1.14
4/6/2006	81652	24.12	90.16	0.95
4/7/2006	71287	21.06	78.72	0.83
4/8/2006	150461	44.45	166.15	1.76
4/9/2006	164022	48.45	181.12	1.92
4/10/2006	141483	41.8	156.23	1.65
4/11/2006	62975	18.6	69.54	0.74
4/12/2006	61829	18.27	68.27	0.72
4/13/2006	100255	29.62	110.71	1.17
4/14/2006	160827	47.51	177.59	1.88
4/15/2006	126683	37.42	139.89	1.48
4/16/2006	146851	43.38	162.16	1.72
4/17/2006	128387	37.93	141.77	1.5
4/18/2006	90663	26.78	100.11	1.06
4/19/2006	112759	33.31	124.51	1.32
4/20/2006	118395	34.98	130.74	1.38
4/21/2006	120211	35.51	132.74	1.41
4/22/2006	113784	33.61	125.65	1.33
4/23/2006	128272	37.89	141.64	1.5
4/24/2006	139528	41.22	154.07	1.63
4/25/2006	136547	40.34	150.78	1.6
4/26/2006	144957	42.82	160.07	1.7
4/27/2006	157651	46.57	174.09	1.84
4/28/2006	146469	43.27	161.74	1.71
4/29/2006	145811	43.07	161.01	1.71
4/30/2006	139788	41.3	154.36	1.63

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#May 1 2006 - May 2006
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#Date (mo/day/	Vent Gas Fl	Methane (lt	NMHC (lbs	Sulfur Dioxide (lbs)
5/1/2006	145629	43.47	160.34	1.78
5/2/2006	147293	43.97	162.17	1.8
5/3/2006	64136	19.15	70.62	0.78
5/4/2006	42689	12.74	47	0.52
5/5/2006	41675	12.44	45.89	0.51
5/6/2006	30968	9.24	34.1	0.38
5/7/2006	20961	6.26	23.08	0.26
5/8/2006	46210	13.79	50.88	0.56
5/9/2006	50527	15.08	55.63	0.62
5/10/2006	74857	22.35	82.42	0.91
5/11/2006	91169	27.22	100.38	1.11
5/12/2006	65378	19.52	71.98	0.8
5/13/2006	54349	16.22	59.84	0.66
5/14/2006	78350	23.39	86.27	0.96
5/15/2006	109353	32.64	120.4	1.33
5/16/2006	111681	33.34	122.96	1.36
5/17/2006	129548	38.67	142.64	1.58
5/18/2006	146432	43.71	161.23	1.79
5/19/2006	126788	37.85	139.6	1.55
5/20/2006	134570	40.17	148.16	1.64
5/21/2006	151435	45.21	166.73	1.85
5/22/2006	120443	35.95	132.61	1.47
5/23/2006	118429	35.35	130.39	1.44
5/24/2006	123706	36.93	136.2	1.51
5/25/2006	121765	36.35	134.07	1.49
5/26/2006	120562	35.99	132.74	1.47
5/27/2006	112832	33.68	124.23	1.38
5/28/2006	104732	31.26	115.31	1.28
5/29/2006	101756	30.38	112.04	1.24
5/30/2006	101787	30.39	112.07	1.24
5/31/2006	103245	30.82	113.67	1.26

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Jun 1 2006 - Jun : 2006
#

#Date (mo/day/	Vent Gas Fl	Methane (lt	NMHC (lbs	Sulfur Dioxide (lbs)
6/1/2006	95634	28.68	105.39	1.21
6/2/2006	118019	35.4	130.05	1.49

6/3/2006	104162	31.24	114.78	1.32
6/4/2006	97171	29.14	107.08	1.23
6/5/2006	113948	34.18	125.57	1.44
6/6/2006	124919	37.47	137.66	1.58
6/7/2006	119609	35.87	131.81	1.51
6/8/2006	119815	35.94	132.03	1.51
6/9/2006	112058	33.61	123.48	1.42
6/10/2006	125443	37.62	138.23	1.58
6/11/2006	132581	39.77	146.1	1.67
6/12/2006	142008	42.59	156.49	1.79
6/13/2006	126645	37.99	139.56	1.6
6/14/2006	160293	48.08	176.64	2.02
6/15/2006	141910	42.56	156.38	1.79
6/16/2006	135875	40.75	149.73	1.72
6/17/2006	153555	46.06	169.21	1.94
6/18/2006	157999	47.39	174.11	2
6/19/2006	163262	48.97	179.91	2.06
6/20/2006	153669	46.09	169.34	1.94
6/21/2006	153800	46.13	169.48	1.94
6/22/2006	137475	41.23	151.49	1.74
6/23/2006	150049	45	165.35	1.9
6/24/2006	144819	43.44	159.59	1.83
6/25/2006	144667	43.39	159.42	1.83
6/26/2006	138199	41.45	152.29	1.75
6/27/2006	138678	41.59	152.82	1.75
6/28/2006	140239	42.06	154.54	1.77
6/29/2006	167682	50.29	184.78	2.12
6/30/2006	143730	43.11	158.39	1.82

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#Refinery: Shell Martinez
#Flare Name: Opcen
#Jul 1 2006 - Jul 3 2006
#

#Date (mo/day/	Vent Gas Fl	Methane (lt	NMHC (lb:	Sulfur Dioxide (lbs)
7/1/2006	125459	67.14	245.62	2.85
7/2/2006	120961	65.78	240.66	2.8
7/3/2006	120049	65.51	239.65	2.78
7/4/2006	117210	64.65	236.52	2.75
7/5/2006	115232	64.05	234.34	2.72
7/6/2006	106597	61.45	224.82	2.61
7/7/2006	91392	56.87	208.05	2.42
7/8/2006	121216	65.86	240.94	2.8
7/9/2006	116825	64.53	236.1	2.74
7/10/2006	118714	65.1	238.18	2.77
7/11/2006	135425	70.14	256.61	2.98
7/12/2006	142983	72.42	264.94	3.08
7/13/2006	117490	64.73	236.83	2.75
7/14/2006	98424	58.99	215.8	2.51
7/15/2006	461959	99.49	709.27	2.41

7/16/2006	339715	55.43	415.97	4.07
7/17/2006	159601	77.43	283.27	3.29
7/18/2006	58196	46.86	171.44	1.99
7/19/2006	19303	35.14	128.55	1.49
7/20/2006	0	0	0	0
7/21/2006	0	0	0	0
7/22/2006	0	0	0	0
7/23/2006	0	0	0	0
7/24/2006	0	0	0	0
7/25/2006	0	0	0	0
7/26/2006	0	0	0	0
7/27/2006	0	0	0	0
7/28/2006	0	0	0	0
7/29/2006	0	0	0	0
7/30/2006	30137	38.4	140.49	1.63
7/31/2006	34514	39.72	145.32	1.69

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Aug 1 2006 - Aug 2006
#

#Date (mo/day/	Vent Gas Fl	Methane (lt	NMHC (lb	Sulfur Dioxide (lbs)
8/1/2006	27200	41.55	154.1	1.71
8/2/2006	32478	43.31	160.64	1.78
8/3/2006	18766	38.74	143.66	1.6
8/4/2006	5269	14.88	55.19	0.61
8/5/2006	1000	7.9	29.31	0.33
8/6/2006	10693	28.9	107.18	1.19
8/7/2006	34186	21.06	78.09	0.87
8/8/2006	12971	36.8	136.49	1.52
8/9/2006	62750	53.42	198.12	2.2
8/10/2006	37473	44.98	166.82	1.85
8/11/2006	86860	61.47	227.98	2.53
8/12/2006	44061	47.18	174.98	1.94
8/13/2006	51215	49.57	183.84	2.04
8/14/2006	59177	52.23	193.7	2.15
8/15/2006	62633	53.38	197.98	2.2
8/16/2006	55497	51	189.14	2.1
8/17/2006	55649	51.05	189.33	2.1
8/18/2006	92887	63.48	235.44	2.61
8/19/2006	322203	90.2	211.04	1.9
8/20/2006	146059	77.57	287.82	3.13
8/21/2006	122094	73.23	271.6	3.02
8/22/2006	101584	66.39	246.21	2.73
8/23/2006	264816	122.97	425.99	879.43
8/24/2006	73796	57.11	211.8	2.35
8/25/2006	87719	61.76	229.04	2.54
8/26/2006	53216	50.24	186.32	2.07
8/27/2006	52995	50.16	186.04	2.07

8/28/2006	82868	54.26	233.41	2.28
8/29/2006	74655	57.4	212.86	2.36
8/30/2006	81309	59.62	221.1	2.46
8/31/2006	87143	61.57	228.33	2.54

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Sep 1 2006 - Sep 2006
#

#Date (mo/day/	Vent Gas Fl	Methane (lb	NMHC (lbs	Sulfur Dioxide (lbs)
9/1/2006	88290	33.01	122.36	1.35
9/2/2006	80045	29.93	110.93	1.22
9/3/2006	72439	27.08	100.39	1.11
9/4/2006	57241	21.4	79.33	0.88
9/5/2006	72638	27.16	100.67	1.11
9/6/2006	65930	24.65	91.37	1.01
9/7/2006	80864	30.23	112.07	1.24
9/8/2006	92576	34.61	128.3	1.42
9/9/2006	76866	28.74	106.52	1.18
9/10/2006	72113	26.96	99.94	1.1
9/11/2006	94644	35.38	131.16	1.45
9/12/2006	101149	37.82	140.18	1.55
9/13/2006	146834	54.9	203.49	2.25
9/14/2006	93925	35.12	130.17	1.44
9/15/2006	97598	36.49	135.26	1.49
9/16/2006	109326	40.87	151.51	1.67
9/17/2006	122081	45.64	169.19	1.87
9/18/2006	110657	41.37	153.35	1.69
9/19/2006	105426	39.42	146.11	1.61
9/20/2006	92474	34.57	128.16	1.41
9/21/2006	91709	34.29	127.09	1.4
9/22/2006	81475	30.46	112.91	1.25
9/23/2006	82201	30.73	113.92	1.26
9/24/2006	86419	32.31	119.76	1.32
9/25/2006	82996	31.03	115.02	1.27
9/26/2006	72562	27.13	100.56	1.11
9/27/2006	92328	34.52	127.95	1.41
9/28/2006	95068	35.54	131.75	1.45
9/29/2006	93529	34.97	129.62	1.43
9/30/2006	98305	36.75	136.24	1.5

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Oct 1 2006 - Oct : 2006
#

#Date (mo/day/	Vent Gas Fl	Methane (lb	NMHC (lbs	Sulfur Dioxide (lbs)
10/1/2006	84740	32.37	120.74	1.37

10/2/2006	80493	30.75	114.69	1.3
10/3/2006	80262	30.66	114.36	1.29
10/4/2006	85708	32.74	122.12	1.38
10/5/2006	91688	35.02	130.63	1.48
10/6/2006	64515	24.64	91.92	1.04
10/7/2006	100253	38.29	142.84	1.62
10/8/2006	90784	34.68	129.35	1.46
10/9/2006	87544	33.44	124.73	1.41
10/10/2006	75747	28.93	107.92	1.22
10/11/2006	95345	36.42	135.85	1.54
10/12/2006	91806	35.07	130.8	1.48
10/13/2006	87719	33.51	124.98	1.41
10/14/2006	86036	32.86	122.58	1.39
10/15/2006	83430	31.87	118.87	1.34
10/16/2006	81020	30.95	115.43	1.31
10/17/2006	75901	28.99	108.14	1.22
10/18/2006	78792	30.1	112.26	1.27
10/19/2006	49663	18.97	70.76	0.8
10/20/2006	36756	14.04	52.37	0.59
10/21/2006	36291	13.86	51.71	0.58
10/22/2006	33973	12.98	48.4	0.55
10/23/2006	30280	11.57	43.14	0.49
10/24/2006	33833	12.92	48.2	0.55
10/25/2006	44150	16.86	62.9	0.71
10/26/2006	55481	21.19	79.05	0.89
10/27/2006	52858	20.19	75.31	0.85
10/28/2006	47097	17.99	67.1	0.76
10/29/2006	51297	19.59	73.09	0.83
10/30/2006	52831	20.18	75.27	0.85
10/31/2006	4086	1.56	5.82	0.07

Average NMHC above: 138.7217

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Nov 1 2006 - Nov 2006
#

#Date (mo/day/	Vent Gas Fl	Methane (lb	NMHC (lbs	Sulfur Dioxide (lbs)
11/1/2006	0	0	0	0
11/2/2006	0	0	0	0
11/3/2006	0	0	0	0
11/4/2006	0	0	0	0
11/5/2006	0	0	0	0
11/6/2006	0	0	0	0
11/7/2006	0	0	0	0
11/8/2006	0	0	0	0
11/9/2006	0	0	0	0
11/10/2006	0	0	0	0
11/11/2006	0	0	0	0
11/12/2006	0	0	0	0

11/13/2006	0	0	0	0
11/14/2006	0	0	0	0
11/15/2006	0	0	0	0
11/16/2006	0	0	0	0
11/17/2006	0	0	0	0
11/18/2006	0	0	0	0
11/19/2006	0	0	0	0
11/20/2006	0	0	0	0
11/21/2006	0	0	0	0
11/22/2006	0	0	0	0
11/23/2006	0	0	0	0
11/24/2006	0	0	0	0
11/25/2006	0	0	0	0
11/26/2006	0	0	0	0
11/27/2006	0	0	0	0
11/28/2006	0	0	0	0
11/29/2006	0	0	0	0
11/30/2006	0	0	0	0

#Refinery: Shell Martinez
#Flare Name: Opcen
#Dec 1 2006 - Dec 2006
#

#Date (mo/day/	Vent Gas Fl	Methane (lt	NMHC (lb:	Sulfur Dioxide (lbs)
12/1/2006	0	0	0	0
12/2/2006	0	0	0	0
12/3/2006	0	0	0	0
12/4/2006	0	0	0	0
12/5/2006	0	0	0	0
12/6/2006	0	0	0	0
12/7/2006	0	0	0	0
12/8/2006	0	0	0	0
12/9/2006	0	0	0	0
12/10/2006	0	0	0	0
12/11/2006	0	0	0	0
12/12/2006	0	0	0	0
12/13/2006	0	0	0	0
12/14/2006	0	0	0	0
12/15/2006	0	0	0	0
12/16/2006	0	0	0	0
12/17/2006	0	0	0	0
12/18/2006	0	0	0	0
12/19/2006	0	0	0	0
12/20/2006	0	0	0	0
12/21/2006	0	0	0	0
12/22/2006	0	0	0	0
12/23/2006	0	0	0	0
12/24/2006	0	0	0	0
12/25/2006	0	0	0	0
12/26/2006	0	0	0	0

12/27/2006	0	0	0	0
12/28/2006	0	0	0	0
12/29/2006	0	0	0	0
12/30/2006	0	0	0	0
12/31/2006	0	0	0	0

shell–opcen–20060101–2006013	Vent Gas Fl	Methane (lt	NMHC (lbs	Sulfur Dioxide (lbs)
Total 2006	32196294	11528.96	42171.41	1365.54
in tons		5.8	21.1	0.7

42171.41

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Jan 1 2006 - Jan 31 2006
#

#Date (mo/d:	Vent Gas Flow Volu	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
1/1/2006	4405716	152.33	17.38	36.38
1/2/2006	12214753	422.33	48.19	100.87
1/3/2006	5101337	176.38	20.13	42.13
1/4/2006	0	0	0	0
1/5/2006	0	0	0	0
1/6/2006	0	0	0	0
1/7/2006	0	0	0	0
1/8/2006	0	0	0	0
1/9/2006	0	0	0	0
1/10/2006	0	0	0	0
1/11/2006	0	0	0	0
1/12/2006	0	0	0	0
1/13/2006	0	0	0	0
1/14/2006	0	0	0	0
1/15/2006	0	0	0	0
1/16/2006	0	0	0	0
1/17/2006	0	0	0	0
1/18/2006	0	0	0	0
1/19/2006	0	0	0	0
1/20/2006	0	0	0	0
1/21/2006	0	0	0	0
1/22/2006	0	0	0	0
1/23/2006	0	0	0	0
1/24/2006	0	0	0	0
1/25/2006	0	0	0	0
1/26/2006	0	0	0	0
1/27/2006	0	0	0	0
1/28/2006	0	0	0	0
1/29/2006	0	0	0	0
1/30/2006	0	0	0	0
1/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Feb 1 2006 - Feb 28 2006
#

#Date (mo/d:	Vent Gas Flow Volu	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
2/1/2006	0	0	0	0
2/2/2006	0	0	0	0
2/3/2006	0	0	0	0
2/4/2006	0	0	0	0

2/5/2006	0	0	0	0
2/6/2006	0	0	0	0
2/7/2006	0	0	0	0
2/8/2006	0	0	0	0
2/9/2006	0	0	0	0
2/10/2006	0	0	0	0
2/11/2006	0	0	0	0
2/12/2006	0	0	0	0
2/13/2006	0	0	0	0
2/14/2006	0	0	0	0
2/15/2006	0	0	0	0
2/16/2006	0	0	0	0
2/17/2006	200989	9.56	4.9	1.74
2/18/2006	0	0	0	0
2/19/2006	0	0	0	0
2/20/2006	0	0	0	0
2/21/2006	0	0	0	0
2/22/2006	0	0	0	0
2/23/2006	0	0	0	0
2/24/2006	0	0	0	0
2/25/2006	0	0	0	0
2/26/2006	0	0	0	0
2/27/2006	0	0	0	0
2/28/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Mar 1 2006 - Mar 31 2006
#

#Date (mo/d	Vent Gas Flow Volı	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
3/1/2006	0	0	0	0
3/2/2006	0	0	0	0
3/3/2006	0	0	0	0
3/4/2006	0	0	0	0
3/5/2006	25821	0.89	0.06	0.22
3/6/2006	0	0	0	0
3/7/2006	0	0	0	0
3/8/2006	0	0	0	0
3/9/2006	215423	7.4	0.53	1.81
3/10/2006	0	0	0	0
3/11/2006	0	0	0	0
3/12/2006	0	0	0	0
3/13/2006	0	0	0	0
3/14/2006	0	0	0	0
3/15/2006	1163531	39.97	2.86	9.8
3/16/2006	0	0	0	0
3/17/2006	0	0	0	0
3/18/2006	34908	1.2	0.09	0.29
3/19/2006	1765110	60.64	4.34	14.86

3/20/2006	78844	2.71	0.19	0.66
3/21/2006	288390	9.91	0.71	2.43
3/22/2006	0	0	0	0
3/23/2006	0	0	0	0
3/24/2006	0	0	0	0
3/25/2006	361171	12.41	0.89	3.04
3/26/2006	52368	1.8	0.13	0.44
3/27/2006	0	0	0	0
3/28/2006	405056	13.92	1	3.41
3/29/2006	0	0	0	0
3/30/2006	0	0	0	0
3/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Apr 1 2006 - Apr 30 2006
#

#Date (mo/d	Vent Gas Flow Vol	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
4/1/2006	0	0	0	0
4/2/2006	0	0	0	0
4/3/2006	0	0	0	0
4/4/2006	0	0	0	0
4/5/2006	0	0	0	0
4/6/2006	0	0	0	0
4/7/2006	0	0	0	0
4/8/2006	0	0	0	0
4/9/2006	0	0	0	0
4/10/2006	0	0	0	0
4/11/2006	0	0	0	0
4/12/2006	0	0	0	0
4/13/2006	183443	7.27	0	2.05
4/14/2006	0	0	0	0
4/15/2006	0	0	0	0
4/16/2006	0	0	0	0
4/17/2006	0	0	0	0
4/18/2006	0	0	0	0
4/19/2006	0	0	0	0
4/20/2006	58645	2.33	0	0.65
4/21/2006	4554	0.18	0	0.05
4/22/2006	11110	0.44	0	0.12
4/23/2006	21443	0.85	0	0.24
4/24/2006	30111	1.19	0	0.34
4/25/2006	0	0	0	0
4/26/2006	365821	14.51	0	4.08
4/27/2006	82830	3.28	0	0.92
4/28/2006	104982	4.16	0	1.17
4/29/2006	986715	39.13	0	11.01
4/30/2006	182905	7.25	0	2.04

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#May 1 2006 - May 31 2006
#

#Date (mo/d:	Vent Gas Flow Volu	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
5/1/2006	0	0	0	0
5/2/2006	0	0	0	0
5/3/2006	0	0	0	0
5/4/2006	0	0	0	0
5/5/2006	0	0	0	0
5/6/2006	0	0	0	0
5/7/2006	0	0	0	0
5/8/2006	0	0	0	0
5/9/2006	0	0	0	0
5/10/2006	0	0	0	0
5/11/2006	0	0	0	0
5/12/2006	0	0	0	0
5/13/2006	0	0	0	0
5/14/2006	82841	3.42	0	0.7
5/15/2006	0	0	0	0
5/16/2006	0	0	0	0
5/17/2006	0	0	0	0
5/18/2006	0	0	0	0
5/19/2006	63734	2.63	0	0.54
5/20/2006	0	0	0	0
5/21/2006	0	0	0	0
5/22/2006	0	0	0	0
5/23/2006	0	0	0	0
5/24/2006	0	0	0	0
5/25/2006	0	0	0	0
5/26/2006	0	0	0	0
5/27/2006	0	0	0	0
5/28/2006	0	0	0	0
5/29/2006	0	0	0	0
5/30/2006	0	0	0	0
5/31/2006	15690	0.65	0	0.13

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Jun 1 2006 - Jun 30 2006
#

#Date (mo/d:	Vent Gas Flow Volu	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
6/1/2006	33904	1.41	0.02	0.33
6/2/2006	6926	0.29	0	0.07
6/3/2006	0	0	0	0

6/4/2006	0	0	0	0
6/5/2006	21819133	909.15	12.09	214.62
6/6/2006	6868	0.29	0	0.07
6/7/2006	0	0	0	0
6/8/2006	0	0	0	0
6/9/2006	0	0	0	0
6/10/2006	0	0	0	0
6/11/2006	0	0	0	0
6/12/2006	0	0	0	0
6/13/2006	0	0	0	0
6/14/2006	0	0	0	0
6/15/2006	0	0	0	0
6/16/2006	0	0	0	0
6/17/2006	142128	5.92	0.08	1.4
6/18/2006	0	0	0	0
6/19/2006	598025	24.92	0.33	5.88
6/20/2006	0	0	0	0
6/21/2006	0	0	0	0
6/22/2006	0	0	0	0
6/23/2006	3378	0.14	0	0.03
6/24/2006	0	0	0	0
6/25/2006	0	0	0	0
6/26/2006	0	0	0	0
6/27/2006	0	0	0	0
6/28/2006	0	0	0	0
6/29/2006	0	0	0	0
6/30/2006	0	0	0	0

#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Jul 1 2006 - Jul 31 2006
#

#Date (mo/d:	Vent Gas Flow Volu	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
7/1/2006	0	0	0	0
7/2/2006	0	0	0	0
7/3/2006	0	0	0	0
7/4/2006	0	0	0	0
7/5/2006	0	0	0	0
7/6/2006	0	0	0	0
7/7/2006	0	0	0	0
7/8/2006	0	0	0	0
7/9/2006	0	0	0	0
7/10/2006	777509	32.4	0	9.14
7/11/2006	21880313	911.7	0	257.2
7/12/2006	42178412	1757.47	0	495.81
7/13/2006	12008880	500.38	0	141.16
7/14/2006	16876029	703.18	0	198.38
7/15/2006	2576523	107.36	0	30.29

7/16/2006	74987	3.12	0	0.88
7/17/2006	20881	0.87	0	0.25
7/18/2006	6462	0.27	0	0.08
7/19/2006	0	0	0	0
7/20/2006	0	0	0	0
7/21/2006	0	0	0	0
7/22/2006	0	0	0	0
7/23/2006	0	0	0	0
7/24/2006	0	0	0	0
7/25/2006	0	0	0	0
7/26/2006	0	0	0	0
7/27/2006	0	0	0	0
7/28/2006	0	0	0	0
7/29/2006	0	0	0	0
7/30/2006	0	0	0	0
7/31/2006	0	0	0	0

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#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Aug 1 2006 - Aug 31 2006
#

#Date (mo/d:	Vent Gas Flow Volu	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
8/1/2006	0	0	0	0
8/2/2006	0	0	0	0
8/3/2006	0	0	0	0
8/4/2006	0	0	0	0
8/5/2006	0	0	0	0
8/6/2006	0	0	0	0
8/7/2006	0	0	0	0
8/8/2006	0	0	0	0
8/9/2006	0	0	0	0
8/10/2006	0	0	0	0
8/11/2006	0	0	0	0
8/12/2006	0	0	0	0
8/13/2006	0	0	0	0
8/14/2006	0	0	0	0
8/15/2006	0	0	0	0
8/16/2006	0	0	0	0
8/17/2006	0	0	0	0
8/18/2006	0	0	0	0
8/19/2006	0	0	0	0
8/20/2006	0	0	0	0
8/21/2006	0	0	0	0
8/22/2006	34023328	1568.48	0	300.57
8/23/2006	44778212	2064.29	0	395.58
8/24/2006	54259292	2501.37	0	479.33
8/25/2006	14733101	679.2	0	130.15
8/26/2006	0	0	0	0
8/27/2006	0	0	0	0
8/28/2006	0	0	0	0

8/29/2006	0	0	0	0
8/30/2006	272075	12.54	0	2.4
8/31/2006	1040372	47.96	0	9.19

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Sep 1 2006 - Sep 30 2006
#

#Date (mo/d:	Vent Gas Flow Volu	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
9/1/2006	0	0	0	0
9/2/2006	0	0	0	0
9/3/2006	0	0	0	0
9/4/2006	0	0	0	0
9/5/2006	0	0	0	0
9/6/2006	0	0	0	0
9/7/2006	0	0	0	0
9/8/2006	0	0	0	0
9/9/2006	0	0	0	0
9/10/2006	0	0	0	0
9/11/2006	189898	7.44	0	2.24
9/12/2006	3990	0.16	0	0.05
9/13/2006	0	0	0	0
9/14/2006	0	0	0	0
9/15/2006	0	0	0	0
9/16/2006	0	0	0	0
9/17/2006	0	0	0	0
9/18/2006	0	0	0	0
9/19/2006	0	0	0	0
9/20/2006	0	0	0	0
9/21/2006	0	0	0	0
9/22/2006	0	0	0	0
9/23/2006	0	0	0	0
9/24/2006	0	0	0	0
9/25/2006	0	0	0	0
9/26/2006	0	0	0	0
9/27/2006	0	0	0	0
9/28/2006	0	0	0	0
9/29/2006	0	0	0	0
9/30/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Oct 1 2006 - Oct 31 2006
#

#Date (mo/d:	Vent Gas Flow Volu	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)

10/1/2006	0	0	0	0
10/2/2006	0	0	0	0
10/3/2006	0	0	0	0
10/4/2006	0	0	0	0
10/5/2006	0	0	0	0
10/6/2006	0	0	0	0
10/7/2006	0	0	0	0
10/8/2006	0	0	0	0
10/9/2006	0	0	0	0
10/10/2006	0	0	0	0
10/11/2006	0	0	0	0
10/12/2006	0	0	0	0
10/13/2006	0	0	0	0
10/14/2006	0	0	0	0
10/15/2006	0	0	0	0
10/16/2006	0	0	0	0
10/17/2006	0	0	0	0
10/18/2006	0	0	0	0
10/19/2006	0	0	0	0
10/20/2006	0	0	0	0
10/21/2006	0	0	0	0
10/22/2006	0	0	0	0
10/23/2006	0	0	0	0
10/24/2006	0	0	0	0
10/25/2006	0	0	0	0
10/26/2006	0	0	0	0
10/27/2006	0	0	0	0
10/28/2006	0	0	0	0
10/29/2006	0	0	0	0
10/30/2006	0	0	0	0
10/31/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Nov 1 2006 - Nov 30 2006
#

#Date (mo/dɛ	Vent Gas Flow Volı	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
11/1/2006	0	0	0	0
11/2/2006	0	0	0	0
11/3/2006	0	0	0	0
11/4/2006	0	0	0	0
11/5/2006	0	0	0	0
11/6/2006	0	0	0	0
11/7/2006	0	0	0	0
11/8/2006	0	0	0	0
11/9/2006	0	0	0	0
11/10/2006	0	0	0	0
11/11/2006	0	0	0	0
11/12/2006	0	0	0	0

11/13/2006	0	0	0	0
11/14/2006	0	0	0	0
11/15/2006	0	0	0	0
11/16/2006	0	0	0	0
11/17/2006	0	0	0	0
11/18/2006	0	0	0	0
11/19/2006	0	0	0	0
11/20/2006	0	0	0	0
11/21/2006	0	0	0	0
11/22/2006	0	0	0	0
11/23/2006	0	0	0	0
11/24/2006	0	0	0	0
11/25/2006	0	0	0	0
11/26/2006	0	0	0	0
11/27/2006	0	0	0	0
11/28/2006	0	0	0	0
11/29/2006	0	0	0	0
11/30/2006	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Dec 1 2006 - Dec 31 2006
#

#Date (mo/da	Vent Gas Flow Volu	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
12/1/2006	0	0	0	0
12/2/2006	0	0	0	0
12/3/2006	0	0	0	0
12/4/2006	0	0	0	0
12/5/2006	7480	0.3	0	0.07
12/6/2006	0	0	0	0
12/7/2006	0	0	0	0
12/8/2006	0	0	0	0
12/9/2006	12114	0.48	0	0.11
12/10/2006	0	0	0	0
12/11/2006	47053	1.87	0	0.45
12/12/2006	24521	0.97	0	0.23
12/13/2006	2216	0.09	0	0.02
12/14/2006	0	0	0	0
12/15/2006	0	0	0	0
12/16/2006	0	0	0	0
12/17/2006	0	0	0	0
12/18/2006	0	0	0	0
12/19/2006	0	0	0	0
12/20/2006	0	0	0	0
12/21/2006	2613	0.1	0	0.02
12/22/2006	0	0	0	0
12/23/2006	185447	7.37	0	1.76
12/24/2006	0	0	0	0
12/25/2006	0	0	0	0

12/26/2006	0	0	0	0
12/27/2006	14981	0.59	0	0.14
12/28/2006	0	0	0	0
12/29/2006	0	0	0	0
12/30/2006	0	0	0	0
12/31/2006	0	0	0	0

shell--opcenfxg--20060101--2006	Vent Gas Flow Volu	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
Total 2006	297115292	12850.82	113.92	2920.02
		6.4	0.1	1.5

Total all Shell Flares	Vent Gas Flow Volu	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
2006	330442361.0	24727.7	42726.5	5594.2
in tons		12.4	21.4	2.8

EXHIBIT L

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Jan 1 2007 - Jar 2007
#

#Date (mo/	Vent Gas I	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
1/1/2007	0	0	0	0
1/2/2007	0	0	0	0
1/3/2007	0	0	0	0
1/4/2007	0	0	0	0
1/5/2007	0	0	0	0
1/6/2007	0	0	0	0
1/7/2007	0	0	0	0
1/8/2007	0	0	0	0
1/9/2007	0	0	0	0
1/10/2007	0	0	0	0
1/11/2007	0	0	0	0
1/12/2007	0	0	0	0
1/13/2007	0	0	0	0
1/14/2007	0	0	0	0
1/15/2007	0	0	0	0
1/16/2007	0	0	0	0
1/17/2007	0	0	0	0
1/18/2007	0	0	0	0
1/19/2007	0	0	0	0
1/20/2007	0	0	0	0
1/21/2007	0	0	0	0
1/22/2007	0	0	0	0
1/23/2007	0	0	0	0
1/24/2007	0	0	0	0
1/25/2007	0	0	0	0
1/26/2007	0	0	0	0
1/27/2007	0	0	0	0
1/28/2007	0	0	0	0
1/29/2007	0	0	0	0
1/30/2007	0	0	0	0
1/31/2007	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Feb 1 2007 - Fet 2007
#

#Date (mo/	Vent Gas I	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
2/1/2007	0	0	0	0
2/2/2007	0	0	0	0
2/3/2007	0	0	0	0
2/4/2007	0	0	0	0
2/5/2007	0	0	0	0
2/6/2007	0	0	0	0
2/7/2007	0	0	0	0

2/8/2007	0	0	0	0
2/9/2007	0	0	0	0
2/10/2007	0	0	0	0
2/11/2007	0	0	0	0
2/12/2007	0	0	0	0
2/13/2007	0	0	0	0
2/14/2007	0	0	0	0
2/15/2007	0	0	0	0
2/16/2007	0	0	0	0
2/17/2007	0	0	0	0
2/18/2007	0	0	0	0
2/19/2007	0	0	0	0
2/20/2007	0	0	0	0
2/21/2007	0	0	0	0
2/22/2007	0	0	0	0
2/23/2007	0	0	0	0
2/24/2007	0	0	0	0
2/25/2007	0	0	0	0
2/26/2007	0	0	0	0
2/27/2007	0	0	0	0
2/28/2007	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Clean Fuels Area
#Mar 1 2007 - Ma 2007
#

#Date (mo	Vent Gas I	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
3/1/2007	0	0	0	0
3/2/2007	0	0	0	0
3/3/2007	0	0	0	0
3/4/2007	0	0	0	0
3/5/2007	186190	37.25	93.6	73.89
3/6/2007	0	0	0	0
3/7/2007	0	0	0	0
3/8/2007	5756	1.34	2.07	8.73
3/9/2007	0	0	0	0
3/10/2007	0	0	0	0
3/11/2007	0	0	0	0
3/12/2007	0	0	0	0
3/13/2007	0	0	0	0
3/14/2007	0	0	0	0
3/15/2007	0	0	0	0
3/16/2007	0	0	0	0
3/17/2007	0	0	0	0
3/18/2007	0	0	0	0
3/19/2007	0	0	0	0
3/20/2007	0	0	0	0
3/21/2007	0	0	0	0
3/22/2007	0	0	0	0
3/23/2007	0	0	0	0

3/24/2007	0	0	0	0
3/25/2007	0	0	0	0
3/26/2007	0	0	0	0
3/27/2007	0	0	0	0
3/28/2007	0	0	0	0
3/29/2007	0	0	0	0
3/30/2007	0	0	0	0
3/31/2007	0	0	0	0

cleanfuels area--20070101	Vent Gas	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
Partial 200	191946	38.59	95.67	82.62
in tons		0.0	0.0	0.0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Jan 1 2007 - Jar 2007
#

#Date (mo/	Vent Gas I	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
1/1/2007	0	0	0	0
1/2/2007	0	0	0	0
1/3/2007	0	0	0	0
1/4/2007	0	0	0	0
1/5/2007	0	0	0	0
1/6/2007	0	0	0	0
1/7/2007	0	0	0	0
1/8/2007	0	0	0	0
1/9/2007	0	0	0	0
1/10/2007	0	0	0	0
1/11/2007	30559	7.18	37.35	123.11
1/12/2007	256253	83.29	255.78	1420.7
1/13/2007	0	0	0	0
1/14/2007	0	0	0	0
1/15/2007	0	0	0	0
1/16/2007	819348	413.74	542.83	1727.4
1/17/2007	0	0	0	0
1/18/2007	32484	11.74	12.82	43.43
1/19/2007	0	0	0	0
1/20/2007	0	0	0	0
1/21/2007	0	0	0	0
1/22/2007	0	0	0	0
1/23/2007	0	0	0	0
1/24/2007	0	0	0	0
1/25/2007	0	0	0	0
1/26/2007	0	0	0	0
1/27/2007	0	0	0	0
1/28/2007	0	0	0	0
1/29/2007	0	0	0	0
1/30/2007	0	0	0	0
1/31/2007	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Feb 1 2007 - Fet 2007
#

#Date (mo/	Vent Gas I	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
2/1/2007	0	0	0	0
2/2/2007	0	0	0	0
2/3/2007	0	0	0	0
2/4/2007	0	0	0	0
2/5/2007	0	0	0	0

2/6/2007	0	0	0	0
2/7/2007	0	0	0	0
2/8/2007	0	0	0	0
2/9/2007	153496	5.24	96.41	116.64
2/10/2007	0	0	0	0
2/11/2007	0	0	0	0
2/12/2007	0	0	0	0
2/13/2007	0	0	0	0
2/14/2007	0	0	0	0
2/15/2007	0	0	0	0
2/16/2007	0	0	0	0
2/17/2007	0	0	0	0
2/18/2007	0	0	0	0
2/19/2007	0	0	0	0
2/20/2007	0	0	0	0
2/21/2007	0	0	0	0
2/22/2007	15394	6.13	6.45	19.19
2/23/2007	0	0	0	0
2/24/2007	0	0	0	0
2/25/2007	0	0	0	0
2/26/2007	0	0	0	0
2/27/2007	0	0	0	0
2/28/2007	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: LOP
#Mar 1 2007 - Ma 2007
#

#Date (mo	Vent Gas	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
3/1/2007	0	0	0	0
3/2/2007	0	0	0	0
3/3/2007	0	0	0	0
3/4/2007	0	0	0	0
3/5/2007	0	0	0	0
3/6/2007	1316	0.46	0.59	1.56
3/7/2007	0	0	0	0
3/8/2007	0	0	0	0
3/9/2007	0	0	0	0
3/10/2007	0	0	0	0
3/11/2007	0	0	0	0
3/12/2007	0	0	0	0
3/13/2007	0	0	0	0
3/14/2007	11897	4.17	5.31	14.08
3/15/2007	0	0	0	0
3/16/2007	0	0	0	0
3/17/2007	0	0	0	0
3/18/2007	0	0	0	0
3/19/2007	0	0	0	0

3/20/2007	0	0	0	0
3/21/2007	0	0	0	0
3/22/2007	0	0	0	0
3/23/2007	0	0	0	0
3/24/2007	0	0	0	0
3/25/2007	0	0	0	0
3/26/2007	0	0	0	0
3/27/2007	0	0	0	0
3/28/2007	0	0	0	0
3/29/2007	0	0	0	0
3/30/2007	0	0	0	0
3/31/2007	0	0	0	0

shell--lop--20070101-20070131	Vent Gas I	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
Partial 200'	1320747	531.95	957.54	3466.11
in tons		0.3	0.5	1.7

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Jan 1 2007 - Jar 2007
#

#Date (mo/	Vent Gas I	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
1/1/2007	0	0	0	0
1/2/2007	0	0	0	0
1/3/2007	0	0	0	0
1/4/2007	0	0	0	0
1/5/2007	0	0	0	0
1/6/2007	0	0	0	0
1/7/2007	0	0	0	0
1/8/2007	0	0	0	0
1/9/2007	0	0	0	0
1/10/2007	0	0	0	0
1/11/2007	0	0	0	0
1/12/2007	0	0	0	0
1/13/2007	0	0	0	0
1/14/2007	0	0	0	0
1/15/2007	0	0	0	0
1/16/2007	0	0	0	0
1/17/2007	0	0	0	0
1/18/2007	0	0	0	0
1/19/2007	0	0	0	0
1/20/2007	0	0	0	0
1/21/2007	0	0	0	0
1/22/2007	0	0	0	0
1/23/2007	0	0	0	0
1/24/2007	0	0	0	0
1/25/2007	0	0	0	0
1/26/2007	0	0	0	0
1/27/2007	0	0	0	0
1/28/2007	0	0	0	0
1/29/2007	0	0	0	0
1/30/2007	0	0	0	0
1/31/2007	209435	60.42	283.96	1025

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Feb 1 2007 - Fet 2007
#

#Date (mo/	Vent Gas I	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
2/1/2007	0	0	0	0
2/2/2007	0	0	0	0
2/3/2007	0	0	0	0
2/4/2007	0	0	0	0
2/5/2007	0	0	0	0

2/6/2007	0	0	0	0
2/7/2007	0	0	0	0
2/8/2007	0	0	0	0
2/9/2007	0	0	0	0
2/10/2007	0	0	0	0
2/11/2007	0	0	0	0
2/12/2007	0	0	0	0
2/13/2007	0	0	0	0
2/14/2007	0	0	0	0
2/15/2007	0	0	0	0
2/16/2007	0	0	0	0
2/17/2007	0	0	0	0
2/18/2007	0	0	0	0
2/19/2007	0	0	0	0
2/20/2007	0	0	0	0
2/21/2007	0	0	0	0
2/22/2007	0	0	0	0
2/23/2007	0	0	0	0
2/24/2007	0	0	0	0
2/25/2007	0	0	0	0
2/26/2007	0	0	0	0
2/27/2007	0	0	0	0
2/28/2007	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen
#Mar 1 2007 - Ma 2007
#

#Date (mo	Vent Gas I	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
3/1/2007	0	0	0	0
3/2/2007	0	0	0	0
3/3/2007	0	0	0	0
3/4/2007	0	0	0	0
3/5/2007	0	0	0	0
3/6/2007	0	0	0	0
3/7/2007	0	0	0	0
3/8/2007	0	0	0	0
3/9/2007	0	0	0	0
3/10/2007	0	0	0	0
3/11/2007	0	0	0	0
3/12/2007	6671	2.77	10.55	3.86
3/13/2007	0	0	0	0
3/14/2007	0	0	0	0
3/15/2007	0	0	0	0
3/16/2007	0	0	0	0
3/17/2007	0	0	0	0
3/18/2007	0	0	0	0
3/19/2007	0	0	0	0
3/20/2007	0	0	0	0

3/21/2007	0	0	0	0
3/22/2007	0	0	0	0
3/23/2007	0	0	0	0
3/24/2007	0	0	0	0
3/25/2007	0	0	0	0
3/26/2007	0	0	0	0
3/27/2007	0	0	0	0
3/28/2007	0	0	0	0
3/29/2007	0	0	0	0
3/30/2007	0	0	0	0
3/31/2007	0	0	0	0

shell--opcen--20070101-2007013	Vent Gas	Methane (	NMHC (lb	Sulfur Dioxide (lbs)
Partial 200	216106	63.19	294.51	1028.86
in tons		0.0	0.1	0.5

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Jan 1 2007 - Jan 31 2007
#

#Date (mo/dε	Vent Gas Flo	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
1/1/2007	0	0	0	0
1/2/2007	0	0	0	0
1/3/2007	0	0	0	0
1/4/2007	0	0	0	0
1/5/2007	0	0	0	0
1/6/2007	0	0	0	0
1/7/2007	0	0	0	0
1/8/2007	0	0	0	0
1/9/2007	0	0	0	0
1/10/2007	0	0	0	0
1/11/2007	0	0	0	0
1/12/2007	0	0	0	0
1/13/2007	0	0	0	0
1/14/2007	0	0	0	0
1/15/2007	0	0	0	0
1/16/2007	0	0	0	0
1/17/2007	0	0	0	0
1/18/2007	0	0	0	0
1/19/2007	0	0	0	0
1/20/2007	0	0	0	0
1/21/2007	0	0	0	0
1/22/2007	0	0	0	0
1/23/2007	0	0	0	0
1/24/2007	0	0	0	0
1/25/2007	10916	0.42	0	0.14
1/26/2007	52936	2.02	0	0.69
1/27/2007	2299	0.09	0	0.03
1/28/2007	0	0	0	0
1/29/2007	0	0	0	0
1/30/2007	17314	0.66	0	0.23
1/31/2007	69653	2.66	0	0.91

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Feb 1 2007 - Feb 2ε 2007
#

#Date (mo/dε	Vent Gas Flo	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
2/1/2007	85033	3.18	0	2.19
2/2/2007	4940	0.18	0	0.13
2/3/2007	0	0	0	0
2/4/2007	0	0	0	0
2/5/2007	0	0	0	0
2/6/2007	33367	1.25	0	0.86
2/7/2007	61833	2.31	0	1.59

2/8/2007	91547	3.42	0	2.36
2/9/2007	79265	2.96	0	2.04
2/10/2007	70952	2.65	0	1.83
2/11/2007	37603	1.41	0	0.97
2/12/2007	10054	0.38	0	0.26
2/13/2007	28045	1.05	0	0.72
2/14/2007	0	0	0	0
2/15/2007	0	0	0	0
2/16/2007	0	0	0	0
2/17/2007	0	0	0	0
2/18/2007	32864	1.23	0	0.85
2/19/2007	26886	1.01	0	0.69
2/20/2007	10236	0.38	0	0.26
2/21/2007	497	0.02	0	0.01
2/22/2007	24183	0.9	0	0.62
2/23/2007	0	0	0	0
2/24/2007	21082	0.79	0	0.54
2/25/2007	100169	3.74	0	2.58
2/26/2007	49886	1.86	0	1.28
2/27/2007	15881	0.59	0	0.41
2/28/2007	15394	0.58	0	0.4

#BAAQMD Refinery Flare Emission Report
#Refinery: Shell Martinez
#Flare Name: Opcen FXG
#Mar 1 2007 - Mar 3' 2007
#

#Date (mo/da	Vent Gas Flo	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
3/1/2007	5397	0.18	0	0.05
3/2/2007	0	0	0	0
3/3/2007	0	0	0	0
3/4/2007	0	0	0	0
3/5/2007	0	0	0	0
3/6/2007	0	0	0	0
3/7/2007	34494	1.12	0	0.29
3/8/2007	0	0	0	0
3/9/2007	0	0	0	0
3/10/2007	0	0	0	0
3/11/2007	0	0	0	0
3/12/2007	8005151	259.9	0	67.04
3/13/2007	2764680	89.76	0	23.15
3/14/2007	6181562	200.7	0	51.77
3/15/2007	9653065	313.41	0	80.84
3/16/2007	6994810	227.1	0	58.58
3/17/2007	6717783	218.11	0	56.26
3/18/2007	4304882	139.77	0	36.05
3/19/2007	4067190	132.05	0	34.06
3/20/2007	4601771	149.41	0	38.54
3/21/2007	4137786	134.34	0	34.65
3/22/2007	4934584	160.21	0	41.32

3/23/2007	6384027	207.27	0	53.46
3/24/2007	13554373	440.07	0	113.51
3/25/2007	19064492	618.97	0	159.66
3/26/2007	877778	28.5	0	7.35
3/27/2007	0	0	0	0
3/28/2007	0	0	0	0
3/29/2007	0	0	0	0
3/30/2007	0	0	0	0
3/31/2007	0	0	0	0

shell-- opcenfxg-- 20070201-- 2007	Vent Gas Flo	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
Partial 2007	103236660	3356.61	0	879.17
in tons		1.7	0.0	0.4

Total all Shell Flares	Vent Gas Flo	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
Partial 2007	104965459.0	3990.3	1347.7	5456.8
in tons		2.0	0.7	2.7

EXHIBIT M

REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 11
FLARE MONITORING AT PETROLEUM REFINERIES

INDEX

REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 11
FLARE MONITORING AT PETROLEUM REFINERIES

(Adopted June 4, 2003)

12-11-100 GENERAL

12-11-101 Description: The purpose of this rule is to require monitoring and recording of emission data for flares at petroleum refineries.

12-11-110 Exemption, Organic Liquid Storage and Distribution: The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from organic liquid storage vessels subject to Regulation 8, Rule 5 or exclusively from loading racks subject to Regulation 8 Rules 6, 33, or 39.

12-11-111 Exemption, Marine Vessel Loading Terminals: The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from marine vessel loading terminals subject to Regulation 8, Rule 44.

12-11-112 Exemption, Wastewater Treatment Systems: The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from wastewater treatment systems subject to Regulation 8, Rule 8.

12-11-113 Exemption, Pumps: The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from pump seals subject to Regulation 8, Rule 18. This exemption does not apply when emissions from a pump are routed to a flare header.

12-11-114 Limited Exemption, Total Hydrocarbon and Methane Composition Monitoring and Reporting: The provisions of Sections 12-11-401.2, 401.3, 401.5, 502.2 and 502.3 that require monitoring and reporting of total hydrocarbon and methane composition shall not apply to a flare that exclusively burns flexicoker gas with or without supplemental natural gas, provided that the owner or operator demonstrates by weekly sampling and analysis, verified by the APCO, that the methane content and the non-methane content of the vent gas flared are less than 2 percent and 1 percent by volume, respectively.

12-11-200 DEFINITIONS

12-11-201 Flare: A combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. Flares may be either continuous or intermittent and are not equipped with devices for fuel-air mix control or for temperature control. This term includes both ground and elevated flares.

12-11-202 Flare Monitoring System: All sample systems, transducers, transmitters, data acquisition equipment, data recording equipment, video monitoring equipment, and video recording equipment involved in flare monitoring.

12-11-203 Flaring: A high-temperature combustion process used to burn vent gases.

12-11-204 Gas: The state of matter that has neither independent shape nor volume, but tends to expand indefinitely. For the purposes of this rule, "gas" includes aerosols and the terms "gas" and "gases" are interchangeable.

12-11-205 Petroleum Refinery: A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411, and including any associated sulfur recovery plant.

12-11-206 Pilot Gas: The gas used to maintain the presence of a flame for ignition of vent gases.

12-11-207 Purge Gas: The gas used to prevent air backflow in the flare system when there is no vent gas.

12-11-208 Sulfur Recovery Plant: A process unit that processes sulfur and ammonia containing material and produces a final product of elemental sulfur.

12-11-209 Thermal Oxidizer: An enclosed or partially enclosed combustion device that is used to oxidize combustible gases, that generally comes equipped with controls for combustion chamber temperature and often with controls for air/fuel mixture, and that exhausts all combustion products through a vent, duct, or stack so that emissions can be measured directly.

12-11-210 Vent Gas: Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

12-11-400 ADMINISTRATIVE REQUIREMENTS

12-11-401 Flare Data Reporting Requirements: The owner or operator of a flare shall submit a monthly report to the APCO on or before 30 days after the end of each month for each flare subject to this rule. Only one report is required for a staged or cascading flare system if all flares in the system serve the same header or headers. The report shall be in an electronic format approved by the APCO. Each monthly report shall include all of the following:

401.1 The total volumetric flow of vent gas in standard cubic feet for each day and for the month, and, effective for the first full month after the commencement of the monitoring required by Section 12-11-501, for each hour of the month.

401.2 If vent gas composition is monitored using sampling or integrated sampling, total hydrocarbon content as propane by volume, methane content by volume, and, hydrogen sulfide content by volume, for each sample or integrated sample required by Section 12-11-502. If the content of any additional compound or compounds is determined by the analysis of a sample or integrated sample, the content by volume of each additional compound.

401.3 If vent gas composition is monitored by a continuous analyzer or analyzers pursuant to Section 12-11-502, average total hydrocarbon content as propane by volume, average methane content by volume, and, depending upon the analytical method used pursuant to Section 12-11-601, total reduced sulfur content by volume or hydrogen sulfide content by volume of vent gas flared for each hour of the month. If the content of any additional compound or compounds is determined by the continuous analyzer or analyzers, the average content by volume for each additional compound for each hour of the month.

401.4 If the flow monitor installed pursuant to Section 12-11-501 measures molecular weight, the average molecular weight for each hour of the month.

401.5 For any pilot and purge gas used, the type of gas used, the volumetric flow for each day and for the month, and the means used to determine flow.

401.6 For any 24-hour period during which more than 1 million standard cubic feet of vent gas was flared, a description of the flaring including the cause, time of occurrence and duration, the source or equipment from which the vent gas originated, and any measures taken to reduce or eliminate flaring.

401.7 Flare monitoring system downtime periods, including dates and times.

401.8 The archive of images recorded for the month pursuant to Section 12-11-507.

401.9 For each day and for the month provide calculated methane, non-methane and sulfur dioxide emissions. For the purposes of emission calculations only, a flare control efficiency of 98 percent shall be used for hydrocarbon flares, and a flare control efficiency of 93 percent shall be used for flexi-gas flares or if, based on the composition analysis specified in Section 12-11-502, the calculated lower heating value of the vent gas is less than 300 British Thermal Units/Standard Cubic Foot (BTU/SCF).

12-11-402 Flow Verification Report: Effective twelve months after adoption of this rule and every six months thereafter, the owner or operator of a flare shall submit a flow verification report to the APCO for each flare subject to the rule. The flow verification report shall be included in the corresponding monthly report required by Section 12-11-401. Only one report is required for a staged or cascading flare system if all flares in the system serve the same header or headers. The report shall compare flow as measured by the flow monitoring equipment required by Section 12-11-501 and a flow verification pursuant to Section 12-11-602 for the same period or periods of time. The owner or operator shall demonstrate that the flow verification was performed using good engineering practices. If there are no flaring events as described in Section 12-11-401.6 during the preceding six-month period, a flow verification report is not required for that period.

12-11-500 MONITORING AND RECORDS

12-11-501 Vent Gas Flow Monitoring: Effective 180 days after adoption of this rule, the owner or operator of a petroleum refinery shall not operate a flare unless vent gas to the flare is continuously monitored for volumetric flow by a device that meets the following requirements:

501.1 The minimum detectible velocity shall be 0.1 foot per second.

501.2 The device shall continuously measure the range of flow rates corresponding to velocities from 0.5 to 275 feet per second in the header in which the device is installed.

501.3 The device shall have a manufacturer's specified accuracy of ±5% over the range of 1 to 275 feet per second.

501.4 The device shall be installed at a location where measured volumetric flow is representative of flow to the flare or to the flare system in the case of a staged or cascading flare system consisting of more than one flare.

501.5 Effective 180 days after adoption of this rule, the owner or operator shall provide access for the APCO to verify proper installation and operation of the flare monitoring system.

501.6 Effective 18 months after adoption of this rule, the flow monitoring system shall be maintained to be accurate to within ±20% as demonstrated by the flow verification report specified in Section 12-11-402.

12-11-502 Vent Gas Composition Monitoring: The owner or operator of a petroleum refinery shall not operate a flare unless the following requirements are met:

502.1 Requirements applicable to all vent gas composition monitoring:

- 1.1 Vent gas monitored for composition, whether by sampling, integrated sampling or continuous monitoring, shall be taken from a location at which samples are representative of vent gas composition. If flares share a common header, a sample from the header will be deemed representative of vent gas composition for all flares served by the header.
- 1.2 Effective 90 days after the adoption of this rule, the monitoring system shall provide access for the APCO to collect vent gas samples to verify the analyses required by Section 12-11-502.

502.2 Effective 90 days after adoption of this rule and until the requirements of Section 12-11-502.3 are met, the owner or operator shall monitor vent gas composition through sampling that meets the following requirements:

- 2.1 For each day on which flaring occurs, one sample shall be taken within 30 minutes of the commencement of flaring.
- 2.2 Samples may be taken from the flare header or from an alternate location at which samples are representative of vent gas composition.
- 2.3 Samples shall be analyzed pursuant to Section 12-11-601.

502.3 Effective 270 days after adoption of this rule, the owner or operator shall monitor vent gas composition using one of the following four methods:

3.1 Sampling that meets the following requirements:

a. If the flow rate of vent gas flared in any consecutive 15-minute period continuously exceeds 330 standard cubic feet per minute (SCFM), a sample shall be taken within 15 minutes, except that, for flares exclusively serving sulfur or ammonia plants, a sample shall be taken within 1 hour or composition data representing worst-case conditions shall be provided by the owner or operator and verified by the APCO. The sampling frequency thereafter shall be one sample every three hours and shall continue until the flow rate of vent gas flared in any consecutive 15-minute period is continuously 330 SCFM or less. In no case shall a sample be required more frequently than once every 3 hours.

b. Samples shall be analyzed pursuant to Section 12-11-601.

3.2 Integrated sampling that meets the following requirements:

a. If the flow rate of vent gas flared in any consecutive 15 minute period continuously exceeds 330 standard cubic feet per minute (SCFM), integrated sampling shall begin within 15 minutes and shall continue until the flow rate of vent gas flared in any consecutive 15 minute period is continuously 330 SCFM or less.

b. Integrated sampling shall consist of a minimum of one aliquot for each 15-minute period until the sample container is full. If sampling is still required pursuant to Section 12-11-502.3.2a, a new sample container shall be placed in service within one hour after the previous container was filled. A sample container shall not be used for a sampling period that exceeds 24 hours.

c. Samples shall be analyzed pursuant to Section 12-11-601.

3.3 Continuous analyzers that meet the following requirements:

a. The analyzers shall continuously monitor for total hydrocarbon, methane, and, depending upon the analytical method used pursuant to Section 12-11-601, hydrogen sulfide or total reduced sulfur.

b. The hydrocarbon analyzer shall have a full-scale range of 100% total hydrocarbon.

c. Each analyzer shall be maintained to be accurate to within 20% when compared to any field accuracy tests or to within 5% of full scale.

3.4 A continuous analyzer employing gas chromatography that meets the following requirements:

a. The gas chromatography system shall monitor for total hydrocarbon, methane, and hydrogen sulfide.

b. The gas chromatography system shall be maintained to be accurate to within 5% of full scale.

12-11-503 Pilot Monitoring: Any flare subject to this rule must be equipped and operated with an automatic igniter or a continuous burning pilot, which must be maintained in good working order. If a pilot flame is employed, the flame shall be monitored with a device to detect the presence of the pilot flame. If an electric arc ignition system is employed, the system shall pulse on detection of loss of pilot flame and until the pilot flame is reestablished.

12-11-504 Pilot and Purge Gas Monitoring: The owner or operator of a petroleum refinery shall not operate a flare unless (1) volumetric flows of purge and pilot gases are monitored by flow measuring devices, or (2) other parameters are monitored so that volumetric flows of pilot and purge gas may be calculated based on pilot design and the parameters monitored.

12-11-505 Recordkeeping Requirements: Except as provided in Section 12-11-507, the owner or operator of a flare shall maintain records for all the information required to be monitored for a period of five years and make such records available to the APCO upon request.

12-11-506 General Monitoring Requirements: Persons responsible for monitoring subject to this rule shall comply with the following:

506.1 Periods of flare monitoring system inoperation greater than 24 continuous hours shall be reported by the following working day, followed by notification of resumption of monitoring. Adequate proof of expeditious repair shall be furnished to the APCO for downtime in excess of fifteen consecutive days. Periods of inoperation of the vent gas flow monitoring required by Section 12-11-501 shall not exceed 30 days per calendar year. Periods of inoperation of vent gas composition monitoring specified in Sections 12-11-502.3.2 (integrated sampling) and 12-11-502.3.4 (gas chromatography) shall not exceed 30 days per calendar year. Effective 450 days after the adoption of this rule, periods of inoperation of the vent gas composition monitoring specified in Section 12-11-502.3.3 (continuous analyzers) shall not exceed 30 days per calendar year per analyzer. Periods of inoperation of video monitoring specified in Section 12-11-507 shall not exceed 30 days per calendar year.

506.2 During periods of inoperation of continuous analyzers or auto-samplers installed pursuant to Section 12-11-502, persons responsible for monitoring shall take samples as required by Section 12-11-502.2.1. During periods of inoperation of flow monitors required by Section 12-11-501, flow shall be calculated using good engineering practices.

506.3 The person(s) responsible for monitors subject to this rule shall maintain and calibrate all required monitors and recording devices in accordance with the applicable manufacturer's specifications. In order to claim that a manufacturer's specification is not applicable, the person responsible for emissions must have, and follow, a written maintenance policy that was developed for the device in question. The written policy must explain and justify the difference between the written procedure and the manufacturer's procedure.

506.4 Data Recording System: All in-line continuous analyzer and flow monitoring data must be continuously recorded by an electronic data acquisition system capable of one-minute averages. Flow monitoring data shall be recorded as one-minute averages.

12-11-507 Video Monitoring: For each flare equipped with video monitoring capability as of January 1, 2003, the owner or operator of a flare subject to this rule shall, effective 180 days after adoption of this rule, install and maintain equipment that records a real-time digital image of the flare and flame at a frame rate of no less than 1 frame per minute. The recorded image of the flare shall be of sufficient size, contrast, and resolution to be readily apparent in the overall image or frame. The image shall include an embedded date and time stamp. The equipment shall archive the images for each 24-hour period. Effective 180 days after adoption of this rule, for any flare for which the report required by Section 12-11-401 shows that more than 1 million standard cubic feet of vent gas was flared in any 24-hour period, the owner or operator of the flare shall, within 90 days after the end of the month covered by the report, meet the same requirements as those imposed by this Section for flares with existing video monitoring capability.

12-11-600 MANUAL OF PROCEDURES

12-11-601 Testing, Sampling, and Analytical Methods:

601.1 Samples and integrated samples shall be analyzed using the following test methods, or latest revision, where applicable:

1.1 Total hydrocarbon content and methane content of vent gas shall be determined using ASTM Method D1945-96, ASTM Method UOP 539-97, or EPA Method 18.

1.2 Hydrogen sulfide content of vent gas shall be determined using ASTM Method D1945-96 or ASTM Method UOP 539-97.

1.3 Any alternative method to the above methods if approved by the APCO and EPA.

601.2 Except as provided in Section 12-11-601.3, if vent gas composition is monitored using continuous analyzers, the analyzers shall employ the following methods, or latest revision, where applicable:

2.1 Total hydrocarbon content and methane content of vent gas shall be determined using EPA Method 25A or 25B.

2.2 Total reduced sulfur content of vent gas shall be determined using ASTM Method D4468-85.

2.3 Hydrogen sulfide content shall be determined using ASTM Method D4084-94.

2.4 Any alternative method to the above methods if approved by the APCO and EPA.

601.3 If vent gas composition is monitored with a continuous analyzer employing gas chromatography, the following requirements shall be met:

3.1 ASTM Method D1945-96 or latest revision, or ASTM Method UOP 539-97 or latest revision shall be used.

3.2 The system shall analyze samples for total hydrocarbon content, methane content, and hydrogen sulfide content.

3.3 The minimum sampling frequency shall be one sample every 30 minutes.

3.4 Any alternative method to the above methods if approved by the APCO and EPA.

12-11-602 Flow Verification Test Methods: For purposes of the semi-annual verification required by Section 12-11-402, vent gas flow shall be determined using one or more of the following methods:

602.1 District Manual of Procedures, Volume IV, ST-17 and ST-18;

602.2 EPA Methods 1 and 2;

602.3 Other flow monitoring devices or process monitors.

602.4 Any verification method recommended by the manufacturer of the flow monitoring equipment installed pursuant to Section 12-11-501.

602.5 Tracer gas dilution or velocity.

602.6 Any alternative method approved by the APCO and EPA.

EXHIBIT N

REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 12
FLARES AT PETROLEUM REFINERIES

INDEX

REGULATION 12
MISCELLANEOUS STANDARDS OF PERFORMANCE
RULE 12
FLARES AT PETROLEUM REFINERIES

(Adopted July 20, 2005)

12-12-100 GENERAL

12-12-101 Description: The purpose of this rule is to reduce emissions from flares at petroleum refineries by minimizing the frequency and magnitude of flaring. Nothing in this rule should be construed to compromise refinery operations and practices with regard to safety.

12-12-110 Exemption, Organic Liquid Storage and Distribution: The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from organic liquid storage vessels subject to Regulation 8, Rule 5 or exclusively from loading racks subject to Regulation 8 Rules 6, 33, or 39.

12-12-111 Exemption, Marine Vessel Loading Terminals: The provisions of this rule shall not apply to flares or thermal oxidizers used to control emissions exclusively from marine vessel loading terminals subject to Regulation 8, Rule 44.

12-12-112 Exemption, Wastewater Treatment Systems: The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from wastewater treatment systems subject to Regulation 8, Rule 8.

12-12-113 Exemption, Pumps: The provisions of this rule shall not apply to thermal oxidizers used to control emissions exclusively from pump seals subject to Regulation 8, Rule 18. This exemption does not apply when emissions from a pump are routed to a flare header.

12-12-200 DEFINITIONS: For the purposes of this rule, the following definitions apply:

12-12-201 Emergency: A condition at a petroleum refinery beyond the reasonable control of the owner or operator requiring immediate corrective action to restore normal and safe operation that is caused by a sudden, infrequent and not reasonably preventable equipment failure, natural disaster, act of war or terrorism or external power curtailment, excluding power curtailment due to an interruptible power service agreement from a utility.

12-12-202 Feasible: Capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors.

12-12-203 Flare: A combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. This term includes both ground-level and elevated flares. When used as a verb, the term "flare" means the combustion of vent gas in a flare.

12-12-204 Flare Minimization Plan (FMP): A document intended to meet the requirements of Section 12-12-401.

12-12-205 Gas: The state of matter that has neither independent shape nor volume, but tends to expand indefinitely. Gas includes aerosols and the terms "gas" and "gases" are interchangeable.

12-12-206 Petroleum Refinery: A facility that processes petroleum, as defined in the North American Industrial Classification Standard No. 32411 and including any associated sulfur recovery plant.

12-12-207 Prevention Measure: A component, system, procedure or program that will minimize or eliminate flaring.

12-12-208 Reportable Flaring Event: Any flaring where more than 500,000 standard cubic feet per calendar day of vent gas is flared or where sulfur dioxide (SO_2) emissions are greater than 500 pounds per day. For flares that are operated as a backup, staged or cascade system, the volume is determined on a cumulative basis; the total volume equals the total of vent gas flared at each flare in the system. For flaring lasting more than one calendar day, each day of flaring constitutes a separate flaring event unless the owner or operator demonstrates to the satisfaction of the APCO that the cause of flaring is the same for two or more consecutive days. A reportable flaring event ends when it can be demonstrated by monitoring required in Section 12-12-501 that the integrity of the water seal has been maintained sufficiently to prevent vent gas to the flare tip. For flares without water seals or water seal monitors as required by Section 12-12-501, a reportable flaring event ends when the rate of flow of vent gas falls below 0.5 feet per second.

(Amended April 5, 2006)

12-12-209 Responsible Manager: An employee of the facility or corporation who possesses sufficient authority to take the actions required for compliance with this rule.

12-12-210 Shutdown: The intentional cessation of a petroleum refining process unit or a unit operation within a petroleum refining process unit due to lack of feedstock or the need to conduct periodic maintenance, replacement of equipment, repair or other operational requirements. A process unit includes subsets and components of the unit operation. Subsets and components includes but are not limited to reactors, heaters, vessels, columns, towers, pumps, compressors, exchangers, accumulators, valves, flanges, sample stations, pipelines or sections of pipelines.

12-12-211 Startup: The setting into operation of a petroleum refining process unit for purposes of production. A process unit includes subsets and components of the unit operation. Subsets and components includes but are not limited to reactors, heaters, vessels, columns, towers, pumps, compressors, exchangers, accumulators, valves, flanges, sample stations, pipelines or sections of pipelines.

12-12-212 Thermal Oxidizer: An enclosed or partially enclosed combustion device, other than a flare, that is used to oxidize combustible gases.

12-12-213 Vent Gas: Any gas directed to a flare excluding assisting air or steam, flare pilot gas, and any continuous purge gases.

12-12-300 STANDARDS

12-12-301 Flare Minimization: Effective November 1, 2006, flaring is prohibited unless it is consistent with an approved FMP and all commitments due under that plan have been met. This standard shall not apply if the APCO determines, based on an analysis conducted in accordance with Section 12-12-406, that the flaring is caused by an emergency and is necessary to prevent an accident, hazard or release of vent gas directly to the atmosphere.

12-12-400 ADMINISTRATIVE REQUIREMENTS

12-12-401 Flare Minimization Plan Requirements: The owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit to the APCO a FMP in accordance with the schedule in Section 12-12-402. The FMP shall be certified and signed by a Responsible Manager and shall include, but not be limited to:

401.1 Technical Data: A description and technical information for each flare that is capable of receiving gases and the upstream equipment and processes that send gas to the flare including:

1.1 A detailed process flow diagram accurately depicting all pipelines, process units, flare gas recovery systems, water seals, surge drums and knock-out pots, compressors and other equipment that vent to each flare. At a minimum, this shall include full and accurate as-built dimensions and design capacities of the flare gas recovery systems, compressors, water seals, surge drums and knockout pots.

1.2 Full and accurate descriptions including locations of all associated monitoring and control equipment.

401.2 Reductions Previously Realized: A description of the equipment, processes and procedures installed or implemented within the last five years to reduce flaring. The description shall specify the year of installation.

401.3 Planned Reductions: A description of any equipment, processes or procedures the owner or operator plans to install or implement to eliminate or reduce flaring. The description shall specify the scheduled year of installation or implementation.

401.4 Prevention Measures: A description and evaluation of prevention measures, including a schedule for the expeditious implementation of all feasible prevention measures, to address the following:

4.1 Flaring that has occurred or may reasonably be expected to occur during planned major maintenance activities, including startup and shutdown. The evaluation shall include a review of flaring that has occurred during these activities in the past five years, and shall consider the feasibility of performing these activities without flaring.

4.2 Flaring that may reasonably be expected to occur due to issues of gas quantity and quality. The evaluation shall include an audit of the vent gas recovery capacity of each flare system, the storage capacity available for excess vent gases, and the scrubbing capacity available for vent gases including any limitations associated with scrubbing vent gases for use as a fuel; and shall consider the feasibility of reducing flaring through the recovery, treatment and use of the gas or other means.

4.3 Flaring caused by the recurrent failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. The evaluation shall consider the adequacy of existing maintenance schedules and protocols for such equipment. For purposes of this Section, a failure is recurrent if it occurs more than twice during any five year period as a result of the same cause as identified in accordance with Section 12-12-406.

401.5 Any other information requested by the APCO as necessary to enable determination of compliance with applicable provisions of this rule.

Failure to implement and maintain any equipment, processes, procedures or prevention measures in the FMP is a violation of this section.

12-12-402 Submission of Flare Minimization Plans: On or before August 1, 2006, the owner or operator of a petroleum refinery with one or more flares subject to this rule shall submit a FMP as required by Section 12-12-401. On or before November 1, 2005 and every three months thereafter until a complete FMP is submitted, the owner or operator shall provide a status report detailing progress towards fulfilling the requirements of Section 12-12-401. Upon the submission of each status report, the APCO may require a consultation regarding the development of the plan to ensure that the plan meets the requirements of Section 12-12-401.

12-12-403 Review and Approval of Flare Minimization Plans: The procedure for determining whether the FMP meets the applicable requirements of this regulation is as follows:

403.1 Completeness Determination: Within 45 days of receipt of the FMP, the APCO will deem the plan complete if he determines that it includes the information required by Section 12-12-401. If the APCO determines that the proposed FMP is not complete, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination and the required corrective action.

403.2 Corrective Action: Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the proposed FMP within 45 days. If the APCO determines that the owner or operator failed to correct any deficiency identified in the notification, the APCO will disapprove the FMP.

403.3 Public Comment: The complete FMP (with exception of confidential information) will be made available to the public for 60 days. The APCO will consider any written comments received during this period prior to approving or disapproving the FMP.

403.4 **Final Action:** Within 45 days of the close of the public comment period, the APCO will approve the FMP if he determines that the plan meets the requirements of Section 12-12-401, and shall provide written notification to the owner or operator. This period may be extended if necessary to comply with state law. If the APCO determines that the FMP does not meet the requirements of Section 12-12-401, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination. Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the FMP within 45 days. If the APCO determines that the owner or operator failed to correct any deficiency identified in the notification, the APCO will disapprove the FMP.

If the owner or operator submitted a complete FMP in accordance with Section 12-12-402, and the APCO has not disapproved the FMP under this section, the FMP shall be considered an approved FMP for the purposes of Section 12-12-301 until the APCO takes final action under Section 12-12-403.4.

12-12-404 **Update of Flare Minimization Plans:** The FMP shall be updated as follows:

404.1 No more than 12 months following approval of the original FMP and annually thereafter, the owner or operator of a flare subject to this rule shall review the FMP and revise the plan to incorporate any new prevention measures identified as a result of the analyses prescribed in Sections 12-12-401.4 and 12-12-406. The updates must be approved and signed by a Responsible Manager.

404.2 Prior to installing or modifying any equipment described in Section 12-12-401.1.1 that requires a District permit to operate, the owner or operator shall obtain an approved updated FMP addressing the new or modified equipment.

404.3 Annual FMP updates (with exception of confidential information) shall be made available to the public for 30 days. The APCO shall consider any written comments received during this period prior to approving or disapproving the update.

404.4 Within 45 days of the close of the public comment period, the APCO shall approve the FMP update if he determines that the update meets the requirements of Section 12-12-401, and shall provide written notification to the owner or operator. The previously approved FMP together with the approved update constitutes the approved plan for purposes of Section 12-12-301. This period may be extended if necessary to comply with state law. If the APCO determines that the FMP update does not meet the requirements of Section 12-12-401, the APCO will notify the owner or operator in writing. The notification will specify the basis for this determination and the required corrective action. Upon receipt of such notification, the owner or operator shall correct the identified deficiencies and resubmit the FMP update within 30 days. If the APCO determines that the owner or operator failed to correct the deficiencies identified in the notification, the APCO will disapprove the FMP update. For purposes of Section 12-12-301, disapproval of the update constitutes disapproval of the existing FMP, unless otherwise specified by the APCO.

404.5 If the owner or operator fails to submit a plan update as required by this Section, the APCO shall provide written notification of the lapse. If the owner or operator fails to submit an update within 30 days of receipt of the notification, the existing FMP shall no longer be considered an approved plan for purposes of Section 12-12-301.

(Amended April 5, 2006)

12-12-405 **Notification of Flaring:** Effective August 20, 2005, the owner or operator of a flare subject to this rule shall notify the APCO as soon as possible, consistent with safe operation of the refinery, if the volume of vent gas flared exceeds 500,000 standard cubic feet per calendar day. The notification, either by phone, fax or electronically, shall be in a format specified by the APCO and include the flare source name and number, the start date and time, and the end date and time.

12-12-406 Determination and Reporting of Cause: The owner or operator of a flare subject to this rule shall submit a report to the APCO within 60 days following the end of the month in which a reportable flaring event occurs. The report shall include, but is not limited to, the following:

406.1 The results of an investigation to determine the primary cause and contributing factors for the flaring event.

406.2 Any prevention measures that were considered or implemented to prevent recurrence together with a justification for rejecting any measures that were considered but not implemented.

406.3 If appropriate, an explanation of why the flaring is consistent with an approved FMP.

406.4 Where applicable, an explanation of why the flaring was an emergency and necessary to prevent an accident, hazard or release of vent gas to the atmosphere or where, due to a regulatory mandate to vent to a flare, it cannot be recovered, treated and used as fuel gas at the refinery.

406.5 The volume of vent gas flared, the calculated methane, non-methane hydrocarbon and sulfur dioxide emissions associated with the reportable flaring event.

(Amended April 5, 2006)

12-12-407 Deleted April 5, 2006

12-12-408 Designation of Confidential Information: When submitting the initial FMP, any updated FMP or any other report required by this Rule, the owner or operator shall designate as confidential any information claimed to be exempt from public disclosure under the California Public Records Act, Government Code section 6250 et seq. If a document is submitted that contains information designated confidential in accordance with this Section, the owner or operator shall provide a justification for this designation and shall submit a separate copy of the document with the information designated confidential redacted.

12-12-500 MONITORING AND RECORDS

12-12-501 Water Seal Integrity Monitoring: Effective August 1, 2006, the owner or operator of a flare subject to this rule with a water seal shall continuously monitor and record the water level and pressure of the water seal that services each flare. Any new installation of a water seal shall be subject to this requirement immediately. Records of these measurements shall be retained for one year. Monitoring devices required pursuant to this section shall be subject to the reporting and record keeping requirements of Regulation 1, Section 523: Parametric Monitors.

EXHIBIT O

TCEQ MASTER CONTROL STRATEGY LIST
Point Sources

TCEQ - MASTER CONTROL STRATEGY LIST

Category
ID Control Strategy

Point Sources

Agricultural Operations

1 Emission reductions from livestock waste (VOC/NH3) WST-01

This control measure considers the ammonia and VOC emissions inventory associated with livestock waste and the development and assessment of feasible control approaches. Potential control options include, but are not limited to, removal of manure out-of-region or processing of manure at controlled composting facilities or at anaerobic digesters.

2 Emission reductions from composting (VOC/NH3) WST-02

This control measure proposes to achieve VOC and NH3 reductions from composting and related operations. A series of rules will be developed to 1) establish a registration program for composting and chipping and grinding facilities; 2) establish holding and/or processing time requirements for greenwaste; and, 3) set forth VOC and ammonia emission reduction requirements. Potential control options may include forced aeration, enclosures, process controls, and add-on controls (e.g. biofilters).

Airport Operations

3 Control emissions from airport terminals

4 Control emissions from facility energy conservation programs (airports)

5 Control emissions from aircraft maintenance

Bakeries

6 Bakeries - VOC

Implement contingency measure to require reductions from bakery ovens at sites with total VOC 25> tpy but < 50 tpy. Extend requirements for control of bakery oven emissions to 5 new counties.

Boilers

7 Apply 90% SO2 and 80% NOx reduction (similar to Best Available Retrofit Technolgoy [BART]) to all medium and large industrial, commercial, and institutional (ICI) boilers

8 Apply likely controls (90% SO2 and 80% NOx Reduction) to chemical plant boilers subject to the proposed Best Available Retrofit Technology (BART) requirements

9 Industrual, commercial and institutional (ICI) boilers - NOx

Expand existing 4 county DFW NOx controls to 5 new counties.- Apply HGB emission specifications to 9 counties.

10 NOx reductions from refinery boilers, steam generators, and process heaters. - NOx

A 5 ppm NOx limit corrected to 3% O2, or 0.0062 lb/MMBtu standard for large refinery boilers and process heaters (larger than 110 MMBtu).

11 Control emissions from boilers

12 Apply 40% SO2 and 60% NOx reduction to all medium and large industrial, commercial, and institutional (ICI) boilers

13 Apply Likely Controls (90% SO2 and 80% NOx Reduction) to industrial, commercial, and institutional (ICI) boilers subject to the proposed Best Available Retrofit Technology (BART) requirements

14 Institute fuel switching projects (point source) changing from coal fired boilers to gas fired boilers with fuel oil and propane backup

Breweries

15 Breweries- VOC

Implement practices to minimize spillage in filling operations, keg cleaning and waste beer processing. Wastewater streams and components could be covered at all times and routed to a treatment system capable of a VOC reduction efficiency equivalent to that obtained from the use of properly operated biotreatment unit. Emissions from the fermentation tanks could be reduced by the use of a condenser. Coding of bottles, cans, cases, and kegs could incorporate the use of low VOC containing inks or an ink-free laser coding process.

Burners

16 Burner Modifications

Burner air and/or fuel modifications to improve air/fuel interaction.

17 Low-NOx Burners

Burners designed to produce lower NOx emissions – "staged" combustion.

18 Fuel Reburn

Inject portion of the fuel into the furnace downstream of burner zone. Usually requires overfire air (OFA) to complete combustion

Chemical Manufacturing

19 Chemical manufacturing - VOC

Loading racks; Transportation & Marketing- Tank trucks/Cars loading; Petroleum storage tank-Loading racks: 30 TAC §§115.211 - 115.219 could be revised to require a 95% control efficiency rather than the 90% level of the current rule. The rule could also be extended to 5 counties in DFW at either 90% or 95 % control level.

Coal Properties and Processes

20 Chemical Coal Cleaning

Uses chemical processes to remove pyrites (inorganic sulfur compounds) and organic sulfur in coal.

21 Physical Coal Cleaning

Uses physical processes to remove pyrites (inorganic sulfur compounds) in coal.

22 Switch to Low Sulfur Coal

Uses low-sulfur western or other coals.

Combustion

23 Overfire Air

Form of "staged" combustion. Divert portion of the air from the windbox to OFA ports installed above the burners.

24 Oxygen-enhanced combustion modification

Improve effectiveness of overfire air (OFA) operation by injecting oxygen into fuelrich flames. Operate more fuel-rich without the problems. Emerging technology.

25 Stationary external combustion - VOC

Optimized combustion practices. External combustion sources are typically fired with natural gas or fuel oil. VOC emissions are produced from unburned organics present in the fuel, and result from poor combustion conditions such as inefficient fuel-air mixing, low temperatures, and short residence time. Since these same conditions cause CO emissions to increase, continuous monitoring of CO may be used as a surrogate for VOC emissions. CO CEMS is already required for large boilers and process heaters under the NOx RACT rule. Combustion modifications for NOx control can result in CO and VOC increases.

26 Engine test cells - NOx and VOC

27 Diesel and dual-fuel engines - NOx

Apply HGB specifications to 9 counties and East Texas (defined by SB7)- Apply HGB emission specifications to 9 counties and East Texas (defined by SB7) to major sources.

28 Gas-fired stationary internal combustion engines - VOC

Assign VOC emission specification.

29 Non-utility turbines - NOx

Apply HGB emission specifications to 9 counties.

30 Backup diesel generators

Apply HGB emission specifications- Convert to natural gas- Convert to fuel cells.

31 Gas-fired engines - NOx

Apply HGB emission specification to the 9 counties and remove the exemption for engines less than 300 hp.

Control Technology Rules

32 Adopt emission caps based on "Retrofit Best Available Control Technology (BACT) Level" of 0.15 lbs/mmBtu for SO2 and 0.10 lbs/mmBtu for NOx

33 Apply likely controls (90% SO2 and 80% NOx Reduction) to sources subject to the proposed Best Available Retrofit Technology (BART) requirements

34 Adopt more stringent Reasonably Available Control Technology (RACT) regulations (90% from uncontrolled), lower applicability thresholds, and extend geographic coverage to all counties

35 Adopt emission caps based on "Best Available Control Technology (BACT) Level for New Plants" of 0.10 lbs/mmBtu for SO2 and 0.07 lbs/mmBtu for NOx

36 Apply likely controls (95% SO2 and 80% NOx reduction) to kilns subject to the proposed Best Available Retrofit Technology (BART) requirements

37 Apply likely controls (90% SO2 and 80% NOx Reduction) to sources subject to the proposed Best Available Retrofit Technology (BART) requirements

Cooling Towers

38 Cooling towers - VOC

Cooling water monitoring of cooling tower heat exchange systems for flow rate and VOC to detect leaks and quantify emissions (similar to HRVOC rules from HGB). VOC controls: Specific point source limit, repair requirements, or cap & trade approach.

Electric Generating Utilities

39 Seek additional cost effective alternatives beyond SB 7 requirements by focusing first on the largest and most frequently operated units

40 Texas Utility Reductions

41 Fogging at combustion turbines at TVA Allen steam plant

42 Electricity surcharge - NOx

Peak usage surcharge on energy use. This will encourage non-peak use, and will provide funding for local energy efficiency programs.

43 Electric generating facilities - NOx

Apply HGB emission specifications to 9 counties- Apply HGB emission specifications to East Texas (defined by SB7). Expand existing 4 county DFW NOx controls to 5 new counties.

44 DFW Electric Generating Utilities - % NOx Reductions - 4 Counties

45 Restrictions on peaking/peak shaving; Limit usage of emergency power generators

46 Wet injection at combustion turbines at TVA Allen steam plant

47 Use of solar energy to produce electrical power

48 Demand-side management for utilities

49 Alcoa/Eastman Agreed Orders (AS)

50 Remove grandfathering provisions for older sources and upgrade facilities with newer technology

51 TNRCC.14 rule for power plants in the nonattainment area

52 VOC reasonably available control technology (RACT) Batch Processing/Wastewater (GD)

Emission Credits

53 Emission fees

54 Cap and trade with other units

55 Do not allow plants to trade credits with other plants in the same region

56 Regional Clean Air Incentives Market (RECLAIM)

Additional NOx Reductions for Regional Clean Air Incentives Market (RECLAIM). There are a variety of control strategies that can be implemented, including reducing ending allocations in 2003-2006, overlaying source-specific regulations, excluding smaller emitting facilities, and/or bifurcated market for powerplants and nonpowerplants.

57 Discrete Emission Reduction Credit (DERC) and Emission Reduction Credit (ERC) Environmental Contribution - VOC and NOx

Increase the environmental contributions for ERCs and DERCs from 10% to 20%.

Emission Limits

58 Emission Charges of $5,000 per Ton of VOC for Stationary Sources Emitting Over 1 Tons per Year (VOC) FSS-04

Emission Charges of $5,000 per Ton of VOC for Stationary Sources Emitting Over 1 Tons per Year. If the federal ambient air standards are not met by the year 2010, the District shall impose an emissions fee, in addition to the federal penalty, of $5,000 per ton of VOC, emitted by each major source in excess of 80 percent of the sources' baseline emissions. The fee rate will be adjusted annually to reflect increases in the consumer price index. The fee shall be paid for each calendar year after the year 2010 and until the area is redesignated as an ozone attainment area.

Flares

59 Flares - VOC

Require continuous monitoring of flow rate, net heating value, and composition on flares (similar to HRVOC rules from HGB). VOC controls: Specific point source limit or cap & trade approach.

Heaters

60 Process heaters - NOx

Apply HGB emission specifications to 9 counties.

61 Dryers, non-process heaters and ovens -NOx

Incinerators

62 Incinerators - NOx

Apply HGB emission specifications to 9 counties.

63 General process vent gas control - VOC
Expand existing general vent gas rule to 5 new counties.The proposed measure raises the control efficiency for non-Synthetic Organic Chemical Manufacturing Industry (SOCMI) processes from 90% to 98%. Incinerators - emission testing to establish demonstrated compliance parameter levels (such as inlet and exhaust temperatures, flow rates, etc.).

Kiln Operations

64 Apply reasonably available controls (90% SO2 and 50% NOx reduction) to all cement kilns in the region

65 Asphalt plant dryers and heaters
Control these sources at asphalt concrete manufacturing plants.

66 Cement kilns - NOx
LoTOx- Selective Noncatalytic Reduction - Selective Catalytic Reduction (SNCR- SCR).

67 Cement Kilns - VOC
Regenerative thermal oxidization.

68 Aggregate Kilns - NOx
Apply HGB emission specifications to 9 counties.

69 Brick Kilns - NOx

70 Lime kilns - NOx
Apply HGB emission specifications to 9 counties.

71 Require that cement kilns only burn natural gas; Retrofit older kilns with improved NOx control technology

72 Require baghouses and scrubbers on existing sources at the Midlothian complex; Restrict fuel use to natural gas

73 Cement kilns-add stack gas controls and restrict fuel to natural gas

74 Cement Kilns
On April 19, 2000, the commission adopted new cement kiln rules as part of the ozone SIP control strategy for the DFW ozone nonattainment area. The rules required portland cement kilns in Bexar, Comal, Ellis, Hays, and McLennan Counties to meet specific NOx reductions.

Lime Technology and Processes

75 Lime spray dryer system (LSD)*

76 Limestone forced oxidation system (LSFO)*
LSFO is a process based on wet limestone scrubbing which reducesscaling and eliminates need for landfilling of the waste product. Currently the preferred FGD technology worldwide.

77 Magnesium enhanced lime system (MEL)*
In the MEL process, slaked lime, containing calcium hydroxide [Ca(OH)2] and a portion of magnesium hydroxide [Mg(OH)2], is used to react with SO2.

Management

78 Reschedule processes at stationary source - VOC and NOx
Limit the following activities on high ozone action days: repair, maintenance, cleaning, and other shutdown of production equipment at industrial facilities. Examples include prohibiting tank cleaning or process vessel depressurization at refineries.

79 Date shifting (point sources) performing tests of emergency generators on forecast green or yellow days and not on forecast orange or red days

80 Early introduction of new, lower polluting technology

81 Tier I and Tier II controls in Ellis County

82 Add flexibility to current programs
This recommendation seeks to add more flexibility to existing stationary source rules by allowing sources to mitigate their emissions by reducing emissions from other less controlled or uncontrolled sources in lieu of complying with more costly controls under the existing framework. The purpose of this program is to achieve emission reductions and environmental improvement in a less costly and more efficient manner and, through compliance flexibility, to minimize the economic and job-related impacts of the Plan and potentially to reduce the size of the black box.

83 Further Emission Reductions from Large VOC Sources (VOC) MSC-08
Facilities will be required to submit a plan to outline specific measures that would be implemented to reduce their overall emissions beyond the existing regulations and achieve a specified emission reduction target. The reduction targets will be based on technology-based control targets for various source categories and would take into account technical feasibility and cost-effectiveness.

84 Remove Disincentives on Voluntary Measures
Stationary source operators may often be hesitant about making modifications or improvements to their permitted sources due to the potential impact on their facilities from rules which require a permit change or new source review for modifications that increase or decrease emissions. Recommendation was made to consider removing impediments potentially created by rules and regulations in order to achieve reductions from voluntary measures implemented by facilities for SIP purposes.

85 More accurate count of small sources with in the inventory is needed

86 Examine point source control possibilities within a 12-county area

Metal Production

87 Primary metal production - VOC
Implement work practice standards to minimize the amount of organics in furnace charge materials or require use of gas-fired preheater where the flame directly contacts the scrap charged. VOC emission specifications for cupola melting furnaces and mold/core production processes; capture and collection systems, thermal incinerators (afterburners).

88 Secondary metal production - VOC
Implement work practice standards to minimize the amount of organics in furnace charge materials or require use of gas-fired preheater where the flame directly contacts the scrap charged. VOC emission specifications for cupola melting furnaces and mold/core production processes; capture and collection systems, thermal incinerators (afterburners).

89 Primary metal production - NOx
Selective noncatalytic reduction (SNCR) for metallurgical furnaces.

90 Secondary metal production - NOx
Selective noncatalytic reduction (SNCR) for metallurgical furnaces.

Oil and Gas Production

91 Emission Reductions from Fugitive Emission Sources (VOC) - FUG-05
Further VOC emission reductions from fugitive emission sources, such as refineries, oil and gas production facilities, terminals, chemical plants, and manufacturing facilities. Implementation of facility-specific and SCAQMD-approved compliance plans to maximize compliance flexibility opportunities.

92 Emission Reductions from Petroleum Refinery Flares (SOx) CMB-07
Emission Reductions from Petroleum Refinery Flares. This control measure applies to all gas flares used at petroleum refineries, sulfur recovery plants and hydrogen production plants. Step I-evaluate and assess to develop an accurate emissions inventory from flare operations. Step II-thoroughly investigate control options to identify the most feasible and cost-effective control strategies available to reduce emissions from refinery flares.

93 Emission reductions from petroleum refinery Fluidized-bed catalytic cracking units (FCCUs) (PM10/NH3) CMB-09
Refine the emission inventory and reduce PM10, PM2.5 and NH3 emissions from petroleum fluid catalytic cracking units. Improve the operation of electrostatic precipitators (ESP) and cyclones presently installed on the catalytic cracking units & replace older equipment with new, more efficient models.

94 Wastewater from coke cutting operations - VOC
Wastewater from coke cutting is not part of the refinery wastewater collection and treatment system. Include it in the existing collection and treatment system.

Pulp and Paper

95 Pulping liquor furnaces - NOx
Apply HGB emission specifications to 9 counties.

96 Pulp and paper - VOC
Maximum available control technology (MACT) standards require the control of hazardous air pollutant (HAP) emissions. VOC emissions are not specifically targeted by the MACT, but the control technologies upon which the standards are based will similarly reduce VOC emissions.

Selective Catalytic/Noncatalytic Reduction

97 Hydrocarbonenhanced Selective Non-Catalytic Reduction (SNCR)
Inject small amount of natural gas to create radicals that enhance SNCR effectiveness at 1700 to 2000 °F. Emerging technology.

98 Selective Noncatalytic Reduction (SNCR)
Inject ammonia-based reagent into upper furnace (1700-2000 degrees F) to destroy NOx.

99 Selective Catalytic Reduction (SCR)
Ammonia added upstream of catalytic reactor installed upstream of air preheater (conventional), downstream of a hot ESP (low dust), or downstream of the cold ESP (tail end).

100 Examine potential disbenefits associated with applying selective catalytic reduction (SCR) and nonselective catalytic reduction (NSCR) controls on fuel combustors (e.g., ammonia slip)

101 Rich Reagent Injection
Selective non-catalytic reduction (SNCR) system with reagent injection into a fuel rich zone of the OFA system. This variation of SNCR is still under demonstration.

Storage Tanks

102 i) Fugitive leaks - VOC- ii) Control emissions from valves and flanges - VOC

i)Expand current Chapter 115 rules to 5 counties- Lower Leak definitions- Institute audit provisions to improve actual reductions. ii) Control emissions from valves and flanges- Set a maximum leak limit for components- Target minimization and repair periods (reduce repair time)- If equipment leaks frequently, replace equipment.- Require inaccessible equipment to be replaced by superior technologies- Quantify mass emissions and impose emission caps- Increase inspections- Use remote sensing technologies to identify the largest leaking components.

103 Storage tank inspections - VOC

The proposed control measure utilizes advanced/enhanced inspection devices/techniques to inspect storage tanks. Gas imaging cameras, internal remote inspection (robot), etc.These inspections would eliminate the necessity to empty a tank during the inspection process. Tank inspection and maintenance emissions would be reduced to a negligible amount.

104 Industrial wastewater- VOC

30 TAC §§115.140-115.149 could be extended to 5 counties in Dallas-Fort Worth.

105 Additional storage tank controls-VOC

Extending existing 115-storage tank rule from 4 counties to 5 new counties. Additional or more stringent requirements in existing storage tank rules.

Surface Coating

106 General surface coating application - VOC

Texas Administrative Code, Sections 115.420 - 115.429 can be expanded for 5 counties in Dallas-Fort Worth.

Total	**106**

EXHIBIT P

Tesoro Reported Flare Data

Date	CAUSE/COMMENTS	Volume MMSCFD	HHV (BTU/SCF)	H2S (Mole %)	Mol. Wt (lbs/mole)	SOx (lbs/day)	District's VOC Estimate 75% HC 44 MW 98% eff (lbs)
			Does not include pilot and purge gas				
			Plant Reported Data				
1/1/01		6.69					11653
1/2/01		5.33					9274
1/3/01		6.47					11269
1/4/01		4.99					8686
1/5/01		5.89					10260
1/6/01		5.13					8938
1/7/01		5.75					10019
1/8/01		5.25					9139
1/9/01		5.00					8699
1/10/01		5.48					9547
1/11/01		5.03					8757
1/12/01		5.23					9110
1/13/01		5.51					9602
1/14/01		6.83					11892
1/15/01		4.89					8513
1/16/01		5.12					8910
1/17/01		4.90					8525
1/18/01		4.75					8271
1/19/01		5.96					10371
1/20/01		4.41					7673
1/21/01		7.27					12664
1/22/01		7.22					12565
1/23/01		6.36					11084
1/24/01		7.49					13036
1/25/01		4.26					7415
1/26/01		4.91					8542
1/27/01		4.78					8330
1/28/01		5.41					9429
1/29/01		4.74					8249
1/30/01		5.81					10117
1/31/01		5.37					9354
2/1/01		4.26					7418
2/2/01		4.74					8251
2/3/01		5.30					9223

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				District's
		Plant Reported Data					VOC Estimate
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
2/4/01		6.18					10763
2/5/01		7.09					12353
2/6/01		7.91					13769
2/7/01		7.79					13570
2/8/01		7.55					13153
2/9/01		6.67					11618
2/10/01		7.98					13899
2/11/01		26.33					45857
2/12/01		7.95					13846
2/13/01		9.99					17393
2/14/01		12.86					22402
2/15/01		13.18					22953
2/16/01		9.51					16564
2/17/01		6.20					10789
2/18/01		6.20					10790
2/19/01		5.91					10294
2/20/01		6.21					10823
2/21/01		6.34					11049
2/22/01		5.34					9302
2/23/01		5.64					9819
2/24/01		4.47					7787
2/25/01		5.32					9271
2/26/01		4.80					8361
2/27/01		4.99					8689
2/28/01		5.21					9070
3/1/01		4.54					7909
3/2/01		4.87					8488
3/3/01		4.43					7722
3/4/01		5.87					10227
3/5/01		5.36					9331
3/6/01		4.79					8339
3/7/01		5.50					9582
3/8/01		5.08					8853
3/9/01		5.01					8719
3/10/01		4.61					8032

Tesoro Reported Flare Data

Date	CAUSE/COMMENTS	Volume MMSCFD	HHV (BTU/SCF)	H2S (Mole %)	Mol. Wt (lbs/mole)	SOx (lbs/day)	District's VOC Estimate 75% HC 44 MW 98% eff (lbs)
			Does not include pilot and purge gas				
			Plant Reported Data				
3/11/01		5.39					9386
3/12/01		5.40					9405
3/13/01		6.31					10981
3/14/01		6.70					11662
3/15/01		6.56					11423
3/16/01		6.51					11337
3/17/01		6.58					11452
3/18/01		9.90					17244
3/19/01		8.34					14515
3/20/01		6.68					11641
3/21/01		7.92					13785
3/22/01		6.05					10528
3/23/01		6.49					11306
3/24/01		7.54					13131
3/25/01		11.27					19627
3/26/01		6.22					10827
3/27/01		6.44					11208
3/28/01		44.91					78216
3/29/01		137.89					240130
3/30/01		90.27					157198
3/31/01		6.90					12018
4/1/01		6.37					11092
4/2/01		5.03					8752
4/3/01		5.42					9430
4/4/01		6.11					10639
4/5/01		8.35					14535
4/6/01		5.85					10195
4/7/01		5.84					10163
4/8/01		6.41					11157
4/9/01		6.82					11868
4/10/01		6.72					11703
4/11/01		7.60					13242
4/12/01		7.65					13330
4/13/01		8.36					14551
4/14/01		5.69					9905

Tesoro Reported Flare Data

Date	CAUSE/COMMENTS	Volume MMSCFD	HHV (BTU/SCF)	H2S (Mole %)	Mol. Wt (lbs/mole)	SOx (lbs/day)	District's VOC Estimate 75% HC 44 MW 98% eff (lbs)
			Does not include pilot and purge gas				
		Plant Reported Data					
4/15/01		6.21					10808
4/16/01		8.23					14336
4/17/01		19.41					33803
4/18/01		12.77					22245
4/19/01		9.78					17023
4/20/01		4.88					8498
4/21/01		4.10					7148
4/22/01		5.36					9342
4/23/01		4.99					8692
4/24/01		5.29					9220
4/25/01		6.29					10955
4/26/01		13.21					23003
4/27/01		5.73					9978
4/28/01		4.87					8475
4/29/01		5.12					8916
4/30/01		5.69					9902
5/I/2001		5.24					9120
5/2/01		5.45					9494
5/3/01		4.44					7724
5/4/01		7.19					12529
5/5/01		5.58					9717
5/6/01		9.16					15945
5/7/01		6.64					11560
5/8/01		6.54					11390
5/9/01		6.07					10569
5/10/01		5.20					9051
5/11/01		5.32					9265
5/12/01		5.28					9199
5/13/01		5.65					9839
5/14/01		4.66					8114
5/15/01		4.95					8613
5/16/01		5.07					8827
5/17/01		4.53					7890
5/18/01		5.70					9922
5/19/01		4.97					8658

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				District's
		Plant Reported Data					VOC Estimate
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
5/20/01		7.34					12783
5/21/01		8.50					14795
5/22/01		6.70					11663
5/23/01		7.25					12629
5/24/01		5.39					9379
5/25/01		5.43					9453
5/26/01		5.07					8832
5/27/01		5.09					8863
5/28/01		5.08					8850
5/29/01		5.82					10137
5/30/01		6.10					10624
5/31/01		6.97					12138
6/l/2001		5.62					9779
6/2/01		4.56					7941
6/3/01		4.81					8381
6/4/01		4.70					8185
6/5/01		4.83					8416
6/6/01		5.12					8912
6/7/01		5.96					10384
6/8/01		5.21					9073
6/9/01		4.90					8538
6/10/01		4.91					8546
6/11/01		4.66					8114
6/12/01		4.86					8461
6/13/01		5.57					9704
6/14/01		5.18					9027
6/15/01		5.27					9185
6/16/01		5.61					9777
6/17/01		5.62					9784
6/18/01		5.60					9759
6/19/01		5.81					10115
6/20/01		8.62					15020
6/21/01		8.28					14426
6/22/01		9.24					16088
6/23/01		6.61					11505

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				District's
		Plant Reported Data					VOC Estimate
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
6/24/01		6.16					10736
6/25/01		6.01					10468
6/26/01		7.56					13167
6/27/01		6.78					11810
6/28/01		6.87					11967
6/29/01		8.57					14920
6/30/01		8.11					14124
7/l/2001		6.62					11531
7/2/01		8.80					15327
7/3/01		8.37					14570
7/4/01		8.54					14867
7/5/01		6.88					11985
7/6/01		6.40					11144
7/7/01		6.02					10488
7/8/01		7.99					13907
7/9/01		6.83					11891
7/10/01		6.33					11020
7/11/01		9.49					16524
7/12/01		8.56					14913
7/13/01		8.25					14365
7/14/01		7.57					13182
7/15/01		6.31					10989
7/16/01		6.30					10973
7/17/01		6.50					11317
7/18/01		6.99					12178
7/19/01		7.16					12476
7/20/01		9.42					16412
7/21/01		7.69					13390
7/22/01		7.77					13537
7/23/01		7.82					13626
7/24/01		10.18					17736
7/25/01		5.86					10200
7/26/01		5.64					9815
7/27/01		5.91					10294
7/28/01		6.88					11988

Tesoro Reported Flare Data

Date	CAUSE/COMMENTS	Volume MMSCFD	HHV (BTU/SCF)	H2S (Mole %)	Mol. Wt (lbs/mole)	SOx (lbs/day)	District's VOC Estimate 75% HC 44 MW 98% eff (lbs)
			Does not include pilot and purge gas				
			Plant Reported Data				
7/29/01		7.21					12560
7/30/01		7.64					13305
7/31/01		8.53					14851
8/l/2001		8.13					14159
8/2/01		7.49					13041
8/3/01		7.83					13637
8/4/01		7.03					12236
8/5/01		6.22					10840
8/6/01		7.71					13426
8/7/01		7.79					13563
8/8/01		7.95					13851
8/9/01		6.80					11847
8/10/01		5.85					10181
8/11/01		5.97					10398
8/12/01		6.02					10482
8/13/01		5.68					9887
8/14/01		6.02					10483
8/15/01		6.27					10921
8/16/01		6.42					11175
8/17/01		6.05					10527
8/18/01		7.55					13143
8/19/01		5.88					10247
8/20/01		5.93					10329
8/21/01		6.05					10535
8/22/01		7.97					13881
8/23/01		6.57					11432
8/24/01		7.46					12984
8/25/01		8.69					15135
8/26/01		13.68					23827
8/27/01		11.90					20726
8/28/01		8.93					15550
8/29/01		8.22					14307
8/30/01		92.53					161129
8/31/01		128.60					223949
9/l/2001		46.32					80662

Tesoro Reported Flare Data

Date	CAUSE/COMMENTS	Volume MMSCFD	HHV (BTU/SCF)	H2S (Mole %)	Mol. Wt (lbs/mole)	SOx (lbs/day)	District's VOC Estimate 75% HC 44 MW 98% eff (lbs)
			Does not include pilot and purge gas				
		Plant Reported Data					
9/2/01		13.19					22969
9/3/01		9.01					15684
9/4/01		7.09					12344
9/5/01		8.55					14886
9/6/01		8.79					15302
9/7/01		8.54					14874
9/8/01		8.58					14940
9/9/01		8.46					14727
9/10/01		8.63					15023
9/11/01		9.07					15801
9/12/01		8.44					14702
9/13/01		8.10					14101
9/14/01		8.35					14542
9/15/01		6.96					12124
9/16/01		8.77					15268
9/17/01		14.50					25243
9/18/01		9.15					15926
9/19/01		8.01					13950
9/20/01		6.27					10914
9/21/01		6.10					10626
9/23/01		5.88					10244
9/28/01		7.01					12202
9/29/01		6.50					11322
9/30/01		8.04					14006
10/l/2001		6.95					12108
10/2/01		7.98					13901
10/3/01		7.17					12483
10/4/01		7.19					12515
10/5/01		9.41					16385
10/6/01		6.17					10746
10/7/01		6.01					10458
10/8/01		5.29					9204
10/9/01		5.78					10060
10/10/01		6.80					11834
10/11/01		7.69					13400

Tesoro Reported Flare Data

Date	CAUSE/COMMENTS	Volume MMSCFD	HHV (BTU/SCF)	H2S (Mole %)	Mol. Wt (lbs/mole)	SOx (lbs/day)	District's VOC Estimate 75% HC 44 MW 98% eff (lbs)
			Does not include pilot and purge gas				
		Plant Reported Data					
10/12/01		7.75					13498
10/13/01		6.68					11633
10/14/01		6.57					11435
10/15/01		8.45					14723
10/16/01		6.25					10888
10/17/01		9.46					16481
10/18/01		5.80					10099
10/19/01		5.57					9698
10/20/01		5.12					8915
10/21/01		4.89					8520
10/22/01		5.21					9075
10/23/01		4.79					8334
10/24/01		5.17					9007
10/25/01		7.07					12317
10/26/01		5.15					8968
10/27/01		6.36					11077
10/28/01		6.60					11492
10/29/01		4.70					8180
10/30/01		4.94					8595
10/31/01		5.25					9140
11/l/2001		4.85					8454
11/2/01		6.85					11936
1113/2001		18.24					31772
11/4/01		8.72					15180
11/5/01		8.82					15359
11/6/01		6.17					10750
11/7/01		4.57					7964
11/8/01		4.65					8099
11/9/01		4.68					8152
11/10/01		5.29					9212
11/11/01		5.53					9626
11/12/01		5.16					8990
11/13/01		6.89					11999
11/14/01		7.15					12443
11/15/01		11.74					20437

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				District's
		Plant Reported Data					VOC Estimate
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
11/16/01		8.04					13998
11/17/01		8.13					14151
11/18/01		8.05					14017
11/19/01		6.33					11029
11/20/01		8.68					15120
11/21/01		11.03					19216
11/22/01		7.96					13858
11/23/01		4.53					7886
11/24/01		7.85					13671
11/25/01		9.21					16031
11/26/01		9.17					15964
11/27/01		7.97					13884
11/28/01		8.69					15129
11/29/01		7.79					13565
11/30/01		6.84					11904
12/1/01		7.35					12792
12/2/01		7.71					13428
12/3/01		18.63					32439
12/4/01		10.89					18972
12/5/01		9.76					16993
12/6/01		18.85					32826
12/7/01		26.94					46912
12/8/01		25.23					43942
12/9/01		22.92					39921
12/10/01		37.64					65541
12/11/01		40.72					70912
12/12/01		40.00					69651
12/13/01		30.15					52509
12/14/01		38.83					67624
12/15/01		39.38					68583
12/16/01		43.25					75315
12/17/01		45.85					79852
12/18/01		45.55					79329
12/19/01		29.52					51399
12/20/01		39.08					68061

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				District's
		Plant Reported Data					VOC Estimate
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
12/21/01		42.36					73762
12/22/01		46.75					81418
12/23/01		46.40					80808
12/24/01		40.83					71104
12/25/01		17.11					29792
12/26/01		10.42					18142
12/27/01		7.41					12908
12/28/01		30.63					53334
12/29/01		20.76					36148
12/30/01		4.95					8616
12/31/01		20.88					36360
I/I/2002		28.86					50251
1/2/02		9.18					15993
1/3/02		18.87					32865
1/4/02		38.64					67296
1/5/02		34.43					59965
1/6/02		30.77					53579
1/7/02		19.76					34412
1/8/02		16.80					29260
1/9/02		35.67					62125
1/10/02		27.22					47397
1/11/02		27.22					47397
1/11/02		28.65					49900
1/12/02		35.64					62060
1/13/02		36.58					63704
1/14/02		38.55					67130
1/15/02		35.87					62466
1/16/02		33.11					57664
1/17/02		31.99					55708
1/18/02		30.36					52876
1/19/02		32.99					57456
1/20/02		19.91					34678
1/21/02		14.97					26065
1/22/02		21.89					38128
1/23/02		27.51					47903

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				District's
			Plant Reported Data				VOC Estimate
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
1/24/02		31.34					54582
1/25/02		51.63					89916
1/26/02		51.63					89916
1/27/02		52.61					91609
1/27/02		51.12					89014
1/28/02		48.63					84693
1/29/02		47.05					81937
1/30/02		18.12					31562
1/30/02		18.12					31562
1/30/02		18.12					31562
1/31/02		20.89					36373
2/l/2002		25.01					43553
2/2/02		33.55					58426
2/3/02		31.63					55074
2/4/02		34.85					60692
2/5/02		34.31					59741
2/6/02		41.87					72920
2/7/02		46.34					80692
2/8/02		36.00					62691
2/9/02		39.49					68766
2/10/02		37.40					65127
2/11/02		28.96					50438
2/12/02		39.05					68011
2/13/02		12.53					21816
2/14/02		34.03					59261
2/15/02		25.04					43599
2/16/02		30.81					53654
2/17/02		29.01					50516
2/18/02		29.43					51243
2/19/02		31.65					55122
2/20/02		43.48					75710
2/21/02		39.19					68247
2/22/02		56.13					97742
2/23/02		51.44					89587
2/24/02		47.74					83140

Tesoro Reported Flare Data

			Does not include pilot and purge gas				**District's**
		Plant Reported Data					**VOC Estimate**
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
2/25/02		44.33					77204
2/26/02		49.23					85726
2/27/02		31.48					54816
2/28/02		34.10					59376
3/l/2002		38.78					67537
3/2/02		37.74					65723
3/3/02		48.94					85222
3/4/02		31.05					54077
3/5/02		41.44					72172
3/6/02		44.17					76923
3/7/02		37.88					65971
3/8/02		25.54					44478
3/9/02		28.10					48943
3/10/02		49.74					86621
3/11/02		46.45					80891
3/12/02		41.73					72670
3/13/02		43.71					76117
3/14/02		41.63					72489
3/15/02		39.93					69527
3/16/02		43.15					75135
3/17/02		33.09					57616
3/18/02		39.78					69272
3/19/02		39.51					68804
3/20/02		35.12					61163
3/21/02		30.88					53781
3/22/02		35.16					61226
3/23/02		27.19					47356
3/24/02		27.44					47787
3/25/02		7.61					13246
3/26/02		20.46					35622
3/27/02		27.26					47475
3/28/02		40.65					70781
3/29/02		34.94					60849
3/30/02		15.55					27085
3/31/02		11.88					20690

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				District's
			Plant Reported Data				VOC Estimate
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
4/1/02		10.90					18985
4/2/02		6.92					12057
4/3/02		7.03					12241
4/4/02		3.61					6295
4/5/02		15.69					27328
4/6/02		22.04					38373
4/7/02		60.46					105290
4/8/02		55.30					96309
4/9/02		45.34					78961
4/10/02		40.39					70328
4/11/02		33.54					58415
4/12/02		10.00					17408
4/13/02		13.10					22815
4/14/02		7.23					12585
4/15/02		9.77					17009
4/16/02		10.28					17911
4/17/02		6.37					11086
4/18/02		2.82					4918
4/19/02		5.56					9678
4/20/02		5.51					9592
4/21/02		11.19					19490
4/22/02		15.49					26977
4/23/02		12.92					22507
4/24/02		7.55					13154
4/25/02		8.54					14873
4/26/02		7.31					12725
4/27/02		6.06					10558
4/28/02		6.22					10825
4/29/02		5.51					9602
4/30/02		7.52					13093
5/l/2002		5.54					9650
5/2/02		9.86					17174
5/3/02		8.83					15372
5/4/02		21.36					37197
5/5/02		15.56					27091

Tesoro Reported Flare Data

Date	CAUSE/COMMENTS	Volume MMSCFD	HHV (BTU/SCF)	H2S (Mole %)	Mol. Wt (lbs/mole)	SOx (lbs/day)	District's VOC Estimate 75% HC 44 MW 98% eff (lbs)
			Does not include pilot and purge gas				
			Plant Reported Data				
5/6/02		10.81					18822
5/7/02		11.17					19450
5/8/02		11.31					19690
5/9/02		8.73					15208
5/10/02		9.90					17249
5/11/02		18.28					31837
5/12/02		10.03					17467
5/13/02		11.94					20790
5/14/02		11.94					20798
5/15/02		12.80					22293
5/16/02		10.24					17832
5/17/02		12.41					21611
5/18/02		9.24					16096
5/19/02		10.53					18332
5/20/02		11.13					19389
5/21/02		10.27					17888
5/22/02		16.83					29308
5/23/02		23.93					41679
5/24/02		25.08					43669
5/25/02		15.24					26535
5/26/02		9.88					17213
5/27/02		5.81					10122
5/28/02		5.78					10061
5/29/02		5.98					10406
5/30/02		6.65					11579
5/31/02		6.58					11462
6/1/02		5.61	839	1.68	33.11	15940	9769
6/2/02		5.72	839	1.68	33.11	16240	9961
6/3/02		6.25	839	1.68	33.11	17760	10884
6/4/02		7.28	839	1.68	33.11	20680	12678
6/5/02		7.14	839	1.68	33.11	20280	12434
6/6/02		4.78	839	1.68	33.11	13580	8324
6/7/02		5.99	839	1.68	33.11	17020	10431
6/8/02		9.21	839	1.68	33.11	21680	16039
6/9/02		11.85	839	1.68	33.11	33640	20636

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				District's
			Plant Reported Data				VOC Estimate
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
6/10/02		18.48	839	1.68	33.11	5252	32182
6/11/02		11.35	839	1.68	33.11	32260	19765
6/12/02		7.74	839	1.68	33.11	22000	13479
6/13/02		9.65	839	1.68	33.11	27420	16805
6/14/02		5.45	839	1.68	33.11	15480	9491
6/15/02		4.85	839	1.68	33.11	13780	8446
6/16/02		4.83	839	1.68	33.11	13720	8411
6/17/02		7.9	839	1.68	33.11	15500	13757
6/18/02		4.8	839	1.68	33.11	22320	8359
6/19/02		6.1	839	1.68	33.11	13540	10623
6/20/02		5	839	1.68	33.11	17460	8707
6/21/02		7.3	839	1.68	33.11	14240	12712
6/22/02		11.5	839	1.68	33.11	20860	20026
6/23/02		7.4	839	1.68	33.11	32720	12887
6/24/02		6.7	839	1.68	33.11	21140	11668
6/25/02		5.2	839	1.68	33.11	19060	9055
6/26/02		6	839	1.68	33.11	14760	10449
6/27/02		5.3	839	1.68	33.11	17080	9230
6/28/02		5.5	839	1.68	33.11	15140	9578
6/29/02		6.6	839	1.68	33.11	15740	11493
6/30/02		7.4	839	1.68	33.11	18760	12887
7/1/02	Foul water compressor down	7.42	826	1.7	32.7	21240	12921
7/2/02		6.26	826	1.7	32.7	17920	10901
7/3/02		5.88	826	1.7	32.7	16840	10240
7/4/02		6.15	826	1.7	32.7	17600	10710
7/5/02		6.97	826	1.7	32.7	19960	12138
7/6/02		6.17	826	1.7	32.7	17640	10745
7/7/02		5.8	826	1.7	32.7	16580	10100
7/8/02		6.38	826	1.7	32.7	18280	11110
7/9/02		7.82	826	1.7	32.7	22400	13618
7/10/02	#2 H2 Plant PSA vent to flare	8.6	826	1.7	32.7	24620	14976
7/11/02		7.02	826	1.7	32.7	20080	12225
7/12/02		6.92	826	1.7	32.7	19800	12051
7/13/02		6.98	826	1.7	32.7	19980	12155
7/14/02		6.09	826	1.7	32.7	17440	10605

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				District's
			Plant Reported Data				VOC Estimate
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
7/15/02		6.39	826	1.7	32.7	18280	11128
7/16/02		6.15	826	1.7	32.7	17620	10710
7/17/02		5.95	826	1.7	32.7	17020	10361
7/18/02	#3 Crude furnace tripped off, #3 HDS Stripper was bypased to fix leak	9.55	826	0.05	32.7	800	16631
7/19/02		7.03	826	1.7	32.7	20120	12242
7/20/02		5.65	826	1.7	32.7	16180	9839
7/21/02		4.92	826	1.7	32.7	14080	8568
7/22/02		4.53	826	1.7	32.7	12980	7889
7/23/02		4.37	826	1.7	32.7	12520	7610
7/24/02		5.23	826	1.7	32.7	14960	9108
7/25/02		7.27	826	1.7	32.7	20800	12660
7/26/02	Lost lean DEA pump, flared fule gas (see note 2)	12.59	1092	3.5	32.7	49240	21925
7/27/02	Adjusting unit rates after upset	8.8	826	1.7	32.7	25180	15325
7/28/02	#2 H2 Plant shutdown	6.1	826	1.7	32.7	17480	10623
7/29/02	Units are cut back due to H2 shortage	3.97	826	1.7	32.7	11360	6913
7/30/02		3.95	826	1.7	32.7	11320	6879
7/31/02		3.27	826	1.7	32.7	9380	5694
8/1/02		3.3	802.89	1.51	32.41	8420	5747
8/2/02		7.3	802.89	1.51	32.41	18580	12712
8/3/02		7.8	802.89	1.51	32.41	19940	13583
8/4/02		6.1	802.89	1.51	32.41	15580	10623
8/5/02	H2 Plant shutdown 13 hours	16.1	802.89	1.51	32.41	19580	28037
8/6/02		6.1	802.89	1.51	32.41	15620	10623
8/7/02		4.8	802.89	1.51	32.41	15520	8359
8/8/02		7.2	802.89	1.51	32.41	12300	12538
8/9/02		5.3	802.89	1.51	32.41	18380	9230
8/10/02		5.1	802.89	1.51	32.41	13580	8881
8/11/02		7.8	802.89	1.51	32.41	12960	13583
8/12/02		5.4	802.89	1.51	32.41	19780	9404
8/13/02		4.8	802.89	1.51	32.41	13720	8359
8/14/02		6	802.89	1.51	32.41	12080	10449
8/15/02		6.3	802.89	1.51	32.41	15260	10971
8/16/02		6.4	802.89	1.51	32.41	16300	11145
8/17/02	Previous 30 days average	6.4	802.89	1.51	32.41	16300	11145
8/18/02	We had problems with data collection on July 17-28 and 31	6.4	802.89	1.51	32.41	16300	11145

Tesoro Reported Flare Data							
			Does not include pilot and purge gas				**District's**
		Plant Reported Data					**VOC Estimate**
Date	CAUSE/COMMENTS	Volume	HHV	H2S	Mol. Wt	SOx	75% HC 44 MW 98% eff
		MMSCFD	(BTU/SCF)	(Mole %)	(lbs/mole)	(lbs/day)	(lbs)
8/19/02		6.4	802.89	1.51	32.41	16300	11145
8/20/02		6.4	802.89	1.51	32.41	16300	11145
8/21/02		6.4	802.89	1.51	32.41	16300	11145
8/22/02		6.4	802.89	1.51	32.41	16300	11145
8/23/02		6.4	802.89	1.51	32.41	16300	11145
8/24/02		6.4	802.89	1.51	32.41	16300	11145
8/25/02		6.4	802.89	1.51	32.41	16300	11145
8/26/02		6.4	802.89	1.51	32.41	16300	11145
8/27/02		6.4	802.89	1.51	32.41	16300	11145
8/28/02		6.4	802.89	1.51	32.41	16300	11145
8/29/02		6.2	802.89	1.51	32.41	15700	10797
8/30/02		6.4	802.89	1.51	32.41	16300	11145
8/31/02		6.4	802.89	1.51	32.41	16300	11145
Notes:	Data supplied by Tesoro except for last column which is the District's emission estimate based on information supplied by Tesoro						
	Purge and pilot flows are not always included above						
	Average based on reported values						
	Number nonzero days		607				
	Total Emissions		14340536				
	Average daily value for reported data is		**13**	**tons**	**Pilot and purge gas included**		
	Maximum reported value is		**120**	**tons**			

Emissions Estimated using Tesoro's Composition and TAD flow Data with Minimum Flow, I

98%	nominal efficiency				
90%	efficiency for flows <	0.5	MMSCFD	per flare	5

Since flare gas is not evenly distributed among the flares,
assume that when the flow is < above value, the efficiency is lower for the following percent of the
Below minimum flow, average daily flow is following percent of minimum flow 50%

Number of flares	2					(1E6 on one header ar	
Minimum flow per flare	625,000	SCFD				(always above this valu	
Purge & pilot gas	800,000	SCFD					
Minimum flow that can be measured					1.25	MMSCFD	
Minimum flow for all flares to be at		98%	efficiency		2.5	MMSCFD	
Fraction of minimum when flaring at		90%	efficiency		50%	of flows <=	2.5
Number days total flow >=	1.25	MMSCFD	is		607	days	
Number days total flow >=	2.5	MMSCFD	is		607	days	
Total number of days	9/1/02-1/1/01				608	days	
Number days flow <	1.25	MMSCFD	is		1	days	
Number days flow <	2.5	MMSCFD	is		1	days	
Number days flow <	2.5	& >		1.25	0	days	
Total flow for days >=	1.25	MMSCFD	is		8234.9	MMSCF	
Total flow for days >=	2.5	MMSCFD	is		8234.9	MMSCF	
Total flow for days between above values is					0.0	MMSCF	
Flow for days <	1.25				0.6	MMSCF	
Total flow					8235.6	MMSCF	
Average daily flow is					13.5	MMSCF	
Total flow eff -	98%				8235.3	MMSCF	
Total flow eff -	90%				0.3	MMSCF	
Days eff -	98%				607.5	days	for estimati
Days eff -	90%				0.5	days	for estimati

	CH4	NMHC	NMHC	H2S	LHV
Flare gas composition	mole %	mole %	MW-lbs	mole %	BTU/scf
	21%	14%	41	1.6%	900

	CH4	NMHC	NMHC	H2S	LHV
Purge gas composition	mole %	mole %	MW-lbs	mole %	BTU/scf
	96%	4%	35	0.0%	1000

Flare efficiency **98%**

		CH4	**NMHC**	**Organics**	**SOx**	**NOx**
Total Flare gas emissions	lbs	1,460,183	2,494,479	3,954,661	########	503,998
Total purge gas emissions	lbs	393,929	35,905	429,834	0	33,048
Total	**tons**	**927.1**	**1265.2**	**2192.2**	**11405.5**	**268.5**

Flare efficiency **90%**

		CH4	**NMHC**	**Organics**	**SOx**	**NOx**

Total Flare gas emissions	lbs	277	473	750	866	19
Total purge gas emissions	lbs	1,621	148	1,769	0	27
Total	**tons**	**0.9**	**0.3**	**1.3**	**0.4**	**0.0**
Average daily emissions						
Flare gas	**tons/day**	1.2	2.1	3.3	18.8	0.4
Purge	**tons/day**	0.3	0.0	0.4	0.0	0.0
Total	**tons/day**	**1.5**	**2.1**	**3.6**	**18.8**	**0.4**

NOx: 0.068 lb/MM BTU

lower eff at lower flows

flares

time 50%

ıd 0.25E6 on other header - **1**ft/s 48 and 24 in headers)
ɹe)

ing purge gas emissions
ing purge gas emissions

Tesoro average of their daily sample
taken approximately 3 am
H2S is average of values reported for 3 months

EXHIBIT Q

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Jan 1 2004 - Jan 31 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
1/1/2004	80289	23.07	42.49	62.37
1/2/2004	23712	6.5	9.48	13.81
1/3/2004	14345	4.76	4.93	8.72
1/4/2004	14738	4.82	5.5	7.96
1/5/2004	818135	240.11	298.94	511.17
1/6/2004	41265	13.13	15.74	25.78
1/7/2004	23433	7.15	8.69	6.33
1/8/2004	20394	6.95	7.84	0
1/9/2004	8844	2.66	3.73	5.38
1/10/2004	12978	4.09	6.12	3.94
1/11/2004	9885	2.89	4.19	6.26
1/12/2004	12319	3.13	5.55	7.07
1/13/2004	12807	2.61	5.71	9.73
1/14/2004	18372	3.41	7.34	5.27
1/15/2004	208758	66.41	93.17	118.98
1/16/2004	9578	2.83	3.92	6.47
1/17/2004	10699	2.7	4.53	6.5
1/18/2004	10807	1.75	5.18	8.39
1/19/2004	2196877	372.37	599.79	964.54
1/20/2004	11469	2.63	2.97	5.42
1/21/2004	8339	2.57	2.93	4.22
1/22/2004	32258	9.58	10.54	209.99
1/23/2004	694918	222.96	340.61	1431.64
1/24/2004	6137551	1928.78	852.28	3264.72
1/25/2004	1125	0.42	0.44	0.82
1/26/2004	2271	0.8	0.87	1.46
1/27/2004	1331	0.46	0.51	0.83
1/28/2004	1473	0.41	1.02	0.57
1/29/2004	253308	60.01	266.29	77
1/30/2004	189875	48.96	179.88	57.71
1/31/2004	430419	123.11	375.75	29.07
Total	**11,312,572.00**	**3,172.03**	**3,166.93**	**6,862.12**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Feb 1 2004 - Feb 29 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
2/1/2004	11385	5.31	4.85	34.41
2/2/2004	19281	5.71	13.15	56.65
2/3/2004	0	0	0	0

2/4/2004	0	0	0	0
2/5/2004	0			
2/6/2004	407803	162.54	119.03	1136.25
2/7/2004	2237172	330.46	1507.35	3097.8
2/8/2004	0	0	0	0
2/9/2004	0	0	0	0
2/10/2004	0	0	0	0
2/11/2004	0			
2/12/2004	170037	34.87	116.32	1325.13
2/13/2004	65297	12.15	33.88	263.53
2/14/2004	539876	90.57	174.89	1449.55
2/15/2004	11297	2.28	4.61	224.15
2/16/2004	0	0	0	0
2/17/2004	0	0	0	0
2/18/2004	0	0	0	0
2/19/2004	0	0	0	0
2/20/2004	6713639	1499.89	2848.71	4421.44
2/21/2004	10971761	1095.9	2138.83	0
2/22/2004	9207544	1397.02	1377.78	14926.43
2/23/2004	13413597	376.01	919.06	5436.22
2/24/2004	8423488	3071.04	1932.82	0
2/25/2004	18360743	3463.25	6252.05	29454.7
2/26/2004	14207606	933.28	1254.62	0
2/27/2004	11743613	1867.08	2205.88	0
2/28/2004	8935582	1232.78	2019.82	905.35
2/29/2004	5963062	653.01	1258.98	0
Total	**111,402,783.00**	**16,233.15**	**24,182.63**	**62,731.61**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Mar 1 2004 - Mar 31 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
3/1/2004	5504442	643.74	627.52	3664.04
3/2/2004	2048067	583.91	563.03	1323.6
3/3/2004	35486	22.49	42.06	48.36
3/4/2004	1566616	254.47	371.57	999.15
3/5/2004	21345972	2254.4	697.63	9127.9
3/6/2004	2877810	442.33	355.3	1084.44
3/7/2004	0	1.09	1.26	1.48
3/8/2004	0	0	0	0
3/9/2004	0	0	0	0.05
3/10/2004	0	0	0	0
3/11/2004	0	0	0	0
3/12/2004	0	0	0	0
3/13/2004	0	0	0	0
3/14/2004	0	0	0	0
3/15/2004	0	0	0	0
3/16/2004	5986	2.06	1.61	4.15
3/17/2004	0	0	0	0

3/18/2004	0	0	0	0
3/19/2004	0	0	0	0
3/20/2004	184	0.07	0.05	0.19
3/21/2004	0	0	0	0
3/22/2004	0	0	0	0
3/23/2004	0	0	0	0
3/24/2004	0	0	0	0
3/25/2004	125	0.04	0.03	0.08
3/26/2004	0	0	0	0
3/27/2004	0	0	0	0
3/28/2004	0	0	0	0
3/29/2004	0	0	0	0
3/30/2004	0	0	0	0
3/31/2004	0	0	0	0
Total	**33,384,688.00**	**4,204.60**	**2,660.06**	**16,253.44**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Apr 1 2004 - Apr 30 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
4/1/2004	0	0	0	0
4/2/2004	0	0	0	0
4/3/2004	129703	43.01	60.35	60.91
4/4/2004	0	0	0	31.1
4/5/2004	8799	2.64	5.29	1.72
4/6/2004	0	0	0	0
4/7/2004	0	0	0	0
4/8/2004	0	0	0	0
4/9/2004	0	0	0	0
4/10/2004	0	0	0	0
4/11/2004	0	0	0	0
4/12/2004	0	0	0	0
4/13/2004	0	0	0	0
4/14/2004	0	0	0	0
4/15/2004	9300098	3160.56	1841.91	19404.48
4/16/2004	3985	1.47	1.59	0.81
4/17/2004	0	0	0	0
4/18/2004	0	0	0	0
4/19/2004	0	0	0	0
4/20/2004	450011	164.01	212.81	120.54
4/21/2004	0	0	0	0
4/22/2004	0	0	0	0
4/23/2004	0	0	0	0
4/24/2004	15420	5.81	5.64	8.76
4/25/2004	1816	0.65	0.85	1.93
4/26/2004	0	0	0	0
4/27/2004	0	0	0	0
4/28/2004	0	0	0	0
4/29/2004	0	0	0	0

4/30/2004	0	0	0	0
Total	**9,909,832.00**	**3,378.15**	**2,128.44**	**19,630.25**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#May 1 2004 - May 31 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
5/1/2004	0	0	0	0
5/2/2004	0	0	0	0
5/3/2004	0	0	0	0
5/4/2004	0	0	0	0
5/5/2004	0	0	0	0
5/6/2004	80583	31.85	26.16	35.42
5/7/2004	0	0	0	0
5/8/2004	0	0	0	0
5/9/2004	0	0	0	0
5/10/2004	0	0	0	0
5/11/2004	0	0	0	0
5/12/2004	0	0	0	0
5/13/2004	0	0	0	0
5/14/2004	0	0	0	0
5/15/2004	0	0	0	0
5/16/2004	0	0	0	0
5/17/2004	0	0	0	0
5/18/2004	0	0	0	0
5/19/2004	0	0	0	0
5/20/2004	0	0	0	0
5/21/2004	0	0	0	0
5/22/2004	0	0	0	0
5/23/2004	0	0	0	0
5/24/2004	0	0	0	0
5/25/2004	0	0	0	0
5/26/2004	0	0	0	0
5/27/2004	394481	8.29	35.67	67.7
5/28/2004	0	0	0	0
5/29/2004	0	0	0	0
5/30/2004	0	0	0	0
5/31/2004	0	0	0	0
Total	**475,064.00**	**40.14**	**61.83**	**103.12**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Jun 1 2004 - Jun 30 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
6/1/2004	0	0	0	0
6/2/2004	0	0	0	0
6/3/2004	20280	5.91	8.55	11.29

6/4/2004	0	0	0	0
6/5/2004	17840	4.78	8.04	5.3
6/6/2004	0	0	0	0
6/7/2004	0	0	0	0
6/8/2004	6907	1.32	2.81	137.34
6/9/2004	0	0	0	0
6/10/2004	0	0	0	0
6/11/2004	0	0	0	0
6/12/2004	292450	76.82	127.69	93.83
6/13/2004	0	0	0	0
6/14/2004	250629	59.61	107.89	3123.4
6/15/2004	0	0	0	0
6/16/2004	0	0	0	0
6/17/2004	0	0	0	0
6/18/2004	0	0	0	0
6/19/2004	0	0	0	0
6/20/2004	0	0	0	0
6/21/2004	78599	27.92	32.45	250.31
6/22/2004	0	0	0	0
6/23/2004	0	0	0	0
6/24/2004	0	0	0	0
6/25/2004	0	0	0	0
6/26/2004	0	0	0	0
6/27/2004	0	0	0	0
6/28/2004	0	0	0	0
6/29/2004	0	0	0	0
6/30/2004	0	0	0	0
Total	**666,705.00**	**176.36**	**287.43**	**3,621.47**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Jul 1 2004 - Jul 31 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
7/1/2004	0	0	0	0
7/2/2004	0	0	0	0
7/3/2004	0	0	0	0
7/4/2004	5860	1.8	6.18	18.54
7/5/2004	599752	167.56	224.08	832.17
7/6/2004	0	0	0	0
7/7/2004	53218	19.09	17.88	39.78
7/8/2004	0	0	0	0
7/9/2004	0	0	0	0
7/10/2004	133143	52.14	32.68	139.06
7/11/2004	30877	10.2	9.88	10.9
7/12/2004	42286	12.41	20.05	18.12
7/13/2004	0	0	0	0
7/14/2004	0	0	0	0
7/15/2004	0	0	0	0

7/16/2004	169514	49.41	61.61	153.89
7/17/2004	0	0	0	0
7/18/2004	891773	161.43	415.95	81.12
7/19/2004	0	0	0	0
7/20/2004	0	0	0	0
7/21/2004	0	2	2	2.41
7/22/2004	0	0	0	0
7/23/2004	0	0	0	0
7/24/2004	0	0	0	0
7/25/2004	0	0	0	0
7/26/2004	0	0	0	0
7/27/2004	0	0	0	0
7/28/2004	0	0	0	0
7/29/2004	0	0	0	0
7/30/2004	0	0	0	0
7/31/2004	0	0	0	0
Total	**1,926,423.00**	**476.04**	**790.31**	**1,295.99**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Aug 1 2004 - Aug 31 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
8/1/2004	0	0	0	0
8/2/2004	0	0	0	0
8/3/2004	60573	17.99	24.58	26.48
8/4/2004	19213	5.16	14.4	17.61
8/5/2004	0	0	0	0
8/6/2004	0	0	0	0
8/7/2004	0	0	0	0
8/8/2004	0	0	0	0
8/9/2004	0	0	0	0.49
8/10/2004	0	0	0	0
8/11/2004	0	0	0	0
8/12/2004	23203	7.48	8.49	9.82
8/13/2004	0	0	0	0
8/14/2004	0	0	0	0
8/15/2004	0	0	0	0
8/16/2004	0	0	0	0
8/17/2004	0	0	0	0
8/18/2004	63389	19.89	24.94	16.11
8/19/2004	0	0	0	0
8/20/2004	413593	111.4	222.9	189.5
8/21/2004	0	0	0	1.23
8/22/2004	0	0	0	0
8/23/2004	0	0	0	0
8/24/2004	0	0	0	0
8/25/2004	0	0	0	0
8/26/2004	0	0	0	0
8/27/2004	0	0	0	0

8/28/2004	0	0	0	0
8/29/2004	0	0	0	0
8/30/2004	0	0	0	0
8/31/2004	0	0	0	0
Total	**579,971.00**	**161.92**	**295.31**	**261.24**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Sep 1 2004 - Sep 30 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
9/1/2004	0	0	0	0
9/2/2004	0	0	0	0
9/3/2004	0	0	0	0.04
9/4/2004	0	0	0	0
9/5/2004	0	0	0	0
9/6/2004	0	0	0	2.42
9/7/2004	4425993	1080.36	4663.49	18090.93
9/8/2004	10576621	4160.55	11283.66	32420.23
9/9/2004	11077107	1694.71	21627.48	27003.71
9/10/2004	5411051	593.47	5778.92	4176.25
9/11/2004	7373436	848.55	4621.26	8130.43
9/12/2004	5604214	724.44	5008.16	5836.12
9/13/2004	5960352	656.24	2017.08	5965.46
9/14/2004	2973135	451.1	1705.7	3152.7
9/15/2004	3904968	753.05	2362.23	4475.56
9/16/2004	3280368	447.31	2927.89	4384.18
9/17/2004	3162713	542.35	1989.84	4783.11
9/18/2004	2872086	723.86	1646.11	2606.52
9/19/2004	6198462	912.2	9475.73	15087.71
9/20/2004	6948061	990.25	9439.54	17490.66
9/21/2004	6239080	937.67	10305.48	14089.96
9/22/2004	6302270	857.77	7198.62	12720.69
9/23/2004	7515155	949.25	11066.5	16826.9
9/24/2004	8029703	965.43	8757.05	18313.68
9/25/2004	6823260	764.58	7090.22	15722.83
9/26/2004	6429378	737.89	8918.71	17283.69
9/27/2004	5483683	825.19	8690.62	20964.18
9/28/2004	4805884	815	6757.83	15656.42
9/29/2004	4865582	973.48	6643.88	12360.47
9/30/2004	9177951	1014.56	11043.09	10120.42
Total	**145,440,513.00**	**23,419.26**	**171,019.09**	**307,665.27**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Oct 1 2004 - Oct 31 2004
#
#Date (mo/day/yr) Vent Gas Flow Volume (scf) Methane (lbs) NMHC (lbs) Sulfur Dioxide (lbs)

10/1/2004	6278250	906.32	7478.57	14878.65
10/2/2004	4657771	808.26	7032.53	14848.29
10/3/2004	4941948	906.14	7632.86	16532.69
10/4/2004	4658455	825.1	7263.21	15863.41
10/5/2004	3216859	657.37	3438.38	9040.43
10/6/2004	4591502	1010.72	6302.65	13877.5
10/7/2004	3417034	738.01	4666.52	7837
10/8/2004	4482717	1110.81	5162.58	9422.12
10/9/2004	4155812	869.19	6550.46	10701.17
10/10/2004	3781295	848.93	4624.45	7832.54
10/11/2004	4970258	889.09	6262.77	11388.24
10/12/2004	4813065	927.97	6984.91	11051.49
10/13/2004	5561055	1022.33	8469.05	18196.98
10/14/2004	1870341	384.85	2204.66	1054.08
10/15/2004	3208034	725.2	2340.42	1544.9
10/16/2004	345778	100.6	85.88	231.78
10/17/2004	2467	0.76	0.74	1.78
10/18/2004	0	0	0	0
10/19/2004	1477	0.52	0.72	0.29
10/20/2004	62547	16.45	57.83	19.36
10/21/2004	48870	9.4	76.64	20.46
10/22/2004	0	0	0	2.4
10/23/2004	0	0	0	0
10/24/2004	0	0	0	0
10/25/2004	0	0	0	0
10/26/2004	60407	14.88	24.43	4.08
10/27/2004	12640	3.09	7.83	1.71
10/28/2004	17858	5.1	8.41	6.33
10/29/2004	4309	1.27	1.61	2.11
10/30/2004	2195855	673.84	1748.94	500.59
10/31/2004	1493871	410.35	1069.42	849.29
Total	**68,850,475.00**	**13,866.55**	**89,496.47**	**165,709.67**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Nov 1 2004 - Nov 30 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
11/1/2004	2044	0.57	0.8	0.39
11/2/2004	780188	204.3	286.16	565.19
11/3/2004	4784	1.02	3.52	2.6
11/4/2004	8771	1.67	9.94	6.57
11/5/2004	1753	0.4	1.31	1.91
11/6/2004	642809	181.06	295.4	266.69
11/7/2004	30065	8.39	10.17	21.22
11/8/2004	16257	5.07	5.83	8.09
11/9/2004	5433	1.68	2.09	4.68
11/10/2004	6216	2.05	1.78	2.76
11/11/2004	23769	7.04	4.35	20.99
11/12/2004	725	0.25	0.19	1.6

11/13/2004	0	0	0	0.78
11/14/2004	6045	1.97	1.9	2.19
11/15/2004	5440	1.93	1.46	2.35
11/16/2004	3733	1.31	0.97	1.65
11/17/2004	9081	2.91	2.13	4.05
11/18/2004	7489	2.62	2.2	3.12
11/19/2004	3579	1.19	0.85	1.9
11/20/2004	3247	0.95	1.63	2.2
11/21/2004	3792	1.13	1.08	2.71
11/22/2004	0	0	0	5.24
11/23/2004	133313	29.34	165.85	59.04
11/24/2004	1599813	445.39	901.35	580.72
11/25/2004	0	0	0	21.18
11/26/2004	0	0	0	3.47
11/27/2004	0	0	0	3.84
11/28/2004	10428	3.11	3.29	6.42
11/29/2004	886824	295.19	310.97	275.16
11/30/2004	822793	274.14	309.97	286.52
Total	**5,018,391.00**	**1,474.68**	**2,325.19**	**2,165.23**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Main
#Dec 1 2004 - Dec 31 2004
#

#Date (mo/day/yr)	Vent Gas Flow Volume (scf)	Methane (lbs)	NMHC (lbs)	Sulfur Dioxide (lbs)
12/1/2004	244668	79.28	88.46	121.92
12/2/2004	475002	173.86	187.58	1458.84
12/3/2004	10418	3.09	1.62	3.61
12/4/2004	14279	2.21	2.48	5.88
12/5/2004	9979	1.5	3.56	4.03
12/6/2004	0	0	0	3.97
12/7/2004	7502	1.34	4.06	3.05
12/8/2004	6988	1.27	1.6	4.39
12/9/2004	0	0	0	0.52
12/10/2004	158954	51.25	90.5	230.52
12/11/2004	55018	13.31	33.7	24.93
12/12/2004	50056	8.53	17.67	50.01
12/13/2004	292696	40.48	23.36	37.21
12/14/2004	6957	0.7	5.58	4.91
12/15/2004	7298	0.48	3.17	6.64
12/16/2004	581979	64.24	92.43	1056.36
12/17/2004	15525	1.98	7.81	28.7
12/18/2004	13117	1.91	4.77	18.64
12/19/2004	13206	1.36	4.32	10.57
12/20/2004	134289	20.49	52.22	60.71
12/21/2004	118362	24.32	66.53	99.4
12/22/2004	39212	5.83	11.83	70.71
12/23/2004	2760883	406.68	738.21	3037.21
12/24/2004	0	0	0	9.1
12/25/2004	0	0	0	28.49

12/26/2004	5316	0.89	1.33	15.92
12/27/2004	9083	1.55	2.61	17.7
12/28/2004	9265	1.88	2.91	12.19
12/29/2004	0	0	0	8.08
12/30/2004	0	0	0	5.5
12/31/2004	9706	1.42	1.71	5.52
Total	**5,049,758**	**910**	**1,450**	**6,445**
Grand Total				
lbs 2004	**394,017,175**	**67,513**	**297,864**	**592,745**
Tons		**33.8**	**148.9**	**296.4**
	Total Hydrocarbon:	182.7		

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Ammonia Plant
#Oct 1 2004 - Oct 31 2004
#

#Date (mo/day/y	Vent Gas Flow	Methane (l	NMHC (lbs	Sulfur Dioxide (lbs)
10/1/2004	84179	0	0	4589.3
10/2/2004	25500	0	0	980.3
10/3/2004	4626	0	0	162.14
10/4/2004	0	0	0	62.13
10/5/2004	0	0	0	8.22
10/6/2004	0	0	0	0
10/7/2004	0	0	0	0
10/8/2004	0	0	0	0
10/9/2004	0	0	0	0
10/10/2004	0	0	0	0
10/11/2004	0	0	0	0
10/12/2004	0	0	0	0
10/13/2004	0	0	0	0
10/14/2004	0	0	0	0
10/15/2004	0	0	0	0
10/16/2004	0	0	0	0
10/17/2004	0	0	0	0
10/18/2004	0	0	0	0.01
10/19/2004	0	0	0	0.32
10/20/2004	0	0	0	0.01
10/21/2004	0	0	0	0
10/22/2004	0	0	0	0
10/23/2004	0	0	0	0.01
10/24/2004	0	0	0	2.01
10/25/2004	0	0	0	0.01
10/26/2004	0	0	0	0.02
10/27/2004	0	0	0	0.03
10/28/2004	0	0	0	13.53
10/29/2004	252468	0	1.5	1020.38
10/30/2004	665247	0	0	2063.77
10/31/2004	83147	0	0	106.67
Total	**1,115,167.00**	**-**	**1.50**	**9,008.86**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Ammonia Plant
#Nov 1 2004 - Nov 30 2004
#

#Date (mo/day/y	Vent Gas Flow	Methane (l	NMHC (lbs	Sulfur Dioxide (lbs)
11/1/2004	3795	0	0	8.59
11/2/2004	42844	0	0	2.08
11/3/2004	246232	0	0	0.47

11/4/2004	295841	0	0	0.55
11/5/2004	47294	0	0	0.13
11/6/2004	0	0	0	0.04
11/7/2004	0	0	0	0.03
11/8/2004	0	0	0	0.04
11/9/2004	23827	0	0	0.09
11/10/2004	176087	0	0	688.65
11/11/2004	136288	0	0	0.28
11/12/2004	19118	0	0	0.08
11/13/2004	0	0	0	0.03
11/14/2004	0	0	0	0.04
11/15/2004	0	0	0	0.05
11/16/2004	40540	0	0	0.12
11/17/2004	0	0	0	0.04
11/18/2004	0	0	0	0.03
11/19/2004	0	0	0	0.01
11/20/2004	0	0	0	0.01
11/21/2004	31826	0	0	5548.42
11/22/2004	10796	0	0	161.27
11/23/2004	0	0	0	0.02
11/24/2004	0	0	0	0.04
11/25/2004	0	0	0	0.02
11/26/2004	0	0	0	0.04
11/27/2004	25962	0	0	0.1
11/28/2004	34730	0	0	0.11
11/29/2004	8622	0	0	0.07
11/30/2004	3621	0	0	0.06
Total	**1,147,423.00**	**-**	**-**	**6,411.51**

#BAAQMD Refinery Flare Emission Report
#Refinery: Tesoro
#Flare Name: Ammonia Plant
#Dec 1 2004 - Dec 31 2004
#

#Date (mo/day/y	Vent Gas Flow	Methane (I	NMHC (lbs	Sulfur Dioxide (lbs)
12/1/2004	3633	0	0	0.06
12/2/2004	0	0	0	0.05
12/3/2004	4532	0	0	0.06
12/4/2004	0	0	0	0.05
12/5/2004	0	0	0	0.02
12/6/2004	0	0	0	0.03
12/7/2004	0	0	0	0.04
12/8/2004	51483	0	0	0.14
12/9/2004	15948	0	0	0.08
12/10/2004	0	0	0	0.04
12/11/2004	159016	0	0	0.32
12/12/2004	195919	0	0	0.38
12/13/2004	170564	0	0	0.34
12/14/2004	143110	0	0	0.29
12/15/2004	63313	0	0	0.16
12/16/2004	56724	0	0	0.15

12/17/2004	17221	0	0	31.61
12/18/2004	35232	0	0	588.46
12/19/2004	55118	0	0	3126.42
12/20/2004	102101	0	0	131.49
12/21/2004	54407	0	0	254.79
12/22/2004	60747	0	0	134.48
12/23/2004	128711	0	0	787.17
12/24/2004	137637	0	0	0.28
12/25/2004	77473	0	0	507.23
12/26/2004	17617	0	0	0.08
12/27/2004	0	0	0	0.04
12/28/2004	0	0	0	0.04
12/29/2004	239	0	0	0.05
12/30/2004	7911	0	0	0.07
12/31/2004	24242	0	0	0.09
Total	**1,582,898.00**	**-**	**-**	**5,564.51**

Little flaring the rest of the year for this particular flare

Grand total of these months				
lbs 2004	**3,845,488.00**	**-**	**1.50**	**20,984.88**
tons		0.0	0.0	10.5

Grand total				
both flares lbs	397,862,663	67,513	297,865	613,730
tons		33.8	148.9	306.9

EXHIBIT R

#BAAQMD Refinery Flare Emission Report
#Refinery: ConocoPhillips Rodeo
#Flare Name: Main C-1
#Oct 1 2004 - Oct 31 2004
#

#Date (mo/day/yr)	Vent Gas F	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
10/1/2004	0	0	0	0
10/2/2004	0	0.17	0.02	0
10/3/2004	0	0.03	0.01	0
10/4/2004	0	0	0	0
10/5/2004	0	0	0	0
10/6/2004	0	0.06	0.02	0
10/7/2004	0	0	0	0
10/8/2004	0	0	0	0
10/9/2004	0	0	0	0
10/10/2004	0	0	0	0
10/11/2004	0	0	0	0
10/12/2004	0	0	0	0
10/13/2004	17734	11.78	3.34	0
10/14/2004	19538	12.97	5.47	0
10/15/2004	12752	8.47	2.27	0
10/16/2004	0	0	0	0
10/17/2004	0	0	0	0
10/18/2004	0	0	0	0
10/19/2004	0	0.17	0.03	0
10/20/2004	734928	62.23	250.39	13421.25
10/21/2004	2233250	247.48	906.03	12976.6
10/22/2004	2779786	382.91	1612.16	15499.64
10/23/2004	9385260	867.25	1497.25	48873.14
10/24/2004	17437484	977.66	1015.35	12231.12
10/25/2004	19536835	967.77	1140.24	6568.03
10/26/2004	15616186	931.38	841.01	2041.65
10/27/2004	15618674	1222.43	717.96	6223.16
10/28/2004	15213924	678.96	651.73	2746.79
10/29/2004	6283986	529.24	1486.74	17902.27
10/30/2004	106940	0.71	0.28	0
10/31/2004	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: ConocoPhillips Rodeo
#Flare Name: Main C-1
#Nov 1 2004 - Nov 30 2004
#

#Date (mo/day/yr)	Vent Gas F	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
11/1/2004	0	0	0	0
11/2/2004	0	0.17	0.02	0

11/3/2004	0	0.03	0.01	0
11/4/2004	0	0	0	0
11/5/2004	0	0	0	0
11/6/2004	0	0.06	0.02	0
11/7/2004	0	0	0	0
11/8/2004	41619	27.64	10.8	0
11/9/2004	1823824	159.64	1219.67	1778.88
11/10/2004	3184413	436.15	1708.45	7771.46
11/11/2004	1666116	332.3	648.32	3291.61
11/12/2004	294748	57.94	119.12	14.68
11/13/2004	386644	83.63	154.11	8.56
11/14/2004	610877	149.77	175.7	6.76
11/15/2004	996601	270.84	239.38	44.12
11/16/2004	793380	268.78	186.27	65.86
11/17/2004	0	0	0	0
11/18/2004	4580217	634.33	1263.44	0
11/19/2004	843333	94.06	549.43	0
11/20/2004	1685159	0	17.97	0
11/21/2004	208921	7.69	8.62	0
11/22/2004	15011	9.97	3.89	0
11/23/2004	1215544	124.26	904.98	0
11/24/2004	2115563	197.63	1455.18	0
11/25/2004	1551110	68.68	1302.46	0
11/26/2004	1259682	121.42	713.7	0
11/27/2004	1929648	222.08	799.92	4.58
11/28/2004	322923	32.22	107.44	0
11/29/2004	69870	46.4	18.12	0
11/30/2004	107856	71.62	27.98	0

#BAAQMD Refinery Flare Emission Report
#Refinery: ConocoPhillips Rodeo
#Flare Name: Main C-1
#Dec 1 2004 - Dec 31 2004
#

#Date (mo/day/yr)	Vent Gas F	Methane (	NMHC (lbs	Sulfur Dioxide (lbs)
12/1/2004	0	0	0	0
12/2/2004	0	0.17	0.02	0
12/3/2004	0	0.03	0.01	0
12/4/2004	0	0	0	0
12/5/2004	0	0	0	0
12/6/2004	0	0.06	0.02	0
12/7/2004	0	0	0	0
12/8/2004	0	0	0	0
12/9/2004	0	0	0	0
12/10/2004	0	0	0	0
12/11/2004	0	0	0	0
12/12/2004	0	0	0	0
12/13/2004	5396	3.58	1.29	0
12/14/2004	59301	39.38	14.77	0

12/15/2004	0	0.17	0.03	0
12/16/2004	0	0	0	0
12/17/2004	0	0	0	0
12/18/2004	0	0	0	0
12/19/2004	0	0.17	0.03	0
12/20/2004	0	0.17	0.03	0
12/21/2004	0	0.17	0.03	0
12/22/2004	0	0.17	0.03	0
12/23/2004	0	0.17	0.03	0
12/24/2004	0	0.17	0.03	0
12/25/2004	0	0.17	0.03	0
12/26/2004	0	0.17	0.03	0
12/27/2004	4465	2.96	1.07	0
12/28/2004	1220491	61.01	487.78	1211.69
12/29/2004	1109912	73.68	448.64	988.89
12/30/2004	0	0.17	0.03	0
12/31/2004	0	0	0	0

#BAAQMD Refinery Flare Emission Report
#Refinery: ConocoPhillips Rodeo
#Flare Name: MP-30
#Oct 1 2004 - Oct 31 2004
#

#Date (mo/da'	Vent Gas Flo	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
10/1/2004	0	0	0	0
10/2/2004	0	0	0	0
10/3/2004	0	0	0	0
10/4/2004	0	0	0	0
10/5/2004	0	0	0	0
10/6/2004	0	0	0	0
10/7/2004	0	0	0	0
10/8/2004	0	0	0	0
10/9/2004	0	0	0	0
10/10/2004	0	0	0	0
10/11/2004	0	0	0	0
10/12/2004	0	0	0	0
10/13/2004	0	0	0	0
10/14/2004	0	0	0	0
10/15/2004	0	0	0	0
10/16/2004	0	0	0	0
10/17/2004	0	0	0	0
10/18/2004	0	0	0	0
10/19/2004	0	0	0	0
10/20/2004	0	0	0	0
10/21/2004	0	0	0	0
10/22/2004	0	0	0	0
10/23/2004	0	0	0	0
10/24/2004	0	0	0	0
10/25/2004	0	0	0	0
10/26/2004	0	0	0	0
10/27/2004	0	0	0	0
10/28/2004	0	0	0	0
10/29/2004	2252088	625.89	1105.52	4823.15
10/30/2004	8107559	2183.62	4043.48	13971.5
10/31/2004	11804354	2459.25	5957.78	23386.2

#BAAQMD Refinery Flare Emission Report
#Refinery: ConocoPhillips Rodeo
#Flare Name: MP-30
#Nov 1 2004 - Nov 30 2004
#

#Date (mo/da'	Vent Gas Flo	Methane (	NMHC (lb:	Sulfur Dioxide (lbs)
11/1/2004	15046149	3127.91	8292.34	29975.21
11/2/2004	10351042	1999.86	5614.19	37806.14
11/3/2004	7710930	1831.07	4139.38	38148.6
11/4/2004	7205067	1781.7	4462.18	33851.67

11/5/2004	8345946	1651.35	5238.48	30067.06
11/6/2004	8437257	1766.03	5872.94	20030.55
11/7/2004	8917690	1690.32	5837.11	19986.73
11/8/2004	8363629	1868.25	6073.7	69981.12
11/9/2004	2903762	529.76	2439.91	10316.45
11/10/2004	0	0	0	0
11/11/2004	0	0	0	0
11/12/2004	0	0	0	0
11/13/2004	0	0	0	0
11/14/2004	0	0	0	0
11/15/2004	0	0	0	0
11/16/2004	0	0	0	0
11/17/2004	0	0	0	0
11/18/2004	0	0	0	0
11/19/2004	0	0	0	0
11/20/2004	0	0	0	0
11/21/2004	0	0	0	0
11/22/2004	0	0	0	0
11/23/2004	0	0	0	0
11/24/2004	0	0	0	0
11/25/2004	0	0	0	0
11/26/2004	0	0	0	0
11/27/2004	0	0	0	0
11/28/2004	0	0	0	0
11/29/2004	0	0	0	0
11/30/2004	0	0	0	0

EXHIBIT S

Flaring Prevention Measures

April 2007

Communities for a Better Environment (CBE)

Flaring Prevention Measures

A CBE report
April 2007

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CBE

The mission of **Communities for a Better Environment** (CBE) is to achieve environmental health and justice by building grassroots power in and with communities of color and working class communities. Founded in 1978, CBE combines in-house scientific, legal and organizing expertise to leverage plant-specific pollution prevention and regional policy progress that could not be achieved using science, organizing or legal advocacy alone. More than 200 industrial facilities have changed production, transport or disposal practices to prevent millions of pounds of pollution annually as a direct result of our efforts. Thousands of CBE members and supporters live in the greater Los Angeles and San Francisco Bay areas. Hundreds of CBE members live in working class communities of color near oil refineries and engage in our work directly.

Contents

Tables

Figures

Glossary

Backup compressor capacity The amount of gases that separate compressors can handle when the primary compressors break down or cannot handle the entire gas stream produced.

Baseline flare gas flow Flow through a flare gas system during typical normal conditions.

C2- Hydrocarbon with two or less carbon atoms per molecule: methane, ethane and ethylene.

C3-5 Hydrocarbon (in the propane-pentane range) with 3-5 carbon atoms per molecule.

Catalytic cracking A process that uses high heat and a catalyst to break large hydrocarbon molecules into smaller ones of the right size for gasoline, diesel and jet fuel.

Coking A process that uses high heat and pressure to break large hydrocarbon molecules into smaller ones for use in gasoline, diesel and jet fuel and that also produces petroleum coke.

Compressor A machine that puts gases under pressure and thereby reduces their volume.

Distillation A process that uses heat to separate hydrocarbons that boil at different temperatures.

Emergency A situation arising from sudden and reasonably unforeseeable events beyond the control of the refinery, that requires immediate corrective action to restore normal operation.

Episodic flaring Flaring episodes that burn more than 500,000 standard cubic feet of gases per day, emit more than 500 pounds of hydrocarbon per day and/or emit more than 500 pounds of sulfur dioxide per day.

Feedstock Raw or partially processed material that is fed into a process unit for manufacturing.

Gas quality The types and concentrations of chemicals in a mixture of gases.

H_2 Hydrogen.

H_2S Hydrogen sulfide. A toxic gas with a rotten-egg odor. Flaring H_2S creates sulfur dioxide.

Hydrocracking A process that uses catalytic cracking with hydrogen and very high pressure.

mmscf Million standard cubic feet. Gas volume at standard temperature and pressure.

N_2 Nitrogen.

Process A plant or operation that produces particular kinds of chemical reactions and products.

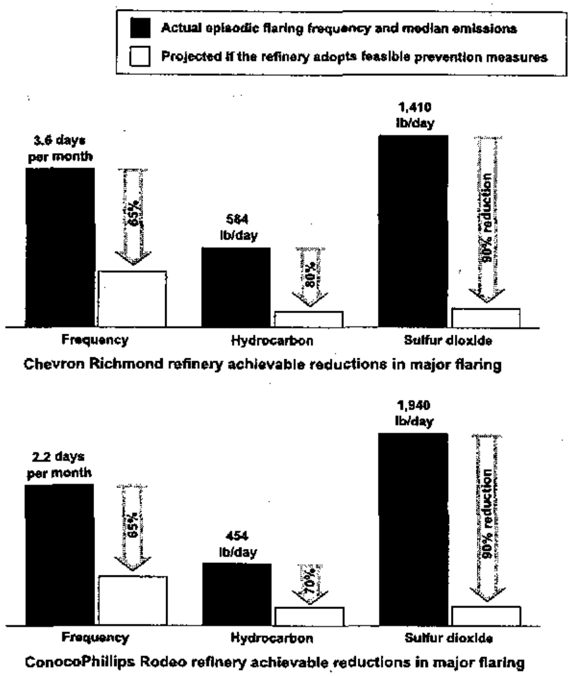
Process rate The speed of production in a process, often measured in barrels of feedstock processed per day.

Recovery/reuse The collection, treatment, and use of gases–often as fuel gas–instead of flaring.

Root-cause analysis Investigation of a specific incident to find its underlying causes for the purpose of follow-up action to prevent the same factors from causing another incident.

SO_2 Sulfur dioxide. A toxic gas. SO_2 is created from hydrogen sulfide (H_2S) by flaring.

Feasible pollution reductions:
Minimum projected reductions in frequency and magnitude of episodic flaring achievable by prevention measures demonstrated in practice.



Summary of data and projections presented in this report (CBE, 2007). See esp. tables 2, 3 and 11.

Figure ES-1

Executive Summary

Oil refinery flaring causes episodic exposures to pollutants that may cause lung disease, cancer and other health problems. This report is about stopping the pollution. It documents feasible flaring prevention measures, and is a resource for community members, workers, and public officials who participate in decisions on stopping pollution from flares.

A community campaign won monitoring of Bay Area refinery flares in 2003 with Rule 12-11 and, with the adoption of Rule 12-12 in July 2005, won the nation's first comprehensive requirements for limiting refinery flares to their legitimate use as emergency safety devices. Instead of simply prohibiting planned and routine flaring, however, the rule requires each refiner to adopt all feasible prevention measures in a "Flare Minimization Plan." Whether the industry does that in fact depends on public pressure and official action. Now, in April-May 2007, the public has the opportunity to comment on the industry's first plans proposed under the new rule.

Although monitoring and investigations of flaring remain problematic, improved monitoring over the past three years supports perhaps the most complete regional data set on refinery flaring to date. Analysis of these data across the five Bay Area refineries–Chevron in Richmond, ConocoPhillips in Rodeo, Shell in Martinez, Tesoro in Avon, and Valero in Benicia–shows that:

- Flaring episodes still impact local air quality frequently.
- Some refineries emit much more episodic flare pollution than other refineries.
- The quality of flared gases drives these differences in emissions between refineries.
- Process sources drive these differences in gas quality between refineries; refiners that flare from dirtier types of refining processes cause the worst flare emissions.
- One refinery has virtually eliminated episodic flaring from dirtier-flaring processes.
- Measures achieved in practice could dramatically reduce the frequency and magnitude of episodic flaring by refineries that flare from dirtier-flaring processes.

Among the five Bay Area refineries, Chevron and ConocoPhillips flare from dirtier process sources the most often and flare the largest episodic emissions.

The Shell refinery uses dedicated backup compressors for flare gas recovery with separate process compressors and procedures that adjust process rates to safely prevent flaring. These measures largely eliminated episodic flaring from Shell's dirtier-flaring processes. Other refiners can apply these measures. The measures can prevent recurrent causes of episodic flaring at Chevron and ConocoPhillips. These feasible measures could reduce the frequency of this flaring at Chevron and ConocoPhillips by at least 65% and, when it occurs, make the flare episodes shorter and reduce their emissions by at least 70-90%.

Chevron's flaring has increased since the flare rule was adopted. Flaring could increase further if Chevron and ConocoPhillips are allowed to refine cheaper low-quality crude oil, as they now propose, without applying the measures in place at Shell. This "dirty crude refining" produces larger volumes of toxic gases from dirtier-flaring processes.

Flaring Prevention Measures

Crude slate switching, underbuilt capacity for handling gases, and failure to operate refineries in balance with their gas handling capacity are ***preventable*** root causes of flaring. Measures that prevent the flaring are demonstrated in practice, and necessary to address frequently-recurring episodic pollution and serious environmental health and justice concerns.

Recommendations

1 All Bay Area refiners should apply the flaring prevention measures that are in place at Shell. The Bay Area Air Quality Management District should identify the specific measures and episodic flaring reductions applicable to the Tesoro and Valero refineries and require them. The Air District should require that Chevron and ConocoPhillips, at a minimum:

install dedicated backup compressor capacity and related equipment sufficient to prevent planned flaring and flaring caused by foreseeable and manageable malfunctions;

employ operating procedures that adjust process rates to prevent and minimize flaring whenever this is consistent with safe and reliable operation; and

reduce episodic flaring frequency by at least 65% and episodic flare emissions by 70-90%.

2 Flare minimization plans should ***not*** allow planned flaring, flaring caused by foreseeable and preventable malfunctions, or flaring caused by failure to install and operate equipment that can manage foreseeable flare gas flows and quality. To ensure that flaring is limited to emergencies, the Air District should establish emission limits based on feasible measures. (Lack of such limits has predictably increased industry secrecy claims and the public resource burden to investigate causes of flaring.) At Chevron and ConocoPhillips, these limits should reduce episodic flaring frequency by at least 65% and emissions by 70-90%.

3 The Bay Area Air District should ensure that all potential flaring impacts of projects to expand dirty crude refining are analyzed and that all measures necessary to prevent non-emergency flaring are required through its public reviews of flare minimization plans.

4 The City of Richmond and Contra Costa County should assess the cumulative impacts from projects to expand dirty crude refining, and support community participation in assessment of alternatives to these projects. These Environmental Quality Act reviews should ensure that this analysis is not piecemealed, and require net reductions in refinery pollution beyond those already promised by existing requirements.

5 All refineries should apply all flaring prevention measures that are demonstrated in practice at another facility. Air districts should require each refinery in their districts to apply these measures. The California Air Resources Board should ensure that air districts take this action.

6 The Bay Area Air District should enforce existing flare rule requirements for complete root-*cause analysis and refinery gas system* audits; and should expand flare monitoring and reporting to include nitrogen compounds, air toxics, carbon dioxide, and hourly gas quality.

Flaring still impacts local air quality frequently.

Flaring by five Bay Area refineries emitted a combined total of more than three million pounds of pollutants since January 2004. Nine-tenths of that pollution comes from flaring that occurs on only about one-tenth of all days. See Table 1. This means on some days episodic emissions are much larger than if the same total amount of pollution was emitted at a constant rate.

Table 1. Flare emissions from five Bay Area refineries in pounds, January 2004–December 2006.

	Sulfur dioxide	Non-methane hydrocarbon	Sulfur dioxide and NM hydrocarbon	Percent of emissions	Percent of days in period
All flaring	1,970,000	1,140,000	3,110,000	100%	62%
Episodic flaring	1,900,000	955,000	2,850,000	92%	12%

Data from refiners' reports under AQMD Rule 12-11. Episodic totals include all days when more than 500,000 standard cubic feet of gases were flared and/or more than 500 lbs of sulfur dioxide or non-methane hydrocarbon were emitted.

Episodic air pollution caused by refinery flaring has been documented in the Bay Area. (CBE, 2005; AQMD, 2006.) This previous work corroborates refinery neighbors' reports of acute exposure symptoms during and after flaring. It can also be used to put the ongoing flaring into context. Local air impacts are strongly associated with high flare emission concentration and mass, and can occur at emissions below 500 pounds per day. (CBE, 2005.)

Flaring episodes still burn more than half a million cubic feet of gases and/or emit more than 500 pounds of pollutants per day frequently. This flaring by the Chevron Richmond Refinery is 80% more frequent since the adoption of the flare rule in July 2005 than in the 19 months before its adoption—and now averages three or four days per month. See Table 2. Although three other refiners reduced their frequencies of these episodic flaring days by 64-74% since then, each of the other four refiners *still flares above this threshold an average of about two days per month.*

Some of these episodes cause massive pollutant emissions of 10,000-100,000 pounds per day, and median emissions from days of episodic flaring exceed 500 pounds/day at four of the five refineries. See Table 3. Nearly two years after the adoption of the Bay Area flare control rule, flaring still impacts local air quality frequently.

The flares still burn more than half a million cubic feet of gases and emit more than 500 pounds of pollutants in a day. This happens two to four times a month.

Table 2. Frequency statistics for days of episodic flaring, January 2004–December 2006.

	Total days of episodic flaring		Days of episodic flaring/month		
	Jan. 2004 -Jul. 2005	Aug. 2005 -Dec. 2006	Jan. 2004 -Jul. 2005	Aug. 2005 -Dec. 2006	Percent change
Chevron Richmond Refinery	38	61	2.0	3.6	+ 80%
ConocoPhillips Rodeo Refinery	50	38	2.6	2.2	− 15%
Tesoro Avon Refinery	135	43	7.1	2.5	− 64%
Valero Benicia Refinery	107	34	5.6	2.0	− 64%
Shell Martinez Refinery	139	32	7.3	1.9	− 74%

Data from AQMD Rule 12-11 flare monitoring reports for all days when more than 0.5 million standard cubic feet of gases were flared and/or more than 500 pounds of sulfur dioxide or non-methane hydrocarbon were emitted.

Table 3. Emission magnitude statistics for days of episodic flaring, August 2005–December 2006.

	Median gas flow (scf/day)	Sulfur dioxide (SO_2) emission: Median concentration (mg/scf)	Median mass (lb/day)	Maximum mass (lb/day)	Non-methane hydrocarbon emission: Median concentration (mg/scf)	Median mass (lb/day)	Maximum mass (lb/day)
Chevron	817,000	932	1,410	33,000	293	584	105,000
ConocoPhillips	1,540,000	350	1,940	17,100	122	454	2,010
Tesoro	1,350,000	343	597	10,800	84	289	1,700
Valero	1,000,000	27	214	4,190	363	1,130	11,900
Shell	2,630,000	5	40	1,530	53	174	1,210

Data from AQMD Rule 12-11 flare monitoring reports for all days when more than 0.5 million standard cubic feet of gases were flared and/or more than 500 pounds of sulfur dioxide or non-methane hydrocarbon were emitted. Concentrations in milligrams emitted per standard cubic foot of gases flared. Mass in pounds per day. Gas flow in standard cubic feet/day. The median flow and emission is shown instead of the mean because this better characterizes episodic data.

Some refiners emit more flare pollution than others.

Chevron, ConocoPhillips and Tesoro emit more sulfur dioxide (SO_2) than Shell and Valero from episodic flaring. See Table 3. Chevron, ConocoPhillips and Valero emit more hydrocarbon than Shell. Chevron and ConocoPhillips cause the largest emissions--and emit drastically more pollution than Shell from episodic flaring. Chevron's median SO_2 emission is 35 times Shell's. ConocoPhillips' SO_2 emission is 48 times Shell's.

This is true despite Shell's larger gas volumes flared because the other refiners flare gases with much higher pollutant concentrations. For example, Shell flares about three times more gases than Chevron but Chevron's SO_2 emission concentration is about 180 times Shell's.

Process sources drive differences in flare emission between refineries.

Chevron and ConocoPhillips flare the dirtiest among Bay Area refineries mostly because they flare from dirtier process sources the most often.

Different refining processes are designed for different feedstock, products, and operating conditions, and produce gases of different quality. This is well known in the industry. It is further confirmed by recent Bay Area data. Analysis of flaring episodes at the five refineries shows that the mix of processes a refinery flares from strongly affects that refinery's flare emission concentrations. Four processes--*distillation, catalytic cracking, coking* and *hydrocracking*--flare gases

Flare Episodes

In this report, "episodic flaring" means flaring that burns more than 500,000 standard cubic feet of gases per day, emits more than 500 pounds of sulfur dioxide per day, and/or emits more than 500 pounds of hydrocarbon/day.

Some of these "episodes" last more than a day, and exceed this threshold on some days but not on other days.

The report looks at days of episodic flaring above this threshold to assess air quality impacts (see pages 1-3). This is because flaring impacts local air quality on the days when the emissions occur. We know this from past work, including CBE's 2005 report, *Flaring Hot Spots*, and the Air District's March 2006 Staff Report for strengthening the flare rule.

Then, the rest of the report looks at the episodes from start to finish, to analyze prevention measures. This is because preventable causes of flaring may occur before, or after, the worst-emitting day of a flaring episode.

with significantly higher hydrocarbon and/or sulfur content than the other types of processes that flare frequently at Bay Area refineries. See Appendix 1 for details of this analysis.

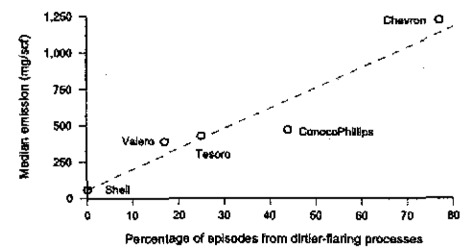
Refiners that flare from dirty processes dominate a pattern of high pollution flaring at relatively lower gas flows.

Distillation separates crude oil into different "fractions" that boil at different temperatures. Crude distillation is an early step in refining and occurs before much of the further processing that removes contaminants such as sulfur from the partially processed feedstocks. Distillation produces gases with high hydrocarbon and hydrogen sulfide (H_2S) content. (Flaring H_2S emits SO_2.)

Catalytic cracking, coking and *hydrocracking* use high temperature and pressure to break large hydrocarbon molecules into gasoline-sized hydrocarbons. Cat-cracking and hydrocracking also use catalysts to speed and control these "cracking" reactions. These reactions create gases with high hydrocarbon and/or H_2S content.

The bigger the portion of a refinery's flaring that burns gases from these dirtier-flaring processes, the higher its flare emission concentrations. Figure 1 shows this for combined emissions of SO_2 and non-methane hydrocarbon.

Figure 1. Episodic flare emission v. percentage of episodes from dirtier-flaring processes.



Concentration of SO_2 and non-methane hydrocarbon, August 2005-December 2006. Sum of medians from Table 3. Percentage of episodes in this period that flared from cat-cracking, coking, distillation and/or hydrocracking processes from refiners' reports that identify primary sources under AQMD rules 12-11 and 12-12 and Shell/EPA Consent Decree.

Chevron flares from dirty processes in almost 80% of its flare episodes and has the highest emission concentration among Bay Area refiners. ConocoPhillips flares from dirty processes in nearly 45% of its events and has the second highest concentration. Dirtier-flaring processes account for 25%, 17% and 0% of the flaring mix at Tesoro, Valero and Shell, respectively. This is for August 2005-December 2006. Appendix 1 confirms a similar pattern since at least 2003.

Refiners that flare from dirtier processes cause the worst emissions.

One refinery has virtually eliminated episodic flaring from dirtier processes.

In contrast to Chevron and ConocoPhillips, the Shell Martinez Refinery appears to have largely stopped episodic flaring from dirtier processes. Table 4 shows the total number of flaring events for which these processes were reported as contributing sources by the three refiners. No counts are shown for catalytic cracking at ConocoPhillips and coking at Chevron because these refineries do not use these respective processes. From 2001 through 2003, all three refiners reported flaring from these dirtier processes; but from 2004-2006, Chevron and ConocoPhillips continued episodic flaring from these processes while Shell did not.

Table 4. Counts of flaring events from dirtier-flaring process sources reported by three Bay Area refiners.

Process	Chevron Events 2001-03	Chevron Events 2004-06	ConocoPhillips Events 2001-03	ConocoPhillips Events 2004-06	Shell Events 2001-03	Shell Events 2004-06
Catalytic Cracking	5	7			3	0
Coking[a]			5	5	5	0
Distillation	3	4	0	1	1	0
Hydrocracking	22	21	11	3	7	0
Subtotals:	30	32	16	9	16	0

Includes all events with these process sources identified as reported under Rule 12-11, Rule 12-12, AQMD Information Request dated 5/21-22/02, ConocoPhillips Land Use Permit and Shell/EPA Consent Decree. [a]Excludes Shell's FXU process.

Flaring from dirtier processes may be more frequent than reported. Chevron and ConocoPhillips do not report flare gas sources or only report "various sources" for many events, and Air District rules require source reporting only for episodic events. Yet even in light of those limitations, *Shell reports no episodic flaring from these dirtier processes during 2004-2006.* This is because Shell has done things that Chevron and ConocoPhillips have not yet done to prevent flaring.

Shell reports prevention measures that integrate a three-part design: equipment with reliable capacity to recover and reuse gases instead of flaring; process operations that maintain refinery gas balance within this capacity, and root-cause analysis to prevent recurrent causes of flaring.

Equipment

Shell's flare gas recovery compressor, treatment and reuse capacities for flare systems serving its cat-cracking, delayed coking, distillation and hydrocracking processes are shown in Table 5. During normal operation with both compressors in service, the Light Oil Processing (LOP) system can recover flare gas flows up to 0.267 million standard cubic feet per hour (mmscf/h) and the Delayed Coking Area (DCU) system can recover flows up to 0.333 mmscf/h. Gas treatment and reuse capacities match these flows. (FMP at 4-2, 4-16, 4-23, 4-32.)

Each of the two compressors serving each flare system can recover the typical "baseline" flare gas flow of its recovery system by itself, and each one is dedicated only to flare gas recovery service. That is important because compressors need more maintenance to prevent malfunctions than many other components of refinery gas systems. Each of Shell's compressors can go off line for preventive maintenance while the other one provides enough "backup" capacity to recover gases instead of flaring during typical flow conditions. This is a reliable design.

Table 5. Flare gas recovery/reuse capacity of Shell Martinez systems serving dirtier-flaring processes.

mmscf/hour	Flare gas recovery (FGR) compressor capacity Unit	Usage	Rating	Normal Cap.	Maintenance	Treatment & Reuse capacity	Baseline FG flow (typical/average)
Light Oil Processing (LOP) FGR system	J-85	FGR	0.133	0.267	0.133	≥ 0.267	0.104
	J-86	FGR	0.133				
Delayed Coking Area (DCU) FGR system	J-205	FGR	0.167	0.333	0.167	≥ 0.333	0.092[a]
	J-206	FGR	0.167				

Data from Rule 12-12 Flare Minimization Plan (FMP), September 2006. [a]DCU includes Opcen hydrocarbon area flows.

Process compressors and their piping connections have been reconfigured to remove some of the loads from the flare gas compressors--especially for "wet gas" with condensable liquids. (FMP at 3-6.) A process compressor upgrade significantly reduced Shell's DCU flaring. (FMP at 4-29.) Piping is designed for flexibility in routing gases between the many refinery processes that produce, handle, and/or use them as fuel. (FMP at 3-6, 4-1, 4-21.) This supports operational measures that prevent flaring.

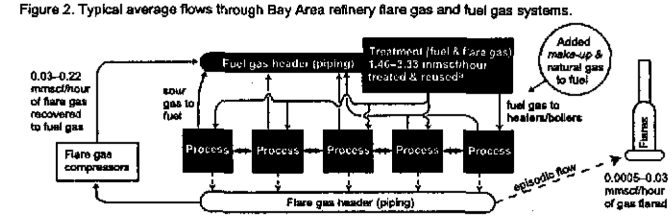
Prevention measures have a three-part design: *Equipment with reliable capacity to recover and reuse gases;* operation that maintains refinery gas balance, and root-cause analysis.

Process operations

Shell's operating policies state: "We will adjust the operation of process units to minimize flaring when consistent with safe and reliable operation." (FMP at 3-1.) Its refinery operators change process rates to keep gases safely in balance instead of flaring. That increases flare gas recovery/reuse capacity by leveraging the greater capacity of refinery fuel gas systems. This capacity difference is huge, as suggested in Figure 2: Typical average flows through five refiners' fuel gas systems range from 1.46-3.33 mmscf/h (shaded portion of figure), while those through their flare gas compressors range from 0.03-0.22 mmscf/h (left-hand portion of figure).

When a refinery is in ideal balance, process gases flow to its fuel gas system header and treatment, then back to the processes for use as fuel, as illustrated by the shaded parts of Figure 2. Gases flow to the flare gas header only if the fuel gas system cannot accept them directly, and those gases are flared only if the flare gas compressors and fuel gas system cannot recover, treat and reuse these gases. Routine flaring does not occur.

Figure 2. Typical average flows through Bay Area refinery flare gas and fuel gas systems.



Range of typical average flows from Rule 12-12 and 12-11 data for Bay Area systems with flare gas recovery.
[a]Flows treated and reused not available for Shell; ConocoPhillips data based on treatment capacity.

Flaring Prevention Measures

Thus, operating measures can maintain refinery gas balance to prevent flaring by taking advantage of the refinery's fuel gas system capacity. Adjusting the rates of gas production and usage by various refinery processes can do this in several ways:

- Adjusting process rates can make room in the fuel gas system to treat and reuse the recovered gases. Shell reports this capacity to match treatment and reuse capacities to its maximum flare gas compressor capacity. (FMP at 4-15, 4-16, 4-32.)
- Adjusting process rates can reduce baseline flare gas flows to increase the amount of available compressor capacity when gas flows increase or compressor capacities decrease due to equipment maintenance outages and process upsets. Shell's operating procedures include such measures. (FMP at 4-15, 4-16, 4-29, 4-32.)
- Adjusting process rates can moderate "spikes" in flare gas flow and fuel gas quality so that flare gases from maintenance activities stay within the range that can be recovered and reused. Shell shows that it has largely eliminated planned maintenance flaring from its LOP and DCU systems by carefully managing equipment depressuring, shutdown, and startup activities. (FMP at 3-6, 4-6, 4-13, 4-14, 4-30; Cause reports.)
- When flaring does occur, adjusting interconnected process and gas systems can also minimize emissions by flaring from less dirty sources. Shell monitors gas quality and avoids flaring gas flows with high H_2S content. (FMP at 3-6.)

These operating measures work together with equipment measures to prevent flaring.

Root-cause analysis and prevention

Shell and the other Bay Area refiners have been required to investigate and report on flaring episodes under a variety of requirements established between 2001 and 2006. (Shell/EPA Consent Decree; ConocoPhillips Land Use Permit; Rule 12-12 § 406; Rule 12-11 § 401.6.) This "root-cause analysis" investigates the causes and contributing factors of flaring episodes, and implements measures to prevent them from happening again. Shell's root-cause reports to EPA are more complete than other refiners' reports under the flare rule. (See e.g., CBE, 2006.)

Root-cause analysis identifies specific equipment and operational measures that can prevent flaring, and may also prevent some massive refinery flaring events, spills, fires and/or explosions. Table 6 shows specific examples for Shell.

Table 6. Cause analysis and prevention for flaring involving Shell flare gas compressor malfunctions.

	Flare gas compressor malfunction	Prevention measure done after flaring event
9/25/01	Condensable liquids trip (shut down) compressors	Process (wet gas) compressor equipment measures
3/22/02	Compressor trips; backup is in maintenance outage	Preventive maintenance measures expanded
5/14/02	Compressor trip; backup in maint.; coker blowdown	Wet gas reliability & process operation measures
2/12/03	Condensable liquids trip compressors	Wet gas compressor eqpmnt./operations measures
6/7/03	Compressor trip after hydrocracker P.R. valve lift	Capacity increased by rerouting gas flows to coker
12/18/05	Loss of cooling and compressors in electrical fault	Electrical insulation eqpmnt. & operating measures

Data from Flare Minimization Plan (FMP), causal reports under rules 12-11 and 12-12 and Shell/EPA Consent Decree.

Cause analyses in Table 6 identified several of Shell's measures to upgrade process compressors and keep wet gas from overwhelming flare gas recovery; its equipment and operating measures that increase this capacity during maintenance and upsets, and its measures that improve preventive maintenance and the reliability of recovery equipment.

From 2001-2003, equipment and operational problems caused flaring at Shell almost as often as they have at Chevron and ConocoPhillips during 2004-2006, but in the recent period these problems occurred far less often at Shell. See Table 7. Compressor problems—the most common equipment problem involved in flaring at these plants—now occur less often at Shell, after the reliability upgrades to this equipment and its operation. Further, gas handling problems no longer contribute to Shell's LOP and DCU flaring after its measures to adjust process rates, and to better manage depressuring, shutdown and startup of process units in planned maintenance. These are all still frequent problems at Chevron and ConocoPhillips.

Table 7. Recurrent causes of flaring identified from causal analysis at three Bay Area refineries.[a]

Number of times causes identified	Shell 2001-2003	Shell 2004-2006	Chevron 2004-2006	ConocoPhillips 2004-2006
Flare gas recovery compressor problem	5	1	9	7
Flare gas recovery compressor limitation	4		5	20
Process compressor problem	6	2	5	3
Valve, gasket or coupling problem	6	1	10	7
Electrical problem	1	1	2	3
Exchanger leak or plugging			3	2
Cooling problem		1	2	1
Pump failure			1	1
Equipment Problems Subtotal	**22**	**6**	**37**	**44**
Hydrogen handling problem	7		2	13
Nitrogen handling problem			4	5
Flare gas steam handling problem	1		3	2
Wet gas liquids handling problem	2		2	2
Flare gas abrasive salts problem			4	
Hydrate plugging problem			2	
H2S gas recovery/reuse problem			1	1
General recovery/reuse limitation	3	1		3
Operational Problems Subtotal	**13**	**1**	**18**	**26**
Prevention Analysis Problems				
Root-cause not reported[b]	**5**		**22**	**13**

CBE review of refiner's cause analysis reports under Shell/EPA Consent Decree, Rule 12-12, Rule 12-11, and ConocoPhillips Land Use Permit; for Shell LOP & DCU, Chevron N. & S. yard, and ConocoPhillips Main & MP30 flare systems. [a] These are minimum estimates; many events have multiple causes but some are not reported: [b] No cause, or no root-cause of an identified initiating cause or contributing factor, is reported for 40 flaring events in the periods shown. 2001-2003 reporting by Chevron and ConocoPhillips is too incomplete for this comparison.

However, Shell still causes frequent high-volume flaring episodes. (Tables 2 and 3.) Its flexicoker (FXU) complex includes a treatment process that produces low-hydrocarbon, low-H_2S, high-nitrogen gases Shell burns in some 19 heaters via a separate reuse system with no flare gas recovery compressor. (FMP at 3-5, 4-41.) This situation, which is not comparable to Chevron or ConocoPhillips, is the source of nearly all Shell's episodic flaring. It should be investigated for NOx emission, and because it appears to be *designed* to flare periodically.

Measures achieved in practice can prevent flaring by Chevron and ConocoPhillips.

Equipment

Chevron and ConocoPhillips flare repeatedly because they lack adequate backup compressor capacity that is dedicated to flare gas recovery service. ConocoPhillips has one compressor in flare gas recovery service, unit G-503. (FMP[1] at Attachment B.) It has no backup. (Id.) ConocoPhillips cannot recover flare gases at any time when compressor G-503 is out of service. Table 8 shows examples of that.

Table 8. Backup flare gas compressor problems reported in flaring episodes at two refineries, 2004-2006.

	Refinery	Source(s)	Flare gas compressor problem that caused or contributed to flaring
10/27/04	ConocoPps.	Various sources	No backup compressor for compressor G-503 maintenance outage
12/28/04	ConocoPps.	Various sources	No backup compressor for maintenance to fix compressor loader
3/12/05	Chevron	Hydrocracking, others	Inadequate backup capacity for planned compressor maintenance
5/9/05	Chevron	Hydrocracking, others	Inadequate backup capacity for compressor maintenance outage
9/14/05	ConocoPps.	Various sources	No backup compressor for maintenance to fix compressor valve
1/10/06	ConocoPps.	Various sources	No backup compressor for maintenance to fix compressor loader
1/11/06	Chevron	Various sources	Inadequate backup capacity for compressor maintenance outage
1/23/06	Chevron	Various sources	Inadequate backup capacity for compressor maintenance outage
4/21/06	Chevron	Hydrocracking	Inadequate backup capacity for compressor maintenance outage
5/10/06	Chevron	Distillation	Backup compressors off line during main compressor maintenance
6/13/06	ConocoPps.	Various sources	No backup capacity for main compressor cooling loss shutdown
7/21/06	Chevron	Distillation	Compressor capacity exceeded in "hot" (86° F Max) weather
8/9/06	Chevron	Distillation	Compressor capacity exceeded in "hot" (92° F Max) weather
8/30/06	Chevron	Distillation	Off-gas shuts down backups and overwhelms main compressor

Data from refiner's reports for Rule 12-12, Rule 12-11, and ConocoPhillips Land Use Permit.

Chevron lacks adequate backup compressor capacity dedicated to flare gas recovery service because backup compressors K-1960 in its North Yard, and K-1171 and K-1171A in its South Yard are in dual service–their primary function is in process service. (FMP at 5, 27.) This lack of compressor capacity is a serious problem, as illustrated by three distillation flaring episodes that are listed at the bottom of Table 8. Compressors K-1171/A are distillation process compressors. (Id.) Chevron reports that on August 30, 2006:

> "Flaring occurred when the flare gas recovery (FGR) capacity in the Distillation and Reforming (D&R) business area was reduced due to the shut-down of the vent gas recovery compressors K-1171/A. The shut-down was caused by high liquid levels in the knockout drum V-1171 due to the increased off-gas production from the Reflux Drum V-1190 and overloading of the E-1190 fin fan coolers in the #4 Crude Unit. Mis-directed nitrogen (N_2) gas flow to the knock-out drums of the overhead gas compressors K-1100A/B caused the increase of the V-1190 off-gas rate and overloaded the E-1190." (8/30-31/06 Cause Report.)

Chevron's backup flare gas recovery was unavailable August 30th because its "backup" compressors were in process service at the same process where they were supposed to handle flare

[1] FMP citations refer to the Flare Minimization Plan of the refinery discussed in the text.

gases, and lacked adequate spare capacity for flare gas recovery. The same compressors were in process service when recovery was overwhelmed on August 9, 2006. (8/9/06 Cause Report.) Flaring from the same cause occurred July 21, 2006. (Id.)

Compressor issues that are addressed by measures in place at Shell contributed to at least 41 flaring episodes at Chevron and ConocoPhillips since January 2004.

In these three episodes, process compressors let gases into the flare system *and* flare gas recovery compressors let them be flared. Flare flows stayed below 0.1 mmscf/h (12-11 reports) and *should* have been recovered. A cause in at least two of the episodes–related to hot weather–was clearly foreseeable. Chevron reported flaring caused by the "heat of the day" repeatedly; in May-July 2001, and in May 2002 when its distillation processes served by compressors K-1171/A "pressured up due to [the] high amount of light products in [the] crude slate and [the] heat of the day." (November 26, 2002 Response to AQMD 5/21/05 Information Request for Flaring.)

Flaring from such minor upsets *in gas balance is clearly preventable, but it requires dedicated* backup flare compressor capacity. This is because compressors need frequent maintenance but the timing of process upsets cannot always be predicted *and* the upsets can make "dual service" process compressors unavailable for flare gas recovery, as in the examples above. Chevron and ConocoPhillips clearly lack adequate dedicated backup capacity, as shown in Table 9.

Table 9. Dedicated backup flare gas recovery capacity at Chevron, ConocoPhillips and Shell.

mmscf/hour	Dedicated backup FGR Capacity[a]	Baseline flare gas flow (typical/avg.)	Dedicated backup average margin
Chevron North Yard Sysem	0.165	0.158	4%
Chevron South Yard System	0.000	0.046	−100%
ConocoPhillips refinery	0.000	0.092	−100%
Shell LOP System	0.133	0.104	28%
Shell DCU System	0.167	0.092	82%

Data from ConocoPhillips and Shell FMPs, and Chevron FMP revised April 5, 2007 per. com. with AQMD staff.
[a] Total capacity of any and all compressors dedicated to flare gas recovery that remain in service when one such compressor is out of service. Excludes Chevron's "dual use" process/flare gas compressors.

Chevron's and ConocoPhillips' over-reliance on process compressors to back up flare gas compressors lets process gases into their flare systems *and* fails to recover the resultant flare gases. This inherently unreliable equipment design limits opportunities for compressor maintenance, overworks compressors, and provides less total capacity to recover episodic process and flare gas loads. It is implicated in at least 41 flare gas compressor malfunctions and limitations that contributed to recurrent episodic flaring by the two refiners since January 2004. See Table 7. By comparison, Shell reported flaring from this cause once in the same period.

Chevron's compressor problems have caused recurrent flaring since at least 2001. (Tables 7 and 8; CBE, 2004.)

Installing dedicated backup capacity to avoid flaring when any one compressor is down for maintenance, and keeping all of it on line at other times, could solve this problem. It did at Shell. Piping upgrades might also be needed. Shell rerouted gases along with its process compressor upgrades, and rerouted its Opcen hydrocarbon gases to its DCU flare gas compressors. (FMP at 3-6, 4-34, 4-39.) To fully utilize the existing and future equipment capacity, however, each refiner must balance its *operation*.

Process operations

Gas handling problems that contributed to episodic flaring occurred at least 18 times at Chevron and 23 times at ConocoPhillips from 2004-2006. (Table 7.) Failure to operate the refineries in balance with the gas handling capabilities of existing equipment is an underlying cause of this flaring. Shell has virtually eliminated episodic flaring caused by such gas quantity and quality issues in its comparable systems. (Table 7.) Chevron and ConocoPhillips have not applied Shell's measure that directs refinery operators to minimize and prevent flaring by adjusting process rates whenever it is safe to do so. By applying this measure they could:

- *Prevent flaring* by making more room in their fuel gas systems to treat and reuse the gases their compressors can recover now, and in the future, when the needed upgrades to their compressor capacities are installed.
- *Prevent flaring* by further reducing baseline flare gas flows to further increase available recovery/reuse capacity during compressor maintenance, process maintenance, malfunctions and process upsets.
- *Minimize flare emissions* by better routing gases between their various process and gas handling equipment to avoid flaring from dirtier processes.
- *Better manage planned maintenance* by moderating peak gas flows from these activities and mixing these flows with other refinery gases (after separating reuse-ready maintenance streams) to avoid gas quantity and quality issues and ensure that the gases can be recovered and reused. This can prevent planned maintenance flaring episodes, as Shell has shown.

When Chevron and ConocoPhillips fix their equipment problems there will be fewer occasions when intensive management and process adjustments are needed to prevent flaring peak maintenance flows. This is illustrated by the—now hypothetical—example in Table 10. Until then, operating their existing equipment within its capacity requires ramping down process rates more than they do now in order to avoid flaring as a method of planned waste disposal.

Table 10. Hours of flaring[a] above and below total achievable future recovery capacity,[b] for 19 flare episodes during maintenance of cracking or coking processes at Chevron and ConocoPhillips.

	All flow rates	Below achievable[b] recovery capacity	1-2 times achievable[b] recovery capacity	2-4 x achievable[b] recovery capacity
Hours of flaring[a]	933	880	26	27
Percentage	100%	94%	3%	3%

[a] Based on flare gas flow for each hour ≥ 0.01 mmscf in episodes starting 2/7/04, 2/15/04, 7/23/04, 10/20/04, 10/31/04, 11/4/04, 2/11/05, 2/23/05, 3/3/05, 3/5/05, 3/12/05, 9/26/05, 10/10/05, 10/23/05, 11/30/05, 2/24/06, 3/8/06, 4/21/06 and 8/25/06 from Rule 12-11, Rule 12-12 and ConocoPhillips land use permit data.
[b] Rough projection to illustrate operational measures. Assumes equipment installed to solve identified backup flare gas and process compressor problems doubles total available capacity during planned maintenance to 0.767, 0.479 and 0.333 mmscf/h for Chevron North and South Yards and ConocoPhillips, respectively. Includes "dual use" process compressors. For reference, the Valero refinery's FMP reports a total flare gas recovery compressor capacity of 0.5 mmscf/h today.

The Chevron Richmond Refinery reported emitting an estimated 114,000 pounds of non-methane hydrocarbon and SO_2 from its flares on October 12, 2005. This is the worst day of flare emission reported by any Bay Area refinery since improved monitoring began in January 2004. Here is the full text of the "root-cause" report Chevron submitted to the Air District, under Rule 12-12, for that flaring event:

"Start Date: 10-Oct. Start Time: 10:30.
Description: Residual liquids/gases were purged and flared prior to performing maintenance activities on equipment within process plants in the Cracking Area Business Unit (ABU).
Primary Cause: Flaring from FCC and Alky-Poly Flares was caused by the need to perform periodic maintenance and catalyst replacements within the FCC, Alky, SHU and Poly process plants within the Cracking ABU. Flaring from RLOP flare was caused by liquid buildup in the North Yard Flare Gas Recovery System header line from steaming and depressuring activities during the Cracking ABU Shutdowns.
Contributing Factors: None identified.
Measures to Be Implemented: Install temporary drain line and initiate routine duty to manually drain accumulated liquids from North Yard Flare Gas Recovery Header line to a recovery vessel. Action Complete. Design and install an automatic system to drain accumulated liquids from the North Yard Flare Gas Recovery Header line to a recovery vessel. Action expected complete by end of 2006.
Measures Considered but not Implemented: None Identified. Justification for not Implementing: Not applicable.
Consistent w/ FMP? This section does not apply until 11/1/2006.
Emergency explanation: Not applicable."

Chevron October 2005 Flaring Cause Investigation Report

Process adjustments that route gases to avoid flaring the dirtiest gas flows are especially important at Chevron and ConocoPhillips. Shell uses this measure, and has largely eliminated episodic flaring from dirtier processes. Chevron and ConocoPhillips cause the worst flare pollution among Bay Area refineries mostly because they flare from dirtier processes the most often. Applying this measure would take advantage of the high hydrocarbon content of the gases from dirtier-flaring processes for use as fuel, and it would greatly reduce flare emissions.

Root-cause prevention

At least 35 cause reports by Chevron and ConocoPhillips do not report a cause of the flaring, or do not report the root cause of an initiating cause or contributing factor in the flaring. See Table 7. For example, Chevron cited the initiating condition of a flaring event—planned maintenance—as its "primary cause" instead of seeking the root cause in its management of this planned flaring. See the box above. Failure to find root causes of flaring is a barrier to flaring prevention.

When they identified causes of their flaring, both refiners often failed to implement known prevention measures. Their recurrent compressor failures are examples of this problem. (Tables 7-9.) ConocoPhillips and Chevron either ignored or rejected measures to provide reliable backup of a failure-prone flare system component. This error violates basic engineering principles for redundancy in critical components of hazardous systems. Recurrent flaring from this cause indicates a chronic failure to complete the implementation step in root-cause analysis.

Shell's root cause analysis identified and applied compressor upgrade, reliability and operations measures that reduced its flaring. Chevron and ConocoPhillips still flare often from the same causal factors that Shell has addressed. Complete root-cause analysis would help to prevent their flaring.

Chevron and ConocoPhillips often failed to prevent known causes of their flaring from recurring.

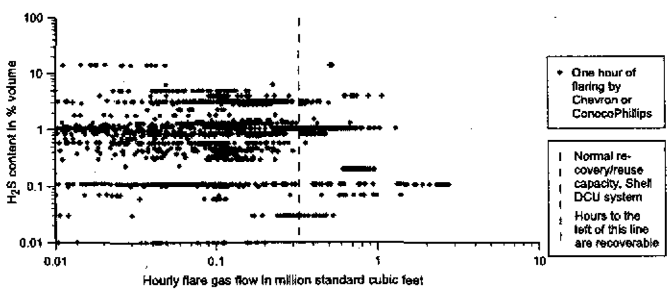
Feasibility

Measures in place at Shell can be used by other refineries to prevent flaring. Compressors are standard, well-understood technology within the industry. Process and flare system evidence shows that the compressors at issue would recover the same types of dirtier-flaring process gases as Shell recovers. Root-cause analyses show that they would address the same problems. All refiners routinely adjust the balance of processing rates between their interconnected units. Chevron admits the technical feasibility of process rate adjustments that help to prevent flaring (FMP at 19, 24-30), as does ConocoPhillips (FMP at 4-9 to 4-14). These measures are demonstrated in practice, transferable between refineries, and feasible at Chevron and ConocoPhillips.

Effectiveness

Applying measures used by Shell would cut Chevron's and ConocoPhillips' flaring dramatically. Recovery/reuse upgrade effectiveness is illustrated in Figure 3. The figure shows individual hours of episodic flaring by Chevron and ConocoPhillips from January 2004 through August 2006. Higher flow hours are toward the right, and episodes with higher H_2S concentrations are toward the top of the chart. The chart uses a log-scale so that flaring hours which are bunched together at lower flows can be pictured. The dashed line shows the normal recovery/reuse capacity of the Shell DCU system for comparison. This comparison shows that most of the hourly gas flows could be recovered and reused to prevent flaring.

Figure 3. Flare gas recovery/reuse potential for episodic flaring by Chevron and ConocoPhillips: Hours of episodic flaring plotted by hourly flare gas flow and episode-specific H_2S content.



Flare gas flow for each hour ≥ 0.01 mmscf and flare gas H_2S content in each flaring episode. For all episodes exceeding 0.5 mmscf/d, 500 lb/d SO_2 and/or 500 lb/d hydrocarbon reported with flow/hr from Jan. 2004-Aug. 2006 (60 episodes). Data from Rule 12-11, Rule 12-12 and ConocoPhillips land use permit reports. Shell DCU capacity from Table 5.

One of Shell's DCU backup compressors recovers up to 0.075 mmscf/h after handling baseline flow during maintenance of the other compressor, and 0.167 mmscf/h in normal operation, when the other unit handles baseline flow. (Table 5.) Applying this added capacity to the hourly flows from each flaring episode at Chevron and ConocoPhillips would reduce the frequency,

duration and mass emission *magnitude of their episodic flaring* by 60%, 35-70% and 70-85%, respectively. See Table 11. Then, modest operational and root-cause prevention measures to avoid flaring from dirtier processes as much as the average performance of the Shell, Valero and Tesoro refineries would further reduce episode frequency (-65%) and SO_2 emissions (-90%). This second part of the projection calculates the percentage difference between the average process factor from the three other refiners combined and those of Chevron and ConocoPhillips,[2] and applies those percentage reductions in emission concentration to the actual concentration and remaining hourly flow volumes of each event.

Applying measures that are already being used by Shell could prevent at least 65% of the flaring episodes at Chevron and ConocoPhillips and cut emissions from their remaining episodes by at least 70-90%.

Table 11. Reductions in frequency and magnitude of episodic flaring at Chevron and ConocoPhillips projected from application of prevention measures demonstrated in practice at the Shell Martinez refinery.

	Episode frequency	Episode duration	Median episode emission: Hydrocarbon	Median episode emission: Sulfur dioxide
Chevron Richmond Refinery	–60 to –65 %	–70 %	–80 %	–80 to –90 %
ConocoPhillips Rodeo Refinery	–60 to –65 %	–35 %	–70 %	–85 to –90 %

Estimates based on added flare gas recovery and reuse of 0.075 mmscf/h during compressor maintenance and 0.167 mmscf/h in other conditions, and actual hourly gas flows flared at Chevron and ConocoPhillips in all episodes from 1/1/04-8/31/06. Rule 12-11 reports. The lower frequency (-65%) and SO_2 (-90%) also reflect measures to avoid dirtier-flaring process sources, based on event-specific gas quality improved in proportion to the average achieved at Shell, Tesoro and Valero. See Appendix 1. For episodes that exceed 0.5 mmscf vent gases flared, 500 lb SO_2 emission and/or 500 lb hydrocarbon emission on any day.

Flare gas recovery/reuse accounts for most of this projected reduction. That is because it would prevent flaring of the toxic gases in so many low flow-high emission hours of flaring from dirtier processes at Chevron and ConocoPhillips.

Table 11 presents a conservative projection. Chevron and ConocoPhillips may need more recovery/reuse capacity than that of Shell's DCU system to recover some high-flow hours, unless they better manage maintenance. Also, ConocoPhillips relies on one flare gas recovery system for its entire refinery. This conservative projection assumes no effect from those additional measures: It assumes adding only Shell's DCU backup capacity cited above and no change in the hourly gas flows from managing planned maintenance. It further assumes no additional reduction in flaring frequency from root-cause analysis. Shell has largely eliminated flaring from dirtier processes, and applying its refinery-wide process factor[2] would reduce emission from episodic flaring at Chevron and ConocoPhillips by 99%.

Feasible prevention measures would be highly effective in reducing the frequency and magnitude of flaring, and its episodic air quality impacts.

This analysis conservatively projects 65% fewer flaring episodes that, when they occur, would be shorter and would emit 70-90% less episodic pollution. Applying measures already being used by Shell at Chevron and ConocoPhillips would be highly effective in reducing the frequency and magnitude of flaring known to cause episodic local air quality impacts.

[2] Process factors quantify the mix of processes each refiner flares from, as detailed in Appendix 1.

Industry cost-benefit arguments do not refute the feasibility of these measures.

Refinery officials argue that the benefits of flaring prevention beyond their proposed plans are not worth the cost. (See FMPs.) However, the flare rule requires all prevention measures that are "[c]apable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors." Rule 12-12 §§ 202, 401.4. The refiners' argument fails to address this requirement.

First, the refiners do not refute the technological feasibility and affordability of these measures; and could not, since the measures are demonstrated in practice and cost only pocket change in comparison with their record-breaking profits.

Second, the refiners' argument ignores a crucial environmental factor by ignoring episodic impacts. Benefits of preventing episodic emissions are reaped at the moment when the emissions would occur. (AQMD, 1997.) However, the refiners' cost-benefit arguments rely on long-term average emission estimates. This erroneous approach to a fundamentally *episodic* emission source ignores their flares' most pronounced environmental impacts. Localized air quality impacts of Bay Area refinery flares have been demonstrated precisely because these episodic impacts occur when episodic flaring occurs, and not during the longer periods between episodes, which typically feature lower, if any, flare emissions. (CBE, 2005; see also AQMD, 2006.) Thus, the industry's cost-benefit argument does not account for the benefits from preventing the best-documented, most serious environmental impact from its flaring.

A similar error ignores Chevron's and ConocoPhillips' concentrated emissions from dirtier-flaring processes at relatively lower flare gas flows. This error projects emission reductions using long-term average emission concentrations and daily flow instead of episode-specific concentrations and hourly flows. The result is that the industry's cost-benefit argument underestimates the environmental benefits that are available from the feasible measures to prevent flaring still further. See Table 12. In one example, ConocoPhillips estimates only an 11% cut instead of the 70-90% reduction documented above, even though it assumes a larger new compressor.

Table 12. Estimation error from applying longterm average statistics to episodic event recovery/reuse.

	Longterm Average Projection Basis[a]		Episodic Event Projection Basis[b]		Difference
	Capacity added	Emission reduction	Capacity added	Emission reduction	(% error)
Chevron	0.167 mmscf/h	–44 %	0.167 mmscf/h	-80 to -90 %	82 to 104 %
ConocoPhillips	0.250 mmscf/h	–11 %	0.167 mmscf/h	-70 to -90 %	530 to 720 %

Comparison of projected reductions in combined emissions of sulfur dioxide and hydrocarbon. [a] Longterm average basis from longterm average concentrations and daily flows: Chevron FMP at 34 and 38 for 4 mmscf/d analysis; ConocoPhillips FMP "Case 2" 6 *mmscf/d* analysis. [b] Episodic event basis from episode concentrations and hourly flow: See Table 11.

Third, the refiners' argument fails to consider important social factors. It ignores the disproportionate impacts of flare emissions on workers and working class communities of color near the refineries. This omission exacerbates a well-documented pattern of institutionalized environmental racism and injustice in the U.S.

The flare rule requires *all* prevention measures that are capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social and technological factors.

Oil companies' interest in profit maximization may conflict with preventing flaring. Valero flared gases it could have recovered to speed maintenance and ramp up gasoline production more quickly. (9/7/05 Cause Report.) Chevron and ConocoPhillips appear to give shifting explanations for declining to apply Shell's measure, which avoids flaring by adjusting process rates whenever this is consistent with safe and reliable operation, to their major maintenance activities.[3]

Refiners say periodic planned process shutdowns for maintenance "turnarounds" are essential for safe and reliable operation, and that is certainly true, but turnarounds may also occur when a refiner switches to a cheaper source of crude oil inputs. Refiners that routinely switch crude inputs generally must do turnarounds to prepare process equipment for the new feedstock. (Per. Com., 3/21/07 Air Resources Board staff.) If they flare in these cases, both their choice to switch crude sources, and their failure to manage turnaround activities with measures such as those demonstrated at Shell, would be preventable causes of that flaring.

Even more troubling, workers in at least two California refineries report the concern that short staffing may force them to choose between controlling process upsets and the other measures that prevent and minimize flaring.[4] An upset that requires efforts to prevent and minimize flaring also requires efforts to prevent it from escalating to cause a potentially catastrophic spill, fire or explosion–and often these tasks must be done at the same time. This concern, that refiners might cut corners on staffing a shift in which a major incident may occur, must be taken seriously.

Refiners' arguments do not account for these factors that support explicit requirements for both operational measures that prevent flaring, and adequate staffing for safety.

Oil industry arguments that environmental benefits of preventing flaring are not worth the cost fail to address the flare rule's actual requirement for all feasible measures. The industry's arguments do not refute the feasibility of the measures at issue here.

The cost-benefit argument also ignores other requirements to maintain adequately sized safety systems and achieve maximum emission control when refineries add new sources of gases and emissions. Chevron and ConocoPhillips are in the midst of major expansions, as shown below, so all of these requirements should apply to their intertwined processes and flare systems.

[3] ConocoPhillips asserted a need to consider "minimization of loss of products to the market" and Chevron asserted "the need to prepare equipment for maintenance within a reasonable and practical period of time" in previous draft FMPs (at 4-9 and 22, respectively), but they replaced these statements with lists of other claimed limitations on process rate adjustment measures to prevent flaring in their March 2007 FMPs (ConocoPhillips FMP at 4-12 and 4-13; Chevron FMP at 26-28, 40).

[4] These conversations, with several representatives of CBE, occurred in the 2005-2007 time frame. CBE confirmed that the workers' concern is accurately restated with a refinery workers' labor union. The refinery staff who reported this information are not named here to protect them from potential retaliation, in light of current, arguably inadequate whistleblower protection laws and enforcement.

A switch to cheaper and dirtier crude oil threatens to increase flaring.

Refineries are expanding their capacity to convert low-quality oil into high-value fuels. This increases the production of gases from dirtier-flaring processes. Some have not upgraded gas system capacity enough to prevent flaring from the initial steps toward refining cheaper crude. This type of "dirty crude refining" expansion is designed to flare. The Shell Martinez refinery expanded gas handling when it expanded dirty crude processing, and largely eliminated episodic flaring from dirtier processes. Chevron and ConocoPhillips now propose dirty crude refining expansions, but they have not yet committed to those steps that Shell has taken.

Different crude oils have different mixtures of smaller hydrocarbons with few carbon atoms per molecule and larger ones with many carbons. Refiners call crude with more small molecules "light" and crude with more of the larger ones "heavy." The difference can be huge: A refinery's *distillation* process can get ten times more gasoline per barrel from lighter crude than from heavier crude, which can yield mostly gas oil and asphalt-like oils. See Figure 4. To make more gasoline, diesel and jet fuel, refiners "crack" these large molecules into smaller ones. Refiners that run heavier crude use more *catalytic cracking, hydrocracking* and/or *coking* capacity.

Different crudes also have different amounts of sulfur and other contaminants. The most contaminated crude can have 30 times more sulfur and 11-36,000 times more toxic trace metals than the least contaminated crude. See Table 13. Refiners call high-sulfur crude "sour" and low-sulfur crude "sweet." They hydro-treat it to remove much of the sulfur and nitrogen, which can poison catalysts used in refinery processes. Hydrotreating also removes some metals. Thus, refiners running sour crude slates use more *hydrotreating*.

Table 13. Ranges of selected contaminants measured in different types of crude oil.

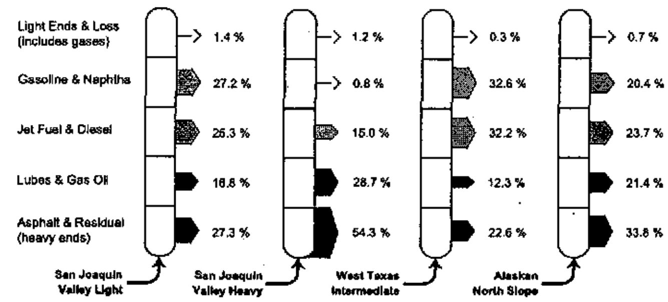
	units	Low-contaminant Sample Results Crude origin	Result	High-contaminant Sample Results Crude origin	Result	Difference (factor)
Arsenic[a]	ng/g	Louisiana	46.400	California	1,110.00	24 times
Chromium[a]	ng/g	Louisiana	1.560	California	17.50	11 times
Mercury[a]	ng/g	Louisiana	22.500	California	29,700.00	1,300 times
Mercury[b]	ng/g	Not reported	0.420	Not reported	15,200.00	36,000 times
Selenium[a]	µg/g	Louisiana	0.026	California	1.40	54 times
Sulfur[c]	%	Texas	0.110	Texas	3.34	30 times
Sulfur[d]	%	San Joaquin Valley	0.200	San Joaquin Valley	1.20	6 times
Uranium[a]	ng/g	Louisiana	4.000	California	434.00	109 times

Low and high U.S. samples from: [a] Shah et al., 1970. [b] Wilhelm and Bloom, 2000. [c] Pillay et al., 1969. [d] Purvin & Gertz, 1992.

Cracked hydrocarbons are then "reformed" or "alkylated" to boost the octane rating of motor fuels, in *reforming* or *alkylation* processes. *Hydrogen plants* are often needed to make hydrogen for a refinery's expanded hydrotreating and hydrocracking. These eight processes, among others, are typically expanded by refineries to make motor fuel from heavy, sour crude.

Refining heavy, sour crude has been linked to increasing refinery pollutant releases for more than ten years. (CBE, 1994.) Both the dirtier oil input and the more intensive processing needed to refine it increase pollution. Selenium discharge to San Francisco Bay increased more than the selenium content of refiners' crude slates because of this more intensive processing. (Id.)

Figure 4. Approximate distillation yields for four types of crude oil, in percent volume.



Computed average yields from U.S. Dept. of Energy Analysis as reported by Purvin & Gertz, 1992.

Dirty crude refining can increase flare pollution in similar ways. It produces more gases from the expanded catalytic cracking, hydrocracking and coking that make vehicle fuels from the increased volumes of gas oil and heavy ends. This is because of the increased volumes cracked in these processes and because cracking reactions produce gases as well as fuel-sized hydrocarbons. Dirty crude may also produce more gases from distillation. See Figure 4. The bigger gas volumes will have higher concentrations of sulfur and other pollutants. See Table 13. Dirtier processes will flare more, and dirtier, unless more gases are recovered and reused.

Refining cheaper crude could make the dirtiest processes flare more, and dirtier, unless refiners expand their gas handling systems.

Chevron and ConocoPhillips propose major new steps in more than a decade of intertwined process expansions that amount to a fundamental shift in their fuel refining technology. One or both refiners has expanded or plans to expand the capacity of each process that the evidence above links to dirty crude refining. See Table 14. Chevron has expanded actual capacities of at least five of the processes that are

Table 14. Approximate completion dates for some expansions of processes linked to dirty crude refining.

	Completed Expansions *Richmond*	*Rodeo*	Planned Expansions Richmond	Rodeo
Alkylation			2007-2008	
Catalytic Cracking	1996		2007	
Coking		2004		
Distillation	1991	2004-2005		
Hydrocracking	1995		2007-2010	2008
Hydrogen plants	1994	1998	2008	2008
Hydrotreating	1995	2005	2007	2008
Reforming			2009	2008

Examples include process expansions, and increases in actual process capacity through de-bottlenecking for purposes other than hydrogen supply, at the Richmond (Chevron) and Rodeo (ConocoPhillips and other owners in previous years) refineries. Data from Chevron FMP at 7; ConocoPhillips 3/13/05 Cause Report; Cal. Env. Quality Act documents for SCH Nos. 92113007, 93121027, 2002122017, 2005072117, 2005092028; and AQMD permit applications. See text for process/crude source link.

associated with dirty crude refining and plans to expand or further expand at least six of them between 2007 and 2010. ConocoPhillips has expanded at least four since 1996 and plans to expand another four between 2007 and 2009. Both refiners' current expansion proposals seek to further increase the amounts of heavy gas oil and high-sulfur crude converted into gasoline, diesel and/or jet fuel. (CEQA documents for SCH# 2005072117; SCH# 2005092028.)

Chevron has not proposed any detailed plan or firm commitment to install dedicated backup flare gas recovery capacity or adequate recovery/reuse capacity to prevent non-emergency flaring with its new expansion. (SCH# 2005072117; FMP at 20-42.) Instead of adding backup capacity sized to its existing flare gas recovery compressor, ConocoPhillips proposes the same scheme that has already failed at Chevron–using a smaller compressor that primarily serves a different purpose in dual use as a *partial* backup for flare gas recovery. (FMP at 3-13, 3-16, 4-25.)

Shell installed its DCU flare gas recovery compressors among other equipment that expanded its gas recovery/reuse capacity when it built a major expansion of its dirty crude refining capacity in the mid-1990s. (AQMD App. 8407; Per. Com. 9/20/04 AQMD staff; SCH# 92093028; FMP.) This equipment has proven effective, with more recent measures, in largely eliminating episodic flaring from dirtier-flaring processes since 2004.

In contrast, Chevron and ConocoPhillips have inadequate equipment capacity for reliable flare gas recovery *today*. Monitoring was too poor twenty years ago to know whether their gas handling systems were adequate before the shift to dirty crude began, but current data show that they are not adequate now. There is a need to upgrade them to prevent flaring, even without the potentially large increase in high-pollutant gases that would result in flaring from their new expansion proposals. This feasible prevention measure would avoid a significant potential impact.

Total impacts from a full-blown shift to dirty crude refining–on workers and working class communities of color, regional environmental health, green energy, green jobs and the pace of energy transition to stop global warming–reach far beyond flaring and demand an urgent search for better alternatives. This review of flaring prevention measures identifies an aspect of these better alternatives that is needed and feasible now. Refinery upgrades should be designed, built and operated to prevent non-emergency flaring.

Closing

Measures to greatly reduce serious pollution from refinery flares are demonstrated in practice. This information supports community demands to stop the pollution, and government requirements to protect our environmental health. In the Bay Area, communities can act to ensure that our Air District will require these measures in "flare minimization" plans that are due for public comment in April-May 2007. Contact information for some of the responsible officials is listed on the last page of this report. In every refinery town, neighbors and workers can act to ensure that refiners commit to these measures before public officials permit expansions of low-cost crude oil refining–which otherwise threaten to further increase pollution from flares.

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Appendix 1: Flare gas quality analysis for refining processes

Different refineries flare from different processes that produce gases of different quality. The *purpose of this analysis is to quantify these* "process factors" at Bay Area refineries for hydrogen sulfide (H_2S) and the major gases from the processes that these plants flare from frequently: C2- hydrocarbon,[1] C3-5 hydrocarbon,[2] hydrogen (H_2) and nitrogen (N_2). The data available for this analysis are limited by industry self-monitoring. Consistent process source and gas quality reporting began only after November 2003, when Rule 12-11 began to require standardized monitoring and reporting. Further, after 2003, refiners often report incomplete flare gas source or quality data, and generally fail to report hourly flare gas composition. However, the refiners flare frequently, so many flaring episodes are reported.

For 130 episodes from December 2003 through August 2006, data are adequate to identify a primary process source of gases flared and quantify at least one of the five gases targeted in at least four episodes with the same type of process source. These represent 73% of the flaring episodes reported in this period, and include eight types of refining processes. Data from these 130 events are presented in *Table A-4 at the end of this appendix, and are summarized in Table A-1* below. Review of Table A-1 shows that each refinery flares from a different mix of processes. This is consistent with their different equipment and different flaring prevention measures, such as Shell's measures to prevent episodic flaring from its catalytic cracking, distillation, delayed coking and hydrocracking processes. (See e.g., Table 4.)

Table A-1. Counts of flaring episodes reported by refinery, process, and gas.

	Chevron Refinery					ConocoPhillips					Shell Refinery					Tesoro Refinery					Valero Refinery				
	C2-	C3-5	H2S	H2	N2	C2-	C3-5	H2S	H2	N2	C2-	C3-5	H2S	H2	N2	C2-	C3-5	H2S	H2	N2	C2-	C3-5	H2S	H2	N2
Cat. Cracking	6	6	6	6	6	No Cat. Cracking					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coking	No Coking					4	4	4	4	4	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1
Distillation	4	4	4	4	4	1	1	1	1	1	0	0	0	0	0	0	0	1	2	2	0	0	0	0	0
Hydrocracking	*15*	*15*	*15*	*15*	*15*	*3*	*3*	*3*	*3*	*3*	*0*	*0*	*0*	*0*	*0*	*4*	*2*	*5*	*7*	*7*	*1*	*1*	*3*	*3*	*3*
Hydrogen plts.	0	0	0	0	0	5	5	5	5	5	0	0	0	0	0	7	7	12	11	11	2	2	2	2	2
Hydrotreating	4	4	4	4	4	2	2	2	2	2	0	0	0	0	0	5	5	6	6	6	6	6	15	15	15
Reforming	1	1	1	1	1	2	2	2	2	2	0	0	0	0	0	0	0	0	2	2	1	1	2	2	2
Shell Flexigas	No Flexigas					No Flexigas					20	20	30	30	30	No Flexigas					No Flexigas				

Gas quality and source data reported by Bay Area refineries for 130 flaring events in Table A-4. Totals from this table do not sum to the total number of events analyzed (130) because different gases were reported for different events in some cases.

The expected gas quality pattern is observed among these processes. Flare gases from catalytic cracking, coking, distillation and hydrocracking have the highest hydrocarbon and/or H_2S content, and those from hydrogen plants have the highest hydrogen content. See Table A-2 below. Median hydrocarbon and H_2S content in gases from the dirtiest-flaring process is always at least 30 times that from the lowest-flaring process. Hydrogen plants flare gases with 12 times higher H_2 content than catalytic cracking.

These differences in gas quality were assessed for statistical significance in paired comparisons (e.g., catalytic cracking v. coking for C2-, cat-cracking v. distillation for H_2S, etc.) using a non-parametric test (Mann-Whitney U). Many of these comparisons between the eight processes for the five gases (57 of 140) indicate significant differences in gas quality (two-tailed $p < 0.01$).

[1] C2- is hydrocarbon with two or less carbon atoms per molecule: methane, ethane and ethylene.
[2] C3-5 is hydrocarbon in the propane-pentane range, with 3-5 carbon atoms per molecule.

Table A-2. Median flare gas concentrations by volume for eight processes.

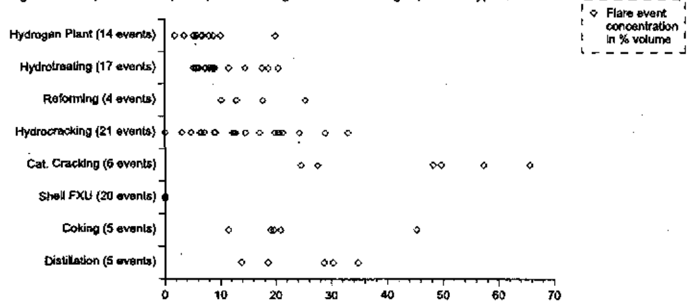
	C2-	C3-5	H_2S	H_2	N_2
Cat. Cracking	41.9 %	48.9 %	0.11 %	4.3 %	12.1 %
Coking	36.4 %	19.6 %	0.78 %	21.0 %	11.9 %
Distillation	13.1 %	28.7 %	1.52 %	28.7 %	7.3 %
Hydrocracking	19.0 %	12.8 %	1.05 %	42.8 %	14.3 %
Hydrogen plants	18.3 %	6.7 %	0.14 %	50.7 %	11.5 %
Hydrotreating	20.6 %	8.1 %	0.14 %	32.7 %	28.0 %
Reforming	22.3 %	15.3 %	0.98 %	35.2 %	18.6 %
Shell Flexigas (FXU)	1.4 %	< 0.01 %	< 0.01 %	16.9 %	53.0 %
All eight processes[a]	17.7 %	8.59 %	0.13 %	26.8 %	18.4 %

Gas quality and source data reported by Bay Area refineries for 130 events in Table A-4. [a] Median of the total data set for these processes. Process-specific values may not average or sum to this median or 100% of volume because processes have different data distributions, some gases are not reported for some events, and gases not shown are flared (e.g., CO_2).

Each dirtier-flaring process–catalytic cracking, coking, distillation and hydrocracking–flares gases with significantly higher hydrocarbon and/or H_2S content than those from several other processes. This finding holds even if Shell is removed from the comparisons.[3]

For example, several significant differences are apparent in the case of C3-5 hydrocarbon. Figure A-1 plots the C3-5 hydrocarbon content of gases in each flaring event for the eight processes. The lowest flaring event concentration from catalytic cracking exceeds the highest event concentrations from hydrogen plants and hydrotreating. At the same time, the lowest hydrogen plant and hydrotreating event concentrations exceed any from the twenty events reported from the FXU process. Each of these differences, among others,[4] is significant.

Figure A-1. Hydrocarbon (C3-5) content of gas flared from eight process types.



Event concentrations in % volume for 130 flaring events at five refineries shown in Table A-4.

[3] Counting paired comparisons between processes for each pollutant (C2-, C3-5, H_2S) individually, when Shell is excluded, cat-cracking and coking each have significantly higher concentrations than other processes in four comparisons; hydrocracking is significantly higher in three comparisons, and distillation is significantly higher than other processes in five comparisons (two-tailed $p < 0.01$).

[4] For C3-5 in gases from dirtier-flaring processes: cat-cracking, coking and distillation are significantly higher than hydrogen plants, hydrotreating and FXU; cat-cracking is higher than hydrocracking, and hydrocracking is significantly higher than hydrogen plants and FXU (two-tailed $p < 0.01$).

Table A-3. Median flare gas concentrations by volume for five refineries.

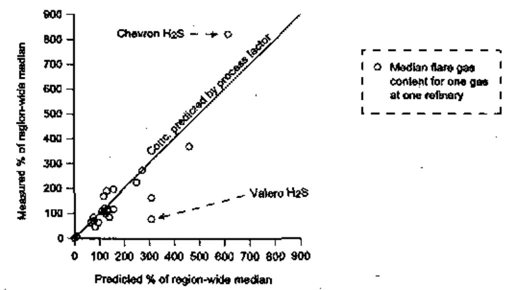
	C2-	C3-5	H_2S	H_2	N_2
Chevron	21.1 %	19.30 %	1.07 %	28.7 %	13.50 %
ConocoPhillips	33.5 %	10.00 %	0.48 %	22.5 %	16.20 %
Shell	1.4 %	< 0.01 %	< 0.01 %	16.9 %	53.00 %
Tesoro	19.1 %	5.44 %	0.21 %	52.7 %	8.64 %
Valero	17.2 %	14.40 %	0.10 %	29.3 %	23.60 %

Gas quality and source data reported by five refineries for 130 flaring events in Table A-4. Values may not sum to 100% because some gases are not reported for some events and gases not shown are flared (e.g., CO_2).

Refiners' flare gas concentrations reflect these different process sources. Flaring from dirtier processes (Table A-1), Chevron and ConocoPhillips flare gases with the highest median hydrocarbon and H_2S content among the five refineries. See Table A-3. Tesoro and Shell do the most hydrogen plant and FXU flaring, and flare gases with the highest H_2 and N_2 content, respectively.

A refinery's process factor is the process-specific median concentration of each gas weighted by the percentage of the refinery's flaring from each process. (See tables A-1 and A-2.) Figure A-2 compares each refinery's process factor for each gas with its refinery-specific median from direct measurements at the refinery in Table A-3. Values for each refinery and gas are shown as percentages of the region-wide median at the bottom of Table A-2. For example, Chevron's measured H_2S content is 820% and Valero's is 77% of the region-wide median.

Figure A-2. Effect of process sources on refinery-specific flare gas content.



Shows observations for five gases (C2-, C3-5, H_2S, H_2 and N_2) at each of five Bay Area refineries. Based on gas quality and source data reported by the refineries for 130 flaring events. Data are shown in Table A-4.

As shown in Figure A-2, there is a good fit between predicted and measured flare gas concentrations. Process factors explain about 80% of the difference in median flare gas quality between refineries for these five gases and 130 flaring episodes (R-squared = 0.79, p = 3E-09). The purpose of this comparison (in Figure A-2) is to gain a more formal understanding of the observations presented in Figure 1 on page 3 of the report. The parametric regression performed on the data shown in Figure A-2[5] further supports the underlying message of Figure 1: The mix of process sources a refinery flares from is a strong predictor of that refinery's flare gas quality.

[5] A nonparametric regression would be more precise. That excercise is left to future analysis.

Table A-4. Gas quality and process source data for 130 flaring episodes.

Flaring event initiated	Refinery flaring	Initiating condition	Primary flare gas process source	Event mean flare gas content (fraction) C2- by vol.	C3-5 by vol.	H2S by vol.	H2 by vol.	N2 by vol.
12/2/03	Valero	Not reported	Hydrotreating			0.0040	0.2830	0.2993
12/20/03	Valero	Not reported	Hydrotreating			0.0045	0.2530	0.2990
12/30/03	Valero	Not reported	Hydrocracking			0.0135	0.4920	0.1260
1/19/04	Tesoro	Planned Maint.	Hydrogen Plant			0.0027	0.5288	0.1267
1/24/04	Tesoro	Planned Maint.	Hydrogen Plant			0.0031	0.2148	0.3150
1/26/04	Shell	Not reported	Shell FXU			0.0000	0.1740	0.5440
1/31/04	Valero	Not reported	Hydrotreating			0.0010	0.5160	0.1530
2/2/04	Valero	Not reported	Hydrotreating			0.0010	0.6800	0.0780
2/3/04	Valero	Not reported	Hydrotreating			0.0000	0.1460	0.6320
2/7/04	Chevron	Planned Maint.	Hydrocracking	0.1166	0.2431	0.0122	0.5414	0.0573
2/7/04	Tesoro	Not reported	Hydrogen Plant			0.0082	0.3263	0.2484
2/10/04	Shell	Planned Maint.	Shell FXU			0.0000	0.1720	0.5300
2/10/04	Valero	Not reported	Hydrotreating			0.0000	0.4300	0.3200
2/15/04	Chevron	Planned Maint.	Hydrocracking	0.0914	0.1221	0.0010	0.6242	0.1213
3/1/04	Tesoro	Planned Maint.	Hydrocracking			0.0021		
3/4/04	Tesoro	Planned Maint.	Hydrogen Plant			0.0021		
3/28/04	Valero	Not reported	Hydrotreating			0.0010	0.6380	0.0830
4/10/04	Shell	Malfunction	Shell FXU			0.0000	0.1310	0.6600
4/15/04	Tesoro	Malfunction	Hydrotreating			0.0083	0.3454	0.1454
6/12/04	Valero	Not reported	Reforming			0.0040	0.2810	0.3410
7/23/04	ConocoPhillips	Planned Maint.	Hydrocracking	0.3355	0.0011	0.0000	0.0037	0.6596
9/7/04	Shell	Planned Maint.	Shell FXU			0.0000	0.1830	0.5170
9/7/04	Tesoro	Planned Maint.	Distillation			0.0121	0.2464	0.1452
10/5/04	Shell	Malfunction	Shell FXU			0.0000	0.1780	0.5230
10/20/04	ConocoPhillips	Planned Maint.	Hydrocracking	0.1569	0.2139	0.0402	0.3822	0.1199
10/24/04	ConocoPhillips	Planned Maint.	Hydrogen Plant	0.0882	0.0653	0.0020	0.7352	0.0741
10/30/04	Tesoro	Planned Maint.	Distillation				0.2874	0.0732
10/31/04	Chevron	Planned Maint.	Hydrocracking	0.0171	0.0914	0.0010	0.0137	0.8716
11/4/04	Chevron	Planned Maint.	Hydrocracking	0.1760	0.0713	0.0321	0.2875	0.2835
11/23/04	Chevron	Malfunction	Hydrotreating	0.0578	0.0847	0.0030	0.3879	0.4639
11/23/04	Tesoro	Malfunction	Hydrogen Plant			0.0032	0.2847	0.0785
12/3/04	Shell	Malfunction	Shell FXU			0.0000	0.1745	0.5195
12/23/04	Tesoro	Planned Maint.	Hydrocracking				0.6677	0.0636
1/3/05	Shell	Planned Maint.	Shell FXU			0.0000	0.1670	0.5270
1/4/05	ConocoPhillips	Planned Maint.	Hydrogen Plant	0.0278	0.0785	0.0011	0.1621	0.5696
1/6/05	Tesoro	Planned Maint.	Hydrocracking				0.4668	0.2422
1/8/05	Shell	Malfunction	Shell FXU			0.0000	0.1670	0.5270
1/14/05	Shell	Planned Maint.	Shell FXU			0.0000	0.1690	0.5350
2/5/05	Tesoro	Planned Maint.	Reforming				0.6533	0.0576
2/11/05	ConocoPhillips	Planned Maint.	Coking	0.2605	0.4523	0.0048	0.2452	0.0000

Table A-4. Gas quality and process source data for 130 flaring episodes (continued).

Flaring event initiated	Refinery flaring	Initiating condition	Primary flare gas process source	Event mean flare gas content (fraction) C2- by vol.	C3-5 by vol.	H2S by vol.	H2 by vol.	N2 by vol.
2/11/05	Tesoro	Planned Maint.	Reforming				0.4877	0.0474
2/13/05	Tesoro	Planned Maint.	Hydrocracking				0.6037	0.0347
2/19/05	Shell	Malfunction	Shell FXU			0.0000	0.1760	0.5195
2/23/05	Chevron	Planned Maint.	Hydrocracking	0.2357	0.1284	0.0130	0.2863	0.2983
3/3/05	Chevron	Planned Maint.	Hydrocracking	0.3163	0.1457	0.0135	0.0049	0.5180
3/5/05	Chevron	Planned Maint.	Catalytic Cracking	0.1759	0.6558	0.0007	0.0012	0.1633
3/12/05	Chevron	Planned Maint.	Hydrocracking	0.2022	0.3306	0.0501	0.2699	0.1470
3/13/05	ConocoPhillips	Planned Maint.	Hydrogen Plant	0.2092	0.0180	0.0010	0.3826	0.2205
3/14/05	ConocoPhillips	Malfunction	Hydrotreating	0.4081	0.0571	0.0006	0.3030	0.1386
3/15/05	ConocoPhillips	Malfunction	Hydrogen Plant	0.3670	0.0800	0.0010	0.3520	0.0000
3/25/05	Valero	Malfunction	Hydrocracking			0.0020	0.2660	0.2360
3/26/05	Shell	Malfunction	Shell FXU	0.0144	0.0000	0.0000	0.1741	0.5237
3/29/05	Valero	Planned Maint.	Hydrotreating			0.0007	0.2637	0.3193
4/5/05	Tesoro	Malfunction	Hydrogen Plant	0.1815	0.0525	0.0013	0.5259	0.0686
4/7/05	Valero	Planned Maint.	Hydrotreating			0.0090	0.3269	0.2163
4/10/05	ConocoPhillips	Malfunction	Reforming	0.4503	0.1286	0.0149	0.1983	0.1861
4/10/05	Shell	Planned Maint.	Shell FXU	0.0300	0.0000	0.0000	0.1644	0.5517
4/18/05	ConocoPhillips	Malfunction	Coking	0.8276	0.1141	0.0001	0.0042	0.0009
5/3/05	Shell	Malfunction	Shell FXU	0.0140	0.0000	0.0000	0.1942	0.5095
5/23/05	Shell	Planned Maint.	Shell FXU	0.0151	0.0000	0.0000	0.1682	0.5802
6/7/05	Tesoro	Not reported	Hydrogen Plant	0.1849	0.0344	0.0014	0.5031	0.0608
6/21/05	Shell	Not reported	Shell FXU	0.0143	0.0000	0.0000	0.1599	0.5337
7/6/05	Shell	*Not reported*	*Shell FXU*	*0.0129*	*0.0001*	*0.0000*	*0.1554*	*0.5377*
7/15/05	Shell	Malfunction	Shell FXU	0.0129	0.0001	0.0000	0.1554	0.5377
7/28/05	Tesoro	Not reported	Hydrotreating	0.1572	0.0563	0.0012	0.7559	0.0292
8/14/05	Valero	Malfunction	Hydrogen Plant	0.1723	0.1988	0.0007	0.3755	0.1457
8/21/05	Shell	Malfunction	Shell FXU	0.0078	0.0000	0.0000	0.1539	0.5266
8/26/05	ConocoPhillips	Planned Maint.	Hydrogen Plant	0.4503	0.1003	0.0111	0.1633	0.1737
9/7/05	Tesoro	Malfunction	Hydrocracking	0.1401		0.0058	0.7856	0.0316
9/7/05	Valero	Planned Maint.	Hydrotreating	0.1941	0.0905	0.0003	0.1731	0.5498
9/12/05	Valero	Planned Maint.	Hydrotreating	0.1653	0.1750	0.0000	0.2553	0.3443
9/14/05	Tesoro	Malfunction	Hydrocracking	0.1178		0.0004	0.8157	0.0241
9/16/05	Shell	Malfunction	Shell FXU	0.0125	0.0003	0.0000	0.1639	0.5294
9/18/05	Shell	Malfunction	Shell FXU	0.0083	0.0002	0.0000	0.1604	0.5390
9/22/05	Shell	Malfunction	Shell FXU	0.0083	0.0002	0.0000	0.1604	0.5390
9/26/05	ConocoPhillips	Planned Maint.	Coking	0.4489	0.1959	0.0285	0.1589	0.1165
9/28/05	Chevron	Malfunction	Catalytic Cracking	0.3970	0.4813	0.0011	0.0604	0.0521
10/8/05	ConocoPhillips	Malfunction	Hydrocracking	0.1789	0.0898	0.0086	0.5493	0.1387
10/10/05	Chevron	Planned Maint.	Catalytic Cracking	0.4442	0.4961	0.0011	0.0053	0.1236
10/20/05	Shell	Malfunction	Shell FXU	0.0129	0.0000	0.0000	0.1628	0.5300

Table A-4. Gas quality and process source data for 130 flaring episodes (continued).

Flaring event initiated	Refinery flaring	Initiating condition	Primary flare gas process source	Event mean flare gas content (fraction) C2- by vol.	C3-5 by vol.	H2S by vol.	H2 by vol.	N2 by vol.
10/23/05	Chevron	Planned Maint.	Hydrocracking	0.1621	0.1251	0.0079	0.4885	0.1945
10/26/05	Tesoro	Malfunction	Hydrotreating	0.2128	0.0515	0.0019	0.6540	0.0615
10/28/05	Chevron	Planned Maint.	Hydrotreating	0.2501	0.1867	0.0317	0.2511	0.2804
11/13/05	Valero	Planned Maint.	Hydrotreating	0.2745	0.1443	0.0024	0.1604	0.3613
11/20/05	Valero	Planned Maint.	Hydrotreating	0.2056	0.1150	0.0026	0.2197	0.3810
11/30/05	Chevron	Planned Maint.	Catalytic Cracking	0.4399	0.2742	0.0001	0.0256	0.2545
12/7/05	Tesoro	Malfunction	Hydrocracking	0.1897	0.0317	0.0175	0.4255	0.3298
12/16/05	Chevron	Malfunction	Hydrocracking	0.2883	0.2899	0.1420	0.2539	0.0259
12/31/05	Shell	Malfunction	Shell FXU	0.0112	0.0000	0.0000	0.1745	0.5330
1/6/06	Tesoro	Planned Maint.	Hydrogen Plant	0.1933	0.0353	0.0002	0.6629	0.0637
1/8/06	Tesoro	Planned Maint.	Hydrotreating	0.1966	0.0734	0.0035	0.5603	0.1504
1/13/06	Chevron	Malfunction	Catalytic Cracking	0.2624	0.5725	0.0023	0.1324	0.0196
1/13/06	Chevron	Planned Maint.	Hydrotreating	0.1090	0.0808	0.0059	0.3417	0.4512
1/22/06	ConocoPhillips	Planned Maint.	Reforming	0.3052	0.1764	0.0132	0.2255	0.2244
1/27/06	Tesoro	Planned Maint.	Hydrogen Plant	0.1521	0.0506	0.0007	0.5533	0.1034
1/31/06	Tesoro	Malfunction	Hydrogen Plant	0.2627	0.0572	0.0017	0.5098	0.0576
2/8/06	Tesoro	Malfunction	Hydrogen Plant	0.1995	0.1005	0.0082	0.5466	0.1277
2/13/06	Tesoro	Malfunction	Hydrogen Plant	0.1349	0.0680	0.0008	0.5584	0.1622
2/17/06	Valero	Planned Maint.	Hydrocracking	0.1883	0.2128	0.0016	0.2695	0.1938
2/20/06	Chevron	Malfunction	Hydrocracking	0.1164	0.1985	0.0157	0.6608	0.0086
2/24/06	Chevron	Planned Maint.	Hydrocracking	0.2586	0.2052	0.0500	0.2292	0.2569
3/1/06	ConocoPhillips	Malfunction	Coking	0.3637	0.1904	0.0092	0.2100	0.1689
3/6/06	Valero	Planned Maint.	Reforming	0.0920	0.2530	0.0008	0.3518	0.2177
3/8/06	Chevron	Planned Maint.	Hydrocracking	0.2190	0.0639	0.0317	0.4151	0.1633
3/11/06	ConocoPhillips	Malfunction	Hydrotreating	0.2437	0.0719	0.0001	0.2466	0.3887
3/12/06	Chevron	Malfunction	Hydrotreating	0.3232	0.0799	0.0116	0.5425	0.0422
3/14/06	Chevron	Malfunction	Catalytic Cracking	0.4526	0.2449	0.0059	0.1720	0.1179
3/15/06	Shell	Malfunction	Shell FXU	0.0133	0.0000	0.0000	0.1661	0.5366
4/7/06	Chevron	Planned Maint.	Reforming	0.1408	0.1014	0.0098	0.6853	0.0627
4/21/06	Chevron	Planned Maint.	Hydrocracking	0.2480	0.2060	0.0087	0.2276	0.2963
4/29/06	Shell	Malfunction	Shell FXU	0.0123	0.0000	0.0000	0.1457	0.5215
5/1/06	ConocoPhillips	Malfunction	Distillation	0.4106	0.1373	0.0303	0.1897	0.1620
5/10/06	Chevron	Malfunction	Distillation	0.1462	0.1857	0.0043	0.6398	0.0230
5/18/06	Valero	Malfunction	Hydrogen Plant	0.1645	0.0870	0.0000	0.6439	0.1010
5/20/06	Valero	Planned Maint.	Hydrotreating	0.0969	0.0516	0.0000	0.2929	0.5550
5/27/06	Valero	Planned Maint.	Hydrotreating	0.1401	0.0614	0.0002	0.6485	0.1136
5/31/06	Tesoro	Malfunction	Hydrotreating	0.3546	0.0876	0.0036	0.3933	0.1430
6/5/06	Shell	Malfunction	Shell FXU	0.0142	0.0000	0.0000	0.1727	0.4976
6/16/06	Tesoro	Malfunction	Hydrotreating	0.4813	0.2047	0.0014	0.1983	0.0942
6/19/06	Shell	Malfunction	Shell FXU	0.0141	0.0000	0.0000	0.1715	0.4990

Table A-4. Gas quality and process source data for 130 flaring episodes (continued).

Flaring event initiated	Refinery flaring	Initiating condition	Primary flare gas process source	Event mean flare gas content (fraction) C2- by vol.	C3-5 by vol.	H2S by vol.	H2 by vol.	N2 by vol.
6/25/06	Chevron	Planned Maint.	Hydrocracking	0.3495	0.1706	0.0042	0.4307	0.0412
7/6/06	Tesoro	Malfunction	Hydrocracking	0.2031	0.0476	0.0013	0.6303	0.0948
7/10/06	Shell	Planned Maint.	Shell FXU	0.0141	0.0000	0.0000	0.1740	0.4981
7/11/06	Chevron	Malfunction	Hydrocracking	0.3839	0.0662	0.0636	0.4660	0.0204
7/11/06	Shell	Planned Maint.	Shell FXU	0.0141	0.0000	0.0000	0.1740	0.4981
7/21/06	Chevron	Malfunction	Distillation	0.0942	0.2867	0.0291	0.5674	0.0226
8/2/06	Valero	Malfunction	Coking	0.3633	0.2083	0.0078	0.3053	0.1513
8/8/06	Chevron	Malfunction	Distillation	0.0920	0.3027	0.0122	0.5605	0.0327
8/22/06	Shell	Planned Maint.	Shell FXU	0.0177	0.0000	0.0000	0.1921	0.5433
8/30/06	Chevron	Malfunction	Distillation	0.1314	0.3473	0.0181	0.2730	0.1715

Data from refiners' monthly monitoring reports under AQMD Rule 12-11 and refiners' cause reports under rules 12-11 and 12-12, Condition 7 of ConocoPhillips Land Use Permit, and Shell/EPA consent decree in Civil Action No. H-01-0978.

Flaring Prevention Measures

Public officials' contact information

> The Flare Minimization Plan proposed by each of the five Bay Area refineries is available in April and May, 2007, from the Air District by phone or web:
>
> (415) 749-4999
>
> www.baaqmd.gov/flares

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EXHIBIT T

United States
Environmental Protection
Agency

EPA 550-F-03-001
August 2003
www.epa.gov/ceppo

Chemical Emergency Preparedness
and Prevention Office
(5104A)

Occupational Safety and Health Administration
Directorate of Science, Technology and Medicine
Office of Science and Technology Assessment

United States
Department of Labor

SHIB 03-08-29
www.osha.gov

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OSHA

Hazards of Delayed Coker Unit (DCU) Operations

Safety and Health Information Bulletin

Chemical Safety ALERT

The Environmental Protection Agency (EPA) and the Occupational Safety and Health Administration (OSHA) are jointly issuing this *Chemical Safety Alert/Safety and Health Information Bulletin (CSA/SHIB)* as part of ongoing efforts to protect human health and the environment by preventing chemical accidents. We are striving to better understand the causes and contributing factors associated with chemical accidents, to prevent their recurrence, and to provide information about occupational hazards and noteworthy, innovative, or specialized procedures, practices, and research that relate to occupational safety and health and environmental protection. Major chemical accidents cannot be prevented solely through regulatory requirements. Rather, understanding the fundamental root causes, widely disseminating the lessons learned, and integrating these lessons into safe operations are also required. EPA and OSHA jointly publish this CSA/SHIB to increase awareness of possible hazards. This joint document supplements active industry efforts to exchange fire and safety technology and to increase awareness of environmental and occupational hazards associated with DCU operations. It is important that facilities, State Emergency Response Commissions (SERCs), Local Emergency Planning Committees (LEPCs), emergency responders, and others review this information and take appropriate steps to minimize risk. This document does not substitute for EPA or OSHA regulations, nor is it a regulation itself. It cannot and does not impose legally binding requirements on EPA, OSHA, states, or the regulated community, and the measures it describes may not apply to a particular situation based upon the circumstances. This guidance does not represent final agency action and may change in the future, as appropriate.

Problem

The batch portion of DCU operations (drum switching and coke cutting) creates unique hazards, resulting in relatively frequent and serious accidents.

The increasingly limited supply of higher quality crude oils has resulted in greater reliance on more intensive refining techniques. Current crude oils tend to have more long chain molecules, known as "heavy ends" or "bottom of the barrel" than the lighter crude oils that were more readily available in the past. These heavy ends can be extracted and sold as a relatively low value industrial fuel or as a feedstock for asphalt-based products, such as roofing tile, or they may be further processed to yield higher value products. One of the most popular processes for upgrading heavy ends is the DCU, a severe form of thermal cracking requiring high temperatures for an extended period of time. This process yields higher value liquid products and creates a solid carbonaceous residue called "coke." As the supply of lighter crude oils has diminished, refiners have relied increasingly on DCUs.

Unlike other petroleum refinery operations, the DCU is a semi-batch operation, involving both batch and continuous stages. The batch stage of the operation (drum switching and coke cutting) presents unique hazards and is responsible for most of the serious accidents attributed to DCUs. The continuous stage (drum charge, heating, and fractionation) is generally similar to other refinery operations and is not further discussed in this document. About 53 DCUs were in operation in the United States in 2003, in about one third of the refineries.

In recent years, DCU operations have resulted in a number of serious accidents despite efforts among many refiners to share information regarding best practices for DCU safety and reliability. EPA and OSHA believe that addressing the hazards of DCU operations is necessary given the increasing importance of DCUs in meeting energy demands, the array of hazards associated with DCU operations, and the frequency and severity of serious incidents involving DCUs.

Understanding the Hazards

Safe DCU operations require an understanding of the situations and conditions that are most prone to frequent or serious accidents.

Process Description

Each DCU module contains a fired heater, two (in some cases three) coking drums, and a fractionation tower.

This document focuses on the coke drums, which are large cylindrical metal vessels that can be up to 120 feet tall and 29 feet in diameter.

In delayed coking, the feed material is typically the residuum from vacuum distillation towers and frequently includes other heavy oils. The feed is heated by a fired heater (furnace) as it is sent to one of the coke drums. The feed arrives at the coke drum with a temperature ranging from 870 to 910°F. Typical drum overhead pressure ranges from 15 to 35 psig. Under these conditions, cracking proceeds and lighter fractions produced are sent to a fractionation tower where they are separated into gas, gasoline, and other higher value liquid products. A solid residuum of coke is also produced and remains within the drum.

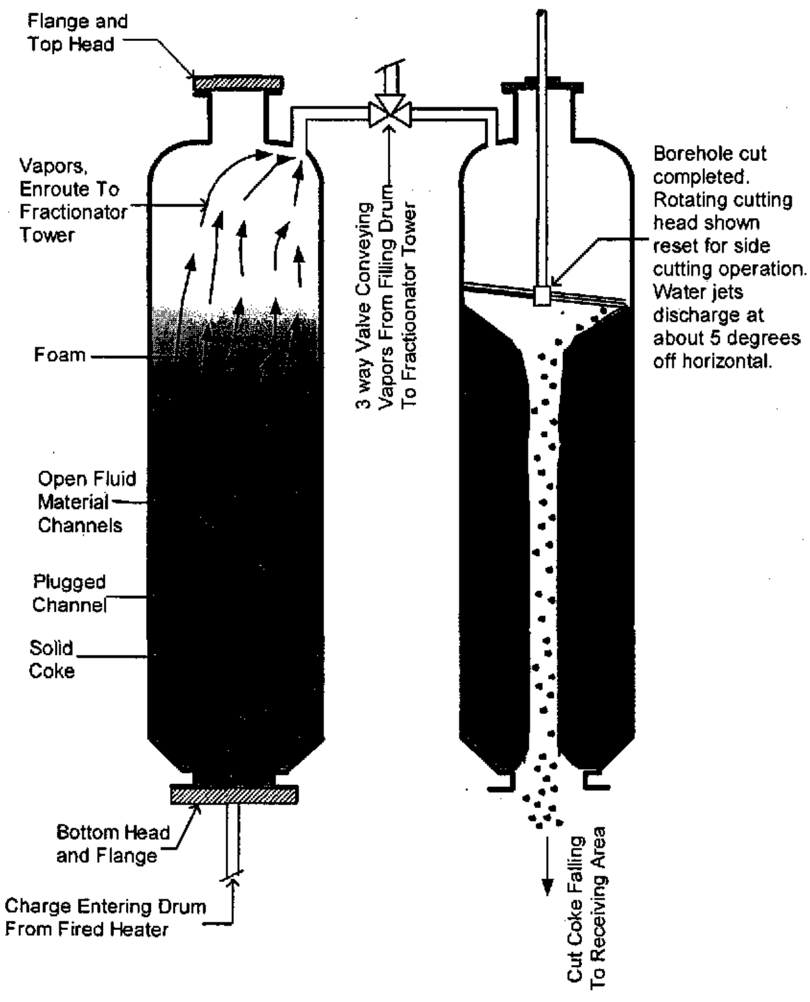

Figure 1 - Delayed Coker Unit
Cutaway to Depict Drum In Filling and Migration Mode (Left) and Drum In Cutting Mode (Right)

After the coke has reached a predetermined level within the "on oil" drum, the feed is diverted to the second coke drum. This use of multiple coke drums enables the refinery to operate the fired heater and fractionation tower continuously. Once the feed has been diverted, the original drum is isolated from the process flow and is referred to as the "off oil" drum. Steam is introduced to strip out any remaining oil, and the drum is cooled (quenched) with water, drained, and opened (unheaded) in preparation for decoking. Decoking involves using high pressure water jets from a rotating cutter to fracture the coke bed and allow it to fall into the receiving area below. Once it is decoked, the "off oil" drum is closed (re-headed), purged of air, leak tested, warmed-up, and placed on stand-by, ready to repeat the cycle. Drum switching frequency ranges from 10 to 24 hours. DCU filling and decoking operations are illustrated in Figure 1. Equipment used in coke cutting (hydroblasting) operations is illustrated in Figure 2.

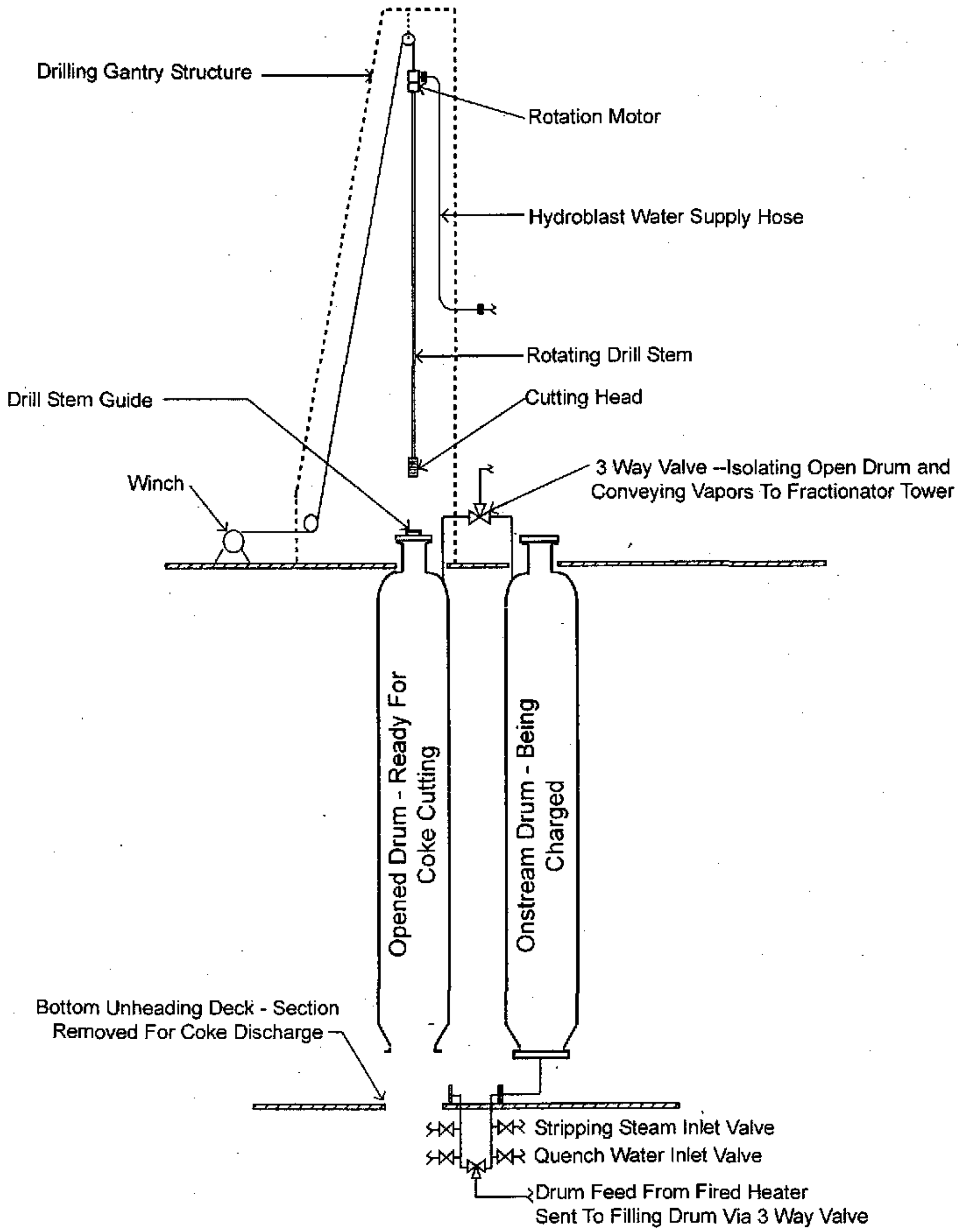

Figure 2 - Delayed Coker Unit

Coke Drums and Hydroblast Systems

Once removed from the coke drums, the coke is transported away from the receiving area. From here, the coke is either exported from the refinery or crushed, washed, and stored prior to export.

The following specific operations and more general situations and conditions contribute most significantly to the hazards associated with DCU operations:

Specific operation hazards

- Coke drum switching
- Coke drum head removal
- Coke cutting (hydroblasting operation)

Emergency and general operational hazards

- Coke transfer, processing, and storage
- Emergency evacuation
- Toxic exposures, dust irritants, and burn trauma

The hazards associated with these specific operations and DCU operations, in general, are explained below to share lessons learned and increase awareness of the situations and conditions that are most prone to serious accidents. Following this section, the joint CSA/SHIB describes actions that can be taken to help minimize the risks associated with these situations and conditions.

Specific Operation Hazards

Coke Drum Switching

Most DCU operations consist of several DCU modules, each typically alternating between two coke drums in the coking/decoking sequence. Some DCU modules include a third drum in this sequence. Each drum includes a set of valving, and each module includes a separate set of valving. Differences in valving among drums and among modules may be difficult to distinguish and can lead to unintended drum inlet or outlet stream routing. Similarly, valve control stations, for remotely activated valves, may not always clearly identify the operating status of different drums and modules. Activating the wrong valve because of mistakes in identifying the operational status of different drums and modules has led to serious incidents.

Coke Drum Head Removal

Conditions within the drum, during and after charging, can be unpredictable. Under abnormal conditions, workers can be exposed to the release of hot water, steam and coke, toxic fumes, and physical hazards during removal of the top and bottom drum heads. The most frequent and/or severe hazards associated with this operation are described below:

- **Geysers/eruptions** - Under abnormal situations, such as feed interruption or anomalous short-circuiting during steaming or quenching, hot spots can persist in the drum. Steam, followed by water, introduced to the coke drum in preparation for head removal can follow established channels rather than permeate throughout the coke mass. Because coke is an excellent insulator, this can leave isolated hot areas within the coke. Although infrequent, if the coke within the drum is improperly drained and the coke bed shifts or partially collapses, residual water can contact the isolated pockets of hot coke, resulting in a geyser of steam, hot water, coke particles, and hydrocarbon from either or both drum openings after the heads have been removed.
- **Hot tar ball ejection** - Feed interruption and steam or quenching water short-circuiting can also cause "hot tar balls," a mass of hot (over 800°F) tar-like material, to form in the drum. Under certain circumstances, these tar balls can be rapidly ejected from the bottom head opening.
- **Undrained water release** - Undrained hot water can be released during bottom head removal, creating a scalding hazard.
- **Shot coke avalanche** - Sometimes, the coke forms into a multitude of individual, various sized, spherical shaped chunks known as "shot coke," rather than a single large mass. In this situation, the drum contents are flowable and may dump from the drum when the bottom head is removed, creating an avalanche of shot coke.
- **Platform removal/falling hazard** - Some DCUs require the removal of platform sections to accommodate unheading the bottom of the drum. This can introduce a falling hazard.

Coke Cutting (Hydroblasting Operation)

Coke-cutting or -hydroblasting involves lowering from an overhead gantry a rotating cutter that uses high pressure (2000 to 5000 psig) water jets. The cutter is first set to drill a bore hole through the coke bed. It is then reset to cut the coke away from the drum interior walls. Workers around the gantry and top head can be exposed to serious physical hazards, and serious incidents have occurred in connection with hydroblasting operations. Some of the most frequent and/or severe hazards are described below:

- If the system is not shut off before the cutting nozzle is raised out of the top drum opening, a high pressure water jet can be exposed and seriously injure, even dismember a nearby worker.
- Fugitive mists and vapors from the cutting and the quench water can contain contaminants that pose a health hazard (see section on Toxic Exposures, Dust Irritants and Burn Trauma, below).
- The water hose can burst while under high pressure, resulting in whipping action that can seriously injure nearby workers.
- The wire rope supporting the drill stem and water hose can fail (part), allowing the drill stem, water hose, and wire rope to fall onto work areas.
- Gantry damage can occur, exposing workers to falling structural members and equipment.

Emergency and General Operational Hazards

Coke Transfer, Processing, and Storage

The following coke conveyance, processing, and storage operations have presented safety and health hazards for DCU workers:

- The repositioning of rail cars by small locomotives or cable tuggers to receive coke being cut from a drum can create physical hazards for workers in the rail car movement area.
- Mechanical conveyors and coke crushers may contain exposed moving parts that can cause fracture or crush type injuries at pinch points.
- Fires are common in coke piles and rail cars. Large chunks of coke can contain pockets of unquenched material at temperatures well above the ignition point. When fractured and exposed to air, this material can ignite. Fires have also been attributed, although less frequently, to reactions that lead to spontaneous combustion.
- Combustion products and/or oxygen depletion resulting from spontaneous fires can create hazardous conditions for workers in confined spaces.
- Wet coke in an enclosed area has been reported to have absorbed oxygen from the surrounding air under certain circumstances. This can make the area oxygen deficient and cause asphyxiation.

Emergency Evacuation

The delayed coking process is very labor intensive. Each batch process cycle requires 25 or more manual operations (valve, winch operation, drum heading, etc.), and many DCUs operate with three or more sets of drums. Tasks are performed at several levels on the coke drum structure. The upper working platform (frequently called the "cutting deck") is generally well over 120 feet above ground. During an emergency, evacuation from the structure can be difficult.

In addition, moisture escaping from drum openings during cold weather can produce fog. This can obscure vision and make walkways, and hand rails wet and slippery, creating additional difficulties during emergency evacuation.

Toxic Exposures, Dust Irritants, and Burn Trauma

DCU workers can be exposed to coke dust and toxic substances in gases and process water around DCU operations. Workers can also be exposed to physical stress and other hazardous conditions. The following exposures to toxic substances, irritants, and hazardous conditions have been associated with DCU operations, in general:

- Hot water, steam, and liquid hydrocarbon (black oil) can escape from a coke drum and cause serious burn trauma. Contact with black oil can cause second or third degree burns. In addition, liquid hydrocarbon escaped from a coke drum can be well above its ignition temperature, presenting a fire hazard.
- Heat stress can be a health hazard during warm weather, particularly for those required to wear protective clothing while performing tasks on the coke drum structure.
- Hazardous gases associated with coking operations, such as hydrogen sulfide, carbon monoxide, and trace amounts of polynuclear aromatics (PNAs), can be emitted from the coke

through an opened drum or during processing operations.

- If allowed to accumulate and become airborne, dust around a DCU may exceed acceptable exposure limits and become a hazard.

Controlling the Hazards

Evaluating hazardous conditions, modifying operations to control hazards, actively maintaining an effective emergency response program, and familiarizing workers about risks and emergency procedures will help reduce the frequency and severity of serious incidents associated with DCU operations.

Specific Operation Hazards

Coke Drum Switching

No one system has proven effective in eliminating all incidents associated with incorrect valve activation due to mistaken coke drum or module identification; however, the following actions have been reported as beneficial:

- Conduct human factors analyses to identify, evaluate, and address potential operator actions that could compromise the safe operation of the coke drum system.
- Provide interlocks for automated or remotely activated valve switching systems.
- Provide interlocks for valves that are manually operated as part of the switching/decoking cycle to avoid unanticipated valve movement.
- Color code and clearly label valves and control points to guard against incorrect identification.
- Provide indicator lights at valve and valve control stations to help the operator determine which is the correct valve station for the intended operator action.
- Use the "buddy system" (employees working in pairs) to help verify accurate valve or switch identification.
- Conduct periodic and documented training focusing on the importance of activating the correct valve or switch and the consequence of incorrect activation.

Coke Drum Head Removal

It can be difficult to anticipate the presence of either a hot spot or a hot tar ball in the coke drum prior to drum head removal. In light of this possibility and the potential for serious incidents, it is prudent to:

- Be alert to any operating abnormalities or variations during charging, steaming, or quenching that may forewarn a hot spot or tar ball. Have a contingency plan to deal with such issues before proceeding with coke drum head removal and coke cutting.
- Always assume the possibility of a hot-spot induced geyser or the release of hot tar balls or undrained hot water, and incorporate protective operational measures in drum unheading operations. Further control the hazard by establishing restricted areas; minimizing the number of workers in restricted areas; minimizing the time spent by essential workers in restricted areas; and maintaining readiness for a rapid evacuation.
- Consider equipment upgrades to further control the hazards associated with geysers and release of hot tar balls and undrained hot water during drum head removal, such as installing protective shrouds and automating both top and bottom head removal operations to keep workers away from these unprotected areas.
- Consider emergency steam/cooling water sources in the event of loss of primary steam/cooling water supply or because of drum inlet flow path obstruction.
- Provide temporary guardrails to prevent employees from falling while platform plating is removed for bottom head removal.
- Consider installation of vapor ejectors to draw vapors away from the open top head area.

Coke Cutting (Hydroblasting Operation)

The following actions could help control hazards associated with coke cutting operations:

- Install an enclosed cutter's shack for worker protection--preferably supplied with air from a remote source to maintain slight positive pressure.

- Ensure that personnel who must be on the coke drum structure when a drum is open wear prescribed personal protective equipment.

- Conduct training in recognition and prevention of worker heat stress.

- Make sure the interlocks will work to shut off and prevent restart of the cutting water pump any time that the cutting head is raised above a predetermined point within the coke drum. Consider installing redundant switches to provide an additional level of protection against extracting a cutting head that is under pressure.

- Verify the adequacy of the inspection and maintenance program for cutting water hoses, wire ropes, and hoists.

- Establish a gantry structure inspection and maintenance program. Periodically verify that gantry structures have not been weakened due to corrosive conditions, such as mist exiting from the top nozzle, that could lead to gantry collapse.

- Install drill stem free fall arresters.

Emergency and General Operational Hazards

Coke Transfer, Processing, and Storage

The following actions could help control hazards associated with coke conveyance, processing, and storage operations:

- Establish and enforce restricted areas (e.g., areas where heavy equipment movement and possible lash path of a wire rope from failed equipment may occur) to prevent personnel entry and, ultimately, injury.

- Establish and periodically verify the operability of an alarm system that activates immediately before and during heavy equipment (rail car, bridge crane, or conveyor) movement.

- Verify conformance with a safe entry permit system to ensure that appropriate measures are taken prior to and during entry into any enclosed area or vessel where coke may be present.

- Establish personnel protective measures to protect against inhalation or personal contact with coke dust or potentially contaminated mists from water used for cutting, quench, or coke conveyance (see section on Toxic Exposures, Dust Irritants, and Burn Trauma, below).

Emergency Evacuation - Preparations and Procedures

Despite best efforts to prevent incidents, DCU operators should anticipate the need for emergency evacuation and other response measures, operate in a manner that will minimize the severity of an incident, and prepare for and implement emergency procedures to protect worker safety.

The following specific actions are recommended:

- Review and address weaknesses associated with the location and suitability of emergency escape routes. Protected stairways, preferably detached from the coke drum structure, are the most effective conventional means of emergency escape route (egress) from tall structures, such as those serving the coke drums. Consider installing horizontal walkways to adjacent structures. Some refineries are exploring the use of commercially available escape chutes. Also, slip resistant walking surfaces will help prevent falling during an emergency evacuation.

- Establish or verify the operability of an evacuation signal (Scram Alarm) to expedite personnel clearing the structure in the event of an emergency. Alarm signal actuation (triggering) stations should be deployed at work areas and along the escape routes.

- Install water sprays to protect work stations and emergency escape routes. Include activation stations at work stations and along the escape route.

- Provide heat shields to protect work stations and escape routes. Ensure that the shield will not interfere with evacuation and will not entrap fugitive vapors.

- Conduct regular emergency exercises to test the plan as well as to ensure familiarity with emergency signals, evacuation routes, and procedures.

Toxic Exposures, Dust Irritants, and Burn Trauma

The following actions could help control exposures to toxic substances, irritants, physical stress, and hazardous conditions associated with DCU operations, in general:

- Configure coke drum inlets and outlets with doubleblock valve and steam seal isolation to reduce the likelihood of unanticipated leakage.
- Establish burn trauma response procedures, including procedures for interacting with emergency medical service providers and the burn trauma center that would be used in the event of a burn incident.
- Conduct burn trauma simulation exercises to ensure appropriate use of the emergency response procedures and the training level of relevant personnel.
- Evaluate health exposure potential and establish appropriate protective measures based on an industrial hygiene survey plan that anticipates variations in the range of DCU feed stocks and operating conditions.
- Shovel, sweep, vacuum, and provide proper ventilation to keep exposures to dust around a DCU to within acceptable limits.

Information Resources

Internet resources - The search entry, "Delayed Coker Unit," yields many sources of information that are believed to be useful. However, neither EPA nor OSHA control this information and cannot guarantee the accuracy, relevance, timeliness or completeness of all facets of the information.

Further, the citation to these resources is not intended to endorse any views expressed, or services offered by the author of the reference or the organization operating the service identified by the reference. The following are examples of informative additional reading.

- **http://www.coking.com** - focuses on coking best practices, safety, reliability, and communications within the DCU industry.
- **http://www.fireworld.com/magazine/coker.html** – describes a May 1999 coking unit fire and offers recommendations on fire protection.

For More Information:

Contact EPA's RCRA Superfund & EPCRA Call Center

(800) 424-9346 or (703) 412-9810
TDD (800) 553-7672

Monday-Friday, 9 AM to 5 PM, Eastern Time

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EXHIBIT U

Bureau of Air Home Page

Governor Blagojevich Launches Global Warming Initiative

In 2006 Governor Blagojevich announced a new global warming initiative that will build on Illinois' role as a national leader in protecting the environment and public health. The announcement marked the beginning of a long-term strategy by the state to combat global climate change, and builds on the steps the state has already taken to reduce greenhouse gas (GHG) emissions, such as enhancing the use of wind power, biofuels and energy efficiency.

Executive Order 2006-11 signed by the Governor Blagojevich creates the Illinois Climate Change Advisory Group, which will consider a full range of policies and strategies to reduce GHG emissions in Illinois and make recommendations to the Governor. The Advisory Group has broad representation including business leaders, labor unions, the energy and agricultural industries, scientists, and environmental groups from throughout the state. The Governor named Doug Scott, Director of the Illinois Environmental Protection Agency, as Chair of the Advisory Group.

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EXHIBIT V

2006-11

EXECUTIVE ORDER ON CLIMATE CHANGE AND GREENHOUSE GAS REDUCTION

WHEREAS, the
consensus is that increasing emissions of greenhouse gases are causing global temperatures to rise at rates that could cause worldwide economic disruption, environmental damage and public health crises;

WHEREAS, global warming is largely due to the combustion of fossil fuels that release carbon dioxide and other greenhouse gases that trap heat in the atmosphere;

WHEREAS, the Intergovernmental Panel on Climate Change and the National Academy of Sciences have reported that atmospheric carbon dioxide is at the highest level in more than 500,000 years;

WHEREAS, average global temperatures were the hottest on record ten of the past sixteen years. Scientists have predicted that temperatures in Illinois could rise significantly by the end of this century, leading to hotter summers, shorter winters, and increased drought and flood events;

WHEREAS, these effects could strain drinking water supplies, overwhelm sewage treatment capacity, reduce the water level of Lake Michigan, destroy wetlands, erode soil, and harm croplands, ecosystems and habitats, among other damaging effects;

WHEREAS, leading climatologists have estimated that less than a decade remains before global warming could be irreversible and that governments, businesses and households must act now to reduce greenhouse gas emissions;

WHEREAS, 165 countries and other entities around the world have signed the Kyoto protocol in recognition of the urgency in acting to reduce greenhouse gas emissions;

WHEREAS, many business leaders, including large manufacturing and insurance companies worldwide, have recognized the need to reduce greenhouse gas emissions;

WHEREAS, the United States government has failed to sign the Kyoto protocol or to enact policies to reduce national greenhouse gas emissions;

WHEREAS, this lack of federal leadership leaves the United States, the world's largest emitter of greenhouse gases, without an effective national strategy to address the threat of global climate change, that includes rising sea levels, droughts, flooding, severe weather events, the expansion of diseases and invasive species, and economic dislocation;

WHEREAS, the State of Illinois recognizes that states can play an integral role in adopting policies to address climate change and promote strategies to reduce greenhouse gases while advancing technologies to develop clean, renewable and homegrown energy resources:

WHEREAS, Illinois is one of the leading states in a multi-state effort to develop a national greenhouse gas registry that businesses and other entities can use to measure and manage greenhouse gas emissions;

WHEREAS, many clean energy and energy efficiency policies that reduce emissions of greenhouse gases can also boost economic development, create jobs, stabilize energy prices, improve air quality, and reduce traffic congestion, among other benefits; and

WHEREAS, Illinois' leadership in the development of state and regional climate change policies will ensure that Illinois businesses and other institutions will be well prepared to adapt to any national climate change policy.

NOW THEREFORE, I, ROD BLAGOJEVICH, Governor of the State of Illinois, by virtue of the power and authority vested in me by the Constitution and the laws of the State of Illinois do hereby order:

I. Creation of the Illinois Climate Change Advisory Group

(a) There is created the Illinois Climate Change Advisory Group ("the Advisory Group"). The purpose of the Advisory Group is to provide recommendations to the Office of the Governor regarding climate change policy.

(b) The Advisory Group shall consist of individuals appointed by the Governor and shall be chaired by the Director of the Illinois Environmental Protection Agency. The Advisory Group will include representatives from business, labor unions, environmental groups, agriculture, the energy sector, as well as scientists and economists from throughout Illinois.

(c) Members of the Advisory Group shall serve at the pleasure of the Governor and shall meet regularly to accomplish the goals of the Advisory Group. The members shall serve without compensation. The chairperson may convene the Advisory Group at any time.

(d) A vacancy in the membership of the Advisory Group shall not impair the right of a quorum to exercise all the rights and perform all the duties of the Advisory Group. A majority of Advisory Group members then appointed constitutes a quorum. A majority vote of the quorum is required for a Advisory Group decision.

(e) The Illinois Environmental Protection Agency shall provide necessary staff assistance to the Advisory Group.

II. Duties of the Illinois Climate Change Advisory Group

(a) The Advisory Group shall, after fully considering the full range of policies and strategies regarding climate change, present proposals to the Governor to reduce statewide greenhouse gas emissions.

(b) The Advisory Group shall present its findings and recommendations, including an inventory of existing and planned actions to reduce greenhouse gas emissions, to the Governor by June 30, 2007.

III. Membership in the Chicago Climate Exchange

It is the intent for the State of Illinois to join Chicago Climate Exchange (CCX), a greenhouse gas emissions registry, reduction and trading system, to reduce emissions from governmental activities by 6% by 2010. The Illinois Environmental Protection Agency shall review all terms associated the efficiency of state government operations.

IV. **Reporting Requirements**

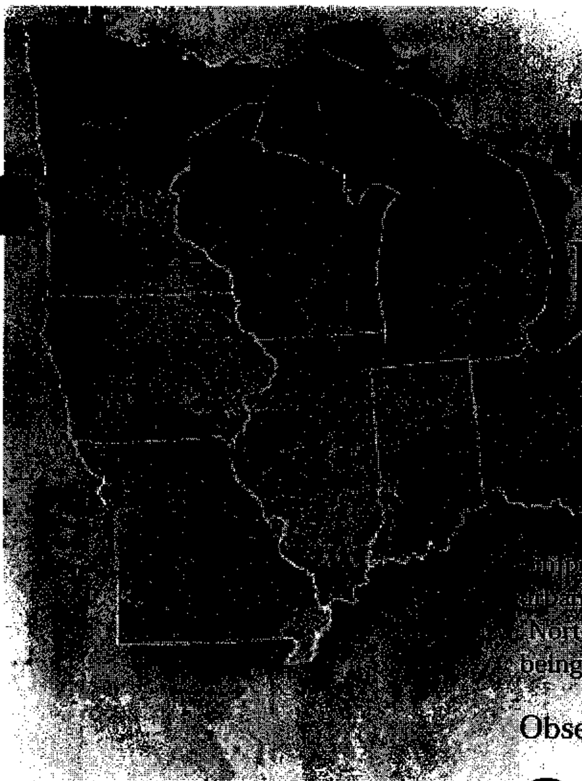
The Illinois Environmental Protection Agency shall produce an annual report to the Governor at the end of each fiscal year tracking statewide greenhouse gas emissions in Illinois and forecasted trends. Additionally, the Illinois Environmental Protection Agency shall annually document the greenhouse gas emissions of State government, and track progress towards meeting the CCX reduction targets.

This Executive Order shall take effect immediately upon filing with the Secretary of State.

ROD R. BLAGOJEVICH
Governor

Issued by Governor: October 5, 2006
Filed with Secretary of State: October 5, 2006

EXHIBIT W



MIDWEST

Farming, manufacturing, and forestry characterize the Midwest. The Great Lakes form the world's largest freshwater lake system, providing a major recreation area as well as a regional water transportation system with access to the Atlantic Ocean via the St. Lawrence Seaway. The region encompasses the headwaters and upper basin of the Mississippi River and most of the length of the Ohio River, both critical water sources and means of industrial transportation providing an outlet to the Gulf of Mexico. The Midwest contains some of the richest farmland in the world and produces most of the Nation's corn and soybeans. It also has important metropolitan centers, including Chicago and Detroit. Most of the largest urban areas in the region are found along the Great Lakes and major rivers. The "North Woods" are a large source of forestry products and have the advantage of being situated near the Great Lakes, providing for easy transportation.

Observed Climate Trends

Over the 20th century, the northern portion of the Midwest, including the upper Great Lakes, has warmed by almost 4°F (2°C), while the southern portion, along the Ohio River valley, has cooled by about 1°F (0.5°C). Annual precipitation has increased, with many of the changes quite substantial, including as much as 10 to 20% increases over the 20th century. Much of the precipitation has resulted from an increased rise in the number of days with heavy and very heavy precipitation events. There have been moderate to very large increases in the number of days with excessive moisture in the eastern portion of the basin.

KEY ISSUES

- Reduction in Lake and River Levels
- Health and Quality of Life in Urban Areas
- Agricultural Shifts
- Changes in Semi-natural and Natural Ecosystems

Scenarios of Future Climate

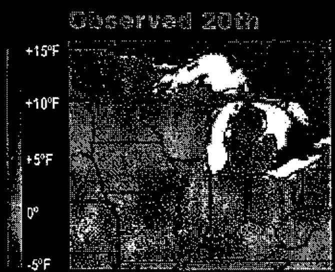
During the 21st century, models project that temperatures will increase throughout the Midwest, and at a greater rate than has been observed in the 20th century. Even over the northern portion of the region, where warming has been the largest, an accelerated warming trend is projected for the 21st century, with temperatures increasing by 5 to 10°F (3 to 6°C). The average minimum temperature is likely to increase as much as 1 to 2°F (0.5 to 1°C) more than the maximum temperature. Precipitation is likely to continue its upward trend, at a slightly accelerated rate; 10 to 30% increases are projected across much of the region. Despite the increases in precipitation, increases in temperature and other meteorological factors are likely to lead to a substantial increase in evaporation, causing a soil moisture deficit, reduction in lake and river levels, and more drought-like conditions in much of the region. In addition, increases in the proportion of precipitation coming from heavy and extreme precipitation are very likely.

Climate Extremes Create Critical Transportation Problems

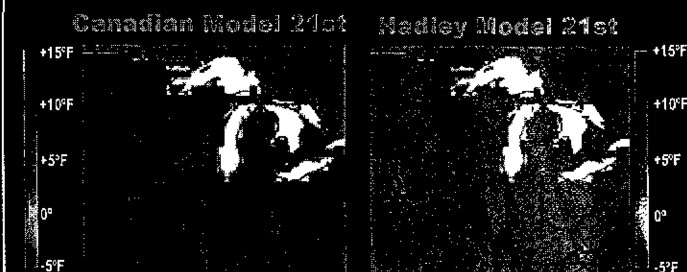
Climate extremes in the Midwest can drastically impede the highly weather-sensitive transportation systems that serve not only the region, but the entire nation. Chicago is the nation's rail hub handling much of the nation freight traffic. Barges operating on the Mississippi River system, that includes the Ohio, Illinois, and Missouri Rivers, handle a large fraction of the country's bulk commodities, such as grain and coal. Prolonged heavy rainfall in the spring and summer of 1993 produced extensive flooding across nine states in the upper Midwest. The flood waters poured over and through many levees and inundated numerous floodplains that many of the key rail lines cross. The flood waters became an

An accelerated warming trend is projected for the 21st century, with temperatures increasing by 5 to 10°F (3 to 6°C). Precipitation is likely to continue its upward trend, at a slightly accelerated rate; 10 to 30% increases are projected across much of the region.

Temperature Change - 20th & 21st Centuries

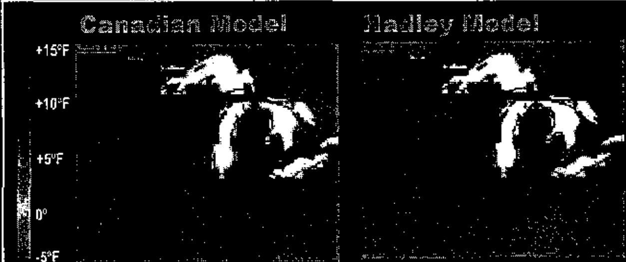


Temperatures in the Midwest have increased, with the largest observed changes for the region in Minnesota and the Upper Peninsula of Michigan. Model scenarios suggest further increases over the 21st century from near 5°F (Hadley model) to more than 10°F (Canadian model).



Winter Minimum Temperature Change

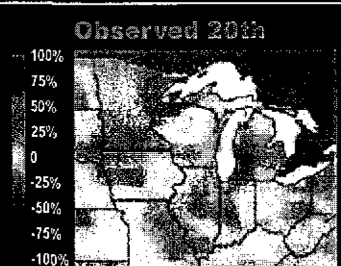
21st Century Average

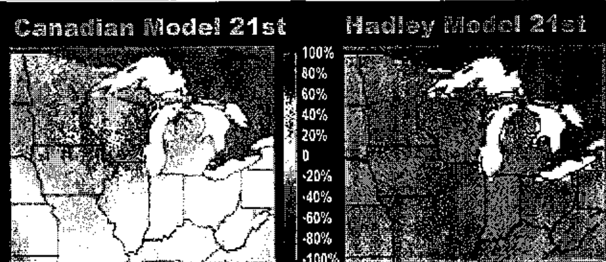


Both climate models indicate that the northern part of the Midwest will experience the largest increases in winter temperatures. The Canadian Model suggests the greatest increases, approaching 15°F in Minnesota and the Upper Peninsula of Michigan.

Precipitation Change - 20th & 21st Centuries

On average, Midwest precipitation over the 20th century has increased.

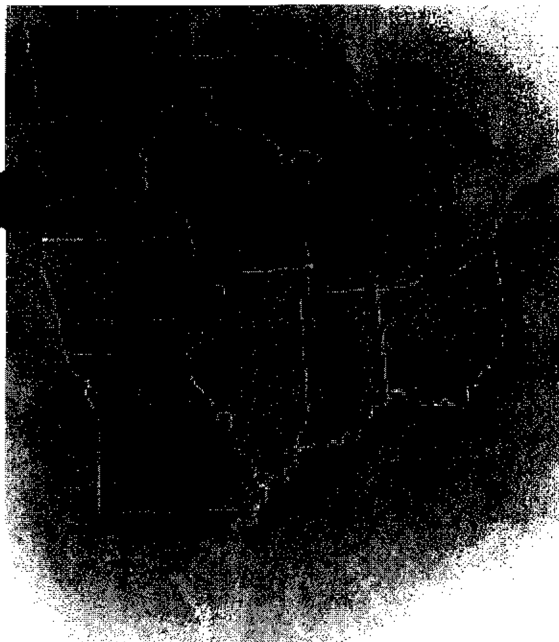




The Hadley model indicates that this trend will continue, resulting in increases of about 25% from the present. The Canadian model suggests that these increases will be confined to the northern and western parts of the region.

absolute barrier to surface transportation in the region for more than six weeks. Train traffic had to be rerouted around the flood area, resulting in long delays and large costs to manufacturing. River barge traffic suffered a similar fate with the additional costs to shipping and manufacturing approaching $2 billion.

This came on the heels of the 1988 drought that also had a major impact on barge shipping due to low river levels, illustrating the sensitivity of transportation systems to both wet and dry climate extremes.



MIDWEST KEY ISSUES

Reduction in Lake and River Levels

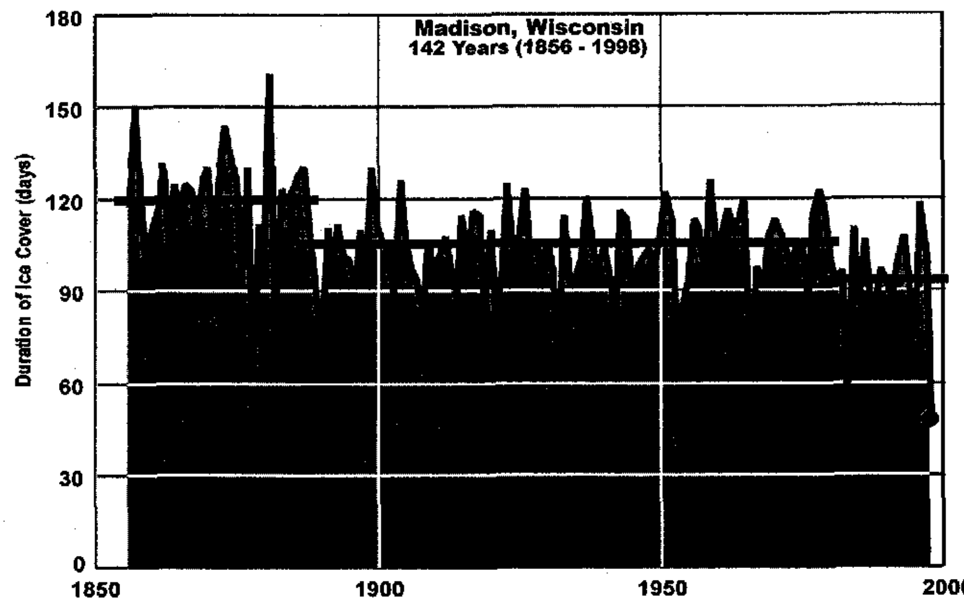
The projected increase in very heavy precipitation events will likely worsen agricultural and other non-point source pollution as more frequent heavy rains wash pollutants into rivers and lakes.

Lower water levels are likely to make water-based transportation more difficult with increases in the costs of navigation of 5 to 40%.

Water levels,supply, quality, and water-based transportation and recreation are all climate-sensitive issues affecting the region. Despite the projected increase in precipitation,increased evaporation due to higher summer air temperatures is likely to lead to reduced levels in the Great Lakes.Of 12 models used to assess this question,11 suggest significant decreases in lake levels while one suggests a small increase. The total range of the 11 models' projections is less than a one-foot increase to more than a five-foot decrease. A five-foot (1.5-meter) reduction would lead to a 20 to 40% reduction in outflow to the St. Lawrence Seaway. Lower lake levels cause reduced hydropower generation downstream,with reductions of up to 15% by 2050. An increase in demand for water across the region at the same time as net flows decrease is of particular concern. There is a possibility of increased national and international tension related to increased pressure for water diversions from the Lakes as demands for water increase. For smaller lakes and rivers, reduced flows are likely to cause water quality issues to become more acute. In addition,the projected increase in very heavy precipitation events will likely lead to increased flash flooding and worsen agricultural and other non-point source pollution as more frequent heavy rains wash pollutants into rivers and lakes. Lower water levels are likely to make water-based transportation more difficult with increases in the costs of navigation of 5 to 40%. Some of this increase will likely be offset as reduced ice cover extends the navigation season. Shoreline damage due to high lake levels is likely to decrease 40 to 80% due to reduced water levels.

Adaptations: A reduction in lake and river levels would require adaptations such as re-engineering of ship docks and locks for transportation and recreation. If flows decrease while demand increases,international commissions focusing on Great Lakes water issues are likely to become even more important in the future.Improved forecasts and warnings of extreme precipitation events could help reduce some related impacts.

Lake Ice Duration at Lake Mendota



Lake ice duration has decreased by nearly one month over the past 150 years, with a record low in the winter of 1997-98. This is consistent with observed increases in temperature.

Health and Quality of Life in Urban Areas

A reduction in extremely low temperatures and an increase in extremely high temperatures are expected. Thus,a reduced risk of life-threatening cold and an increased risk of life-threatening heat are likely to accompany warming. Reduced expenditures on snow and ice removal and fewer snow and ice related accidents and delays are likely. During the summer, however, in cities,heat-related stresses are very likely to be exacerbated by the urban heat island effect,a phenomenon in which cities remain much warmer than surrounding rural areas. This elevates nighttime temperatures,and in combination with the greater expected rise of nighttime temperatures compared to those of daytime,there will be less relief at night during heat waves. Elevated nighttime temperatures were a notable characteristic of the 1995 heat wave that resulted in over 700 deaths in Chicago. In addition,during heat waves in the Midwest, air pollutants are trapped near the surface,as atmospheric ventilation is reduced. Without strict attention to regional emissions of air pollutants,the undesirable combination of extreme heat and unhealthy air quality is likely to result. There is also a possibility of an increased risk of water-borne diseases with increases in extreme precipitation events,and increased insect- or tick-borne diseases,such as St.Louis encephalitis. Recreational activities will very likely shift as cold-season recreation such as skiing,snowmobiling,ice skating, and ice-fishing,are reduced,and warm-season recreation such as swimming,hiking,and golf, are expanded,although during mid-summer, these activities are likely to be affected by excessive heat.

During the summer, in cities, heat-related stresses are very likely to be exacerbated by the urban heat island effect, a phenomenon in which cities remain much warmer than surrounding rural areas.

Elevated nighttime temperatures were a notable characteristic of the 1995 heat wave that resulted in over 700 deaths in Chicago.

Adaptations: Active responses,such as those taken by Chicago during the 1999 heat wave,are likely to help reduce the death toll due to extreme heat. Separate storm water and sewer lines and other appropriate preventative measures can help mitigate the possible increased risk of water-borne diseases.

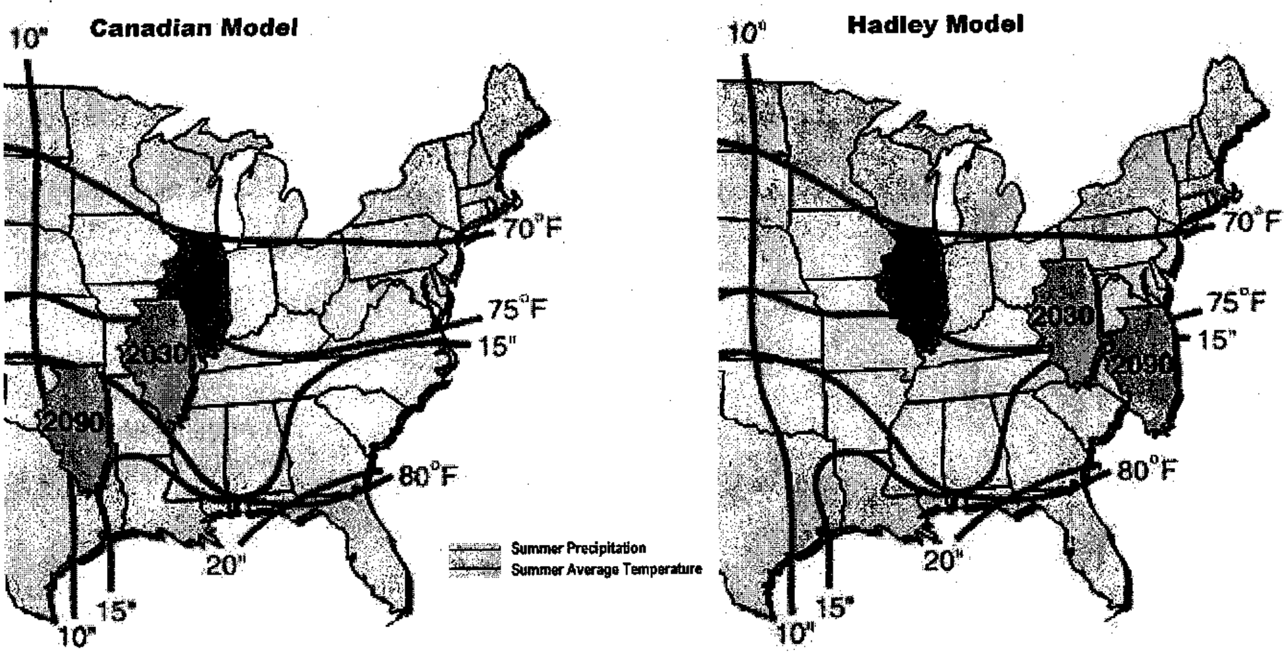


Illustration of how the summer climate of Illinois would shift under the Canadian and Hadley model scenarios. Under the Canadian scenario, the summer climate of Illinois would become more like the current climate of southern Missouri in 2030 and more like Oklahoma's current climate in 2090. The primary difference in the resulting climates of the two models relates to the amount of summer rainfall.

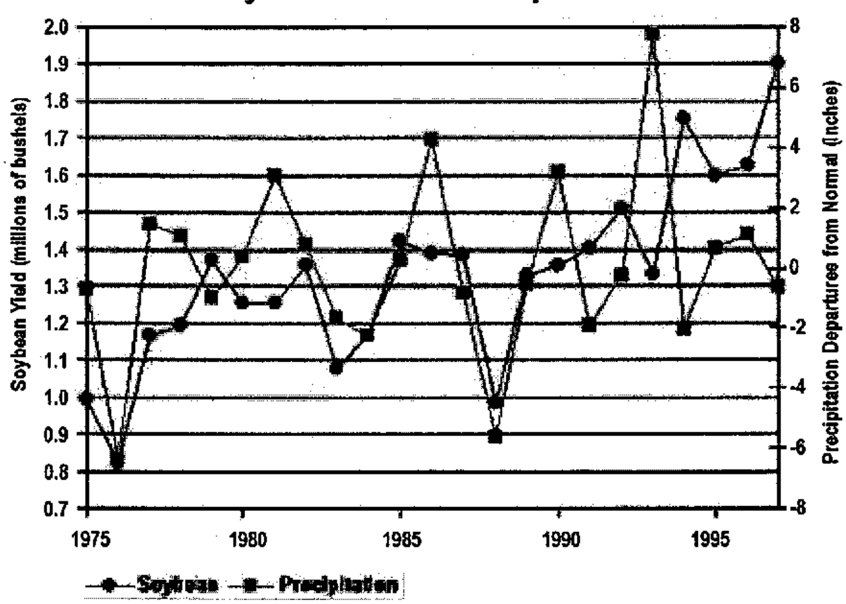
MIDWEST KEY ISSUES

Agriculture is of vital importance to this region,the nation,and the world. It has exhibited a capacity to adapt to moderate differences in growing season climate,and it is likely that agriculture would be able to continue to adapt. With an increase in the length of the growing season, double cropping,the practice of planting a second crop after the first is harvested,is likely to become more prevalent. The CO_2 fertilization effect is likely to enhance plant growth and contribute to generally higher yields. The largest increases are projected to occur in the northern areas of the region,where crop yields are currently temperature limited. However, yields are not likely to increase in all parts of the region. For example,in the southern portions of Indiana and Illinois,corn yields are likely to decline,with 10-20% decreases projected in some locations. Consumers are likely to pay lower prices due to generally increased yields,while most producers are likely to suffer reduced profits due to declining prices. Increased use of pesticides and herbicides are very likely to be required and to present new challenges.

Adaptations: Plant breeding programs can use skilled climate predictions to aid in breeding new varieties for the new growing conditions. Farmers can then choose varieties that are better attuned to the expected climate. It is likely that plant breeders will need to use all the tools of plant breeding,including genetic engineering,in adapting to climate change.Changing planting and harvest dates and planting densities,and using integrated pest management, conservation tillage,and new farm technologies are additional options. There is also the potential for shifting or expanding the area where certain crops are grown if climate conditions become more favorable. Weather conditions during the growing season are the primary factor in year-to-year differences in corn and soybean yields. Droughts and floods result in large yield reductions;severe droughts,like the drought of 1988, cause yield reductions of over 30%. Reliable seasonal forecasts are likely to help farmers adjust their practices from year to year to respond to such events.

Farm flooded by Mississippi river in 1993.

Midwest Soybean Yield and Precipitation



The relationship between Midwest soybean yield and precipitation is shown here. Soybean yields in thousands of bushels are shown as the differences from the average yield in recent decades. Precipitation is the difference from the 1961-90 average precipitation. Note that lower yields result from both extreme wet and extreme dry conditions.

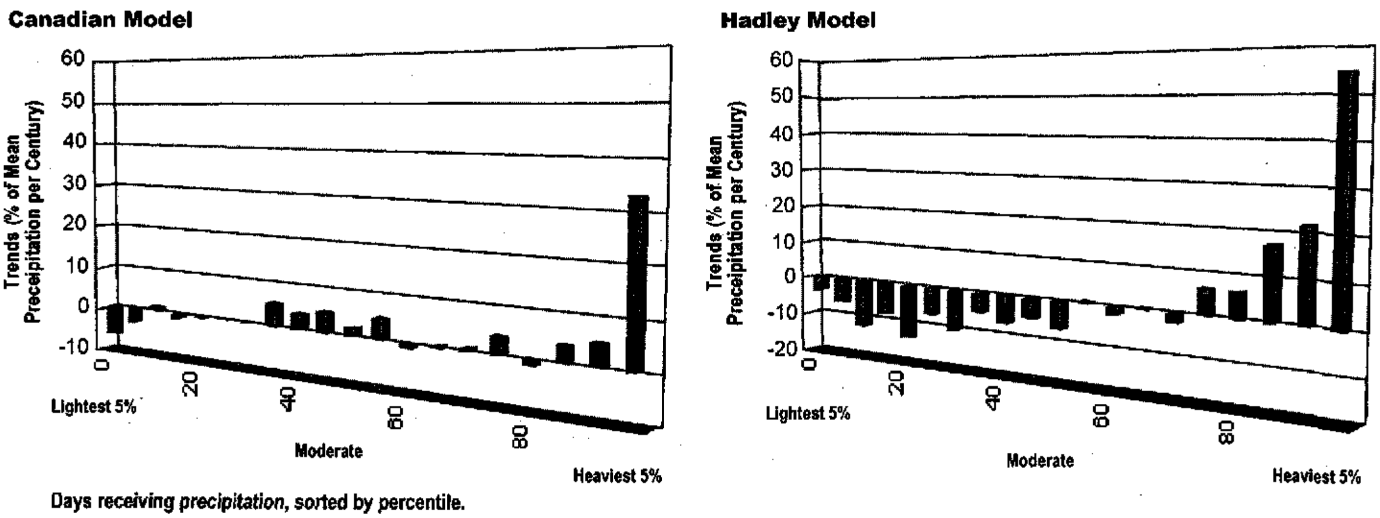
Changes in Semi-natural and Natural Ecosystems

The upper Midwest has a unique combination of soil and climate that allows for abundant coniferous tree growth. Higher temperatures and increased evaporation will likely reduce boreal forest acreage,and make current forestlands more susceptible to pests and diseases. It is likely that the southern transition zone of the boreal forest will be susceptible to expansion of temperate forests, which in turn will have to compete with other land use pressures. However, warmer weather (coupled with beneficial effects of increased CO_2),are likely to lead to an increase in tree growth rates on marginal forestlands that are currently temperature-limited. Most climate models indicate that higher air temperatures will cause greater evaporation and hence reduced soil moisture, a situation conducive to forest fires. As the 21st century progresses,there will be an increased likelihood of greater environmental stress on both deciduous and coniferous trees,making them susceptible to disease and pest infestation,likely resulting in increased tree mortality.

As water temperatures in lakes increase,major changes in freshwater ecosystems will very likely occur, such as a shift from cold water fish species,such as trout,to warmer water species,such as bass and catfish. Warmer water is also likely to create an environment more susceptible to invasions by non-native species. Runoff of excess nutrients (such as nitrogen and phosphorus from fertilizer) into lakes and rivers is likely to increase due to the increase in heavy precipitation events. This, coupled with warmer lake temperatures,is likely to stimulate the growth of algae,depleting the water of oxygen to the detriment of other living things. Declining lake levels are likely to cause large impacts to the current distribution of wetlands. There is some chance that some wetlands could gradually migrate,but in areas where their migration is limited by the topography, they would disappear. Changes in bird populations and other native wildlife have already been linked to increasing temperatures and more changes are likely in the future. Wildlife populations are particularly susceptible to climate extremes due to the effects of drought on their food sources.

Runoff of excess nutrients (such as nitrogen and phosphorus from fertilizer) into lakes and rivers is likely to increase due to the increase in heavy precipitation events.

Projected Midwest Daily Precipitation
21st Century



Days receiving precipitation, sorted by percentile.

Annual trends in daily precipitation by percentile for the Canadian and Hadley model scenarios for the 21st century. Notice the largest trend is in the heaviest daily precipitation amount for both model simulations, indicating that most of the projected increase in annual precipitation will be due to an increase in precipitation on days already receiving large amounts.

EXHIBIT X

ConocoPhillips: The anti-Exxon

The Texas-based oil company breaks with the other U.S. majors to support mandatory national regulation of greenhouse gas emissions, reports Fortune's Marc Gunther.

By Marc Gunther, Fortune senior writer
April 11 2007: 9:20 AM EDT

FORTUNE Magazine

NEW YORK (Fortune) -- Here's yet another sign that the debate over climate change has shifted decisively: ConocoPhillips today becomes the first U.S.-based oil company to support mandatory national regulation of greenhouse gas emissions.

In so doing, ConocoPhillips breaks ranks with the two biggest U.S. oil companies - ExxonMobil (Charts) and Chevron (Charts) - as well as with the Bush administration. With revenues of $188 billion in 2006, ConocoPhillips (Charts) operates in 40 nations around the world from its headquarters in Bush country - Houston, Texas.

James J. Mulva, the chairman and chief executive of ConocoPhillips, announced the change at a meeting with reporters in Washington, where congressional hearings or industry forums on climate issues are happening almost daily. It's become almost impossible for big companies to stay out of the fray.

mulva_conocophillips.03.jpg

James J. Mulva, chairman and chief executive of ConocoPhillips

Mulva said no particular event caused ConocoPhillips to step forward. "We believe that the science is quite compelling," he said. "Human activity, including the burning of fossil fuels, is contributing to climate change. Now is the time we need a national mandated framework to deal with climate change."

He didn't endorse a specific regulatory regime. But ConocoPhillips has become the second major oil company - after BP America, a unit of British-based BP (Charts) - to join the U.S. Climate Action Partnership, an alliance of big companies and environmental organizations that support federal action to achieve "significant reductions" in greenhouse gas emissions caused by burning fossil fuels.

Other members of the coalition include GE (Charts), Dupont (Charts) and four big green groups - the World Resources Institute, Environmental Defense, the Natural Resources Defense Council and the Pew Center on Global Climate Change.

Unlike BP, which has tried to recast itself as a company that goes "beyond petroleum" by touting its (mostly small) investments in renewable energy, ConocoPhillips makes all of its money - about $15.5 billion last year - from producing, refining and selling oil, gas and petrochemicals.

That isn't likely to change anytime soon, Mulva said: "The old Conoco and the old Phillips have been oil companies for many, many years. We expect to be an oil company for a long time. Whatever we can produce, we sell. And our refineries are running at the max."

He did say that ConocoPhillips' investment in alternative and renewable energy would grow from about $100 million in 2006 to about $150 million this year. But the company defines alternatives broadly, to include the process of extracting oil from the sands of western Canada as well as efforts to develop cellulosic ethanol.

Last year, ConocoPhillips began producing renewable diesel fuel from vegetable oil and animal fats at a refinery in Ireland.

ConocoPhillips is such a newcomer to the climate debate that it has yet to even calculate its own carbon footprint. The company says it will set public targets for reducing its own greenhouse gas emissions later this year.

Low-key and publicity-shy, Mulva quietly acknowledged that regulation of carbon dioxide will impose added costs on the oil industry, and on consumers who buy gasoline, heating oil or natural gas.

Higher prices, he said, may be necessary to induce Americans to become more efficient users of energy. The U.S. has less than 5 percent of the world's population but consumes about 25 percent of the world's oil production.

10 green giants in business

After the press event, Mulva told me that he'd reflected personally on the issue of climate change for about a year or so; he travels about 180 days a year, and has heard government officials, environmental groups and scientists sounding alarms over the issue.

William K. Reilly, former administrator of the U.S. Environmental Protection Agency and a member of ConocoPhillips' board, was among those urging the company to act.

Now, Mulva said, there's no time to waste.

"Voluntary programs are not going to meet the challenge of climate change," Mulva said. "The longer we wait - two or five years or more from now - it won't be mitigation, it will be adaptation."

Yes, that's the CEO of a Texas-based oil company talking.

EXHIBIT Y

Excerpt:

CONOCOPHILLIPS RODEO REFINERY CLEAN FUELS EXPANSION PROJECT

Final Environmental Impact Report
SCH 2005092028
LP 052048

Volume 1 – Response to Comments

Contra Costa County
Community Development Department

April 2007

TABLE
CFEP TOTAL PROJECT ANNUAL CO_2 EMISSIONS (metric tons per year)

	CO_2[a]
Refinery Sources	
New Unit 240/246 HGO Feed Heater	47,284
New SRU (Unit 235)	10,013
Unit 240 B-1 Boiler Reductions[b]	-64,529
Increased Heater Utilization	69,536
Dissolved Air Flotation (DAF) Unit[c]	146
Railcar Emissions[d]	108
Truck and Commuter Auto Trips[e]	32
Total Refinery Emissions[f]	**62,590**
Hydrogen Plant Sources	
Hydrogen Plant Emission Increases	1,169,994
Total Direct Emissions From Project Sources	**1,232,585**
Indirect Electricity Emissions[g]	**15,849**

[a] The CO_2 emission factor is based on the average carbon content of the refinery fuel gas measured from fuel samples. This emission factor is comparable to the Higher Heating Value for other typical refinery fuels used provided in the API Compendium. Additionally, ConocoPhillips is a member of the Registry, so methodologies are consistent with the Registry General Reporting Protocol.
[b] The Unit 240 B-1 Boiler would be shut down.
[c] The DAF Unit emissions are due to the installation of a new thermal oxidizer that would control VOC emissions (a collateral benefit of the DAF emission control would be capture and destruction of methane emissions from the DAF process).
[d] CO_2 emissions from railcar trips are based on emission factors provided in the Registry General Protocol. Each railcar trip includes one trip with empty railcars and a return trip with full railcars.
[e] CO_2 emissions from truck and commuter auto trips were determined based on the Road Emission Factor Model (EMFAC 2002) developed by the California Air Resources Board and daily vehicle traffic in the refinery.
[f] Flaring may be necessary when the Hydrogen Plant or the New Unit 240/246 is shut down. The GHG emissions from flaring would be based on refinery fuel gas or natural gas feed that would be rerouted to the flare, or clean hydrogen product that would not have GHGs. Both the Hydrogen Plant furnace and the HGO Feed Heater emissions of GHGs in the above table have been calculated based on maximum design capacity and operation for 8,760 hours per year. Therefore, GHGs from fuel that would be rerouted to the flare during startups and shutdowns has already been addressed in the GHG calculations that are based on the capacity of the Hydrogen Plant and HGO heater. Calculating the amount of GHGs from the flare would be double counting.
[g] Indirect Electricity Emissions are calculated to represent the import of 5.5 MW for 24 hours a day and 365 days a year (peak use) from PG&E and emission factors provided by the Registry Protocol. The Registry stipulates that any organization that purchases electricity from an electric utility must report indirect emissions. These indirect emissions are reported separately to the Registry by the energy provider and should not be added with direct emissions. Adding them together would be considered double counting of emissions.

Carbon Dioxide

Emissions from the Air Liquide Hydrogen Plant - The vast majority of CO_2 emissions from the Proposed Project would be attributable to the Hydrogen Plant that would be constructed, owned, and operated by Air Liquide. The Hydrogen Plant, when operating at full capacity of 120 million standard cubic feet per day (SCFD), would generate approximately 1.17 million metric tons per year of CO_2.

Emissions from the ConocoPhillips Refinery - The remainder of the Proposed Project's CO_2 emissions would be 62,590 metric tons per year – including the 69,459 metric tons/year reduction of CO_2 emissions from the shutdown of the Unit 240 B-1 Boiler – that would be generated from ConocoPhillips' equipment.

EXHIBIT Z

Home > Basic Petroleum Statistics > Top U.S. Refineries

U.S. Refineries Operable Atmospheric Crude Oil Distillation Capacity (Barrels per Calendar Day)

as of January 1, 2006

Rank	COMPANY NAME	STATE	SITE	Barrels per Calendar Day
1	EXXONMOBIL REFINING & SUPPLY CO	Texas	BAYTOWN	562,500
2	EXXONMOBIL REFINING & SUPPLY CO	Louisiana	BATON ROUGE	501,000
3	BP PRODUCTS NORTH AMERICA INC	Texas	TEXAS CITY	437,000
4	CITGO PETROLEUM CORP	Louisiana	LAKE CHARLES	429,500
5	BP PRODUCTS NORTH AMERICA INC	Indiana	WHITING	410,000
6	EXXONMOBIL REFINING & SUPPLY CO	Texas	BEAUMONT	348,500
7	SUNOCO INC (R&M)	Pennsylvania	PHILADELPHIA	335,000
8	DEER PARK REFINING LTD PARTNERSHIP	Texas	DEER PARK	333,700
9	CHEVRON USA INC	Mississippi	PASCAGOULA	330,000
10	CONOCOPHILLIPS COMPANY	Illinois	WOOD RIVER	306,000
11	Flint Hills Resources LP	Texas	CORPUS CHRISTI	288,126
12	Motiva Enterprises LLC	Texas	PORT ARTHUR	285,000
13	Flint Hills Resources LP	Minnesota	SAINT PAUL	279,300
14	LYONDELL CITGO REFINING CO LTD	Texas	HOUSTON	270,200
15	BP West Coast Products LLC	California	LOS ANGELES	260,000
16	CHEVRON USA INC	California	EL SEGUNDO	260,000
17	PREMCOR REFINING GROUP INC	Texas	PORT ARTHUR	260,000
18	CONOCOPHILLIPS COMPANY	Louisiana	BELLE CHASSE	247,000
19	CONOCOPHILLIPS COMPANY	Texas	SWEENY	247,000
20	MARATHON PETROLEUM CO LLC	Louisiana	GARYVILLE	245,000
21	CHEVRON USA INC	California	RICHMOND	242,901
22	CONOCOPHILLIPS COMPANY	Louisiana	WESTLAKE	239,400
23	EXXONMOBIL REFINING & SUPPLY CO	Illinois	JOLIET	238,500
24	CONOCOPHILLIPS COMPANY	New Jersey	LINDEN	238,000
25	Motiva Enterprises LLC	Louisiana	CONVENT	235,000
26	TOTAL PETROCHEMICALS INC	Texas	PORT ARTHUR	232,000
27	Motiva Enterprises LLC	Louisiana	NORCO	226,500
28	BP West Coast Products LLC	Washington	FERNDALE (CHERRY POINT)	225,000
29	MARATHON PETROLEUM CO LLC	Kentucky	CATLETTSBURG	222,000
30	VALERO REFINING CO TEXAS	Texas	TEXAS CITY	213,750
31	FLINT HILLS RESOURCES ALASKA LLC	Alaska	NORTH POLE	210,000
32	CONOCOPHILLIPS COMPANY	Oklahoma	PONCA CITY	194,000

33	MARATHON PETROLEUM CO LLC	Illinois	ROBINSON	192,000
34	Chalmette Refining LLC	Louisiana	CHALMETTE	188,160
35	VALERO REFINING NEW ORLEANS LLC	Louisiana	NORCO	185,003
36	CONOCOPHILLIPS COMPANY	Pennsylvania	TRAINER	185,000
37	PREMCOR REFINING GROUP INC	Delaware	DELAWARE CITY	181,500
38	PREMCOR REFINING GROUP INC	Tennessee	MEMPHIS	180,000
39	SUNOCO INC	Pennsylvania	MARCUS HOOK	175,000
40	PDV Midwest Refining LLC	Illinois	LEMONT (CHICAGO)	167,000
41	TESORO REFINING & MARKETING CO	California	MARTINEZ	166,000
42	SUNOCO INC	Ohio	TOLEDO	160,000
43	VALERO REFINING CO NEW JERSEY	New Jersey	PAULSBORO	160,000
44	VALERO ENERGY CORPORATION	Texas	SUNRAY	158,327
45	CITGO REFINING & CHEMICAL INC	Texas	CORPUS CHRISTI	156,000
46	Shell Oil Products US	California	MARTINEZ	155,600
47	EXXONMOBIL REFINING & SUPPLY CO	California	TORRANCE	149,500
48	PREMCOR REFINING GROUP INC	Ohio	LIMA	146,900
49	CONOCOPHILLIPS COMPANY	Texas	BORGER	146,000
50	Shell Oil Products US	Washington	ANACORTES	145,000
51	SUNOCO INC	New Jersey	WESTVILLE	145,000
52	VALERO REFINING CO CALIFORNIA	California	BENICIA	144,000
53	VALERO REFINING CO TEXAS	Texas	CORPUS CHRISTI	142,000
54	CONOCOPHILLIPS COMPANY	California	WILMINGTON	139,000
55	BP PRODUCTS NORTH AMERICA INC	Ohio	TOLEDO	131,000
56	MURPHY OIL USA INC	Louisiana	MERAUX	120,000
57	Tesoro West Coast	Washington	ANACORTES	120,000
58	WESTERN REFINING COMPANY LP	Texas	EL PASO	116,000
59	COFFEYVILLE RESOURCES LLC	Kansas	COFFEYVILLE	112,000
60	FRONTIER EL DORADO REFINING CO	Kansas	EL DORADO	106,000
61	MARATHON PETROLEUM CO LLC	Michigan	DETROIT	100,000
62	PASADENA REFINING SYSTEMS INC	Texas	PASADENA	100,000
63	Shell Oil Products US	California	WILMINGTON	98,500
64	CONOCOPHILLIPS COMPANY	Washington	FERNDALE	96,000
65	TESORO HAWAII CORP	Hawaii	KAPOLEI	93,500
66	VALERO ENERGY CORPORATION	Texas	THREE RIVERS	90,000
67	SUNOCO INC	Oklahoma	TULSA	85,000
68	VALERO REFINING CO OKLAHOMA	Oklahoma	ARDMORE	83,640
69	VALERO REFINING CO TEXAS	Texas	HOUSTON	83,000
70	NCRA	Kansas	MCPHERSON	81,200
71	ULTRAMAR INC	California	WILMINGTON	80,887
72	CHEVRON USA INC	New Jersey	PERTH AMBOY	80,000
73	Shell Chem LP	Alabama	SARALAND	80,000

74	VALERO REFINING CO LOUISIANA	Louisiana	KROTZ SPRINGS	80,000
75	CONOCOPHILLIPS COMPANY	California	RODEO	76,000
76	NAVAJO REFINING CO	New Mexico	ARTESIA	75,000
77	MARATHON PETROLEUM CO LLC	Ohio	CANTON	73,000
78	MARATHON PETROLEUM CO LLC	Texas	TEXAS CITY	72,000
79	TESORO PETROLEUM CORP	Alaska	KENAI	72,000
80	SINCLAIR OIL CORP	Oklahoma	TULSA	70,300
81	LION OIL CO	Arkansas	EL DORADO	70,000
82	MARATHON PETROLEUM CO LLC	Minnesota	SAINT PAUL PARK	70,000
83	ALON USA ENERGY INC	Texas	BIG SPRING	67,000
84	BIG WEST OF CALIFORNIA	California	BAKERSFIELD	66,000
85	SINCLAIR OIL CORP	Wyoming	SINCLAIR	66,000
86	UNITED REFINING CO	Pennsylvania	WARREN	65,000
87	SUNCOR ENERGY (USA) INC	Colorado	COMMERCE CITY	62,000
88	EXXONMOBIL REFINING & SUPPLY CO	Montana	BILLINGS	60,000
89	GIANT YORKTOWN REFINING	Virginia	YORKTOWN	58,600
90	CONOCOPHILLIPS COMPANY	Montana	BILLINGS	58,000
91	DELEK REFINING LTD	Texas	TYLER	58,000
92	Tesoro West Coast	North Dakota	MANDAN	58,000
93	Tesoro West Coast	Utah	SALT LAKE CITY	58,000
94	PLACID REFINING CO	Louisiana	PORT ALLEN	56,000
95	Cenex Harvest States Coop	Montana	LAUREL	55,000
96	Shell Chem LP	Louisiana	SAINT ROSE	55,000
97	CHEVRON USA INC	Hawaii	HONOLULU	54,000
98	WYNNEWOOD REFINING CO	Oklahoma	WYNNEWOOD	54,000
99	PARAMOUNT PETROLEUM CORPORATION	California	PARAMOUNT	50,000
100	PETRO STAR INC	Alaska	VALDEZ	48,000
101	FRONTIER REFINING INC	Wyoming	CHEYENNE	47,000
102	CHEVRON USA INC	Utah	SALT LAKE CITY	45,000
103	CONOCOPHILLIPS COMPANY	California	ARROYO GRANDE	44,200
104	CALUMET SHREVEPORT LLC	Louisiana	SHREVEPORT	42,000
105	US OIL & REFINING CO	Washington	TACOMA	37,850
106	HUNT REFINING CO	Alabama	TUSCALOOSA	34,500
107	MURPHY OIL USA INC	Wisconsin	SUPERIOR	34,300
108	CITGO ASPHALT REFINING CO	New Jersey	PAULSBORO	32,000
109	SUNCOR ENERGY(USA)INC	Colorado	DENVER	32,000
110	CALCASIEU REFINING CO	Louisiana	LAKE CHARLES	30,000
111	BIG WEST OIL CO	Utah	NORTH SALT LAKE	29,400
112	CITGO ASPHALT REFINING CO	Georgia	SAVANNAH	28,000
113	EDGINGTON OIL CO INC	California	LONG BEACH	26,000
114	KERN OIL & REFINING CO	California	BAKERSFIELD	26,000
115	HOLLY CORP REFINING & MARKETING	Utah	WOODS CROSS	24,700
116	LITTLE AMERICA REFINING CO	Wyoming	EVANSVILLE (CASPER)	24,500

117	COUNTRYMARK COOPERATIVE INC	Indiana	MOUNT VERNON	23,000
118	ERGON REFINING INC	Mississippi	VICKSBURG	23,000
119	GIANT REFINING CO	New Mexico	GALLUP	20,800
120	ERGON WEST VIRGINIA INC	West Virginia	NEWELL (CONGO)	20,000
121	PETRO STAR INC	Alaska	NORTH POLE	17,000
122	GIANT INDUSTRIES INC	New Mexico	BLOOMFIELD	16,800
123	GULF ATLANTIC OPERATIONS LLC	Alabama	MOBILE	16,700
124	SAN JOAQUIN REFINING CO INC	California	BAKERSFIELD	15,000
125	CONOCOPHILLIPS ALASKA INC	Alaska	KUPARUK	14,000
126	CALUMET LUBRICANTS CO LP	Louisiana	COTTON VALLEY	13,020
127	BP EXPLORATION ALASKA INC	Alaska	PRUDHOE BAY	12,500
128	WYOMING REFINING CO	Wyoming	NEWCASTLE	12,500
129	AGE REFINING INC	Texas	SAN ANTONIO	12,200
130	HUNT SOUTHLAND REFINING CO	Mississippi	SANDERSVILLE	11,000
131	Silver Eagle Refining	Utah	WOODS CROSS	10,250
132	AMERICAN REFINING GROUP INC	Pennsylvania	BRADFORD	10,000
133	Greka Energy	California	SANTA MARIA	9,500
134	LUNDAY THAGARD CO	California	SOUTH GATE	8,500
135	CALUMET LUBRICANTS CO LP	Louisiana	PRINCETON	8,300
136	MONTANA REFINING CO	Montana	GREAT FALLS	8,200
137	CROSS OIL REFINING & MARKETING INC	Arkansas	SMACKOVER	7,200
138	VALERO REFINING CO CALIFORNIA	California	WILMINGTON	6,200
139	HUNT SOUTHLAND REFINING CO	Mississippi	LUMBERTON	5,800
140	SOMERSET REFINERY INC	Kentucky	SOMERSET	5,500
141	GOODWAY REFINING LLC	Alabama	ATMORE	4,100
142	Silver Eagle Refining	Wyoming	EVANSTON	3,000
143	TENBY INC	California	OXNARD	2,800
144	FORELAND REFINING CORP	Nevada	EAGLE SPRINGS	2,000

Source: Refinery Capacity Data by individual refinery as of January 1, 2006

EXHIBIT Z2

CHALLENGES AND ECONOMICS OF USING PETROLEUM COKE FOR POWER GENERATION

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1. Introduction

Forecasts for electric power generating capacity growth over the next 10 years indicate an average worldwide growth rate of about 2.5 percent per year. The growth rate is expected to be above this average for the developing nations of the Asia-Pacific region and Latin America and below this average for Western Europe and North America. One of the enablers for accelerated growth in certain regions is the accelerated pace of privatization of the electric power industry. Privatization with a fair rate of return provides the necessary economic incentive for investment in markets that otherwise might not be able to raise the required capital.

In many developing countries, the existing fuel transportation systems are overstretched. As a result, governments in these countries are receptive to power plant developers bringing their own fuel. In a solid fuel-based power plant, fuel can constitute as much as 35 percent of the cost of electricity (COE). For gaseous and liquid fuel-based power plants, this figure can approach 70 percent. Thus there is a big incentive to use waste and other inexpensive fuels, provided they can be burned economically and in an environmentally friendly manner.

Petroleum coke's high heating value and low ash content tend to lower transportation cost relative to coal on a per-Giga-Joule (GJ) basis. On the other hand, its high sulfur content, low volatile matter, and high metal content tend to make petroleum coke an unattractive fuel. However, its increasing supply and declining prices are hard to ignore.

This paper examines the issues and economics of burning petroleum coke using commercial or nearly commercial technologies such as conventional boiler, atmospheric and pressurized fluidized bed boilers, and gasification combined cycle. Technical, environmental, and economic issues are addressed for each of these technologies.

Top of Page

2. What is petroleum coke?

Petroleum coke is a by-product of the oil refining process. Delayed coking, the most widely used process, uses heavy residual oil as a feedstock. During delayed coking, heavy residual oil is introduced into a furnace, heated to about 480 °C, and pumped into coking drums. The coking process initiates the formation of coke and causes it to solidify on the drum wall. Thermal decomposition drives off gases, which are removed continuously. When this reaction is complete, the drum is opened, and coke removal begins. Water spraying thermally shocks the coke and allows it to break off. Coke that remains on the drum walls is subsequently cut from the drum with a high pressure water jet. After the water drains, coke is transported for use or storage. [1,2]

3. Petroleum coke supply and consumption

Ongoing advances in established refining technologies have markedly enhanced options for processing and economically using residues [3]. While the year-to-year additions of new bottom-of-the-barrel conversion projects and the associated changes in production of petroleum coke depend on the price differential between light and heavy crude oil, experts predict an inevitable increase in the production of heavier crude oil. This is attributed to the fact that world crude oil demand has been increasing at an annual average rate of nearly 1 x 10^6 barrels/day since 1985, and major producer/refining companies forecast this rate of increase to continue well into the next decade [3]. Thus over the long range, production of petroleum coke is expected to increase worldwide. In the U.S. alone it has increased more than 50 percent in the last 10 years [4]. Further, because of better bottom-of-the-barrel heavy oil refining technologies, the production of petroleum coke per thousand barrels of crude oil processed has increased about 70 percent (from about 3 to 5 tonnes) in the U.S. in just 10 to 15 years [5]. Because the market for needle or anode grades of coke is limited, most of the additional coke production is expected to be of fuel grade quality.

As of January 1, 1998, total worldwide production of coke was reported to be approximately 46 x 10^6 tonnes per annum [6]. Of this, North America (predominantly the U.S.) accounted for approximately 66.5 percent; Europe, about 17 percent; the Asia-Pacific region, about 9.5 percent; South America/Caribbean, about 4.5 percent; and the Middle East/Africa, about 2.5 percent [6]. Nearly 90 percent of the total coke produced is delayed petroleum coke. Of the petroleum coke produced in the U.S., about 66 percent is exported. Japan, Turkey, Italy, Spain, Belgium, The Netherlands, and Canada consume 75 percent of U.S. exported coke [4]. Of the approximately 10 x 10^6 tonnes of petroleum coke consumed domestically, approximately 2.5 x 10^6 tonnes (which is equivalent to about 1,000 MW of electric power) are used for power generation. No hard statistics are available as to how much of the world's annual petroleum coke production is currently used for power generation. However, projections of major boiler suppliers indicate that between 1,500 and 2,000 MW of additional petroleum coke-based power is expected to come on line within the next 5 years. With the maturation of petroleum coke-based power generation technologies and increased production of petroleum coke, it is expected that these numbers will grow.

4. Petroleum coke pricing and plant size

In the U.S., petroleum coke has historically been priced at a discount relative to coal because of its poorer environmental characteristics. Because of the more than 50 percent increase in petroleum coke production over the past few years, driven by the incentive to process heavier and high sulfur crude oil, its price, while cyclical, has declined steadily. Further, being a by-product, petroleum coke will be produced regardless of its market price. Thus, imbalance between supply and demand has pushed the price at some refineries (especially ones that are landlocked) below $6/tonne at the refinery, which is about 20¢s;/GJ. This price is very attractive and merits serious consideration as a fuel for power generation. It is important, however, to ascertain that a long-term supply contract can be secured.

Long-distance ground transportation (rail) in the U.S. can add about 1.7¢s;/tonne per km. Assuming the petroleum coke price at the refinery to be 20¢s;/GJ (which is about $6.00/tonne), transporting it 350 km would add another $6.00/tonne. Thus, the delivered cost of the fuel at the power plant would literally be doubled [5]. Short-distance (100 km) truck transportation can add as much as 7¢s;/tonne per km. Hence to minimize transportation cost, it is very desirable to build the plant at or adjacent to a refinery. A typical U.S. refinery of 200,000 barrels/day crude capacity that has coking facilities produces about 2,100 tonnes/day of coke, which is sufficient to support a power plant of 250 to 300 MW.

About 58 percent of U.S. refineries (95 out of 163 as of January 1, 1998) have a capacity of over 200,000 barrels/day and account for approximately 87 percent of total crude processing capacity [6]. Alternatively, coke can be contracted from two or three smaller nearby refineries, or the plant size can be made smaller to minimize fuel transportation costs. A project-specific study must be conducted to evaluate various tradeoffs to establish an optimum size.

Top of Page

5. The pros and cons of petroleum coke as a fuel

Petroleum coke quality depends on the feedstock used in the coker. Table 1 lists the ultimate analysis and ash properties of petroleum coke used at a major petroleum coke-based plant in the U.S. The major advantages and disadvantages of using petroleum coke as a boiler fuel are discussed in references 1, 5, 7, 8, and 9 and summarized in Table 2.

6. How is petroleum coke used in a power plant?

Petroleum coke can be used as either a primary or a secondary fuel in a new grassroots plant or for co-firing in an existing coal-fired power plant. The primary focus of this paper is the use of petroleum coke in new grassroots plants.

6.1 Grassroots plants

Two factors are important for a grassroots plant. First, the plant must have a long-term and reliable source(s) of fuel nearby. Second, the plant must be as large as possible within the proven size range of the technologies under consideration to take advantage of the economy of scale. Section 7 covers the available technologies for a grassroots plant.

Top of Page

6.2 Co-firing in existing plants

A large percentage of petroleum coke used in power generation in the U.S. is for co-firing in existing suspension boilers. Because coke has superior heating value and negligible ash content, it is typically blended with coal. Blending also has a positive impact on reducing operation and maintenance (O&M) costs. Because of the low volatile matter of petroleum coke, the blending ratio is generally kept below 20 percent. This is done to ensure stable flame and preclude ignition problems. Another reason for maintaining a low blending ratio is that the high level of sulfur content in petroleum coke could necessitate the addition of flue gas desulfurization (FGD) equipment to remain within the allowable emission limits. At least 15 U.S. utilities are currently using petroleum coke for co-firing in existing boilers [9]. Two more have recently been authorized to co-fire petroleum coke, and one is reportedly studying the use of petroleum coke from a nearby refinery [10].

7. Technology options and major issues

The four major technologies for using petroleum coke for a grassroots power plant are:

- Pulverized Petroleum Coke (PPC) Boiler
- Circulating Fluidized Bed (CFB) Boiler
- Pressurized Fluidized Bed Combustion (PFBC) Boiler
- Coke Gasification Combined Cycle (CGCC)

The advantages and disadvantages of using petroleum coke are briefly discussed above in Section 5. The major issues specific to each of the four technologies are described below.

7.1 PPC boiler

The pulverized coal firing technology has been the dominant technology for power generation worldwide for over 50 years. Delayed petroleum coke with its low volatile content has burning characteristics similar to low volatile bituminous coal or reactive anthracite [8]. The furnace design for the low volatile and high fixed carbon content solid fuels has been well developed. Thus, successful combustion of petroleum coke in a PPC boiler is not a concern.

The first U.S. plant to burn mostly coke started operation in 1956 [11]. The Texaco/Star Delmarva City cogeneration facility was designed to burn fluid coke from an adjacent refinery with 7 percent sulfur and 6 percent volatiles. The plant employs three down-shot boilers, each rated at 227,300 kg/hr of steam. Total power output exceeds 130 MW. Because of the high maintenance cost and for environmental reasons, the plant is being repowered with CGCC Technology (see Section 7.4). Suncor Inc. of Oil Sands Group in Canada has successfully fired petroleum coke in three nominal 350,000 kg/hr forced draft down-shot units since 1967 with only minor modifications to the original equipment [12]. Unit 2 recently underwent a major renovation and was uprated to produce about 455,000 kg/hr of steam. Plans are underway for a similar uprating program on the other two units. More recently, the 135 MWe and 272,300 kg/hr process steam AES/Deepwater cogeneration facility, located adjacent to a major refinery in Pasadena, Texas, USA and designed by Bechtel Power Corporation, has operated successfully since 1986. It is capable of burning 100 percent pulverized petroleum coke. The decision to use a PPC boiler at AES/Deepwater was driven by the fact that CFB boiler technology was not considered a proven technology when this plant was built. The primary issues with this pulverized coke combustion technology are:

- SO_X emissions - The higher sulfur content in petroleum coke (exceeding 5 percent) is a negative for this fuel. Sulfur in the coke is primarily converted to SO_2. However, because of the significant amount of heavy metals such as vanadium in the ash, large amounts of SO_3 are also formed. A wet FGD system, while capable of removing over 95 percent of SO_2, can scrub only about 20 percent of SO_3 [8]. Since SO_3 increases the flue gas dew point and the air heater exit gas temperature must be kept above the dew point, higher sulfur content adversely affects the boiler efficiency. Control of SO_3 stack emissions would require a wet precipitator in addition to a dry electrostatic precipitator (ESP) and a wet FGD system.

- NO_X emissions - The low volatile matter in coke makes this fuel harder to burn unless the firing temperature is raised, and longer residence time is provided. High flame temperature and a relatively high nitrogen content lead to higher relative nitrogen oxide (NO_X). To achieve the desired residence time and reduce NO_X formation, a down-shot, low-NO_X burner design (if available) is often used. Further, with low-NO_X burners, the level of NO_X reduction is not as large as with the wall and tangential fired boilers. Thus a larger selective catalytic reduction (SCR) system may be required. For certain emission requirement levels, even a larger SCR may not be adequate. Low volatile content can also lead to higher unburned carbon and associated lower boiler efficiency.

- Others - The low ash content results in lower ash handling equipment cost and lower attendant O&M cost.

Top of Page

7.2 CFB boiler

Since the 1970s, CFB technology has been used in industrial steam and power generation applications. Long recognized for its flexibility in handling a wide range of fuels, it is currently considered a mature technology for sizes up to 250 MW. Larger sizes (up to 400 MW) are being offered by major equipment suppliers. Demonstrated experience includes volatile matter as low as 4 percent, ash as high as 76 percent, sulfur as high as 7 percent, and higher heating value as low as 1,400 kCal/kg [13]. A number of small petroleum-coke-fueled CFB boilers have come on line since 1987 [11]. In 1990 the Texas-New Mexico Power Co. One facility, comprising two 165 MW units, started up in Bremond, Texas, USA. At that time, it was the largest CFB ever built, with a steaming rate of 500,000 kg/hr at 131 bar(g) and 540 °C, designed to burn lignite [14]. After successfully test firing with petroleum coke, the fuel was eventually switched to petroleum coke. The first large CFB facility to use petroleum coke exclusively was Nelson Industrial Steam Company's NISCO cogeneration plant, located in Westlake, Louisiana, USA. This 202 MW and

36,300 kg/hr process steam cogeneration facility designed by Bechtel Power Corporation utilizes two Foster Wheeler CFB boilers to repower existing steam turbines. This showcase facility has operated successfully since 1992. The primary issues concerning CFB boiler technology are:

- SO_2 emissions - Depending on the required SO_2 limit, for sulfur content up to 7 percent, SO_2 removal can be accomplished in the bed by injecting finely ground limestone into the combustion chamber along with the petroleum coke feed. The limestone is first calcinated and decrepitated to become calcium oxide. The calcium oxide formed reacts with SO_2 and oxygen to form calcium sulfate. These reactions occur within a narrow temperature range of 760 to 900 °C [8]. If the furnace temperature is below this range, limestone calcination will not take place, and there would be no calcium oxide to absorb SO_2. If the temperature exceeds the maximum range, calcium oxide will start to lose its sulfur capture capability, the calcium sulfate already formed will start to decompose, and SO_2 will be released. At atmospheric pressure, sulfur capture capability is severely hindered at temperatures above 900 °C. The formation of SO_3 is proportional to the concentration of SO_2 in the flue gas. Since SO_2 is removed by the CFB, SO_3 is not a concern with this technology.

Should the sulfur content in the fuel exceed 7 percent, it may be more economical to only partially scrub the SO_2 in the bed and remove the rest with a dry FGD system outside the bed.

- NO_X emissions - Since NO_X formation is a function of furnace flame temperature, the low furnace temperature in the CFB boiler makes it an inherently low NO_X producer. Further, selective noncatalytic reduction (SNCR) can be used with CFBs more effectively than with PPC boilers. Compared with an SCR required for the PPC boiler, SNCR results in lower capital cost.

- Others - The biggest drawback with this technology is that it produces large amounts of solid waste (almost 1.5 to 2.0 times as much as PPC technology and 30 to 40 times as much as CGCC technology). With very high sulfur content (7 to 8 percent), the quantity of waste can be as much as 50 percent of the amount of petroleum coke burned. If local ash disposal cannot be accommodated at a reasonable cost, this technology may not be economically feasible. However, opportunities may exist for selling the CFB fly ash as a commercial by-product. In certain commercial applications, relatively high amounts of unreacted limestone and lime inherently present in the ash have been found to be advantageous.

7.3 PFBC boiler

The world's first commercial PFBC power plant, Stockholm Energy's Vartan plant, went into operation in 1990 [15]. It employs two 250,000 kg/hr steam P200 modules and a 120 MW steam turbine and is the main district heating station for the Swedish capital. Other subsequent commercial units include the 70 MW units at Tidd in the U.S., Escatron in Spain, and Wakamatsu in Japan [16]. The largest PFBC unit under construction today, the 360 MW unit at Karita Power Station in Japan, is expected to start up in late 1998 [15]. All of these units are based on bubbling bed technology and have been designed to burn coal or lignite. A 155 MW circulating bed PFBC is due to start up in Florida in 2000. This unit will require a hot gas cleanup system that has not been fully demonstrated commercially.

While, in the long run, PFBC technology seems to offer improved economics, smaller plant footprint, reduced amount and environmentally more benign solid waste, and higher thermal efficiency than its atmospheric CFB cousin, it is not considered as mature a technology as the other three technologies, particularly at larger sizes. Also, its viability with petroleum coke fuel has not been demonstrated on a commercial scale.

7.4 CGCC technology

While gasification processes have been employed for more than 50 years for converting a variety of hydrocarbons to syngas, the Ube Ammonia plant in Japan has the distinction of being the oldest commercial unit operating with coke [17]. Although originally designed for coal gasification, the attractive pricing of coke in Japan resulted in a gradual change in feedstock. In 1996 Texaco started up its own coke gasification facility at Texaco's El Dorado refinery near Wichita, Kansas, USA. The gasification facility is designed to supply one-third of the fuel needs of the refinery's cogeneration plant of 35 MW and 82,000 kg/hr process steam [17].

In mid-1997 the power island of Elcogas's 300 MW gasification-combined cycle unit in Puertolano, Spain came on line, initially using only natural gas. The first firing of the gasifier was accomplished in December 1997. The 100 hour test is scheduled for April 1998, and the plant is expected to go commercial in early 1999. This facility is designed to use a feedstock of 50 percent coal and 50 percent coke. Another CGCC unit on order in the U.S. is Star Refinery's nominal 180 MW (excluding existing steam turbine) Delaware City repowering facility with 295,000 kg/hr of 41 bar process steam. As a large number of other big units in the 250 MW range that use feedstocks ranging from coal to refinery residues have recently come on line or are in the design stages, the gasification technology is coming of age. Further, this technology is environmentally superior to the others discussed above. However, its higher capital costs continue to be an impediment to its use for power generation only. Many projects now being considered are economically viable because they co-produce chemicals in addition to electricity and steam. These higher value products can include hydrogen, carbon monoxide, ammonia, and methanol. Increasingly higher sulfur content in the fuel, tighter environmental regulations, and the potential for synergistic economics through co-production of chemicals may tend to favor this technology in the long run.

Top of Page

7.5 Technology summary

The author believes that in the near term (next 5 years), the use of petroleum coke in pulverized coal suspension boilers will increase (assuming current price differential between coal and coke holds) primarily as a co-firing or blending fuel. Even a modest 10 to 15 percent blending in large plants can greatly increase petroleum coke consumption and put an upward push on petroleum coke price [10]. No grassroots plants, however, are expected to be built using PPC boiler technology.

As far as CFB boiler technology is concerned, it is the most-chosen technology today. This is evidenced by the fact that at least six petroleum coke-based units in the 150-265 MW range and nine units in the 25-80 MW range are on order or in advanced planning stages in the U.S. and abroad.

Japan will continue to be the leading market for PFBC technology in the near term, driven primarily by the fact that all fuels are imported and are, therefore, expensive, and environmental regulations are very tight. To make this technology competitive, large 360 MW units are being marketed. A unit of this size would consume close to 3,000 tonnes of petroleum coke per day. It is highly unlikely that a petroleum coke-based PFBC unit of this size will be built in the near term given the fact that there is currently no petroleum coke experience with this technology.

Basically, cokers are employed in the refining value chain when, for environmental or other reasons, there is no market for heavy residual oil. As heavy residual oil is an acceptable feedstock for a gasifier, CGCC technology will be confined to countries like the U.S., where petroleum coke is available in abundance. As the gasification process is expensive and energy-intensive, its competitiveness in power production can only be realized when additional revenues can be accrued from valuable co-products or when environmental offsets are available. Further, there is no incentive to use syngas for pure power generation when opportunities exist to convert it to other higher-value products more economically. Given this scenario, the near-term market for CGCC technology strictly for power generation is likely to be limited.

8. Economics

The suitability and economics of a technology for a given project depend greatly on the characteristics of the fuel, the applicable environmental requirements, and the geographical location of the plant. For this analysis, the site was assumed to be in the U.S. Because the capital cost, fuel cost, and O&M cost vary from site-to-site within the U.S. and abroad, sensitivity analyses were performed for the key variables to assess their impact on the levelized COE. Further, because natural-gas-fired gas turbine combined cycle (GTCC) is the technology of choice today due to its lower capital cost, higher thermal efficiency, lower O&M cost, and lower emissions, it, too, is included in this comparative analysis.

The major variables for each technology, such as plant engineering, procurement, and construction (EPC) cost; plant heat rate; construction schedule; and assumed O&M costs, are included in Table 3. Financial model assumptions are listed in Table 4.

8.1 Financial model result

Figure 1 shows the levelized COE as a function of fuel cost. As can be seen from this figure, levelized COE with CFB boiler technology is about 2 mills/kWh less than the PPC boiler, about 6 mills/kWh less than the PFBC, and about 9 mills/kWh less than the CGCC. Because a 3-4 mills/kWh variation is within the accuracy of this study, a project-specific analysis is recommended, with due consideration for the applicable emission requirements. In addition, if project-specific opportunities exist for ancillary revenues from such sources as CFB ash or chemical co-products from syngas, project economics may be significantly improved. Table 5 provides the sensitivity analysis. It shows how much change is required in each key parameter to change the levelized COE by 1 mill/kWh.

Top of Page

8.2 Comparison between GTCC and CFB boiler

Further, Figure 1 shows that even if coke is free, CFB (and other technologies) can compete with gas-fuel-based GTCC technology only when the price of gas is greater than $2.30/GJ. Thus, in gas-producing regions of the world where fuel cost is below, say, $2/GJ, petroleum coke is generally not a viable fuel. However, for gas-deficient regions of the world where gas has to be imported as LNG at around $4/GJ, petroleum coke, even if imported at $1.30/GJ ($39/ton), can compete effectively, assuming there are no environmental barriers to getting a petroleum coke-based plant permitted.

Integrating coker and power generation facilities can enhance the overall project economics through the use of common systems and facilities and nonmanual construction staffing.

9. Conclusions

A deterioration in the quality of crude oil and improvements in oil refining technology have led to increased production of petroleum coke. The mismatched supply and demand situation has caused the price of petroleum coke to drop, and experts predict that this situation will continue for the near-term. This has created an opportunity for increased use of petroleum coke as both a primary and a co-firing fuel for power generation. Today four technologies are available to successfully use petroleum coke. The oldest proven technology, the PPC boiler, is not favored by plant operators because of the higher capital and O&M costs of the environmental control equipment. The PFBC technology, while very promising, is still at a demonstration stage, has no experience with petroleum coke, and is currently not competitive. Petroleum-coke-based gasification technology, which is the most environmentally friendly, is only in the early stages of deployment. For power generation only, i.e., without value-added chemical co-production, it is currently not competitive. The CFB technology has gained widespread acceptance in the last 10 years, provides sufficient experience in burning petroleum coke, and can effectively compete with gas-fired combined cycle technology. Petroleum coke's low cost can offset the increased capital cost associated with burning it in a CFB. For regions of the world where gas prices are substantially higher than $2.30/GJ, petroleum coke can be competitive and is a viable alternative fuel. Securing a long-term supply agreement at a competitive price inclusive of transportation cost is the real challenge.

10. References

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Table 1: Typical properties of delayed petroleum coke (Ultimate Analysis as Received, Weight %)

Constituent	Average	Range
Carbon	79.74	75.0 - 86.0
Hydrogen	3.31	3.0 - 3.6
Nitrogen	1.61	1.3 - 1.9
Sulfur	4.47	3.4 - 5.3
Ash	0.27	0.0 - 0.6
Oxygen	0.00	0.0 - 0.1
Moisture	10.60	5.5 - 15.0
HHV, MJ/kg	31.3	29.3 - 33.7
Ash Properties, ppm	Average	Range
Vanadium	<2,000	500 - 2,000
Nickel	336	250 - 450
Iron	84	50 - 250
Volatile Matter, %	10	8 - 16

Table 2: Advantages and disadvantages of petroleum coke as a boiler fuel

Parameter	Advantages/Disadvantages
High Heating Value	• Results in lower handling cost per GJ • Blending improves combustion of subbituminous coals
Low Volatile Matter	• Has possible ignition problems • May require supplemental fuel
Low Ash Content	• Reduces ash handling cost
High Vanadium/Other Metals	• May make fly ash more saleable • Leads to deposits and corrosion problems
High Sulfur Content	• Inhibits ability to meet SO_2 emissions Produces large amount of

	solid waste and may lead to high disposal cost • Leads to acid dew point problems
Low Grindability Index	• Reduces pulverizing and maintenance costs

Table 3: Major plant variables

Parameter	GTCC	PPC Boiler	CFB Boiler	PFBC	CGCC
Plant Output (MW net)	250	250	250	250	250
EPC Cost ($/kW)	350	950	850	1150	1200
Heat Rate (kJ/kWh)	7200	10,000	10,000	9400	9400
Construction Schedule (months)	20	30	30	33	36
Levelized O&M (mills/kWh)	5	11	11	11	12

Notes:

1. Plant output: PPC boiler and CFB boiler plants (pure Rankine cycles) can be designed for any desired output. GTCC, PFBC, and CGCC plant size will vary with the selected gas turbine which, in turn, is affected by the generation frequency (50 vs. 60 Hz).
2. Assumed EPC cost could vary from -10% to +30%, depending on the geographical location of the site in the U.S. or abroad. PPC boiler cost includes an SCR, an electrostatic precipitator, a wet scrubber, and a wet precipitator to comply with U.S. emission requirements. For PFBC, it is assumed that three P200 boiler modules and a single steam turbine would be used.
3. Levelized O&M costs in mills/kWh ($1 = 1000 mills) for the petroleum-coke-based plants have been assumed to be the same as listed in reference 18 even though different fuels and emissions requirements are involved. No credits have been taken for any co-products from CGCC, as the primary purpose is power generation.
4. The heat rate for the CGCC is based on a quench gasifier, which is generally appropriate for low cost petroleum coke.

Table 4: Financial model assumptions

1. Plant commercial operation date is year 2001.
2. General inflation is 2.5 percent/year. Fuel escalation over general inflation is 0.5 percent/year for natural gas and 0 percent/year for petroleum coke.
3. Project economic life is 20 years.
4. Discount rate is 12 percent nominal.
5. Equity share is 30 percent.
6. Return on equity (after tax, nominal) is 15 percent.
7. Interest on term debt (blended rate) is 8.5 percent.
8. Plant capacity factor is 85 percent.
9. The listed plant heat rate is in high heating value (HHV).
10. Limestone cost @ $16.50/tonne is included in the O&M costs.
11. Total project costs include typical Owner's costs, such as project development and closing costs, construction insurance and taxes, general administration, construction period costs (interest during construction), and working capital, etc.

Table 5: Sensitivity analysis for CFB

Parameter	A Change of:	Will change levelized COE by:
EPC Cost	$45/kW	1 mill/kWh
Heat Rate	2000 kJ/kWh with $0.5/GJ fuel	1 mill/kWh
	1000 kJ/kWh with $1.0/GJ fuel	1 mill/kWh
O&M	1 mill/kWh	1 mill/kWh
Fuel	$3/tonne	1 mill/kWh
Capacity Factor	4 percent	1 mill/kWh

Fig. 1 Levelized cost of electricity versus fuel cost

Top of Page

Summary

Increased use of heavier grades of crude, coupled with technological advances in oil refining processes, has led to increased supplies of petroleum coke. This imbalance in supply and demand has resulted in a decline in the price of petroleum coke, thus making it an attractive fuel for power generation. While it has high heat density and low ash content, which are good, it also contains large amounts of sulfur, vanadium, and other heavy metals and has a low volatile matter content, which pose some technical and environmental challenges.

Four power generation technologies that can use petroleum coke as a combustion fuel are:

- Pulverized petroleum coke (PPC) boiler
- Circulating fluidized bed (CFB) boiler
- Pressurized fluidized bed combustion (PFBC)
- Coke gasification combined cycle (CGCC)

Some of these technologies have more proven experience with petroleum coke than others. The economics of each technology depend on the characteristics of the fuel, regulatory emission requirements, other site-specific parameters, and the market for co-products, if any.

For the data assumed for this case study, the CFB boiler results in the lowest levelized cost of electricity. Above a threshold price of natural gas, petroleum coke is a competitive and viable fuel. Securing a long-term supply contract for petroleum coke at a discounted price is key to a viable project with any of the four technologies.

American Bottom Conservancy
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June 16, 2007

Ms. Rachel Doctors
Hearing Officer
Illinois EPA

Via email Rachel.doctors@illinois.gov

Re: ConocoPhillips Wood River CORE Public Comments

Dear Ms. Doctors:

In our rush to submit public comment by the June 15 deadline, we inadvertently omitted some documents and comments on the ConocoPhillips (COP) Wood River Coker and Refinery Expansion (CORE) draft permit. We ask that you accept this additional public comment, which should arrive at the offices of the Illinois EPA at the same time as if we had submitted them by the Friday midnight deadline and sooner than if they had been postmarked and mailed by the deadline.

We appreciate that you extended the deadline by a week, but as we indicated in our request for an extension, there are three extremely complex permits and citizens were prejudiced by the short comment period. Because the comment would arrive at the IEPA office at the same time as comments emailed at midnight and even before comments postmarked by midnight Friday, June 15, there should therefore be no prejudice to ConocoPhillips. (We note that construction of the pipeline that would carry bitumen from the tar sands in Alberta, Canada, to the Wood River refinery for this project has not yet been authorized by the federal government. It is still in the draft Environmental Impact Statement phase of permitting.)

Should IEPA not agree to evaluate the cumulative impacts to air quality of the refining of tar sands and the use of tar sands-derived fuel on air quality as we requested in our earlier comment, we request that IEPA consider alternatives to the COP proposed process; i.e., primary upgrading by combined hydrocracking, hydrotreating and smaller coking units rather than relying primarily on delayed coking and hydrotreating as planned. Hydrocracking is a more sophisticated and modern process that, in tandem with smaller cokers and aggressive hydrotreating, would produce cleaner fuels, with less waste petroleum coke by-product. The combined hydrocracking-coking-hydrotreating process would also produce considerably more usable refined light products for the company. According to sources we have consulted, thermal coking without the hydrocracking step results in 65-70 per cent conversion rate to usable product as opposed to a much higher 85-92 per cent conversion rate from combined hydrocracking/after-coking/hydrotreating.

Tar sands are higher in cycloparaffins and aromatics and emit more particulates. We believe that the addition of a hydrocracking step—as used to great success in Canada—would result in lower emissions from the refinery and from tailpipes in the areas where the fuels would be used. This is especially important in the Greater St. Louis/Metro East area, which is nonattainment for both ozone and fine particulates. Our region would be impacted not only by dirtier diesel and gasoline tailpipe emissions but also from commercial and military aviation fuel emissions. We sit just under the takeoff and landing path for Lambert International Airport in St. Louis and are home to Scott Air Force Base in Belleville. The change from using six giant cokers as planned to a hydrocracker and smaller cokers would results in both substantially lower refinery emissions and water usage and pollution.

We also assume that ConocoPhillips would want to maximize its product output even though the combined hydrocracking-coking process would be more expensive than the older, cheaper, simple coking method. It is our understanding that the entire cost of the refinery expansion can be written off by ConocoPhillips for state and federal tax purposes. Fully half of the entire cost of the expansion can be written off the very first year it is in operation. See Attachment ABC1--2005 Energy Tax Incentives Act (title XIII of the Energy Policy Act of 2005), Section 179C. In addition, the hydrocracker should qualify for Illinois pollution control tax subsidies and perhaps even sales tax exemptions.

We also note that in the current Senate Finance Energy Bill Tax Title, reported out of committee on June 14, 2007, ConocoPhillips would be allowed to collect a $1 per gallon subsidy for renewable diesel fuel for the first 60 million gallons produced and 50 cents a gallon for every additional gallon. That is a substantial source of potential revenue for the company.

We also ask that you consider requiring ConocoPhillips to gasify its coke rather than shipping it to local utilities and that you require the strictest of controls on the gasification process and on the consumption of the syngas produced by that process which is used to displace consumption of natural gas as a plant fuel and source of hydrogen to make clean fuels.

ConocoPhillips can well afford the best available technologies and controls at the Wood River refinery. According to information on its website, www.conocophillips.com, its net income last year was $15.6 billion with a 26.5 per cent return to shareholders. In the first quarter of 2007, the company had a net income of $3.5 billion. Gasoline prices have been at historic highs and are predicted to go much higher. The cost per barrel of Canadian tar sands will be considerably less than conventional crude, although it is unlikely to cost consumers less at the pump, resulting in even higher profits to those companies using the cheaper, dirtier feedstock.

Electing a process that would produce more product would also help to deflect criticism leveled at big oil companies that they conspire to restrict supplies. (And although outside the purview of IEPA and this permit, increasing the size of the proposed pipeline from Alberta, Canada to ConocoPhillips' Wood River refinery from 30 inches to 36 or even 42 inches would also help increase supply, alleviate fuel shortages and further blunt critics' claims of supply manipulation.)

We also bring your attention to several papers obtained from the Lake Michigan Air Directors Consortium (LADCO) website (www.ladco.org): Midwest Regional Planning Organization (MRPO) on Petroleum Refinery Best Available Retrofit Technology (BART), (Attachment ABC2), and Attachment ABC3, an MRPO White Paper on Candidate Control Measures for Petroleum Refineries. Information about the ConocoPhillips Wood River Refinery indicates inconsistencies referred to in Julia May's comments and discrepancies between reported emissions and permitted emissions.

Thank you for your consideration of these additional comments.

Sincerely,

Kathy Andria

Kathy Andria
President.

Attachments