BOARD MEETING DATE: May 3, 2013 AGENDA NO. 30

PROPOSAL: Adopt Rule 1114 – Petroleum Refinery Coking Operations

SYNOPSIS: The proposed rule will reduce volatile organic compounds, particulate matter, hazardous air pollutants, sulfur compounds and methane emissions released during the delayed coking process at petroleum refineries. The proposed rule will establish a depressurization limit of less than two pounds per square inch gauge (psig) pressure prior to venting a coke drum to atmosphere and includes options for alternative compliance schedules and interim limits for facilities not able to meet the less than two psig compliance deadline within six months of rule adoption, depending on the number of delayed coking units they operate. The proposed rule also includes deadlines for permit applications, installation of monitoring equipment and exemptions from certain Regulation IV requirements.

COMMITTEE: Refinery, March 12, 2013, Reviewed

RECOMMENDED ACTIONS:
Adopt the attached resolution:

1. Certifying the CEQA Final Environmental Assessment for Proposed Rule 1114 - Petroleum Refinery Coking Operations;
2. Adopting Rule 1114 – Petroleum Refinery Coking Operations.

Barry R. Wallerstein, D.Env.
Executive Officer

EC:LT:NB:DO:ET

Background

The South Coast Air Quality Management District (SCAQMD) currently regulates most processes and equipment used at petroleum refineries. The gamut of existing rules regulate volatile organic compounds (VOC), particulate matter (PM), hazardous air pollutants (HAPs), sulfur compounds, oxides of nitrogen (NOX), and methane (CH4) emissions released. Delayed coking process is one of the processes at petroleum refineries not currently regulated by the SCAQMD.

The SCAQMD initiated development of Proposed Rule (PR) 1114 - Petroleum Refinery Coking Operations in 2010 following a series of source tests carried out between 2003 and 2009 at the delayed coking units at the refineries in the South Coast. Staff has worked extensively with industry and environmental community representatives in order to review and estimate emissions from delayed coking units and has conducted five working group meetings, as well as a public workshop in Wilmington, incorporating overall feedback through several proposed rule language iterations.

Summary of Rule 1114 Proposed for Adoption

The purpose of PR 1114 is to minimize the amount of pollutants generated during the delayed coking process by requiring that a coke drum be depressurized to less than two (2) psig prior to venting to atmosphere. The proposed rule includes the following:

- Establishes a limit of less than two (2) psig for when a coke drum may be depressurized to atmosphere, effective November 1, 2013.
- Allows for an alternative compliance schedule with interim limits for facilities not able to meet the less than two (2) psig rule limit by November 1, 2013.
    - Facilities with one delayed coking unit are required to:
        - Comply with an interim pressure limit of less than five (5) psig by May 1, 2014, and
        - Achieve the less than two (2) psig limit by the next turnaround or December 31, 2016, whichever is earlier.
    - Facilities with more than one delayed coking unit are required to:
        - Comply with an interim facility specific average baseline pressure or a delayed coking unit specific pressure limit of less than five (5) psig;
        - Achieve less than five (5) psig for each coke drum by the next turnaround or by December 31, 2016, whichever is earlier, and
        - Comply with the less than two (2) psig limit within 24 months following the turnaround when the less than five (5) psig is achieved.

- A requirement for facilities to submit permit applications for equipment or process modifications no later than nine months prior to the applicable compliance date.
- Monitoring and recording requirements for the coke drum internal pressure, atmospheric vent valve or equivalent interim parameter, downtime and associated notification provisions and recordkeeping.
- An exemption from the provisions of Rule 404 for coke drums.

Emission Inventory and Emission Reduction
SCAQMD staff estimates baseline emissions from petroleum refinery coking operations of 268 tons per year (tpy) VOC, 1,140 tpy CH4, and 54 tpy HAPs. Based on the lower depressurization requirement the proposed rule is expected to reduce this inventory by approximately 50%, and result in annual reductions of 129 tpy VOC, 547 tpy of CH4 and 26 tpy HAPs. Additional reduction in PM and sulfur compounds are expected by implementing the lower depressurization limit.

Cost-Effectiveness
SCAQMD staff estimates the cost effectiveness to be $8,700 per ton of VOC, with concurrent reductions in PM, HAPs and CH4. The range of cost-effectiveness is within that for other VOC rules adopted by the Board.

AQMP and Legal Mandates
The California Health and Safety Code requires the SCAQMD to adopt an Air Quality Management Plan (AQMP) to meet state and federal ambient air standards in the Basin. In addition, the California Health and Safety Code requires that the SCAQMD adopt rules and regulations that carry out the objectives of the AQMP. The 2012 AQMP, specifically Control Measure CM #2012 MCS-01 – Application of All Feasible Measures Assessment, commits the SCAQMD to adopt and implement new retrofit technology control standards based on research and development and other information, that are feasible and cost-effective as new Best Available Retrofit Control Technology standards become available. PR 1114 will partially implement CM #2012 MCS-01.

California Environmental Quality Act
Pursuant to California Environmental Quality Act (CEQA) Guidelines § 15252 and § 15162 and SCAQMD Rule 110, the SCAQMD has prepared an Environmental Assessment (EA) for Proposed Rule 1114. The environmental analysis in the Draft EA concluded that Proposed Rule 1114 would not generate any significant adverse environmental impacts. The Draft EA was released for a 30-day public review and comment period from February 28, 2013 to March 29, 2013, resulting in the receipt of two comment letters from the public. Both the comment letters and responses are included as Appendix D of the EA.

Since the release of the Draft EA, minor modifications have been made to the document. However, none of the modifications alter any conclusions reached in the Draft EA, nor provide new information of substantial importance relative to the draft document. As a result, these minor revisions do not require recirculation of the Draft EA pursuant to CEQA Guidelines § 15073.5 and § 15088.5. Therefore, the Draft EA is now a Final EA and is included as an attachment to this Board package. Prior to making a decision on the proposed adoption of Rule 1114, the SCAQMD Governing Board must review and certify the Final EA as providing adequate information on the potential adverse environmental impacts of the proposed project.

Socioeconomic Analysis

PR 1114 would affect six petroleum refineries in Los Angeles County, two of which are already capable of meeting the proposed rule requirements. The remaining four refineries are expected to install four steam ejector systems. The total annual cost of PR 1114 is estimated to be $1.79 million. PR 1114 is projected to result in a modest job creation (five jobs annually, on average, between 2013 and 2035) in the four-county area, a modest figure typically assumed to be within the noise level of the regional economic model.

Implementation and Resource Impacts

Existing SCAQMD resources will be sufficient to implement the proposed rule with minimal impact on the budget.

Attachments

A. Summary of Proposed Rule
B. Rule Development Process
C. Key Contacts
D. Resolution
E. Rule Language
F. Final Staff Report
G. Final Environmental Assessment

ATTACHMENT A

SUMMARY OF PROPOSED RULE

Purpose and Applicability; PR 1114 (a)

Reduce emissions from atmospheric vents of coke drums of delayed coking units (DCUs) at petroleum refineries.

Proposed Rule Requirements; PR 1114 (c)

Depressurize coke drums in DCUs to less than 2 psig prior to venting to atmosphere by 11/1/2013.

If modifications are needed to comply, submit permit applications at least nine months prior to applicable dates and,

For Single DCU Facilities:

- Comply with interim pressure threshold of less than 5 psig by 5/1/2014
- Achieve less than 2 psig by next turnaround or 12/31/2016, whichever is earlier

For Multiple DCU Facilities:

- Comply with interim pressure threshold by 5/1/2014 of less than 5 psig or less than 110% of 2012 baseline (30-day average)
- Achieve less than 5 psig by next turnaround or 12/31/2016, whichever is earlier
- Achieve less than 2 psig within 24 months following next turnaround

Monitoring and Recording; PR 1114 (d)

Continuous monitoring and recordkeeping of:

- Coke drum internal pressure
- Atmospheric vent valve position (open/closed) or approved alternative

Monitoring and recording downtime provisions:

- 96 hours per DCU per year
- Manual recording during downtime

Notification; PR 1114 (e)

Notification of a monitoring system downtime within 24 hours from occurrence

Recordkeeping; PR 1114 (f)

Maintain operational and calibration records for at least five years

Exemptions; PR 1114 (g)

Coke drums are exempt from Rule 404

ATTACHMENT B

RULE DEVELOPMENT PROCESS

Proposed Rule 1114 – Petroleum Refinery Coking Operations

Beginning of Rule Development Process
October 6, 2010

⇩

Meetings with Stakeholders
October 6, 2010 – February 13, 2013
(5 Working Group meetings, 4 Industry meetings and 5 Site Visits)

⇩

Public Workshop – Wilmington, CA
December 12, 2012

⇩

Refinery Committee Meeting
March 12, 2013

⇩

Set Hearing
February 1, 2013 (60 Days)

⇩

Public Hearing
May 3, 2013

(30) months spent in rule development

ATTACHMENT C

KEY CONTACTS

Affected Facilities

BP West Coast Products LLC

Chevron Products Company

ExxonMobil Corporation

Phillips 66

Tesoro Corporation

Valero Energy Corporation

Other Interested Parties

American Lung Association

Citizens for Better Environment

Coalition for Clean Air

Coalition for a Safe Environment

National Resource Defense Council

Sierra Club

Western States Petroleum Association

ATTACHMENT D

RESOLUTION NO. 2013-____

A Resolution of the South Coast Air Quality Management District (SCAQMD) Governing Board certifying the Final Environmental Assessment for Proposed Rule 1114 – Petroleum Refinery Coking Operation.

A Resolution of the SCAQMD Governing Board adopting Rule 1114 – Petroleum Refinery Coking Operation.

WHEREAS, the SCAQMD Governing Board approved the Air Quality Management Plan in December 2012 (2012 AQMP), which included Control Measure MCS-01 to ensure the application of all feasible measures; and

WHEREAS, volatile organic compounds are precursors to ozone (O3) which the U.S. Environmental Protection Agency has identified as an air contaminant and has set criteria air pollutant national ambient air quality standards for ozone and the South Coast Air Basin has not yet attained these air quality standards and is exceeding the corresponding state standards by an even greater margin; and

WHEREAS, the SCAQMD staff conducted a public workshop regarding Proposed Rule 1114; and

WHEREAS, the SCAQMD Governing Board has determined with certainty that Proposed Rule 1114 is considered a "project" pursuant to the terms of the California Environmental Quality Act (CEQA); and

WHEREAS, the SCAQMD has had its regulatory program certified pursuant to Public Resources Code § 21080.5 and has conducted a CEQA review pursuant to such program (SCAQMD Rule 110); and

WHEREAS, SCAQMD staff has prepared a Draft Environmental Assessment (EA) pursuant to its certified regulatory program and CEQA Guidelines § 15252, setting forth the potential environmental consequences of Proposed Rule 1114; and

WHEREAS, the Draft EA was circulated for a 30-day public review from February 28, 2013 to March 29, 2013; and

WHEREAS, two comment letters were received relative to the analysis presented in the Draft EA and responses were prepared for each individual comment in the letters. None of the individual comments in the comment letters identified any

potentially significant adverse impacts from the proposed project, and the Draft EA has been revised such that it is now a Final EA; and

WHEREAS, minor modifications to Proposed Rule 1114 were made subsequent to the release of the Draft EA, which do not trigger the requirements for recirculation pursuant to CEQA Guidelines §§ 15073.5 and 15088.5; and

WHEREAS, findings pursuant to Public Resources Code § 21081.6 and CEQA Guidelines § 15091 and a Statement of Overriding Considerations pursuant to CEQA Guidelines § 15093 were not prepared because the analysis of the proposed project shows that Proposed Rule 1114 would not have a significant adverse effect on the environment and thus, are not required; and

WHEREAS, it is necessary that the adequacy of the Final EA, including responses to comments, be determined by the SCAQMD Governing Board prior to its certification; and

WHEREAS, pursuant to CEQA Guidelines § 15252 (a)(2)(B), since no significant adverse impacts were identified, no alternatives or mitigation measures are required and thus, a Mitigation Monitoring Plan pursuant to Public Resources Code § 21081.6 and CEQA Guidelines § 15097, has not been prepared; and

WHEREAS, the SCAQMD Governing Board voting on Proposed Rule 1114, has reviewed and considered the Final EA, including responses to comments prior to its certification; and

WHEREAS, the SCAQMD Governing Board finds and determines, taking into consideration the factors in Section (d)(4)(D) of the Governing Board Procedures, that the modifications which have been made to Proposed Rule 1114, since notice of public hearing was published, do not significantly change the meaning of the proposed rule within the meaning of the Health and Safety Code § 40726 and would not constitute significant new information requiring recirculation of the Draft EA pursuant to CEQA Guidelines §§ 15073.5 and 15088.5; and

WHEREAS, Health and Safety Code § 40727 requires that prior to adopting, amending or repealing a rule or regulation, the SCAQMD Governing Board shall make findings of necessity, authority, clarity, consistency, non-duplication, and reference based on relevant information presented at the public hearing and in the staff report; and

WHEREAS, the SCAQMD Governing Board obtains its authority to adopt, amend, or repeal rules and regulations from §§ 39002, 40000, 40001 and 40440, 40441, 40463, 40702 and 40725 through 40728 and 41508 of the Health and Safety Code; and

WHEREAS, the SCAQMD Governing Board has determined that a need exists to adopt Proposed Rule 1114 to partially implement Control Measure MCS-01 – Application of All Feasible Measures from the 2012 AQMP and help the SCAQMD attain the National Ambient Air Quality Standard for ozone for which SCAQMD is classified as an Extreme Non-Attainment Area; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Rule 1114 is written and displayed so that the meaning can be easily understood by persons directly affected by it; and

WHEREAS, the SCAQMD Governing Board has determined that Rule 1114, as proposed, is in harmony with, and not in conflict with, or contradictory to, existing statutes, court decisions, or state or federal regulations; and

WHEREAS, the SCAQMD Governing Board has determined that Rule 1114, as proposed, does not impose the same requirement as any existing state or federal regulation, except to the extent they are necessary and proper to execute the powers and duties granted to, and imposed upon the SCAQMD; and

WHEREAS, the SCAQMD Governing Board has determined that by adopting Proposed Rule 1114, the SCAQMD Governing Board will be implementing, interpreting or making specific the provisions of the Health and Safety Code §§ 40001 (rules to achieve ambient air quality standards), 40440 (a) (rules to carry out the AQMP), 40440 (c) (cost effectiveness), 40702 (do such acts necessary to execute duties imposed by law), and 40910 et seq., (California Clean Air Act); and

WHEREAS, adoption of Proposed Rule 1114 will alleviate a problem, that is the Basin is in non-attainment of the federal ozone standards, and the proposed rule will promote attainment of this standard; and

WHEREAS, the SCAQMD Governing Board has determined that the Socioeconomic Impact Assessment for Proposed Rule 1114 is consistent with the March 17, 1989 and October 14, 1994 Governing Board Socioeconomic Resolutions for rule adoption; and

WHEREAS, the SCAQMD Governing Board has determined that the Socioeconomic Impact Assessment is consistent with the provisions of Health and Safety Code §§ 40440.8, 40728.5 and 40920.6; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Rule 1114 will result in increased costs to the industry, yet are considered to be reasonable, with a total annualized cost as specified in the Final Socioeconomic Impact Assessment; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Rule 1114, is cost-effective as demonstrated in the Final Socioeconomic Impact Assessment; and

WHEREAS, the SCAQMD Governing Board has actively considered the socioeconomic impact assessment and has made a good faith effort to minimize such impacts; and

WHEREAS, the SCAQMD Governing Board has determined that Proposed Rule 1114 should be adopted for the reasons contained in the staff report; and

WHEREAS, a public hearing has been properly noticed in accordance with all provisions of Health and Safety Code § 40725; and

WHEREAS, the SCAQMD Governing Board has held a public hearing in accordance with all provisions of law, inclusive of Health and Safety Code § 40726; and

NOW, THEREFORE, BE IT RESOLVED, that the SCAQMD Governing Board does hereby certify that the Final EA for Proposed Rule 1114 was completed in compliance with CEQA and SCAQMD Rule 110 provisions; and finds that the Final EA was presented to the Governing Board, whose members reviewed, considered and approved the information therein prior to acting on Proposed Rule 1114; and

BE IT FURTHER RESOLVED, that because no significant adverse environmental impacts were identified as a result of implementing Proposed Rule 1114, findings pursuant to Public Resources Code § 21081.6 and CEQA Guidelines § 15091, a Statement of Overriding Considerations pursuant to CEQA Guidelines § 15093, and a Mitigation Monitoring Plan pursuant to Public Resources Code § 21081.6 and CEQA Guidelines § 15097 are not required; and

BE IT FURTHER RESOLVED, that the SCAQMD Governing Board does hereby adopt, pursuant to the authority granted by law, Proposed Rule 1114, as set forth in the attached, and incorporated herein by this reference.

DATE: _____ _____

CLERK OF THE BOARDS

ATTACHMENT E

(Proposed May 3, 2013)

PROPOSED RULE 1114 PETROLEUM REFINERY COKING OPERATIONS

(a) Purpose and Applicability

The purpose of this rule is to reduce emissions from atmospheric venting of coke drums. This rule applies to all petroleum refineries equipped with delayed coking units.

(b) Definitions

For the purpose of this rule, the following definitions shall apply:

(1) COKE DRUM is a batch system pressure vessel in which petroleum coke is produced.

(2) DELAYED COKING UNIT is a petroleum refinery process unit in which high molecular weight petroleum derivatives are converted to lighter gaseous and liquid products and petroleum coke by means of thermal cracking in a series of coke drums. A delayed coking unit consists of the coke drums and ancillary equipment associated with a main fractionator.

(3) PETROLEUM REFINERY is a facility identified by the North American Industry Classification System Code 324110, Petroleum Refineries.

(4) TURNAROUND is a planned activity involving shutdown and startup of one or several process units for the purpose of performing periodic maintenance, repair or replacement of equipment, or installation of new equipment.

(c) Requirements

(1) Effective November 1, 2013, the owner or operator of a delayed coking unit shall depressurize each coke drum to less than two (2) pounds per square inch, gauge (psig) prior to venting it to atmosphere; or

(2) If unable to comply with the provisions of paragraph (c)(1), the owner or operator of a delayed coking unit shall comply with the following:

(A) At a facility with a single delayed coking unit, effective May 1, 2014, depressurize each coke drum prior to venting to atmosphere to less than five (5) psig until compliance with paragraph (c)(1) is achieved, which is required upon completion of the first unit turnaround after May 1, 2014 or by December 31, 2016, whichever is earlier.

(B) At a facility with more than one delayed coking unit:

(i) By November 1, 2013, submit to the Executive Officer:

(I) For approval, a baseline calculation using general engineering practices and substantiating records that identify the facility-wide average coke drum internal pressure at which atmospheric venting was initiated for all the coke drums during calendar year 2012, or

(II) A notification that the facility intends to depressurize each coke drum to less than five (5) psig until achieving compliance with paragraph (c)(1);

(ii) Effective May 1, 2014, until completion of the first turnaround at an affected delayed coking unit following May 1, 2014 or by December 31, 2016, whichever is earlier, either:

(I) Depressurize each coke drum prior to venting to atmosphere to a pressure not to exceed, when averaged over a 30 day period for all affected drums, 110% of the 2012 baseline submitted and approved pursuant to subclause (c)(2)(B)(i)(I), or

(II) Depressurize each coke drum to less than five (5) psig, pursuant to subclause (c)(2)(B)(i)(II); and,

(iii) Effective upon resuming operations at an affected delayed coking unit following its turnaround or January 1, 2017, whichever is earlier, depressurize each affected coke drum to less than 5 (five) psig prior to venting to atmosphere until compliance with paragraph (c)(1) is achieved within the next 24 months of the earlier trigger date.

(C) Submit to the Executive Officer any required permit applications pursuant to Regulation II~~I~~ for equipment and process modifications necessary to achieve compliance with subdivision (c) at least nine months prior to effective dates.

(d) Monitoring and Recording

Effective November 1, 2013, the owner or operator of a delayed coking unit shall:

(1) Monitor the coke drum pressure and record it continuously from feed introduction until atmospheric venting is initiated, using a device calibrated at least once annually according to manufacturer's specifications;

(2) Monitor and record continuously from feed introduction until atmospheric venting is initiated the following:

(A) Coke drum atmospheric vent valve position (open or closed) or, if unable to comply with subparagraph (d)(2)(A),

(B) Coke drum blowdown valve position or the temperature of the coke drum vent at a location ~~*above*~~ downstream of the atmospheric vent valve, until achieving compliance with subparagraph (d)(2)(A), which is required upon completion of the first unit turnaround following November 1, 2013 or by December 31, 2016, whichever is earlier;

(3) Maintain the monitoring equipment required in paragraphs (d)(1) and (d)(2) in good operating condition except for periods of downtime due to calibration, maintenance ~~*and*~~ or repair, which shall not exceed 96 hours per calendar year per delayed coking unit, and

(4) Manually record the coke drum pressure and the atmospheric vent valve position at five minute intervals covering a time period of no less than 15 minutes immediately prior to atmospheric venting during periods of downtime as specified in paragraph (d)(3).

Notwithstanding the effective date in subdivision (d), the owner or operator of a facility subject to paragraph (c)(2) shall comply with the requirements in this subdivision effective May 1, 2014.

(e) Notification

The owner or operator of a delayed coking unit shall notify the Executive Officer by telephone within 24 hours of any failure of the monitoring or recording equipment required by subdivision (d).

(f) Recordkeeping

Effective November 1, 2013, the owner or operator of a delayed coking unit shall maintain all operational and calibration records required by subdivision (d) for at

least five years and shall make such records available to the Executive Officer upon request. Notwithstanding the effective date in subdivision (f), the owner or operator of a facility subject to paragraph (c)(2) shall comply with the requirements in this subdivision effective May 1, 2014.

(g) Exemptions

Any coke drum subject to the provisions of this rule shall be exempt from the provisions of Rule 404.

ATTACHMENT F

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Staff Report

Proposed Rule 1114 – Petroleum Refinery Coking Operations

Final Staff Report

May 2013

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Planning, Rule Development, & Area Sources
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SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

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REFERENCES

Achieving attainment status for ambient ozone and particulate concentration in the South Coast Air Basin (SCAB) as more stringent federal air quality standards are adopted and implemented is required. The South Coast Air Quality Management District (SCAQMD) is continuously looking for ways to reduce air pollution from all sources, both mobile and stationary under this purview. The 2007 and 2012 Air Quality Management Plan (AQMP) revisions have been developed in partnership with California Air Resources Board (CARB), U.S. EPA, Southern California Association of Governments (SCAG) and stakeholders throughout the region, including input from local government, health and environmental organizations, and the business community.

The AQMP is the blueprint for how to meet and maintain state and federal air quality standards. The 2007 AQMP identifies Control Measures needed to demonstrate attainment with the federal annual average $PM_{2.5}$ standard by 2015 and federal 8-hr ozone standard by 2023. The 2012 AQMP identifies Control Measures needed to demonstrate attainment with the federal 24-hour standard for $PM_{2.5}$ by 2014 in the SCAB. In addition, the 2012 AQMP provides updates on progress towards meeting the 8-hour ozone standard for 2023, an attainment demonstration for the revoked 1-hour ozone standard, a vehicle per miles traveled (VMT) offset demonstration for ozone standards, and a report on the health effects of $PM_{2.5}$. In the 2012 AQMP, Control Measure MCS-01 - All Feasible Measures Assessment is a continuation of the former Control Measure MCS-07 from the 2007 AQMP, in which the District has committed to the adoption and implementation of new retrofit control technology standards. The 2012 AQMP Control Measure MCS-01 provides the impetus for developing Proposed Rule 1114 (PR 1114).

Among stationary sources, petroleum refineries are one of the major emitters, accounting for seven tons per day (tpd) volatile organic compounds (VOC), 10 tpd carbon monoxide (CO), 10 tpd nitrogen oxides (NOx), six tpd sulfur oxides (SOx) and five tpd total suspended particulate (TSP) emissions in the year 2011. Over the past nine years, District staff has conducted studies of emissions from atmospheric venting of delayed coking units (DCU's) at local refineries, concluding that there is a sufficient amount of VOC, PM, methane (CH4, a greenhouse gas), sulfur compounds and hazardous air pollutants (HAPs), including polycyclic organic matter (POM[*]) compounds, from this operation to warrant consideration. U.S. EPA has also acknowledged that DCU emissions are significant and, as a result, in 2008, U.S. EPA promulgated 40 CFR 60 Subpart Ja, which establishes a five (5) pounds per square inch, gauge (psig) vent limit for coke drums at new or modified DCU's.

In 2010, staff initiated discussions with local refineries and the public on concepts to establish baseline emissions from DCU's but were unable to reach consensus. Baseline emissions are necessary to establish emission reduction targets. In 2011, the U.S. EPA required refineries to conduct some detailed source testing on various equipment, including DCU's. Therefore, based on feedback from the refineries, staff awaited the latest source testing information in an effort to establish an emissions baseline. However, the quality of additional data collected left a lot to be desired. Thus, over the past six months, staff has worked with U.S. EPA, the refineries, and the

[*] Polycyclic organic matter (POM) is a federal hazardous air pollutant and was identified in California as a toxic air contaminant in April 1993 under AB 2728. The State of California has determined under Proposition 65 that several POM compounds (including benzo[b]fluoranthene, benzo[j]fluoranthene, benzo[k]fluoranthene, benzo[a]pyrene, chrysene, indeno[1,2,3-cd]pyrene, 3,7-dinitrofluoranthene, and 3,9-dinitrofluoranthene) are carcinogencs (CCR, 1997).

public on alternate approaches to estimate emissions from DCU's and has recently reached consensus.

The purpose of PR 1114 is to minimize the amount of pollutants generated during the delayed coking process by requiring that a coke drum be depressurized to less than two (2) psig prior to venting to atmosphere. The proposed rule includes the following:

- Establishes a limit of less than two psig for when a coke drum may be vented to atmosphere.
- Allows for an alternative compliance schedule for facilities not able to meet the rule compliance timeline which extends compliance through the facilities' turnaround period that:
    - Establishes a facility-specific vent pressure that facilities cannot exceed based on either a baseline average vent pressures recorded in 2012 or less than five psig;
    - Requires facilities with more than one delayed coking unit taking advantage of the alternate compliance schedule to demonstrate compliance with an interim vent pressure limit of less than five psig for all coke drums following a turnaround or by December 31, 2016, whichever is earlier;
    - Allows up to an additional 24 months following completion of the interim period to meet the final depressurization limit.
- A requirement for facilities to submit permit applications for equipment or process modifications no later than nine months prior to the applicable compliance date.
- Monitoring and recording requirements for the coke drum internal pressure, atmospheric vent valve or equivalent interim parameter, downtime and associated notification provisions, and recordkeeping.
- An exemption from the provisions of SCAQMD Rule 404 for coke drums.

District staff estimates baseline emissions of 268 tons per year (tpy) VOC, 1,140 tpy CH4, and 54 tpy HAPs. The proposed rule is estimated to result in reductions of 129 tpy VOC, 547 tpy of CH4 and 26 tpy HAPs at an estimated cost effectiveness of $8,700 per ton of VOC. Additional reduction in particulate emissions and sulfur compounds are expected by implementing the lower depressurization limit.

Pursuant to California Environmental Quality Act (CEQA) Guidelines §15252 and §15162 and SCAQMD Rule 110, the SCAQMD has prepared an Environmental Assessment (EA) for Proposed Rule 1114. The environmental analysis in the Draft EA concluded that Proposed Rule 1114 would not generate any significant adverse environmental impacts. The Draft EA was released for a 30-day public review and comment period from February 28, 2013 to March 29, 2013, resulting in the receipt of two comment letters. Both comment letters and responses are included as Appendix D of the EA.

Since the release of the Draft EA, minor modifications have been made to the document. However, none of the modifications alter any conclusions reached in the Draft EA, nor provide new information of substantial importance relative to the draft document. Moreover, these minor revisions do not require recirculation of the Draft EA pursuant to CEQA Guidelines §15073.5

and §15088.5. Therefore, the Draft EA is now a Final EA and is included as an attachment to this Governing Board package. Prior to making a decision on the proposed adoption of Rule 1114, the SCAQMD Governing Board must review and certify the Final EA as providing adequate information on the potential adverse environmental impacts of the proposed project.

~~Pursuant to California Environmental Quality Act (CEQA) Guidelines §15252 and §15162 and SCAQMD Rule 110, the SCAQMD has prepared an Environmental Assessment (EA) for proposed Rule 1114. The environmental analysis in the Draft EA concluded that proposed Rule 1114 would not generate any significant adverse environmental impacts. The Draft EA was released for a 30-day public review and comment period from February 28, 2013 to March 29, 2013. Any comments received during the public comment period on the analysis presented in the Draft EA will be responded to and included in the Final EA. Prior to making a decision on the proposed adoption of Rule 1114, the SCAQMD Governing Board must review and certify the Final EA as providing adequate information on the potential adverse environmental impacts of the proposed project.~~

The 2012 Air Quality Management Plan (AQMP), specifically Control Measure CM#2012 MCS-01 – Application of All Feasible Measures Assessment, commits the District to adopt and implement new retrofit technology control standards based on research and development and other information, that are feasible and cost-effective as new Best Available Retrofit Control Technology standards become available. PR 1114 will partially implement CM#2012 MCS-01.

C H A P T E R I

BACKGROUND

A. *HISTORY*

Coking Process

Although some early attempts at coking were made in the second part of the nineteenth century, the first delayed coking unit was built by Standard Oil in Whiting, Indiana in 1929. In the 1930's, Shell Oil refined the technology by separating the heater from the coke drum, combined pressure and heat, and made the process semi-continuous by pairing up two drums working in conjunction with each other. Later in the twentieth century, the process became more popular due to the increase in the number of fluid catalytic cracking units (FCCU's) [1].

As the availability of light, sweet crude oil declined, additional oil refineries processed heavier and sourer stocks which are more readily available at lower prices. However, in order to do this, changes in process and equipment are needed to accommodate for the increased level of sulfur and heavier molecules present in these feedstocks. For that purpose, local refineries have upgraded processing equipment to be able to withstand more adverse conditions, have installed additional scrubbing/treating capacity and expanded the throughput of existing delayed coking units, which thermally break the heavy, long chain molecules and maximize liquid product yields while also producing petroleum coke.

The California refineries typically process Alaska North Slope (ANS) crude, San Joaquin Valley (SJV) crude and crude from several other oil fields throughout California and offshore; they also import crude from Saudi Arabia, Iraq and Ecuador.*

Emissions from Coking

In April 1997, District enforcement staff noticed visible emissions from a DCU at a local refinery. The source of visible emissions was traced to a coke drum being vented to the atmosphere prior to being open for coke removal. The incident triggered an investigation of emissions from coke drums atmospheric venting at petroleum refineries located in the SCAB. Subsequently, from 2003 and through 2006, District staff conducted source tests at the local refineries, initially in order to quantify VOC and PM emissions, and later sulfur compounds and HAP emissions from coke drums.

In order to conduct these source tests, staff needed to overcome several adverse conditions, including the unavailability of adequate ports on the coke drums vent pipes, high temperatures inherent to the process, high elevations and other physical hazards existent on the top deck of coking drums. District staff developed the necessary testing procedures and was able to complete most of the source tests despite the high moisture content (up to 99% steam) of the stream being vented; in a few instances, however, hazardous conditions developed or the venting was too short to the point where test results became compromised.

After the first couple of tests, it became evident that the tests should be expanded to also quantify sulfur compounds such as hydrogen sulfide (H_2S) and HAPs such as benzene, toluene, ethyl benzene and xylene (BTEX). Starting in 2006 and until 2009, a second round of source tests was initiated after refineries installed ports on coke drum vent pipes at staff's request.

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* http://www.energy.ca.gov/2005publications/CEC-600-2005-031/CEC-600-2005-031.PDF, p. 14.

Further, in 2006, U.S. EPA staff became aware of the source tests conducted at the DCU's and contacted District staff to request copies of the results. Subsequently, U.S. EPA staff, in an effort to develop an emission inventory for DCU's throughout the U.S., requested several refineries to develop protocols and conduct source tests for their coke drum atmospheric venting. The first refineries to conduct the source tests were the Hovensa refinery in St. Croix, U.S. Virgin Islands and the CITGO refinery in Corpus Christi, TX.

As a result, in June 2008, U.S. EPA promulgated new regulation 40 CFR 60 Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced after May 14, 2007; this new regulation affected, among other process units, DCU's at petroleum refineries and established a five psig depressurization limit for the atmospheric venting of coke drums at refineries subject to the rule. Furthermore, in 2011 U.S.EPA issued more source test requests for coke drum vent emissions to several U.S. refineries in an effort to establish emission factors for these petroleum refineries emission points and update AP-42, Compilation of Air Pollutant Emission Factors.

B. AQMD RULES FOR PETROLEUM REFINERIES

Current District rules cover a variety of industrial processes and regulate the amount of criteria pollutants and HAP emissions associated with these operations. This section focuses on the rules covering processes and operations directly related to petroleum refineries, most relevant being under Regulation IV – Prohibitions, Regulation XI – Source Specific Standards, Regulation XIV – Toxics and Other Non-Criteria Pollutants and Regulation XX - Regional Clean Air Incentives Market (RECLAIM).

VOC Emissions

Rule 462 – Organic Liquid Loading

Rule 462 was adopted in 1976 and last amended in 1999. The purpose of the rule is to control VOC emissions from facilities that load organic liquids into any tank truck, trailer or railroad tank car. The rule requires vapor recovery and/or a disposal system for displaced organic vapors, as well as an operator leak inspection program for VOC vapor leaks or liquid leaks from facility piping components.

Rule 463 - Organic Liquid Storage

Rule 463 was adopted in 1977 and last amended in 2011. It applies to any aboveground stationary tank used for storage of organic liquids and any aboveground tank used for storage of gasoline. The purpose of the rule is to control VOC emissions from tanks by requiring them to be pressurized or designed and equipped with a vapor control device such as external floating roofs, fixed roofs with an internal floating-type cover or a vapor recovery system.

Rule 1173 - Control of Volatile Organic Compound Leaks and Releases from Components at Petroleum Facilities and Chemical Plants

Rule 1173 was adopted in 1989 and last amended in 2009. The purpose of the rule is to minimize fugitive VOC emissions from piping components at petroleum refineries through a self inspection leak detection and repair program (LDAR), done on a quarterly basis.

Rule 1176 – VOC Emissions from Wastewater Systems

Rule 1176 was originally adopted in 1989 and subsequently amended in 1990, 1994 and 1996. The purpose of the rule is to reduce VOC emissions from components of the wastewater system such as process drains, sumps, separators, forebays, sewer lines and junction boxes. The emissions are generated whenever the surface of a liquid containing VOC is exposed to the atmosphere. The facilities subject to this rule produce VOC-containing process water that has a potential to emit VOC directly into the atmosphere when routed to an open drain system.

Rule 1178 - Further Reduction of VOC Emissions from Storage Tanks at Petroleum Refineries

Rule 1178 was adopted in 2001. The purpose of this rule is to further reduce VOC emissions from storage tanks located at petroleum facilities. It applies to all aboveground storage tanks that have capacity equal to or greater than 75,000 liters (19,815 gallons), are used to store organic liquids with a true vapor pressure greater than 5 mm Hg (0.1 psi) absolute under actual storage conditions, and are located at any petroleum facility that emits more than 40,000 pounds (20 tons) per year of VOC in any emission inventory year starting with the emission inventory year 2000.

Rule 1189 – Emissions from Hydrogen Plants Vents

Rule 1189– was adopted in 2000. The purpose of this rule is to reduce emissions of VOC from hydrogen plant process vents. The rule applies to all hydrogen plants that produce any hydrogen for use in petroleum refining operations.

Particulate Emissions

Rule 404 – Particulate Matter - Concentration

Rule 404 limits the concentration of particulate matter being emitted from a source.

Rule 405 – Solid Particulate Matter - Weight

Rule 405 limits the mass emissions of particulate matter from a source.

Rule 1105.1 - Reduction of PM_{10} and Ammonia Emissions from Fluid Catalytic Cracking Units

Rule 1105.1 was adopted in 2003 with the purpose of reducing emissions of PM_{10} and ammonia from fluid catalytic cracking units at petroleum refineries.

Sulfur Compounds Emissions

Rule 407 – Liquid and Gaseous Air Contaminants

Rule 407 limits emissions of sulfur compounds from any source to atmosphere, expressed as SO_2, to 500 ppmv when averaged over 15 minutes.

Rule 431.1 – Sulfur Content of Gaseous Fuels

Rule 431.1 establishes limits for sulfur compounds concentration in gaseous fuels.

Rule 1118 – Control of Emissions from Refinery Flares

Rule 1118 was first adopted in 1998 and amended in 2005. The purpose of this rule is to monitor and record data on refinery and related flaring operations, and to control and minimize flaring and flare related emissions.

Rule 1105 – Fluid Catalytic Cracking Units – Oxides of Sulfur

Rule 1105 was first adopted in 1978 and last amended in 1984. The purpose of the rule is to limit the sulfur oxide emissions from fluid catalytic units at petroleum refineries.

Rule 2011 - Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Sulfur (SOx) Emissions

Rule 2011 was first adopted in 1993 and last amended in 2005. The purpose of this rule is to establish the monitoring, reporting, and recordkeeping requirements for SOx emissions under the RECLAIM program.

Air Toxics

Rule 1401 - New Source Review of Toxic Air Contaminants

Rule 1401 was adopted in 1990 and last amended in 2010. This rule specifies limits for maximum individual cancer risk (MICR), cancer burden, and noncancer acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permit units which emit toxic air contaminants.

Rule 1402 - Control of Toxic Air Contaminants from Existing Sources

Rule 1402 was adopted in 1994 and last amended in 2005. The purpose of this rule is to reduce the health risk associated with emissions of toxic air contaminants from existing sources by specifying limits for maximum individual cancer risk (MICR), cancer burden, and non-cancer acute and chronic hazard index (HI) applicable to total facility emissions and by requiring facilities to implement risk reduction plans to achieve specified risk limits, as required by the Hot Spots Act and this rule. The rule also specifies public notification and inventory requirements.

C. OTHER DISTRICTS' RULES FOR DELAYED COKING UNITS

There are no rules at any other Air Pollution Control District in California for DCU's at this time.

D. FEDERAL REGULATIONS FOR COKING UNITS AT PETROLEUM REFINERIES

On June 24, 2008, U.S. EPA issued its final rule 40 CFR60 Subpart Ja that requires petroleum refineries with newly constructed or modified delayed coking units to depressurize a coke drum to five psig or less before venting it to atmosphere.

40 CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants (NESHAP) from Petroleum Refineries, classifies delayed coke drum vents as miscellaneous process vents; if the atmospheric depressuring of the coke drum is done at a pressure higher than 15 psig it is subject to controls, such as venting to a vapor recovery system, scrubber, etc, depending on the amount and concentration of HAPs emitted.

E. AFFECTED FACILITIES

There are currently six petroleum refineries in the SCAQMD that operate delayed coking units, as summarized in Table 1.1 below:

Table 1.1-SCAB Petroleum Refineries with Delayed Coking Units

Facility	City
BP	Carson
Chevron USA	El Segundo
ExxonMobil	Torrance
Phillips 66	Carson
Tesoro	Wilmington
Valero	Wilmington

F. PROCESS DESCRIPTION

Coking is the refinery process that converts vacuum distillation bottom fractions, or resid, into gasoline, light gas oil and heavy gas oil; petroleum coke is a by-product of this process. Resid is fed to a fractionation tower; the bottom fraction is then passed through a heater that brings the temperature to 850 °F – 900 °F and, under steam injection, is sent to the bottom of an empty coke drum at a pressure of 30-60 psig. The purpose of steam injection is to delay coking, or solidification of the hot material until it reaches the drum, therefore the name "delayed coker".

The heavy resid molecules at high temperature start breaking into smaller, lighter molecules that rise and leave the top of the coke drum as vapors, and are routed back to the fractionation tower. The material left behind polymerizes to solid coke within 30 minutes to one hour. Because more feed and steam are forced through the drum, pores are created into the structure which gives the coke a sponge-like appearance. Eventually the coke drum is filled to a predetermined level where no more coke can fit and the feed is switched to another empty drum for the start of another cycle. Two coke drums and a feed heater form a module that allows for a semi-continuous batch operation.

Once the drum is filled and the heavy oil turns into coke, steam is injected to strip leftover hydrocarbons from the coke bed and the vapors are routed to a fractionation tower for a period of time. Quench water is then injected from the bottom of the drum for a few hours until the drum cools down to the desired temperature, usually in the range of 220 °F - 300 °F. As the quench water flashes into steam due to the elevated temperature in the drum, the vapors continue to be routed to the fractionation tower together with light hydrocarbons; once the stream becomes mostly water vapors, it is diverted to a blowdown/flare system until the coke drum pressure and that of the blowdown/flare system become equal. The drum is then vented to atmosphere until its internal pressure equals ambient pressure. The atmospheric depressurization phase is the focus of PR 1114.

As the top and bottom lids are removed from the coke drum, a high pressure water drill is lowered into the drum and is used to remove the coke from the drum. A pilot hole is drilled first with a small drill head, after which a larger drill head is used to remove the bulk of the coke. The coke drops on a pad or into a pit, then is conveyed to a crusher for size reduction and then conveyed to a barn for storage. On average, the coke contains 9 - 12 % volatiles, 4% sulfur and 5 - 9% moisture, and as such is called green coke. It is stored in barns and kept moist to prevent fugitive dust emissions. Typically, 18 hours of coking are followed by 18 hours of coke removal or decoking, but due to technological advancements the length of the cycle can be reduced to as low as 12 hours per cycle.

Coke with a high percent of impurities is used as fuel for steel foundries; coke that has a low metals and sulfur content is used for manufacturing anodes for aluminum and titanium producers. In order to make anode grade coke, moisture, sulfur and metal impurities are removed from the green coke through a process called calcining, where coke is heated at high temperatures in rotary kilns, converting the coke to almost pure carbon with a defined structure.

A process flow diagram of a delayed coker is shown below:

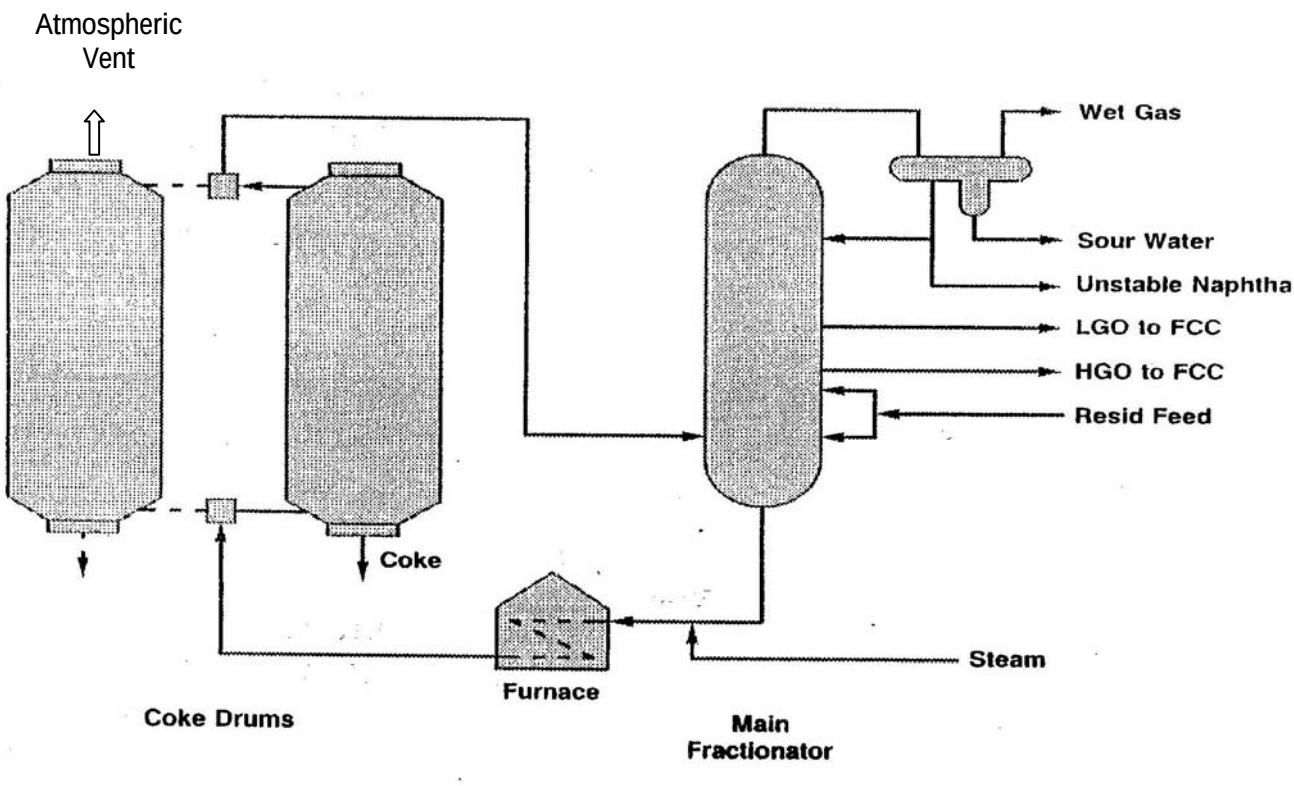

Figure 1.1 - Delayed Coker Process Flow Diagram

G. LEGISLATIVE AUTHORITY

The SCAQMD was created by the California Legislature in 1977 (the Lewis-Presley Air Quality Management Act, Health and Safety Code Section 40400 et seq.) as the agency responsible for developing and enforcing air pollution control rules and regulations in the SCAB. By statute, the SCAQMD is required to adopt an Air Quality Management Plan (AQMP) demonstrating compliance with all state and federal ambient air quality standards for the Basin (Health and Safety Code Section 40460(a)). In addition, the SCAQMD must adopt rules and regulations that implement the AQMP (Health and Safety Code Section 40440(a)).

The long-term trend of the quality of air shows continuous improvement, although recent leveling off in ozone improvement causes marked concern. The SCAB, comprising the counties of Los Angeles, Orange, Riverside and San Bernardino, is the second most populated urban area in the U.S. − and the smoggiest. To ensure continued progress toward clean air and comply with state and federal requirements, the SCAQMD, in conjunction with CARB, SCAG and the U.S. EPA prepared the 2012 AQMP, which employs the most up-to-date science and analytical tools and incorporates a comprehensive strategy aimed at controlling pollution from all sources, including stationary sources, on-road and off-road mobile sources and area sources.

Although the new federal fine particulates ($PM_{2.5}$) and 8-hour surface level ozone standards provide a longer compliance schedule, the standards are much more stringent than the previous PM_{10} and 1-hour surface level ozone standards. To reach clean air goals in the next seven to 16 years provided by the Clean Air Act (CCA) deadlines, Southern California must not only continue its diligence but intensify its pollution reduction efforts. Continuing the SCAB's progress toward clean air is a challenging task, not only to recognize and understand complex interactions between emissions and resulting air quality, but also to pursue the most effective possible set of strategies to improve air quality while maintaining a healthy economy.

The purposes of the 2012 AQMP for the SCAB are to set forth a comprehensive and integrated program that will lead the SCAB into compliance with the federal 24-hour $PM_{2.5}$ air quality standard, to satisfy the planning requirements of the federal CCA, and to provide an update to the SCAB's commitments towards meeting the federal 8-hour ozone standards. It will also serve to satisfy the recent U.S. EPA proposed requirement for a new attainment demonstration of the revoked 1-hour ozone standard, as well as a VMT emissions offset demonstration. Specifically, the AQMP serves as the official SIP submittal for the federal 2006 24-hour $PM_{2.5}$ standard. In addition, the 2012 AQMP updates specific new control measures and commitments for emissions reductions to implement the attainment strategy for the 8-hour ozone State Implementation Plan (SIP), and thus help to reduce reliance on CAA Section 182(e)(5) long-term measures.

C H A P T E R I I

PROPOSED RULE LANGUAGE

PROPOSED RULE

Proposed Rule 1114 – Petroleum Refinery Coking Operations

A. PURPOSE AND APPLICABILITY

The purpose of the rule is to reduce emissions resulting from atmospheric venting of coke drums and applies to petroleum refineries operating DCU's.

B. DEFINITIONS

The proposed rule has four definitions:

- Coke Drum
- Delayed Coking Unit
- Petroleum Refinery
- Turnaround

C. REQUIREMENTS

The proposed rule requires the owner or operator of a DCU to reduce the pressure in a coke drum to less than two (2) psig prior to venting the coke drum to atmosphere, effective six months following rule adoption.

Facilities not able to comply by this date will be allowed an extra period of time, depending on the number of DCU's they operate, to make necessary process and equipment modifications that can be completed during downtime periods for maintenance and repair known as turnarounds. Effective 12 months after rule adoption, facilities operating a single DCU are required to depressurize each coke drum to less than five psig until achieving compliance with the less than two psig limit following the first unit turnaround scheduled after the effective date or by December 31, 2016, whichever is earlier.

Facilities operating more than one DCU have two options available. Under the first option, they must submit for the Executive Officer' approval within six months from rule adoption a baseline calculation, along with substantiating records identifying the facility wide average coke drum internal pressure at which atmospheric venting was initiated during the year 2012. Facilities currently not equipped with monitoring and recording instrumentation necessary to determine the 2012 baseline may use general engineering practices for calculating this value, subject to approval.

Effective 12 months from rule adoption, these facilities must depressurize a coke drum to atmosphere to a pressure less than 110% of the 2012 baseline pressure until the first turnaround at an affected DCU following the effective date or by December 31, 2016, whichever is earlier. Upon completion of the turnaround the facility is required to depressurize each coke drum at an affected DCU prior to venting to atmosphere to less than five psig until achieving compliance with the two psig limit within the following 24 months.

Under the second option, effective 12 months following rule adoption, facilities operating more than one DCU must depressurize each coke drum to less than five psig until the first turnaround

at an affected DCU following the effective date or by December 31, 2016, whichever is earlier. Upon completion of the turnaround, these facilities must depressurize their coke drums to less than five psig until achieving less than two psig depressurization requirement within the next 24 months.

Facilities that need extended compliance dates must submit any required permit applications to the Executive Officer at least 9 months prior to the applicable compliance dates.

D. MONITORING AND RECORDING

Effective six months after rule adoption, the owner or operator of a DCU is required to:

- Monitor and record continuously the internal pressure of a coke drum from the time of feed introduction until the coke drum pressure is less than two psig, using a device that is calibrated at least annually according to manufacturer's specifications;
- Monitor and record continuously the position of the coke drum atmospheric vent valve (open or closed); facilities that do not have the this capability upon effective date have the option of either continuously monitoring and recording the coke drum blowdown vent valve position or the temperature of the atmospheric vent line at a location ~~above~~ downstream of the atmospheric vent valve, from feed introduction until atmospheric venting is initiated, until completing the first unit turnaround at an affected DCU or by December 31, 2016, whichever is earlier, after which the atmospheric vent valve must be monitored;
- Maintain the monitoring and recording equipment in good operating condition except for periods of downtime caused by breakdowns, ~~or~~ unplanned maintenance or calibration, which cannot exceed 96 hours per DCU per calendar year. During downtime periods, the owner or operator is required to manually record the coke drum internal pressure and the atmospheric vent valve position every five minutes for a period of at least 15 minutes immediately prior to the coke drum being vented to atmosphere.

For facilities that need an extended compliance schedule, these requirements are effective 12 months after rule adoption.

E. NOTIFICATION

In the event of a failure of the monitoring or recording equipment, the owner or operator of a DCU is required to notify the Executive Officer by telephone within 24 hours from the time the failure occurred.

F. RECORDKEEPING

Effective six months after rule adoption, the owner or operator of a DCU is required to maintain records of the coke drum's internal pressure, the atmospheric vent valve position, pressure gauge calibration records and records of monitoring system breakdown periods, along with associated manual readings, and make them available to the Executive Officer upon request. The records have to be maintained for a period of five years and made available to the Executive Officer upon request. For facilities that need an extended compliance schedule, these requirements are effective 12 months after rule adoption.

G. EXEMPTIONS

The proposed rule exempts all coke drums from the provisions of Rule 404 – Particulate Matter – Concentration. This exemption merely codifies an existing legal interpretation, already implemented by Engineering and Compliance, that Rule 404 does not apply to a delayed coking drum.

C H A P T E R I I I

EMISSION INVENTORY

A. AFFECTED FACILITIES

Affected facilities are the petroleum refineries with NAICS Code 324110 that operate delayed coking units and are located in the SCAB. There are six refineries operating eight DCU's with a total of 36 coke drums.

B. EMISSION INVENTORY

Source Tests

As stated earlier, beginning in 2003, SCAQMD staff conducted several source tests at the refineries in the basin in order to assess emissions from coke drums. During the source tests, staff had little input over the process parameters, such as the pressure and temperature at which the drums were vented and did not run multiple tests at the same location in order to be able to develop any correlations between these parameters. Consequently, the results were overall inconclusive, due also to additional factors. For example: one test had to be aborted due to hazardous conditions that developed; during another source test samples were not taken due to the extremely short vent time; only qualitative results were obtained as part of a third source test.

The District source test results are summarized in Table 3.1.

Table 3.1 Summary of District Source Test Results

Refinery	Initial Drum Vent Pressure, psig	VOC	PM	Condensable PM/VOC	Sulfur Compounds	Methane
		lbs/cycle				
A	3.9	4.28	0.26	0.46	0.45	1.86
B	7	5.3	0.36	1.46	N/A	34
C	0.89	4.44	3.77	0.66	8.18	165.47
D[1]	11	1.38	0.34	0.54	N/A	12.72
E[2,3]	2.5	N/A	N/A	N/A	N/A	N/A
F	0.4	11.16	1.25	12.50	N/A	66.96

1 Results inconclusive, test was not completed due to safety concerns
2 Vent time was very short, not enough sample was collected
3 Qualitative results only

Subsequently, the U.S. EPA conducted more comprehensive source tests at the Hovensa refinery in St. Croix, U.S. Virgin Islands [2] in order to quantify emissions from coke drum atmospheric venting. For this reason, staff chose to use the U.S. EPA source test results as the primary reference for establishing the emission inventory for the delayed coking units in the SCAB. The summary of the Hovensa source test results is presented in Table 3.2:

Table 3.2 – Hovensa Source Test Results (lbs/cycle)

	VOC	PM	Semivolatile VOC	Methane	Drum Vent Pressure (psig)
Average (4 runs)	178	61.6	6.44	N/A	7.72

Heat Balance Calculation

The PR1114 baseline emission inventory is estimated based on emissions from all 36 coke drums in the basin. Emissions per single drum are calculated for an average coke drum, assumed cylindrical, with dimensions that represent the weighted average of all drums; the pressure and temperature under which this drum operates represents the weighted average of the operating conditions at the six refineries, based on a survey completed by local refineries [9].

Based on source test results and U.S. EPA input, staff assumed that prior to venting, the head space of a coke drum is filled with gas containing between 97% and 99% steam. In order to calculate the amount of vent gas, staff assumed that once the atmospheric vent is open, the quench water in the coke drum will flash to steam and lower the coke bed temperature due to evaporative cooling. Using the heat balance between the quench water, the coke bed, the coke drum and the steam generated, the amount of steam generated can be calculated such that the drum temperature reaches the water boiling point or 212 °F at ambient pressure. The conductive and convective contribution to heat loss from the coke drum will be assumed minimal for an insulated drum, and is assumed to account for no more than 10% of the heat dissipated.

Assumptions

The following assumptions are used to assist in the estimation of VOC emissions from delayed coking operations.

1. The approximation of the amount of steam generated during the final venting to atmosphere prior to removing coke from the drum based on a heat balance of initial and final states is accurate and representative for the facilities surveyed.

2. The industry provided survey data, including facility specific number and dimensions of coke drums, as well as operating parameters for average final depressurization and internal drum temperature prior to venting and coking cycle time are accurate and representative for the facilities surveyed.

3. Physical property data for steam, water and coke, including density, heat capacity and latent heat at operating conditions identified in the survey are representative for the facilities surveyed.

4. Additional physical and operational property data (see Tables 3.3, 5.2, and 5.3) related to coke porosity, average drum outage, coke bed height, drum water level prior to venting, as identified through a review of source test results and U.S. EPA input is representative for the facilities surveyed.

5. The final thermodynamic state of a coke drum prior to opening the drum to remove the coke is approximated by a final temperature of 212 °F based on the boiling point of water at atmospheric pressure.

6. The dry vent gas pollutant concentrations as identified through a review of source test results and U.S. EPA input is representative for the facilities surveyed.

Emission Calculations

The heat balance equation for the coke drum is:

$$(1-0.1) \times (m_c c_c + m_w c_w) \times (t_i - t_f) = m_s \times \Delta H_{vap} \quad (1)$$

where:

m_c = coke bed mass (lbs)
c_c = coke heat capacity (Btu/lb-°F)
t_i = average initial temperature of the coke bed (°F)
t_f = average final temperature of the coke bed (°F)
m_s = mass of steam generated (lbs)
ΔH_{vap} = water heat of vaporization (Btu/lb)

Solving the equation for m_s:

$$m_s = 0.9 \times (m_c c_c + m_w c_w) \times (t_i - t_f) / \Delta H_{vap} \quad (2)$$

The calculations are performed using weighted averages of parameters obtained from the facilities survey for all 36 drums (see Table 3.3).

In order to calculate the emission inventory, the number of annual cycles needs to be determined. For the refineries in the SCAQMD, the average cycle duration for a coke drum is 32.8 hours (16.4 hours coking and 16.4 hours decoking), therefore:

For one drum, the number of cycles in a year is:

Cycles = 24 hrs/day x 365 days / 32.8 hrs = 267 cycles

For all 36 drums in operation, the total number of cycles is:

Total cycles = 36 drums x 267 cycles/drum/year ~ 9,610 cycles/year

The emission inventory is determined based on the assumption that the coke drum vent gas moisture is 97% to 99% (steam). As mentioned earlier, the existing emissions inventory is based on the U.S. EPA Hovensa source test results, where the VOC emissions were 6% by weight of the dry vent gas, the CH4 emissions were 70% of the dry vent gas and HAP emissions were 20% of the VOC emissions. Staff believes that there is not sufficient data to estimate creditable PM and sulfur emissions and emission reductions at this time.

The calculations are summarized in Table 3.3.

Table 3.3 – Coke Drum Emissions Inventory Calculations

Parameter	Value	Unit	Notes
Avg drum diameter D	22.3	ft	
Typical outage	17.15	ft	Assumed 0.25 H_d
Avg. drum height H_d	68.6	ft	
Avg. Coke bed height H_c	51.5	ft	Assumed 0.75 H_d
Initial Coke Temp T_{ci}	254	°F	Weighted average temperature (survey)
Final coke temp T_{cf}	212	°F	
Coke density ρ_c	84.3	lb/cu ft	
Coke heat capacity c_c	0.27	Btu/lb - °F	
Coke porosity p_c	0.50	Volume fraction	Assumption
Coke mass, m_c	847,000	lbs	$m_c = \prod * D^2/4 * H_c * \rho_c * p_c$
Water density ρ_w	59.5	lb/cu ft	
Average water level at vent	56.5	ft	Assumed 5' above coke bed
Quench water mass	714,000	lbs	
Water heat of vaporization ΔH_{vap}	960	Btu/lb	
Water heat content c_w	1	Btu/lb - °F	
Specific volume sat steam V_s	21.4	scf/lb	At standard conditions
Flashing water mass	37,100	lbs	Assume all water is vaporized to saturated steam
Total steam volume V_t	794,000	scf	
Vent gas volume	802,000	scf	Displayed @ 99% H_2O
Dry vent gas	8,020	dscf	1 % of total vent gas volume
CH4/cycle	237	lbs/cycle	0.7 volume fraction
VOC/cycle	55	lbs/cycle	As propane (C_3) 0.06 vol. fraction
HAPs/cycle	11	lbs/cycle	
PM/cycle	8	lbs/cycle	Based on 0.001 lbs/dscf average from local source tests
Average cycle length	16.4	hrs/cycle	
Number of drums	36		
Cycles/year	9610		36 drums
VOC inventory	**268**	**tpy**	
CH4 Inventory	**1140**	**tpy**	
HAPs Inventory	**54**	**tpy**	
PM Inventory	**38**	**tpy**	

Annual emissions are summarized in Table 3.4. It should be noted that the estimates are conservatively based on a vent stream steam content of 99% although the observed range of moisture content varied between 97% and 99%. The lower moisture content would imply a higher dry vent gas volume and consequent increase in emission estimates. Based on the methodology used, emissions are proportional to the dry vent gas volume, so that the upper end of the range would be three times higher than the conservative estimate used by staff, as shown in Table 3.4:

Table 3.4 - Coke Drum Annual Emissions Inventory

Estimate	VOC	HAPs	CH4	PM
Conservative Estimate (Tons per Year)	268	54	1,140	38
Estimated Range @ 1-3 % Dry Vent Gas (Tons per Year)	268 - 804	54 - 162	1,140 – 3,420	38 - 114

Estimated Potential Emissions

Further review of the source test data by staff to determine an upper emission range for DCU operations indicated that a high end temperature of roughly 274 °F approximated a worse case scenario for comparison purposes and to reflect some of the existing facilities' current level of control. Using the calculation steps previously outlined for 36 drums with an initial coke temperature of 274 °F results in an estimated district-wide worse case DCU emission rate of 402 tpy VOC, 80 tpy HAPs, and 1,710 tpy CH4.

C H A P T E R I V

CONTROL TECHNOLOGY ASSESSMENT

Early delayed coker designs had blowdown systems that were tied into the refinery flare system such that hydrocarbon vapors were flared during coke drum quenching or warming up. Due to environmental considerations though, in modern cokers, the gases are routed back to the main fractionator overhead accumulator where they are recovered and sent to the refinery fuel gas system rather than to the flare. As long as the pressure in the drum head space is higher than that of the blowdown system it is possible for the vapors to be routed to the blowdown system. However, at the point when the pressures equalize, the operator has to start atmospheric venting in order to depressurize the drum to ambient pressure and open it for drilling the coke bed.

Since there is a significant amount of pollutants, including HAPs left in the head space during atmospheric venting, the best way to reduce emissions is to send the vapors in the head space to the maximum extent feasible to the blowdown system prior to switching to atmospheric venting. There are several alternatives for achieving this goal.

One alternative is to increase the drum cooling time and reduce the temperature such as to condense more vapors and reduce the drum's internal pressure. However, this alternative would increase the coke drum cycle time length and therefore reduce the unit throughput, potentially creating a bottleneck in the refinery operations and impacting the refinery's productivity.

A more realistic alternative is to increase the rate at which vapors are evacuated from the head space to the blowdown system by optionally using either compressors or steam ejectors, thus lowering the drum's internal pressure as close to ambient pressure as possible and minimizing emissions to atmosphere. Each option has its own advantages and disadvantages. A compressor, which is a complex piece of equipment driven by an electric motor, does not generate any waste stream but has higher capital, operating, and maintenance costs. A steam ejector, which uses the Venturi effect of a converging-diverging nozzle to convert the pressure energy of steam to velocity energy which creates a vacuum, costs less and has lower maintenance and operating costs but generates sour water as a waste stream that needs to be stored and treated.

Staff's understanding is that the current state of the art for a DCU is to be equipped with steam ejectors for depressurizing the coke drums in a timely manner, thus reducing the length of the cycle and improving the unit's productivity by being able to process more feed in the same amount of time.

Currently, there are both local and outside California refineries with DCU's that already meet or vent their drums at pressures near the proposed rule depressurization limit of less than two (2) psig. Considering that the current maximum allowable atmospheric vent pressure for uncontrolled venting of a coke drum is 15 psig (per 40 CFR 63 Subpart CC), operating at this proposed lower depressurization limit represents a significant emissions reduction (> 90%, see Table 5-4 following). Therefore, the proposed limits reflect an achieved in practice standard.

C H A P T E R V

EMISSION REDUCTIONS

This chapter presents the estimated VOC emission reductions based on the control option incorporated into PR 1114.

From Chapter III – Emissions Inventory, the emissions attributed to coke drum venting are as summarized in Table 5.1, reflecting the conservative estimate based on one percent dry vent gas and 99% steam:

Table 5.1 Annual Emission Inventory

Pollutant	VOC	HAPs	Methane (CH4)	PM
Tons per Year	268	54	1,140	38

Staff estimates that 10 existing coke drums either already achieve the proposed depressurization limit or are near the limit, whereas the remaining 26 coke drums, located at four facilities, would need to make modifications to their equipment and/or process in order to meet the proposed rule limit. The emission reductions will be determined by first calculating the emissions associated with the 26 drums at the current average vent pressure and temperature and then subtracting the emissions calculated at the proposed rule limit of less than two psig that approximately corresponds to a temperature of 220 °F. The emissions are calculated based on the same methodology used to calculate the baseline emission inventory. The parameters used are weighted averages for the 26 drums and are listed in Table 5.2.

For one drum, the number of cycles in a year is:

Cycles = 24 hrs/day x 365 days / (17.4 x 2) hrs = 252 cycles

For all 26 drums in operation, the total number of cycles is:

Total cycles = 26 drums x 252 cycles/drum/year ~ 6,540 cycles/year

The emission inventory calculations are summarized in Table 5.2.

Table 5.2 Emissions at Current Conditions (26 Drums, 7.8 psig avg.)

Parameter	Value	Unit	Notes
Avg drum diameter D	20.8	ft	
Typical outage	17.2	ft	Assumed 0.25 of drum height
Avg. drum height H_d	68.8	ft	
Avg. Coke bed height H_c	51.6	ft	Assumed 0.75 of drum height
Initial Coke Temp T_{ci}	220	°F	Weighted average temperature (survey)
Final coke temp T_{cf}	212	°F	
Coke density ρ_c	84.3	lb/cu ft	
Coke heat capacity c_c	0.27	Btu/lb - °F	
Coke porosity p_c	0.50	Volume fraction	Assumption due to channeling
Coke mass, m_c	739,000	lbs	$m_c = \prod * D^2/4 * H_c * \rho_c * p_c$
Water density ρ_w	59.5	lb/cu ft	
Average water level at vent	56.6	ft	Assume 5 ft over coke bed
Quench water mass	622,700	lbs	
Water heat of vaporization λ	960	Btu/lb	
Water heat content c_w	1	Btu/lb - °F	
Specific volume sat steam V_s	21.4	scf/lb	Standard conditions
Flashing water mass	32,400	lbs	Assume all water is vaporized to saturated steam
Total steam volume V_t	692,800	scf	Displayed @ 99% steam
Vent gas volume (99% H_2O)	700,000	scf	
Dry vent gas	7,000	dscf	
Methane content/cycle	207	lbs/cycle	0.7 volume fraction
VOC content/cycle	48.7	lbs/cycle	As propane (C_3) 0.06 vol. fraction
HAPs content/cycle	9.7	lbs/cycle	Assumed 20% of VOC by weight
PM content/cycle	7	lbs/cycle	Based on 0.001 lbs/dscf average from local source tests
Average cycle time	17.4	hrs/cycle	
Number of drums	26		
Cycles/year	6,540		26 drums
VOC	**159**	**tpy**	
Methane	**676**	**tpy**	
HAPs	**32**	**tpy**	
PM	**23**	**tpy**	

The emissions generated when the coke drum is vented at less than two psig are calculated based on corresponding coke drum top temperature of 220 °F at the start of venting and the assumption that the final temperature is 212 °F at ambient pressure. The results are shown in Table 5.3.

Table 5.3 Remaining Emissions after Rule Implementation (26 drums, < 2 psig)

Parameter	Value	Unit	Notes
Avg. drum diameter D	20.8	ft	
Typical outage	17.2	ft	Assumed 0.25 of drum height
Avg. drum height H_d	68.8	ft	
Avg. Coke bed height H_c	51.6	ft	Assumed 0.75 of drum height
Initial Coke Temp T_{ci}	254	°F	Weighted average temperature (survey)
Final coke temp T_{cf}	212	°F	
Coke density ρ_c	84.3	lb/cu ft	
Coke heat capacity c_c	0.27	Btu/lb - °F	
Coke porosity p_c	0.50	Volume fraction	Assumption due to channeling
Coke mass, m_c	739,000	lbs	$m_c = \Pi * D^2/4 * H_c * \rho_c * p_c$
Water density ρ_w	59.5	lb/cu ft	
Average water level at vent	56.6	ft	Assume 5 ft over coke bed
Quench water mass	622,700	lbs	
Water heat of vaporization λ	960	Btu/lb	
Water heat content c_w	1	Btu/lb - °F	
Specific volume sat steam V_s	21.4	scf/lb	Standard conditions
Flashing water mass	6,170	lbs	Assume all water is vaporized to saturated steam
Total steam volume V_t	132,000	scf	Displayed @ 99% steam
Vent gas volume (99% H_2O)	133,000	scf	
Dry vent gas	1,330	dscf	
Methane/cycle	39.3	lbs/cycle	0.7 volume fraction
VOC/cycle	9.3	lbs/cycle	As propane (C_3) 0.06 vol. fraction
HAPs/cycle	1.9	lbs/cycle	Assumed 20% of VOC by weight
PM/cycle	1.33	lbs/cycle	Based on 0.001 lbs/dscf average from local source tests
Average cycle time	17.4	hrs/cycle	
Number of drums	26		
Cycles/year	6,540		26 drums
VOC Inventory	**30**	**tpy**	
Methane Inventory	**129**	**tpy**	
HAPs Inventory	**6**	**tpy**	
PM Inventory	**4**	**tpy**	

The emissions reduction attributed to the rule are as follows:

VOC = 159 tpy – 30 tpy = 129 tpy

HAPs = 32 tpy – 6 tpy = 26 tpy

CH4 = 676 tpy -129 tpy = 547 tpy

PM = 23 tpy – 4 tpy = 19 tpy

Table 5.4 Estimated Emission Reductions

Estimate	VOC	HAPs	CH4	PM
Baseline Emissions, tpy (All drums)	268	54	1,140	38
Baseline Emissions, tpy (Affected drums)	159	32	676	23
Emissions Reduction (tpy)	129	26	547	19
• % from baseline (all drums)	50			
• % from baseline (affected drums)	81			
• % from uncontrolled	92*			

* Based on upper end of federally allowable initial vent pressure (see Chapter III page III-5). The percent reduction from potential emissions independent of existing regulations would be higher.

C H A P T E R V I

COST AND COST EFFECTIVENESS

A. COSTS

This chapter presents the cost effectiveness calculations related to the Proposed Rule 1114 as well as other emission reduction options. Staff evaluated the following options and the cost effectiveness of each is shown below. Some refineries will incur capital expenditures and annual operating costs for the equipment to be installed that is necessary to ensure compliance with the proposed rule. Following discussions with the affected refineries, staff concluded that two refineries are already able to meet the proposed rule requirements within six months of the rule adoption. However, four other refineries will need to install new instrumentation and equipment or resize existing equipment in order to comply. Staff's understanding is that, due to lower equipment and maintenance costs, these facilities will likely install steam ejectors in order to comply with the depressurization limit required by the rule, as this is the current design standard for coke drum depressurization.

Based on costs for similar installations at two other DCU's, staff estimates that the total installed cost (TIC) for a steam ejector system is between $1.25 and $3 million. Staff estimates that four steam ejector systems will be installed, of which three will have a $3MM TIC each and one $1.25MM TIC for a total of $10.25 million. Although staff believes that the total installed costs for similar installations are representative, because of the site-to-site variability that may affect actual upgrades to meet PR 1114, staff is incorporating a contingency factor of roughly 30%. During individual meetings with refineries, staff was given initial cost estimates for modifications needed to comply with the proposed rule by the affected facilities, amounting to approximately $35 MM.

B. COST EFFECTIVENESS CALCULATIONS

In order to calculate the cost effectiveness of the proposed rule, the present value of the capital cost and the operating cost during the useful life of the control equipment and/or program must be calculated, using the following formula:

PV = C + A x PVF, where:

PV = Present Value of the control equipment

C = Capital costs associated with process modifications and/or to install equipment

A = Annual costs incurred to operate the control equipment, estimated at 4% of the capital cost, plus the cost of utilities, estimated at 3% of the capital cost.

PVF = Present Value Factor, which is 15.622 for an assumed 25 years equipment life and 4% real interest rate.

The cost effectiveness of the equipment will be calculated using the emission reductions calculated in Chapter V and the formula presented above.

The cost effectiveness of the proposed changes and associated calculations and assumptions used to derive it are shown in the following sections. Cost effectiveness is expressed as the ratio

between the total cost of implementing a proposed control measure and the associated benefits, in this case the emission reduction:

CE = PV / (Emission Reductions x Equipment Life)

The present value is:

PV = $10,250,000 + ($10,250,000 x 0.07 x 15.622) = $21,458,785

The cost effectiveness is:

CE = $21,458,785 / (129 tpy x 25 years) = $6,700 / ton VOC reduced

To account for facility-to-facility variability, a contingency factor of 30% has been incorporated as follows:

CE = $6,700 / ton x 1.30 = $8,700 / ton VOC reduced

It should be noted that, because the emission reductions are based on the 99% steam content in the vent stream, the consequent cost effectiveness number is conservatively represented at roughly three times the value at the less conservative end of the range of 97% steam. On an additional note, considering that more vent gas is recovered due to the lower depressurization, it is estimated that 1.51 tpd of usable methane in the vent gas could be recovered, thus lowering the annual fuel costs to the refineries. The 1.51 tpd translates into approximately 268,000 therms per year, which at the current price of $1.072/therm for natural gas translates into an estimated $287,300 savings in annual costs for the affected facilities.

Table 6.1 – VOC Cost Effectiveness

Capital costs ($MM) (Process modifications)	$10.25
Present Value ($MM)	$21.45
VOC Emission Reduction (TPY)	129
Equipment Life	25
Cost Effectiveness($/ton)	$6,700
With 30% Contingency:	**$8,700/ton**

C. INCREMENTAL COST EFFECTIVENESS

Pursuant to Health and Safety Code Section 40920.6, prior to adopting rules or regulations to meet the requirement for Best Available Retrofit Control Technology (BARCT) pursuant to

Sections 40918, 40919, 40920, and 40920.5, or for a feasible measure pursuant to Section 40914, SCAQMD is required by the Health and Safety Code to identify one or more potential control options which achieve emission reduction objectives, determine the cost-effectiveness of each potential control option and determine the incremental cost-effectiveness of potential control options.

Health and Safety Code 40920.6 requires determination of incremental cost-effectiveness of potential control options, defined as "the difference in the dollar costs divided by the difference in the emission reduction potentials between each progressive/most stringent potential control option as compared to the next less expensive control option".

Coke Production

The most stringent control scenario would be to strive towards eliminating the need for atmospheric venting of the drums by capturing all the vapors and routing them to a fuel gas/blowdown system. In order to achieve this, it is assumed that an operator would have to increase the cycle time at a minimum by two hours to condense all the vapors in the headspace below 212 ^{o}F prior to opening the drum. The same parameters and assumptions used for calculating the emissions inventory in Table 3.3 Chapter III are made in order to calculate the cost of this option. In addition, the coke bulk density is assumed to be 55 lbs/cu ft.

For the average drum the coke bed volume is:

V = (22.25^2 x 3.14 / 4 x 52) cu ft x 7.481 gal / cu ft x 1 bbl / 42 gal = 3,600 bbl

The average coking cycle per drum is 16.44 hours, resulting in a charge rate of:

Charge rate = 3,600 bbl / 16.44 hrs = 219 bbl/hr

If the decoking cycle is extended by two hours, the coking cycle will have to be extended by two hours also, therefore the charge rate in this instance will be:

Charge rate = 3,600 bbl / 18.44 hrs = 195 bbl/hr

The lower charge rate represents a decrease of:

Decrease in charge rate = (219 -195) / 219 x 100 = 11 %

The decrease will negatively impact the production of coker gasoline and petroleum coke since less is produced per day. The number of full cycles (2 x 18.44 hr) per year per drum is:

Cycles = 24 hrs/day x 365 days/yr / 36.88 hrs/cycle = 238 cycles/yr/drum

The number of full cycles (2 x 16.44 hr) cycles per year per drums is:

Cycles = 24 hrs/day x 365 days/yr / 32.88 hrs/cycle = 266 cycles/yr/drum

The 28 cycles difference represents lost production per year, which can be calculated for all 36 drums:

Lost product = (22.25^2 x 3.14 / 4 x 52) cu ft x 55 lbs/cu ft x 36 drums x 28 cycles/yr x 1 ton / 2,000 lbs = 560,178 tons coke/yr

At the current petroleum coke market conditions, a ton of coke can sell for approximately $150/ton; therefore, the value of lost production is:

Cost of lost coke production = 560,178 tons x $150/ton = $84MM/yr

Gasoline Production

The 11% decrease in charge rate will also affect the gasoline production of the delayed coking unit. In order to calculate the lost gasoline production the following assumptions are made:

- Assume the average feed rate for the six delayed coking units is 40,000 bbl/day
- The typical gasoline yield is 16% wt
- The specific gravity of coker resid feed is 8.37 lb/gal
- The specific gravity of gasoline is 5.6 lb/gal
- Average retail price for a gallon of gasoline is $ 3.80

The lost gasoline production is:

Lost gasoline production = 0.11 x 40,000 bbl/day x 6 x 42 gal/bbl x 8.37 lb/gal x 0.16 / 5.6 lbs/gal = 265,162 gal/day

The wholesale price per gallon of gasoline is the retail less federal, state and local taxes, assumed to be approximately 55 cents per gallon based on data from the California Energy Commission

The annualized cost of the lost gasoline production is:

Cost = 265,162 gal/day x $(3.80- 0.55)/gal x 365 days/yr = $315MM/yr

The total annual cost of lost coke and gasoline production is:

Total cost = $84MM + $315MM = $399 MM/yr

Incremental Cost Effectiveness

The most stringent control is to control all emissions from venting, which is the total emission inventory of 268 tpy. The next less expensive control that is proposed by the rule is to reduce emissions by 129 tpy. As shown before, the cost of the proposed rule high range present value is:

PV = $27,896,369 (at a 30% contingency)

Per Health and Safety Code 40920.6, the incremental cost effectiveness is:

Incremental Cost = ($399,000,000 – $27,896,369) / (268 tons – 129 tons) =

= $2.7 MM/ton VOC reduced

Table 6.2 summarizes the total annual cost increase, permanent emission reductions and incremental cost effectiveness of the two scenarios discussed above.

Table 6.2

Control Option	VOC Reductions (tpy)	Annual Cost Increase ($)	Incremental Cost Effectiveness
No Project	0	0	N/A
PR 1114 < 2 psig	129	$27,896,369	$8,700
No Atmospheric Venting	268	$399,000,000	$2,700,000

C H A P T E R V I I

COMMENTS AND RESPONSES

The following comments were received with regards to the public workshop conducted on December 12, 2012 in Wilmington, CA.

Comment #1

What is the rationale for the initial six months deadline following rule adoption and the additional extension in the compliance deadline beyond the six months for certain facilities?

Response

The initial six month period is proposed to allow for any modifications that can be accomplished outside of a turnaround such as software or procedural updates, for facilities that can achieve the proposed final compliance limit with existing equipment but that may require quality control improvements to ensure safety and continuous compliance. Units in petroleum refineries typically operate continuously on approximately five year cycles in-between shutdown periods for maintenance and repair, or "turnaround" periods. It is during these turnarounds that necessary modifications can be implemented for rule compliance. The proposed up to five year period is intended to accommodate the staggered nature of the various turnaround periods at multiple facilities. Furthermore, projects that might be required for compliance with the proposed rule involve engineering and design, funding, equipment procurement, new hardware and require adequate time to complete. Therefore, staff believes that the proposed timelines are reasonable.

Comment #2

What are the enforceable mechanisms for ensuring compliance with the proposed rule?

Response

Facilities will be required under the proposed rule to keep and provide records of the coke drum internal pressure, atmospheric vent valve position (open/closed), on a continuously monitored basis. Calibration records for the pressure gauges will also be required under the proposal to further demonstrate compliance.

Comment #3

What are the provisions for failure to comply with the interim requirements associated with the proposed rule?

Response

Failure to comply with the interim requirements associated with the proposed rule would put a facility in violation of the rule, which would trigger the issuance of a Notice of Violation, and subsequent enforcement action.

Comment #4

Can the compliance schedule be more explicitly linked to turnaround activities to ensure compliance is achieved as soon as possible?

Response

Staff has evaluated issues associated with the planning of maintenance turnaround for delayed coking units and the proposed rule language was modified to require compliance following the unit turnaround or a set date, whichever is earlier.

Comment #5

What is the relationship between the quality of crude oil feedstocks and the potential emissions and emission characterization? Can particular feedstocks be limited or excluded from processing?

Response

Typically, light sweet crude oil feedstocks have a lower amount of sulfur, whereas heavy, sour crude oil feedstocks contain a relatively higher amount of sulfur (~4%) as well as long chain molecules called asphaltenes which require more intensive processing and pollution controls. While there are no regulations limiting the type of feedstocks used, there are limits on the amount of emissions being generated from processing them in units upstream or downstream of the delayed coking operation.

Comment #6

There should be more community outreach and participation in the rule development process to improve awareness and address concerns.

Response

Staff publishes workshop notices on its website as well as local newspapers. The public workshop for PR 1114 was held in the Wilmington area on December 12, 2012 at 5:30 PM in an effort to maximize public awareness and participation and be able to hear directly from the affected public. Staff will continue to look for additional ways to enhance its outreach efforts and increase community awareness about proposed new regulations.

Comment #7

Staff's estimated cost for compliance is based on an assessment of "similar" installations. Industry has provided a much higher estimated cost that is more facility specific. The representativeness for the range in costs should be reconsidered.

Response

The initial cost estimate provided by industry are design-based, while the similar installations used by staff for comparison were retrofit projects, therefore staff believes the cost estimate is adequate since they have similar compliance requirements. However, in order to account for site to site variability, staff is broadening the cost estimates by incorporating an additional 30% contingency into the approximation.

Comment #8

How does a facility demonstrate compliance with the proposed depressurization limit?

Response

Once the internal pressure of the coke drum falls below two psig while being depressurized to the blowdown system at the end of the coking cycle, the operator has achieved compliance with the depressurization limit. During the short transition period when the drum is isolated from blowdown and until the atmospheric vent valve is open, there may be a spike in the drum pressure that may momentarily exceed the specified limit, however these spikes will not be considered a violation of the depressurization limit.

Comment #9

Can a facility calculate the proposed 2012 interim average depressurization baseline based on general engineering practices due to the lack of necessary monitoring instrumentation that it did not have during the baseline year?

Response

Staff is modifying the rule language to allow, at facilities where monitoring and recording equipment is not yet installed, calculations using general engineering practices and substantiating records to be submitted to the Executive Officer for approval for determining the 2012 vent pressure average for all drums at a facility.

Comment #10

Facilities need some time following rule adoption to implement the continuous monitoring requirement of the proposed rule.

Response

The proposed rule has been modified to harmonize the effective dates for the continuous monitoring and depressurization requirements.

Comment #11

The continuous monitoring requirement should allow for downtime to account for maintenance and breakdown periods.

Response

Rule language was modified to allow for 96 hours of downtime per calendar year per DCU due to breakdowns, ~~or~~ maintenance or calibration of the monitoring equipment for the coke drum pressure and the atmospheric valve position. Manual readings for pressure and valve position will be required at five minute set intervals for a period of at least 15 minutes immediately prior to venting the coke drum to atmosphere.

Comment #12

The exemption for Rules 404, 405 and 407 under the proposed rule should apply to any delayed coking unit that is compliant with the provisions of the proposed rule, and not limited to only those that meet the final depressurization limit of two psig.

Response

Staff is proposing to exempt delayed coking units from the provisions of Rule 404 only based on a determination that the rule does not apply to delayed coking units. Staff does not believe that exemptions from Rules 405 and 407 are necessary after evaluating DCU source test results that show compliance with the mass emission and CO emission limits; Rule 407 provisions for sulfur compounds emissions do not apply to equipment subject to Regulation XI.

Comment #13

The proposed rule should allow for additional time to meet the final depressurization limit at the Executive Officer's discretion if scheduling or other unforeseen events necessitate a slippage in otherwise planned turnaround events during which the equipment modifications needed to meet the proposed final limit would occur. Rule 1105.1 has a similar provision.

Response

Because the US EPA generally disapproves incorporation of Executive Officer discretion into the State Implementation Plan (SIP), it is the general policy of the District to avoid incorporating this approach into rule language. Other administrative remedies, such as the Hearing Board, are available for such situations.

Comment #14

For clarification purposes, the definition of delayed coking unit should refer to a "main" fractionators rather than a "single" fractionator, and references to operation should refer to "venting" rather than "discharging" to atmosphere.

Response

The proposed rule language has been updated to replace the words "single" and "discharging" with "main" and "venting", respectively, as noted, in paragraph (b)(2) and (c)(1).

Comment #15

The emission calculation section in the staff report should more clearly indicate that the inventory is based on estimates.

Response

An additional section listing the emission calculation assumptions has been added to the staff report.

Comment #16

The process flow diagram provided in the preliminary draft staff report is unclear and should identify fresh feed going to the main fractionators rather than directly to the delayed coker heater.

Response

The process flow diagram has been replaced with a more detailed depiction, including the initial feed into the main fractionators.

Comment #17

The data from the source test results identified in the staff report do not establish a correlation between the drum initial venting pressure and emissions.

Response

The source tests conducted at local refineries, as noted in the preliminary draft staff report, were not run to establish correlations. Prior to drawing any conclusions with respect to correlating pressure and emissions, additional testing would be required. While industry may support additional testing in order to establish correlations between process parameters, District staff believes that the use of a theoretical approximation based on the temperature driven heat balance methodology supported by U.S. EPA is sufficient to establish emission estimates and to demonstrate effectiveness. Based on discussions with the refineries and WSPA, with consideration of the assumptions, facilities concur that a heat balance methodology is the preferred approach over additional source tests.

Comment #18

Reference to the phrase "near-compliance" is subjective and ambiguous and should not be used in the staff report.

Response

The phrase "near-compliance" has been removed. Where appropriate, when describing the current status of affected facilities, the more objective reference to current operating pressures is used instead.

Comment #19

Would periods of downtime at DCU's, such as heater tube spalling or other unplanned breakdowns and repairs be construed as "Turnarounds" and therefore trigger compliance deadlines?

Response

Staff's intention is to link the planned turnaround activities to deadlines for achieving compliance. Staff would consider a DCU to be shut down for turnaround when all major vessels,

including the main fractionator, have been gas freed and opened. Stoppages in production for heater spalling, unplanned breakdown and repairs would not be considered turnarounds for the purpose of this rule.

Comment #20

The requirement to continuously monitor the vent valve position may require equipment upgrades dependent on turnaround scheduling. Can alternative parameters that are currently being monitored or that do not rely on turnaround installation be used in the interim?

Response

The proposed rule has incorporated an alternative monitoring provision allowed until the next unit turnaround but no later than December 31, 2016, whichever is earlier, for monitoring the blowdown valve position or coke drum vent pipe temperature, in lieu of monitoring the atmospheric vent valve position.

Comment #21

Can a facility's safety interlock system for the coke drum operation be used to demonstrate compliance with the atmospheric vent valve position monitoring (open or closed) and recording requirement?

Response

The purpose of the vent valve monitoring requirement is to determine when atmospheric venting has occurred. District staff would consider continuous monitoring and recording of the vent valve via a safety interlock system to meet the conditions for determining when atmospheric venting has occurred, so long as the safety interlock conditions clearly indicate a closed or opened position, and would consider a partially open valve, or valve that is in the process of being opened or closed, to be opened, until fully closed.

C H A P T E R V I I I

IMPACT ASSESSMENT

A. ENVIRONMENTAL IMPACT ASSESSMENT

Pursuant to California Environmental Quality Act (CEQA) Guidelines §15252 and §15162 and SCAQMD Rule 110, the SCAQMD has prepared an Environmental Assessment (EA) for Proposed Rule 1114. The environmental analysis in the Draft EA concluded that Proposed Rule 1114 would not generate any significant adverse environmental impacts. The Draft EA was released for a 30-day public review and comment period from February 28, 2013 to March 29, 2013, resulting in the receipt of two comment letters. Both comment letters and responses are included as Appendix D of the EA.

Since the release of the Draft EA, minor modifications have been made to the document. However, none of the modifications alter any conclusions reached in the Draft EA, nor provide new information of substantial importance relative to the draft document. Moreover, these minor revisions do not require recirculation of the Draft EA pursuant to CEQA Guidelines §15073.5 and §15088.5. Therefore, the Draft EA is now a Final EA and is included as an attachment to this Governing Board package. Prior to making a decision on the proposed adoption of Rule 1114, the SCAQMD Governing Board must review and certify the Final EA as providing adequate information on the potential adverse environmental impacts of the proposed project.

~~Pursuant to California Environmental Quality Act (CEQA) Guidelines §15252 and §15162 and SCAQMD Rule 110, the SCAQMD has prepared an Environmental Assessment (EA) for PR 1114. The environmental analysis in the Draft EA concluded that PR 1114 would not generate any significant adverse environmental impacts. The Draft EA was released for a 30-day public review and comment period from February 28, 2013 to March 29, 2013. Any comments received during the public comment period on the analysis presented in the Draft EA will be responded to and included in the Final EA. Prior to making a decision on the proposed adoption of PR 1114, the SCAQMD Governing Board must review and certify the Final EA as providing adequate information on the potential adverse environmental impacts of the proposed project. Copies of the CEQA document prepared for PR 1114, can be obtained by calling the SCAQMD's Public Information Center at (909) 396-2039 or by downloading it from the SCAQMD's website at: http://www.aqmd.gov/ceqa/aqmd.html.~~

B. SOCIOECONOMIC ASSESSMENT

PR 1114 would require petroleum refineries with delayed coking units (DCU's) to reduce pressure in coke drums to less than two pounds per pressure inch gauge (psig) prior to venting coke drums to atmosphere. In addition, PR 1114 would require the affected facilities to continuously monitor and record the internal pressure of coke drums, and maintain records for a period of five years.

Affected Industries

The proposed rule would affect six refineries. All six affected refineries are located in Los Angeles County. The affected facilities belong to the sectors of petroleum refineries [North American Industrial Classification System (NAICS) 324110].

Compliance Cost

It is assumed that affected refineries would install steam ejector systems to comply with the proposed pressure limit. Out of the six affected refineries, two are already capable of meeting

the proposed pressure limits. The remaining four refineries are expected to install four steam ejector systems. The capital and installation cost of three steam ejector systems is estimated at $3 million each. The cost of the remaining steam ejector system is estimated to be $1.25 million. Staff is incorporating a contingency factor of 30 percent of capital and installation cost to account for site-to-site variability that may affect actual upgrades to comply with PR 1114. This would bring the total one-time cost to $13.33 million. Based on the equipment life of each system at 25 years and a four-percent real interest rate, the annualized cost of capital and installation for all four systems is estimated to be $0.85 million.

The annual operating and maintenance cost of a steam ejector system is assumed to be seven percent of the capital, installation, and contingency cost, and is estimated to be $0.93 million for all four systems. Of the $0.93 million, $0.53 million is assumed for labor maintenance and the remaining for additional utility costs ($0.40 million). The annual cost of monitoring and recordkeeping is expected to be minimal and thus is not considered here. The total annual cost of PR 1114 is estimated to be $1.79 million.

Regional Economic Impacts

The cost of PR 1114 is used as input to an economic model, REMI, for an assessment of secondary and induced impacts from 2013 to 2035. Costs of equipment, installation, and operating and maintenance would result in increases in the cost of doing business for petroleum refineries. The additional labor required for maintaining steam ejector systems would result in a reduction in labor productivity for the affected refineries because more labor will now be required to produce the same amount of output.

Additional purchases of steam ejector systems are expected to increase sales of the machinery manufacturing sector. However, none of those facilities are located within the four-county area. Installation of the above equipment, however, is expected to benefit the construction, and professional and technical services sectors locally.

Overall, five jobs could be created annually, on average, between 2013 and 2035, which is about 0.0001 percent of the baseline jobs in the four county area. Table 1 presents the estimated job impact by industry. In the first four years (2013-2016), there would be additional jobs created in the overall economy. The sectors of construction and professional and technical services would gain a larger share of additional jobs due to additional spending on equipment installations. Overall, positive job impacts from the expenditures made by petroleum refineries would more than offset the jobs forgone from the additional cost of doing business. The remaining sectors would incur minor jobs forgone from secondary and induced impacts of the proposed rule.

Table 1 - Job Impacts of Proposed Rule

Industries	2013	2016	2035	Average Annual (2013-2035)
Construction	17	16	-1	2
Manufacturing	2	1	0	0
Wholesale Trade	1	1	0	0
Retail Trade	4	3	-1	0
Professional, Scientific, and Technical Serv.	8	8	0	1
Administrative and Waste Management Serv.	2	2	0	0
Health Care and Social Assistance	3	2	0	0
Accommodation and Food Services	2	2	0	0
Other Services, except Public Administration	2	2	0	0
Government	3	3	0	0
Other Industries	4	3	0	0
Total*	**48**	**43**	**-2**	**5**

*Numbers may not add up to the total due to rounding.

Rule Adoption Relative to the Cost-Effectiveness Schedule

On October 14, 1994, the Governing Board adopted a resolution that requires staff to address whether proposed rules being considered for adoption are presented in rank order by cost-effectiveness as defined in the Air Quality Management Plan (AQMP). PR 1114 partially implements Control Measure MCS-01—Application of All Feasible Measures—in the 2012 AQMP. The cost-effectiveness of Control Measure MCS-01 was not assessed for the 2012 AQMP. The overall cost effectiveness of the proposed rule is estimated to be $8,700 per ton of VOC, which is well below the cost-effectiveness of recently adopted VOC rules.

C. COMPARATIVE ANALYSIS

Pursuant to Health and Safety Code Section 40727.7 staff has prepared a comparison of existing or proposed AQMD rules, regulations, requirements with other California Districts and federal air pollution control measures that apply to the same source type. The following table summarizes the analysis:

Comparison of PR 1114 with 40 CFR 60 Subpart Ja and 40 CFR 63 Subpart CC

Category	PR 1114	40 CFR 60 Subpart Ja*	40 CFR 63 Subpart CC
Averaging provisions, units, and any other pertinent provisions associated with emission limits	Drum pressure, psig	Drum pressure, psig	Drum pressure, psig
Operating parameters and work practice requirements.	Depressurize drum to less than two psig	Depressurize drum to 5 psig	Drum vent gas at > 15 psig must be routed to control device
Monitoring, reporting, and recordkeeping requirements, including test methods, format, content, and frequency	Continuous pressure and vent valve monitoring and recording. Maintain records for 5 years	Not identified	Continuous monitoring of the control device relevant parameter, performance test, recordkeeping and semiannual reporting

* Applies to new or modified DCU's

D. DRAFT FINDINGS UNDER CALIFORNIA HEALTH AND SAFETY CODE SECTION 40727

Health and Safety Code Section 40727 requires that prior to adopting, amending or repealing rules, 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 adopt Rule 1114 – Petroleum Refinery Coking Operations, to partially implement Control Measure CM #2012 MCS-01 – Application of All Feasible Measures Assessment from the 2012 AQMP and help AQMD attain the National Ambient Air Quality Standard for ozone for which AQMD is classified as an Extreme Non-Attainment Area.

Authority: The District obtains its authority to adopt, amend or repeal rules and regulations from California Health and Safety Code Sections 39002, 40000, 40001, 40440, 40441, 40463, 40702, and 40725 through 40728, and 41508.

Clarity: Rule 1114 – Petroleum Refinery Coking Operations as proposed to be adopted, is written or displayed so that its meaning can be easily understood by the persons directly affected by it.

Consistency: Proposed Rule 1114 – Petroleum Refinery Coking Operations is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or federal or state regulations.

Non Duplication: Rule 1114 – Petroleum Refinery Coking Operations, as proposed to be adopted, does not impose the same requirements as any existing state or federal regulations, and the amendments are necessary and proper to execute the powers and duties granted to, and imposed upon, the District.

Reference: This regulation would implement, interpret or make specific the provisions of: Health and Safety Code Sections 40001 (rules to achieve ambient air quality standards),

40440(a) and (c) (rules to carry out the Air Quality Management Plan and rules which are also cost-effective and efficient), 40702 (do such acts necessary to execute duties imposed by law), and 40910 et seq., (California Clean Air Act).

1 Paul J. Ellis and Christopher A. Paul, "Tutorial: Delayed Coking Fundamentals", 1998.

2 http://www.epa.gov/ttn/atw/petref/petrefpg.html.

3 http://en.wikipedia.org/wiki/Delayed_coker.

4 40 CFR 63.640 – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, August 18, 1995.

5 Federal Register/Vol. 73, No. 122, June 24, 2008 p. 35857.

6 http://energyalmanac.ca.gov/gasoline/gasoline_taxes.html.

7 "Chemical Engineering", February 2011, p. 60.

8 Perry, R.H., Green, D.W., "Perry's Chemical Engineer's Handbook", Seventh Edition, McGraw-Hill, 1997.

9 SCAQMD Source Tests of Delayed Coking Units at Six Local Refineries, 2003 – 2009.

10 Communication between U.S. EPA Brenda Shine and Eugen Teszler, SCAQMD, 2012.

ATTACHMENT G

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

Final Environmental Assessment for
Proposed Rule 1114 – Petroleum Refinery Coking Operations

April 2013

SCAQMD No. 02262013BAR
State Clearinghouse No: 2013021066

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PREFACE

This document constitutes the Final Environmental Assessment (EA) for Proposed Rule (PR) 1114 – Petroleum Refinery Coking Operations. The Draft EA was released for a 30-day public review and comment period from February 28, 2013 to March 29, 2013. Two comment letters were received from the public on the Draft EA. The comment letters, along with responses to the comments, are included in Appendix D of this document.

Subsequent to release of the Draft EA, minor modifications were made to PR 1114. To facilitate identification, modifications to the document are included as underlined text and text removed from the document is indicated by ~~strikethrough~~. Staff has reviewed the modifications to PR 1114 and concluded that none of the modifications alter any conclusions reached in the Draft EA, nor provide new information of substantial importance relative to the draft document. Moreover, these minor revisions do not require recirculation of the document pursuant to CEQA Guidelines §15073.5 and §15088.5. Therefore, this document now constitutes the Final EA for PR 1114.

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CHAPTER 1

PROJECT DESCRIPTION

Introduction

California Environmental Quality Act

Project Location

Project Background

Project Description

Technology Overview

INTRODUCTION

The California Legislature created the South Coast Air Quality Management District (SCAQMD) in 1977[1] as the agency responsible for developing and enforcing air pollution control rules and regulations in the South Coast Air Basin (Basin) and portions of the Salton Sea Air Basin and Mojave Desert Air Basin referred to herein as the district. By statute, the SCAQMD is required to adopt an air quality management plan (AQMP) demonstrating compliance with all federal and state ambient air quality standards for the district[2]. Furthermore, the SCAQMD must adopt rules and regulations that carry out the AQMP[3]. The 2012 AQMP concluded that major reductions in emissions of particulate matter (PM), oxides of sulfur (SOx) and oxides of nitrogen (NOx) are necessary to attain the state and national ambient air quality standards for ozone, particulate matter with an aerodynamic diameter of 10 microns or less (PM10) and particulate matter with an aerodynamic diameter of 2.5 microns or less (PM2.5). More emphasis is placed on NOx and SOx emission reductions because they provide greater ozone and PM emission reduction benefits than volatile organic compound (VOC) emission reductions. VOC emission reductions, along with NOx emission reductions, continue to be necessary, because emission reductions of both of these ozone precursors are necessary to meet the ozone standards. VOC emission reductions also contribute to achieving the PM2.5 ambient air quality standards. Proposed Rule (PR) 1114 – Petroleum Refinery Coking Operations, would partially implement 2012 AQMP Control Measure MCS-01 – Application of All Feasible Measures, to achieve additional emission reductions from specified pollutants, as explained in more detail below.

Ozone, a criteria pollutant that is formed when NOx and VOCs react in the atmosphere, has been shown to adversely affect human health. The federal one-hour[4] and eight-hour ozone standards were exceeded in the district in 2010. The Central San Bernardino Mountain area recorded the greatest number of exceedences of the one-hour state standard (52 days), eight-hour state standard (101 days), and eight-hour federal standard (74 days). However, none of the four counties had health advisory days in 2010. Altogether, in 2010, the South Coast Air Basin exceeded the federal eight-hour ozone standard on 102 days, the state one-hour ozone standard on 79 days, and the state eight-hour ozone standard on 131 days[5].

Although health-based standards have not been established for VOCs, health effects can occur from exposures to high concentrations of VOCs because of interference with oxygen uptake. In general, ambient VOC concentrations in the atmosphere are suspected to cause coughing, sneezing, headaches, weakness, laryngitis, and bronchitis, even at low concentrations. Some hydrocarbon components classified as VOC emissions are thought or known to be toxic air contaminants (TACs). With stationary and mobile sources being the major producers of VOCs, which contribute to ozone formation, reducing the quantity of VOCs in the district has been an on-going effort by the SCAQMD.

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[1] The Lewis-Presley Air Quality Management Act, 1976 Cal. Stats., ch 324 (codified at Health and Safety Code, §§40400-40540).
[2] Health and Safety Code, §40460 (a).
[3] Health and Safety Code, §40440 (a).
[4] The federal one-hour ozone standard was replaced by the federal eight-hour ozone standard, effective June 15, 2005.
[5] 2010 Air Quality Historical Data, South Coast Air Quality Management District, http://www.aqmd.gov/smog/historical/AQ10card.pdf.

The California Clean Air Act (CCAA) requires districts to achieve and maintain state standards by the earliest practicable date and for extreme non-attainment areas, to include all feasible measures pursuant to Health and Safety Code §§40913, 40914, and 40920.5. The term "feasible" is defined in the Title 14 of the California Code of Regulations, §15364, as a measure "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, legal, social, and technological factors."

PR 1114 would apply to delayed coking units (DCUs) at petroleum refineries located within SCAQMD's jurisdiction and classified by the North American Industry Classification System (NAICS) code 324110. There are six refineries operating eight DCUs with a total of 36 coke drums. All six refineries are ~~location~~ located in Los Angeles County.

The 2012 AQMP Control Measure MCS-01 contains unspecified emission reduction goals that apply to a variety of emission sources. Based on the general emission reduction goals in the 2012 AQMP and the technological advancements achieved for delayed coking operations, PR 1114, upon full implementation, would partially implement Control Measure MCS-01 to reduce VOC emissions by up to 0.36 ton per day, PM emissions by up to 0.05 ton per day, hazardous air pollutant (HAP) emissions by up to 0.07 ton per day~~,~~ and methane emissions by up to 1.51 tons per day. PR 1114 is also anticipated to reduce sulfur as hydrogen sulfide (H2S) by up to 0.05 ton per day.

CALIFORNIA ENVIRONMENTAL QUALITY ACT

PR 1114 would regulate the depressurization limit of coke drums in delayed coking units. Because the proposed project requires discretionary approval by a public agency, it is a "project" as defined by the California Environmental Quality Act (CEQA). SCAQMD is the lead agency for the proposed project and has prepared this ~~draft~~ Final Environmental Assessment (EA) with no significant adverse impacts pursuant to its Certified Regulatory Program. California Public Resources Code §21080.5 allows public agencies with regulatory programs to prepare a plan or other written document in lieu of an environmental impact report once the Secretary of the Resources Agency has certified the regulatory program. The SCAQMD's regulatory program was certified by the Secretary of the Resources Agency on March 1, 1989, and is codified as SCAQMD Rule 110 - Rule Adoption Procedures to Assure Protection and Enhancement of the Environment.

CEQA and Rule 110 require that potential adverse environmental impacts of proposed projects be evaluated and that feasible methods to reduce or avoid significant adverse environmental impacts of these projects be identified. To fulfill the purpose and intent of CEQA and pursuant to Rule 110 (the rule which implements the SCAQMD's certified regulatory program), SCAQMD has prepared this ~~Draft~~ Final EA to evaluate potential adverse environmental impacts associated with implementing the proposed project. The ~~Draft~~ Final EA is a public disclosure document intended to: ~~-~~(a) provide the lead agency, responsible agencies, decision makers and the general public with information on the environmental effects of the proposed project; and, (b) be used as a tool by decision makers to facilitate decision making on the proposed project. This ~~Draft~~ Final EA includes an

Environmental Checklist and project description. The Environmental Checklist provides a standard evaluation tool to identify a project's adverse environmental impacts.

SCAQMD's review of the proposed project shows that PR 1114 would not have a significant adverse effect on the environment. Because PR 1114 will have no statewide, regional or areawide significance, no CEQA scoping meeting was required to be held for the proposed project pursuant to Public Resources Code §21083.9(a)(2). Further, pursuant to CEQA Guidelines §15252, since no significant adverse impacts were identified, no alternatives or mitigation measures are required to be included in this ~~Draft~~ Final EA. The analysis in Chapter 2 supports the conclusion of no significant adverse environmental impacts.

Two comment letters were received relative to the analysis prepared in the Draft EA during the 30-day public review period (from February 28, 2013 to March 29, 2013). These comment letters, along with responses to the comments, are included in Appendix D of this document. Prior to making a decision on the proposed rule, the SCAQMD Governing Board must review and certify that the Final EA complies with CEQA as providing adequate information on the potential adverse environmental impacts of the proposed rule. None of the comments in the letters alter any conclusions reached in the Draft EA, nor provide new information of substantial importance relative to the draft document. ~~Written comments on the environmental analysis will be evaluated and responses to all comments received will be prepared and included in the Final EA.~~

PROJECT LOCATION

The SCAQMD has jurisdiction over an area of approximately 10,743 square miles, consisting of the four-county South Coast Air Basin (Basin) (Orange County and the non-desert portions of Los Angeles, Riverside and San Bernardino counties), and the Riverside County portions of the Salton Sea Air Basin (SSAB) and Mojave Desert Air Basin (MDAB). The Basin, which is a subarea of the SCAQMD's jurisdiction, is bounded by the Pacific Ocean to the west and the San Gabriel, San Bernardino, and San Jacinto mountains to the north and east. It includes all of Orange County and the nondesert portions of Los Angeles, Riverside, and San Bernardino counties. The Riverside County portion of the SSAB is bounded by the San Jacinto Mountains in the west and spans eastward up to the Palo Verde Valley. The federal nonattainment area (known as the Coachella Valley Planning Area) is a subregion of Riverside County and the SSAB that is bounded by the San Jacinto Mountains to the west and the eastern boundary of the Coachella Valley to the east (Figure 1-1).

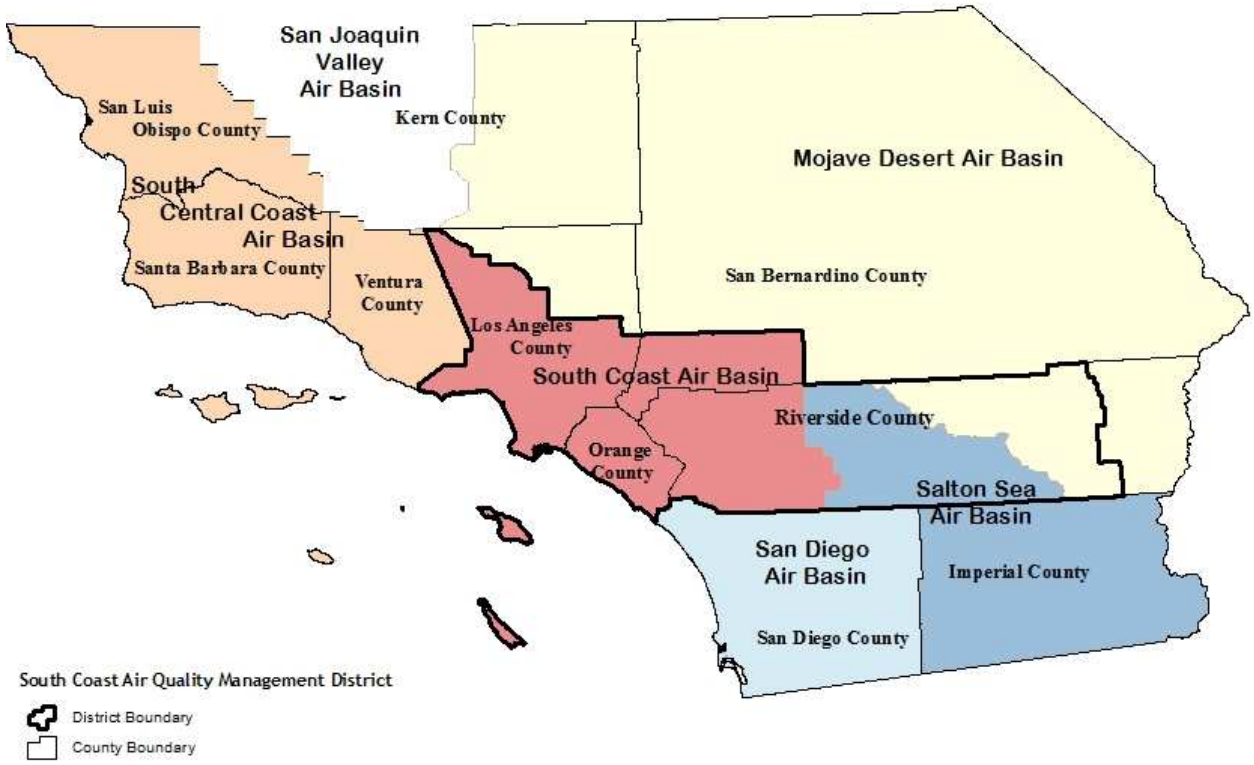

FIGURE 1-1
Southern California Air Basins

PROJECT BACKGROUND

Among stationary sources, petroleum refineries are one of the major emitters of air pollutants, accounting for seven tons per day (tpd) of VOC emissions, 10 tpd carbon monoxide (CO) emissions, 10 tpd NOx, six tpd sulfur oxides (SOx), and five tpd total suspended particulate (TSP) emissions in the year 2011. While there are several SCAQMD regulations that contain individual rules specific to a variety of industrial processes at petroleum refineries (e.g., under Regulation IV – Prohibitions, Regulation XI – Source Specific Standards, Regulation XIV – Toxics and Other Non-Criteria Pollutants and Regulation XX – Regional Clean Air Incentives Market (RECLAIM), currently there is no SCAQMD rule or regulation specific to DCU operations. Further, there are no rules at any other Air Pollution Control District in California applicable to DCUs. For this reason, SCAQMD staff has studied emissions specific to the atmospheric venting of DCUs at local petroleum refineries and determined that the quantities of emissions (e.g., VOC, PM, methane (CH4), sulfur compounds and polycyclic organic matter (POM) compounds) from DCU operations warranted consideration for further emission reductions.

At the federal level, in 2008, the United States Environmental Protection Agency (USEPA), after evaluating source test results from DCUs at three facilities, promulgated a regulation

specifically applicable to DCU operations that establishes a vent limit of five pounds per square inch, gauge (psig) for coke drums at new or modified DCUs in Chapter 40, Part 60, Subpart Ja of the Code of Federal Regulations (40 CFR 60 Subpart Ja) - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced after May 14, 2007. In addition, the USEPA also addresses DCUs in 40CFR 63 Subpart CC – National Emission Standards for Hazardous Air Pollutants (NESHAP) from Petroleum Refineries, which classifies delayed coke drum vents as miscellaneous process vents that are subject to controls, such as venting to a vapor recovery system, scrubber etc., if the atmospheric depressuring of the coke drum is done at a pressure higher than 15 psig.

More recently, in 2010, the USEPA issued more source test requests for coke drum vent emissions to several refineries at various locations throughout the United States in an effort to improve emission inventory protocols and establish emission factors for the DCU emission points in order to update AP-42 - Compilation of Air Pollutant Emission Factors.

SCAQMD staff estimates the baseline emissions from DCU operations at 264 tons per year (tpy) VOC, 1,119 tpy CH4 (which is a greenhouse gas (GHG)), and 53 tpy HAP, which are mainly comprised of benzene and POM (e.g., naphthalene, anthracene and fluorine). This inventory is compiled from emissions from six petroleum refineries that operate DCUs in the district as shown in Table 1-1:

TABLE 1-1
Petroleum Refineries Operating DCUs

Petroleum Refinery	Location
BP	Carson
Chevron USA	El Segundo
ExxonMobil	Torrance
Phillips 66	Carson
Tesoro	Wilmington
Valero	Wilmington

PROJECT DESCRIPTION

The following is a summary of the key components to PR 1114. A copy of the proposed rule can be found in Appendix A.

Proposed Rule 1114 – Petroleum Refinery Coking Operations

Purpose and Applicability - subdivision (a)
This subdivision establishes the applicability of PR 1114 to include the atmospheric venting of coke drums at all petroleum refineries that are equipped with DCUs.

Definitions - subdivision (b)
The following definitions are proposed for inclusion in PR 1114: "coke drum," "delayed coking unit," "petroleum refinery," and "turnaround."

Requirements - subdivision (c)
Paragraph (c)(1) establishes a requirement for a DCU coke drum to be depressurized to less than two psig prior to being discharged to atmosphere. This requirement would go into effect on November 1, 2013~~six months following the adoption of PR 1114~~.

In the event that a facility is unable to comply with the two psig depressurization limit in paragraph (c)(1) by the specified date, an extra period of time will be allowed, depending on the number of DCUs they operate, to make necessary process and equipment modifications that can be completed during downtime periods for maintenance and repair known as turnarounds. Specifically, paragraph (c)(2) provides for an interim depressurization limit of five psig, provided that the following conditions are met. Specifically, subparagraph (c)(2)(A), effective May 1, 2014, is applicable to a facility with a single delayed coking unit and would temporarily allow depressurization to less than five psig until ~~requires~~ compliance with the two psig depressurization limit is reached upon completion~~by the date~~ of the first unit turnaround after May 1, 2014 or December 31~~6~~, 2016, whichever is earlier. Similarly, subparagraph (c)(2)(B) is applicable to a facility with more than one delayed coking unit and requires the submission of either: 1) a baseline calculation along with supporting documentation to be submitted to the SCAQMD by November 1, 2013 ~~within six months following the adoption of PR 1114~~ that identifies the facility-wide average depressurization value at which atmosphere venting was initiated for all coke drums at the facility during calendar year 2012; or, 2) a notification that the facility intends to depressurize each coke drum to less than five psig until achieving final compliance with the two psig depressurization limit. Clause (c)(2)(B)(ii) requires a facility to depressurize all coke drums, by the date of the first unit turnaround after May 1, 2014 or December 31, 2016, whichever is earlier, to either: 1) no more than 110 percent of the 2012 average depressurization value (over a 30-day averaging period) reported in the baseline calculation; or, 2) depressurize each coke drum to less than five psig. Further, clause (c)(2)(B)(iii) would require each coke drum to be depressurized to: 1) less than five psig following its turnaround or until January 1, 2017, whichever is earlier; and, 2) to less than two psig within the following 24 months of the earlier trigger date. Lastly, subparagraph (c)(2)(C) would require a facility operator to submit permit applications within ~~18~~nine months prior to the applicable effective dates for any equipment and process modifications needed to achieve compliance with the final depressurization limit in paragraph (c)(1).

Monitoring and Recording - subdivision (d)
Subdivision (d) contains requirements for monitoring and recording. These requirements will go into effect ~~12 months following the adoption of PR 1114~~November 1, 2013. Specifically, paragraph (d)(1) establishes a requirement for the continuous monitoring of each coke drum pressure from the time when feed is introduced into the drum until prior to when atmospheric venting occurs using an annually calibrated device.

Paragraph (d)(2) establishes a requirement for continuous monitoring from the time when feed is introduced into the drum until when atmospheric venting is initiated of either the

coke drum atmospheric vent valve position (open or closed) per the requirement in subparagraph (d)(2)(A) or the coke drum blowdown valve position or temperature of the coke drum vent per the requirement in subparagraph (d)(2)(B) upon completion of the first unit turnaround following November 1, 2013 or by December 31, 2016, whichever is earlier, if unable to comply with the requirements in subparagraph (d)(2)(A).

Paragraph (d)(3) establishes a requirement to maintain the monitoring equipment in good condition and allows for up to 96 ~~72~~ hours per calendar year of downtime to conduct maintenance and repair, as needed.

Paragraph (d)(4) establishes a requirement to manually record the coke drum pressure and atmosphere~~e~~ic vent valve position at five minute intervals covering a time period of no less than 15 minutes immediately prior to ~~from feed introduction until~~ atmospheric venting ~~is initiated at five minute intervals~~ during any period of downtime.

Notification - subdivision (e)
Subdivision (e) establishes a requirement for the owner or operator to notify the Executive Officer by telephone within 24 hours of any failure of monitoring or recording equipment.

Recordkeeping - subdivision (f~~e~~)
Subdivision (f~~e~~) establishes a requirement, effective November 1, 2013~~six months following the adoption of PR 1114~~, for the owner or operator of a DCU to maintain records of all operational and calibration records for at least five years and to make these records available to the Executive Officer upon request.

Exemptions - subdivision (g~~f~~)
Subdivision (g~~f~~) establishes an exemption from having to comply with SCAQMD Rule 404 - Particulate Matter – Concentration, for any coke drum subject to the rule ~~that can be depressurized to less than two psig prior to being discharged to atmosphere~~.

TECHNOLOGY OVERVIEW

Delayed Coking Process

Delayed coking is a petroleum refinery process that converts mostly heavy residual oils, also known as residuum or "resid" for short, from vacuum distillation towers into gasoline, light gas oil and heavy gas oil. Petroleum coke is a by-product of this process.

The resid is fed into a fractionation tower and the bottom fraction (e.g., the heavy components of the resid), is passed through a heater to raise the temperature in a range of 850 degrees Fahrenheit (°F) to 900 °F as it makes its way to a coke drum under steam injection. The purpose of the steam injection is to delay coking or the solidification of the hot material until it reaches the drum, hence the name "delayed coker." When heated to high temperatures, the heavy ~~feed~~ hydrocarbon chains break~~s~~ into smaller, lighter molecules that rise to the top of the coke drum as vapors that are routed back to the fractionation tower for more separation into gas, gasoline, and other higher value liquid products. Even after heating, the heavier components remain in the coke drum. Within approximately 30 minutes

to one hour, the material left behind in the drum ~~becomes a solid resid~~turns into~~,~~ petroleum coke, a coal-like substance.

Upon introduction of feed within the first drum, also referred to as the "on oil" drum, the coking process begins until reaching capacity, after which the feed is diverted to a second coke drum to start another batch. At the point when the feed has been diverted to the second drum, the first drum is ready to begin the coke removal or decoking process. During decoking, the first drum is referred to as the "off oil" drum. The use of multiple coke drums in tandem pairs allows for a semicontinuous batch operation.

At the end of the coking process, to cool the coke drum, quench water is injected into the bottom of the drum for a few hours until the drum cools down to a desired temperature, usually in the range of 220 °F to 300 °F. During this process, the quench water turns into steam due to the elevated temperature in the drum and these vapors continue to be routed to the fractionation tower together with any light hydrocarbons that remain after the coking process is complete. (Both the injected steam and the steam that is generated from the quench water cause pores to be created in the coke that gives the coke a sponge-like appearance.) As the head space above the coke bed turns mostly into water vapors (steam), the vapors ~~is~~are switched from the fractionator and routed to a blowdown/flare system until equilibrium is reached (e.g., when the pressure inside the coke drum is equal to the pressure in the blowdown/flare system). At this point, the vapors can no longer be exhausted to the blowdown/flare system. This is the end of the coking cycle. The drum is then vented to the atmosphere until the internal pressure of the drum equals ambient pressure.

The next step is the process of removing the coke from the drum, or decoking. The decoking process begins with the removal (de-heading) of the top and bottom head ~~lids~~ of the coke drum. Once opened, a high pressure water (about 2000 psi) hydraulic drill is lowered into the drum at the top of the drum and a pilot hole is drilled into the solidified coke toward the bottom of the drum. Subsequently, a bigger rotating drill is lowered back into the ~~hole~~ drum and ~~additional high pressure water is sprayed into the coke bed. T~~the high pressure water ~~spray~~ jet breaks the coke into lumps, allowing the coke to fall through the bottom opening of the coke drum into a receiving area such as a pad or a pit located directly below the coke drum. A bridge crane is used to transfer the wet coke from the pit to a belt conveyor that carries the coke to a crusher, and then to an enclosed barn for storage. To prevent fugitive dust emissions, the coke ~~slurry~~ is kept moist throughout its storage life at a facility. The belt conveyor, the crusher, and enclosed storage building are typically exhausted to fabric filter baghouses to minimize fugitive coke dust emissions.

Once the decoking process is completed, the now empty "off oil" drum is closed (re-headed), purged of air, leak tested, warmed-up, and placed on stand-by, ready to repeat the cycle. The length of a coking or decoking cycle varies from refinery to refinery but can range from 12 to 24 hours. On average, 18 hours of coking are followed by 18 hours of decoking, but due to technological advancements~~,~~ associated with the design and construction of new coke drums, including improved metallurgy which allows drums to withstand the higher thermal stress resulting from a decreased batch cycle time relative to existing older coke drums, the length of the cycle can be reduced to as low as 12 hours per cycle.

Petroleum coke typically contains water and some hydrocarbons. On average, the coke contains nine to 12 percent volatiles and five to nine ~~2.7~~ percent moisture[6]. ~~However, f~~Fugitive dust emissions are minimal during crushing because the coke is very wet. Before the coke can be used, it must be crushed and dried. Heating coke to drive off the volatiles and moisture is called calcining. Petroleum coke is used as fuel for manufacturing steel and high purity coke is used for manufacturing anodes (also known as electrodes) through which electric current flows into an electrical device or circuit. Anodes are used for aluminum production.

Controlling Emissions From Delayed Coking

Reducing the emissions from the atmospheric depressurization phase at the end of the coking cycle prior to starting the decoking process is the focus of the PR 1114. There are pollutants, such as VOCs and hazardous air pollutants (HAPs), remaining in the head space that are released during atmospheric venting. To reduce the amount of emissions that would be released to the atmosphere at the end of the coking cycle, the following discussion explains several control options.

Early designs for a delayed coking system included a blowdown system that was tied into a refinery flare system so that hydrocarbon vapors could be flared during coke drum warming early on in the coking process and during quenching towards the end of the coking process. However, due to environmental considerations and to further recover product, instead of venting to a flare system, modern cokers are now designed to recover the vapors remaining in the head space above the coke in the drum by routing them to the refinery fuel gas system.

To minimize atmospheric venting, at the end of the coking cycle, more of the vapors remaining in the head space above the coke in the drum can be sent to the blowdown system prior to opening the drum, provided that the pressure in the drum head space is higher than that of the blowdown system. This pressure differential will cause the vapors to be routed to the blowdown system allowing more vapors to be captured. However, once the pressures equalize between the drum and the blowdown system, the only way to depressurize the drum to ambient pressure is to vent the remaining vapors, which primarily consist of steam (roughly 97 percent to 99 percent), from the drum to the atmosphere before drilling of the coke bed can commence. Currently all of the affected DCUs route the head space vapors in the coke drum to a blowdown system where recovered hydrocarbons are sent to the refinery fuel gas system.

One way to minimize emissions during coke drum venting would be to change the process by increasing the drum cooling time. Waiting longer before opening the coke drum will allow it to cool down further. With the coke drum at a reduced temperature, more vapors would cool and condense and the pressure in the drum would also be reduced. Thus, by the time the coke drum is vented, fewer emissions would escape into the atmosphere. However, this method would increase the overall length of the coke drum cycle time. As mentioned earlier in the delayed coking process description, the switching frequency between coking and decoking varies from refinery to refinery but can range from 12 to 24 hours with an

[6] Comparison of Fuel Properties of Petroleum Cokes and Coals Used in Power Generation, http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/44_1_ANAHEIM_03-99_0080.pdf, p. 82.

average of 18 hours of coking followed by 18 hours of decoking. The advantage of this emission reduction approach is that it does not require installing new or modifying existing equipment. However, by increasing the cooling time, there could be a dramatic reduction in the processing throughput of the delayed coking system, potentially creating a bottleneck in the refinery operations that could impact the refinery's output. Because refineries are comprised of multiple, sophisticated inter-connected and inter-dependent systems, any potential process changes could have unintended consequences that may cause other bottlenecks and throughput problems elsewhere. For these reasons, it is impractical and improbable that refinery operators would choose to allow for additional time for the coke drums to cool, as other alternatives are available.

Another way to minimize emissions to atmosphere would be to increase the rate at which vapors are evacuated from the head space to the blowdown system. This can be accomplished by installing either compressor or steam ejector technology to create a pressure differential that would more quickly lower the drum's internal pressure (e.g., to less than two psig) as close as currently possible to ambient pressure (e.g., by definition, zero psig) before venting the drum to the atmosphere at the end of the coking cycle.

A compressor is a device used to compress gases and/or vapors with the support of an electric motor, internal combustion engine or steam. Compressors can handle a constant volume of gases with various discharge pressures. The volume of gas can be varied only by changing the motor speed or under-utilizing the design capacity of the unit. Sliding vane and oil flooded rotary screw compressors are commonly used for vapor recovery, but depending on final discharge routing, a reciprocating compressor may also be used.

A steam ejector is a simplified type of pumping device which, unlike a compressor, has no pistons, valves, rotors or other moving parts. A steam ejector consists of a nozzle which discharges a high-speed pressure steam jet across a suction chamber that is connected to the equipment to be evacuated (e.g., the coke drum head space). With a steam ejector in place, the vapors from the coke drum head space would be entrained in the steam from the steam ejector and carried into a venturi-shaped diffuser that would create a strong suction or vacuum effect that would allow for a quick evacuation of the remaining vapors in the coke drum.

Either of these devices could effectively serve as emissions control equipment by achieving lower pressures within the coke drum at the end of the coking cycle. However, operation of these devices has its own pros and cons. For example, if a compressor is installed, energy would be needed to operate the unit and that could create adverse air quality and energy impacts. While there would be no additional waste stream generated from operating a compressor, such as wastewater, for example, compressors have higher capital, operating, and maintenance costs. However, if steam ejector technology is installed, steam is required for operation, which could mean that more water would be needed to create the steam and more energy may be needed to heat the water to meet the increased steam demand. The use of steam ejector technology would also generate a sour water waste stream. Sour water is generated when the steam ejector creates a vacuum that draws the overhead vapors into a condenser where the vapors are partially condensed against cooling water. The condensates

then flow to a sour water degasser. Sour waters from the steam ejector condensates are pumped to treatment.

When comparing overall maintenance and operating costs, steam ejector technology typically has less maintenance requirements and associated costs than compressor technology. The potential adverse environmental impacts pertaining to the installation of either of these technologies has ~~will~~ been analyzed in Chapter 2 of this ~~Draft~~ Final EA.

CHAPTER 2

ENVIRONMENTAL CHECKLIST

Introduction

General Information

Potentially Significant Impact Areas

Determination

Environmental Checklist and Discussion

INTRODUCTION

The environmental checklist provides a standard evaluation tool to identify a project's adverse environmental impacts. This checklist identifies and evaluates potential adverse environmental impacts that may be created by adopting PR 1114.

GENERAL INFORMATION

Project Title:	Final Environmental Assessment (EA) for Proposed Rule 1114 – Petroleum Refinery Coking Operations
Lead Agency Name:	South Coast Air Quality Management District
Lead Agency Address:	21865 Copley Drive, Diamond Bar, CA 91765
CEQA Contact Person:	Barbara Radlein, (909) 396-2716
PR 1114 Contact Person:	Eugen Teszler, (909) 396-2077
Project Sponsor's Name:	South Coast Air Quality Management District
Project Sponsor's Address:	21865 Copley Drive, Diamond Bar, CA 91765
General Plan Designation:	Not applicable
Zoning:	Not applicable
Description of Project:	PR 1114 would: 1) establish a limit of less than two pounds per square inch, gauge pressure (psig) for when a coke drum may be depressurized to atmosphere; 2) allow for an alternative compliance schedule for facilities not able to meet the compliance timeline under limited circumstances; 3) require facility operators to submit permit applications for equipment or process modifications no later than ~~18~~ nine months prior to the final compliance date; 4) require monitoring of the coke drum internal pressure and atmospheric vent valve, and recordkeeping; 5) exempt coke drums from the requirements in SCAQMD Rule 404 upon meeting the final depressurization limit. Analysis of the proposed project did not result in the identification of any environmental topic areas that would be significantly adversely affected by the proposed project. PR 1114 is anticipated to reduce VOC emissions by up to 0.36 ton per day, PM emissions by up to 0.05 ton per day, HAP emissions by up to 0.07 ton per day, and methane emissions by up to 1.51 tons per day. PR 1114 is also anticipated to reduce sulfur as H2S by up to 0.05 ton per day.
Surrounding Land Uses and Setting:	Residential, but primarily commercial, industrial and/or institutional
Other Public Agencies Whose Approval is Required:	Not applicable

ENVIRONMENTAL IMPACT AREAS POTENTIALLY AFFECTED

The following environmental impact areas have been assessed to determine their potential to be affected by the proposed project. Any checked items represent areas that may be adversely affected by the proposed project. An explanation relative to the determination of impacts can be found following the checklist for each area.

☐	Aesthetics	☐	Geology and Soils	☐	Population and Housing
☐	Agriculture and Forestry Resources	☐	Hazards and Hazardous Materials	☐	Public Services
☑	Air Quality and Greenhouse Gas Emissions	☑	Hydrology and Water Quality	☐	Recreation
☐	Biological Resources	☐	Land Use and Planning	☐	Solid and Hazardous Waste
☐	Cultural Resources	☐	Mineral Resources	☑	Transportation and Traffic
☑	Energy	☐	Noise	☑	Mandatory Findings of Significance

DETERMINATION

On the basis of this initial evaluation:

☑ I find the proposed project, in accordance with those findings made pursuant to CEQA Guideline §15252, COULD NOT have a significant effect on the environment, and that an ENVIRONMENTAL ASSESSMENT with no significant impacts has been prepared.

☐ I find that although the proposed project could have a significant effect on the environment, there will NOT be significant effects in this case because revisions in the project have been made by or agreed to by the project proponent. An ENVIRONMENTAL ASSESSMENT with no significant impacts will be prepared.

☐ I find that the proposed project MAY have a significant effect(s) on the environment, and an ENVIRONMENTAL ASSESSMENT will be prepared.

☐ I find that the proposed project MAY have a "potentially significant impact" on the environment, but at least one effect 1) has been adequately analyzed in an earlier document pursuant to applicable legal standards, and 2) has been addressed by mitigation measures based on the earlier analysis as described on attached sheets. An ENVIRONMENTAL ASSESSMENT is required, but it must analyze only the effects that remain to be addressed.

☐ I find that although the proposed project could have a significant effect on the environment, because all potentially significant effects (a) have been analyzed adequately in an earlier ENVIRONMENTAL ASSESSMENT pursuant to applicable standards, and (b) have been avoided or mitigated pursuant to that earlier ENVIRONMENTAL ASSESSMENT, including revisions or mitigation measures that are imposed upon the proposed project, nothing further is required.

Date: February 26, 2013 **Signature:** Steve Smith

Steve Smith, Ph.D.
Program Supervisor, CEQA Section
Planning, Rules, and Area Sources

ENVIRONMENTAL CHECKLIST AND DISCUSSION

As discussed in Chapter 1, the main focus of PR 1114 is to reduce emissions (VOC, HAP, methane, PM and sulfur) from the atmospheric depressurization phase at the end of the coking cycle prior to starting the decoking process. To comply with the requirements in PR 1114, operators of delayed coking units may choose to change the process by increasing the rate at which vapors are evacuated from the head space to the blowdown system by installing either compressor or steam ejector technology to create a pressure differential that would lower the internal pressure in each coke drum as close to ambient pressure before opening to atmosphere at the end of the coking cycle.

There are six petroleum refineries that operate delayed coking units that would be subject to the requirements in PR 1114. Of these six, one facility can already demonstrate compliance with PR 1114 because its coke drums have been permitted to less than two psig through the use of steam ejectors. For the remaining five facilities, operators may choose to optimize their delayed coking operation or either install compressor or steam ejector technology to achieve the two psig depressurization limit in PR 1114.

Thus, answers to the following checklist items are based on the worst-case assumption that the operators of delayed coking units at these facilities would install either compressor or steam ejector technology in order to achieve a drum pressure less than two psig in each coke drum. The installation of either of these technologies is considered worst-case because physical modifications requiring construction and operation activities may create adverse environmental impacts at the some or all of the five existing affected facilities with delayed coking units that do not currently comply with the requirements in PR 1114.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
I.	**AESTHETICS.** Would the project:				
a)	Have a substantial adverse effect on a scenic vista?	☐	☐	☐	☑
b)	Substantially damage scenic resources, including, but not limited to, trees, rock outcroppings, and historic buildings within a state scenic highway?	☐	☐	☐	☑
c)	Substantially degrade the existing visual character or quality of the site and its surroundings?	☐	☐	☐	☑
d)	Create a new source of substantial light or glare which would adversely affect day or nighttime views in the area?	☐	☐	☑	☐

Significance Criteria

The proposed project impacts on aesthetics will be considered significant if:

- The project will block views from a scenic highway or corridor.
- The project will adversely affect the visual continuity of the surrounding area.
- The impacts on light and glare will be considered significant if the project adds lighting which would add glare to residential areas or sensitive receptors.

Discussion

I.a), b), & c) Any physical modifications, such as installing compressor or steam ejector technology, that may occur as a result of implementing PR 1114 would be located within the existing confines of petroleum refineries. Because the affected petroleum refineries are all located in heavily industrialized areas, no scenic vistas or scenic resources are located in the vicinity of the these facilities. Therefore, the proposed project would not affect scenic vistas or scenic resources.

Further, construction activities associated with the proposed project are not expected to adversely impact views and aesthetics resources since the construction activities are expected to occur within the confines of the existing refineries, all of which are heavy industrial facilities, and are expected to introduce minor visual changes to areas outside these facilities, if at all. Except for the use of cranes, the majority of the construction equipment is expected to be low in height and not substantially visible to the surrounding areas due to existing fencing along the property lines and existing structures currently within the refineries that would buffer the views of the construction activities. Further, the construction activities will be temporary in nature and will cease following completion of the construction activities.

Once construction is completed, the newly installed equipment would not be expected to substantially further degrade the existing visual character of the affected refineries because these devices are low profile and would blend in with the existing equipment to the extent that they would not be visible or discernable from outside the boundaries of each of the refineries.

I.d) While there are no components in the proposed project that would require construction activities to occur at night, operators of the existing refineries have indicated that construction of equipment installed on the delayed coking units would occur prior to a turnaround and the actual tie-in (final connection) of the equipment would occur during a turnaround when the delayed coking units are shut down. Since time to implement a turnaround for a delayed coking unit can be as short as 30 days, refinery operators may choose to employ compressed construction schedules that may include a nighttime shift such that temporary additional lighting would be needed. Nonetheless, since construction of the proposed project would be completely located within the boundary of each affected facility, additional temporary lighting, if needed, is not expected to be discernable from the existing permanent night lighting since all of the affected refineries are already lit at night for safety and security reasons. Likewise, additional light or glare would not be created which would adversely affect day or nighttime views in the area since no light generating equipment would be required to comply with the requirements in PR 1114.

Based upon these considerations, significant adverse aesthetics impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant aesthetics impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
II. AGRICULTURE AND FORESTRY RESOURCES. Would the project:				
a) Convert Prime Farmland, Unique Farmland, or Farmland of Statewide Importance (Farmland), as shown on the maps prepared pursuant to the Farmland mapping and Monitoring Program of the California Resources Agency, to non- agricultural use?	☐	☐	☐	☑
b) Conflict with existing zoning for agricultural use, or a Williamson Act contract?	☐	☐	☐	☑

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
c) Conflict with existing zoning for, or cause rezoning of, forest land (as defined in Public Resources Code §12220(g)), timberland (as defined by Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code §51104 (g))?	☐	☐	☐	☑
d) Result in the loss of forest land or conversion of forest land to non-forest use?	☐	☐	☐	☑

Significance Criteria

Project-related impacts on agriculture and forestry resources will be considered significant if any of the following conditions are met:

- The proposed project conflicts with existing zoning or agricultural use or Williamson Act contracts.
- The proposed project will convert prime farmland, unique farmland or farmland of statewide importance as shown on the maps prepared pursuant to the farmland mapping and monitoring program of the California Resources Agency, to non-agricultural use.
- The proposed project conflicts with existing zoning for, or causes rezoning of, forest land (as defined in Public Resources Code §12220(g)), timberland (as defined in Public Resources Code §4526), or timberland zoned Timberland Production (as defined by Government Code § 51104 (g)).
- The proposed project would involve changes in the existing environment, which due to their location or nature, could result in conversion of farmland to non-agricultural use or conversion of forest land to non-forest use.

Discussion

II. a), b), c), & d) All construction and operational activities that would occur as a result of implementing the proposed project are expected to occur within the confines of the existing affected petroleum refineries. The proposed project would be consistent with the heavy industrial zoning requirements for the various facilities and there are no agriculture or forestry resources or operations on or near the affected facilities. No agricultural resources including Williamson Act contracts are located within or would be impacted by construction activities at the affected facilities. Therefore, the proposed project would not result in any new construction of buildings or other structures that would convert farmland to non-agricultural use or conflict with zoning for agricultural use or a Williamson Act contract.

Since the proposed project would not substantially change any facility or process for which the affected units are utilized, there are no provisions in the proposed project that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements relative to agricultural resources will be altered by the proposed project. For these same reasons, PR 1114 would not result in the loss of forest land or conversion of forest land to non-forest use.

Based upon these considerations, significant agricultural and forestry resources impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant agriculture and forestry resources impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
III. AIR QUALITY AND GREENHOUSE GAS EMISSIONS. Would the project:				
a) Conflict with or obstruct implementation of the applicable air quality plan?	☐	☐	☑	☐
b) Violate any air quality standard or contribute to an existing or projected air quality violation?	☐	☐	☑	☐
c) Result in a cumulatively considerable net increase of any criteria pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard (including releasing emissions that exceed quantitative thresholds for ozone precursors)?	☐	☐	☑	☐
d) Expose sensitive receptors to substantial pollutant concentrations?	☐	☐	☑	☐
e) Create objectionable odors affecting a substantial number of people?	☐	☐	☑	☐
f) Diminish an existing air quality rule or future compliance requirement resulting in a significant increase in air pollutant(s)?	☐	☐	☐	☑
g) Generate greenhouse gas emissions, either directly or indirectly, that may have a significant impact on the environment?	☐	☐	☑	☐

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
h) Conflict with an applicable plan, policy or regulation adopted for the purpose of reducing the emissions of greenhouse gases?	☐	☐	☑	☐

Air Quality Significance Criteria

To determine whether or not air quality impacts from adopting and implementing PR 1114 are significant, impacts will be evaluated and compared to the criteria in Table 2-1. The project will be considered to have significant adverse air quality impacts if any one of the thresholds in Table 2-1 are equaled or exceeded.

Discussion

III. a) The 2012 AQMP Control Measure MCS-01 – Application of All Feasible Measures, contains unspecified emission reduction goals for all pollutants that apply to a variety of emission sources. Based on the general emission reduction goals in the 2012 AQMP and the technological advancements achieved for delayed coking operations, PR 1114, upon full implementation, would partially implement Control Measure MCS-01. The net effect of implementing PR 1114 is that VOC emissions from this source category will be reduced up to 0.36 ton per day, PM emissions will be reduced by up to 0.05 ton per day, HAP emissions will be reduced by up to 0.07 ton per day, and methane emissions will be reduced by up to 1.51 tons per day. PR 1114 is also anticipated to reduce sulfur as H2S by up to 0.05 ton per day. These anticipated reductions are expected to provide an overall direct air quality benefit. Further, the projected VOC emission reductions will assist the SCAQMD's progress in attaining and maintaining the ambient air quality standards for ozone.

The proposed project has the potential to temporarily increase VOC, NOx, CO, PM10 and TAC emissions (as diesel PM) during construction, but construction emissions are not expected to exceed the applicable air quality significance thresholds for construction activities. (See the discussion under Section III. b) & c) for the construction air quality analysis.) However, the temporary less than significant increase in VOC, NOx, CO, PM10 and TAC emissions (as diesel PM) due to construction is not expected to impede the emission reduction goals of the 2012 AQMP because the inventory prepared for the 2012 AQMP already takes into account the future emission estimates from all construction activities associated with implementing the proposed control measures[7]. Further, implementation of all other SCAQMD rules along with AQMP control measures, when considered together, is expected to reduce emissions throughout the region overall by 2023.

[7] SCAQMD's Final Program Environmental Impact Report for the 2012 Air Quality Management Plan, SCH#2012061093, November 2012.

TABLE 2-1
SCAQMD Air Quality Significance Thresholds

Mass Daily Thresholds [a]		
Pollutant	**Construction [b]**	**Operation [c]**
NOx	100 lbs/day	55 lbs/day
VOC	75 lbs/day	55 lbs/day
PM10	150 lbs/day	150 lbs/day
PM2.5	55 lbs/day	55 lbs/day
SOx	150 lbs/day	150 lbs/day
CO	550 lbs/day	550 lbs/day
Lead	3 lbs/day	3 lbs/day
Toxic Air Contaminants (TACs), Odor, and GHG Thresholds		
TACs (including carcinogens and non-carcinogens)	Maximum Incremental Cancer Risk ≥ 10 in 1 million Cancer Burden > 0.5 excess cancer cases (in areas ≥ 1 in 1 million) Chronic & Acute Hazard Index ≥ 1.0 (project increment)	
Odor	Project creates an odor nuisance pursuant to SCAQMD Rule 402	
GHG	10,000 MT/yr CO2eq for industrial facilities	
Ambient Air Quality Standards for Criteria Pollutants [d]		
NO2 1-hour average annual arithmetic mean	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 0.18 ppm (state) 0.03 ppm (state) and 0.0534 ppm (federal)	
PM10 24-hour average annual average	10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation) 1.0 $\mu g/m^3$	
PM2.5 24-hour average	10.4 $\mu g/m^3$ (construction)[e] & 2.5 $\mu g/m^3$ (operation)	
SO2 1-hour average 24-hour average	0.25 ppm (state) & 0.075 ppm (federal – 99th percentile) 0.04 ppm (state)	
Sulfate 24-hour average	25 $\mu g/m^3$ (state)	
CO 1-hour average 8-hour average	SCAQMD is in attainment; project is significant if it causes or contributes to an exceedance of the following attainment standards: 20 ppm (state) and 35 ppm (federal) 9.0 ppm (state/federal)	
Lead 30-day Average Rolling 3-month average Quarterly average	1.5 $\mu g/m^3$ (state) 0.15 $\mu g/m^3$ (federal) 1.5 $\mu g/m^3$ (federal)	

[a] Source: SCAQMD CEQA Handbook (SCAQMD, 1993)
[b] Construction thresholds apply to both the South Coast Air Basin and Coachella Valley (Salton Sea and Mojave Desert Air Basins).
[c] For Coachella Valley, the mass daily thresholds for operation are the same as the construction thresholds.
[d] Ambient air quality thresholds for criteria pollutants based on SCAQMD Rule 1303, Table A-2 unless otherwise stated.
[e] Ambient air quality threshold based on SCAQMD Rule 403.

KEY: lbs/day = pounds per day ppm = parts per million $\mu g/m^3$ = microgram per cubic meter ≥ = greater than or equal to
MT/yr CO2eq = metric tons per year of CO2 equivalents > = greater than

Lastly, the proposed project contains an exemption from SCAQMD Rule 404 that codifies an existing legal interpretation, already implemented by SCAQMD's engineering and enforcement divisions, that Rule 404 does not apply to delayed coking processes. For this reason, no change in emissions from the baseline is expected to occur as a result of this proposed exemption. Thus, implementing the proposed project will not conflict or obstruct implementation of the AQMP.

Implementing PR 1114 is not expected to conflict with or obstruct implementation of the applicable air quality control plan because the 2012 AQMP demonstrates that the effects of all existing rules, in combination with implementing all AQMP control measures (including "black box" measures not specifically described in the 2012 AQMP) would bring the district into attainment with all applicable national and state ambient air quality standards. Further, PAR 1114 is not expected to significantly conflict or obstruct implementation of the applicable air quality plan, but instead, would contribute to attaining and maintaining the ozone and PM standards by achieving VOC reductions.

For these reasons, implementation of all other SCAQMD VOC rules along with AQMP control measures, when considered together, is expected to reduce VOC emissions throughout the region overall by 2023. Therefore, implementing the proposed project will not conflict or obstruct implementation of the 2012 AQMP. Accordingly this impact issue will not be further analyzed.

III. b) & c) For a discussion of these items, refer to the following analysis.

Construction Air Quality Impacts

The SCAQMD makes significance determinations for construction impacts based on the maximum or peak daily emissions during the construction period, which provides a "worst-case" analysis of the construction emissions. There are six petroleum refineries that operate delayed coking units that would be subject to the requirements in PR 1114. Of these six, one facility (Facility F) can already demonstrate compliance with PR 1114 because their coke drums have been permitted to less than two psig through the use of steam ejectors. For the remaining five facilities, one facility operator may choose to optimize their delayed coking operation via computer programming or upgrading software (Facility D). For the remaining four facilities (Facilities A, B, C, and E) operators may either install compressor or steam ejector technology to achieve the two psig depressurization limit in PR 1114.

SCAQMD staff met with representatives from each refinery to learn how each refinery operator intended to comply with the requirements in PR 1114. Based on their responses, the timing of construction (for those that would need to undergo construction) could occur as early as up to one year prior to the year when a turnaround of the delayed coking units would be scheduled. Table 2-2 contains of summary of the potential construction schedule based on discussions with the various refinery operators.

TABLE 2-2
Potential Construction Schedule per Refinery

Refinery	Equipment Technology Anticipated	Estimated Construction Year(s)
A	steam ejector system	2014 and 2016
B	steam ejector system	2014 and 2015
C	compressor or steam ejector system	2015
D	None – only optimization needed	N/A
E	steam ejector system	2015
F	None – this facility is already permitted to meet 2 psig through the use of steam ejectors	N/A

Potentially significant impacts that may result from implementing the proposed project are related to the construction activities associated with installing the compressor or steam ejector technologies at the affected facilities. Specifically, the physical changes involved with the type of construction activities that may occur, focus mainly on the modification of existing equipment by installing either of these technologies.

While optimization activities are expected to require relatively minor changes that would not be expected to involve any construction activities, preliminary analysis showed that installation of compressor or steam ejector technology in order to achieve a drum pressure less than two psig in each coke drum has the greatest potential for generating potentially significant adverse impacts for an individual project. Thus, construction of either of these technologies is considered the worst-case scenario and is the primary focus of the construction analysis in this ~~Draft~~ Final EA.

The installation of either of these technologies is considered worst-case because physical modifications requiring construction may create adverse environmental impacts. Further, based on the estimated construction schedule, two refineries could potentially have overlapping construction activities in year 2014 on a given day and three refineries could potentially have overlapping construction activities in year 2015 on a given day.

The worst-case construction assumptions for installing steam ejectors are based on information (e.g., Design and Cost Estimate, Decision Support Package, and Initial Capital Budget) from Marathon Petroleum Company LLC (Marathon) for a refinery operating in Louisiana. In 2010, Marathon prepared an initial budget for a coker drum depressurization project called the "G-955 Coker Drum Depressuring Project" (see Appendix C of this ~~Draft~~ Final EA). The project considered two options: 1) to install a blowdown vent gas compressor; and, 2) to install a steam ejector system. Due to substantially lower construction and operational costs associated with steam ejectors, Marathon operators chose to install a steam ejector system which consisted of two steam ejectors, one for use in operation and one for use as a spare. Further, Marathon's decision was influenced by the fact that the industry standard design for coker units manufactured by Foster Wheeler, a

leader in DCU technology, is to use steam ejectors to reduce coke drum pressure prior to venting, in lieu of compressors.

In addition, similar to Marathon's project, facility operators of three facilities have suggested that they are considering installing steam ejector systems in order to comply with PR 1114. Because the facility with the largest amount of coke drums affected by PR 1114 would have the largest amount of projected steam ejectors to be installed, this facility will be considered the worst-case example for a facility installing a steam ejector system. Typical construction time needed to install a steam ejector system is anticipated to be 30 days per facility, with a relatively small amount of construction workers and construction equipment. Lastly, the operators of one facility have indicated that they may install either a compressor or a steam ejector system.

To determine what the worst-case would be, construction emissions for facilities under construction during year 2014 (when construction activities may overlap at two facilities) and year 2015 (when construction activities may overlap at three facilities) were analyzed. Lastly, for construction year 2015, an analysis was conducted for overlapping construction at three facilities with one these facilities either installing a compressor or steam ejector system.

The environmental analysis assumes that installation of either compressor or steam ejector technologies at the affected refineries will reduce VOC and other emissions overall, but construction activities associated with both the installation of these devices will create secondary air quality impacts (e.g., emissions), which can adversely affect local and regional air quality.

Implementation of the proposed project is expected to involve construction activities related to the installation of either compressor or steam ejector technology. The proposed project may also involve the construction of new or the modification of existing structures as part of installation of this equipment. Construction-related activities are also expected to generate emissions from worker vehicles, trucks, and construction equipment.

From a construction point of view, the installation of a compressor or steam ejector technology is a relatively straightforward process. If a facility operator chooses to install either a compressor or steam ejector system, approximately one year will be needed for pre-construction/advance planning activities such as engineering analysis of the affected equipment, engineering design of the potential equipment, contracting with a vendor, securing financing, ordering and purchasing the equipment, obtaining permits and clearances, and lining up contractors and workers. While the scale of construction that would be expected from implementing the proposed project is relatively small, the timing of construction could be compressed due to the need to ensure that the main construction is completed prior to a scheduled process turnaround of the coking units. Thus, once all of the pre-engineering is completed, to physically build or install a compressor or steam ejector system, approximately 30 days would be needed. Ultimately, the decision when construction would commence is dependent upon the turnaround schedule of the coker units; once construction of the compressor or steam ejector system is completed, the equipment will need to be "tied-in" to the coker unit piping to start-up which would typically occur later during a scheduled turnaround period (e.g., regularly scheduled shutdown) of the coker units.

Assumptions

As part of installing a compressor or steam ejector system, heavy-duty construction activities or equipment, major construction activities and operational maintenance requirements are anticipated. To estimate what the impacts would be for installing either of these technologies, the following general assumptions were made to determine the peak daily construction emissions:

- For a "worst-case" analysis, two refineries may be under construction during 2014 and three refineries may be under construction during 2015. The construction activities will take place during the same 30 days at multiple facilities in a given year and the peak daily emissions would occur on the same day.
- Actual construction of one compressor or steam ejector system will take approximately 30 days per facility.
- Construction activities associated with installing a steam ejector system are assumed to take approximately 30 days (five days per week at 16 hours per day) with a crew of eight workers. This construction schedule also includes the time needed for installing ancillary support equipment.
- Construction activities associated with installing a compressor are assumed to take approximately 30 days (five days per week at eight hours per day) with a crew of eight workers. This construction schedule also includes the time needed for installing ancillary support equipment.
- The construction of a steam ejector system is assumed to require the use of: two aerial lifts, one 75-ton crane, one forklift, two generator sets, two diesel welding machines, and one off-highway truck.
- The construction of a compressor is assumed to require the use of: one aerial lift, one 75-ton crane, two generator sets, two diesel welding machines, and one off-highway truck.
- To provide a "worst-case" analysis, it is assumed that each facility will have its own construction crew and equipment.
- As a practical matter, the earliest construction could begin would be approximately 12 months after adoption of the proposed project, in construction year 2014, for two facilities. Therefore, for a conservative construction analysis, the on-road and off-road emission factors will be based on the 2014 fleet years. However, since there are also three facilities with potentially overlapping construction activities during year 2015, an additional conservative construction analysis will be conducted that is based on the 2015 fleet year. Lastly, the construction analysis for year 2015 will consider two scenarios: 1) Scenario A: all three facilities will install steam ejector systems; and, 2) Scenario B: two facilities will install steam ejector systems and one facility will install one compressor.

Construction Emissions

Construction-related emissions can be distinguished as either onsite or offsite. Onsite emissions generated during construction principally consist of exhaust emissions (NOx,

SOx, CO, VOC, PM2.5 and PM10) from heavy-duty construction equipment operation, fugitive dust (primarily as PM10) from disturbed soil, and VOC emissions from asphaltic paving and painting. Offsite emissions during the construction phase normally consist of exhaust emissions and entrained paved road dust (primarily as PM10) from worker commute trips, material delivery trips, and haul truck material trips to and from the construction site.

To get a better understanding of what size and scope of steam ejector system would be needed, it is necessary to estimate the average headspace volume that needs to be evacuated from the coke drums. The volume and estimated headspace of each affected coke drum was calculated and an average headspace was estimated to be 6,925 cubic feet (which was assumed to be 25 percent of the total coke drum volume). Refer to Appendix B for the spreadsheet that contains this analysis.

SCAQMD staff contacted a steam ejector manufacturer, Schutte and Koerting, and obtained a steam ejector quote for the evacuation of the headspace of a coke drum (approximately 8,000 cubic feet). The coke drum was assumed to be approximately 84 ~~20~~ feet in height and 22 feet in diameter, and the coke drum is assumed to be filled with 75 percent coke and flooded with water above the coke bed~~)~~. The manufacturer recommended a steam ejector that is approximately three feet long by nine inches in height and weighs approximately 130 pounds. This size of steam ejector would be able to evacuate the head space in approximately five minutes or less using 317 pounds per hour of steam at a pressure of 150 psig. Because of the varying sizes of coke drums at each of the affected refineries, the steam ejector quote may not be exact to individual refinery operations as some coke drums would have a smaller headspace to evacuate while others would have a larger headspace to evacuate. Nonetheless, the steam ejector quote is within the range of the size and scope of what would be appropriate and expected for the affected refineries to install.

While each affected refinery has space limitations, the size of the steam ejectors to be installed is relatively small, especially when compared to the size of the existing coke drums. Thus, the placement of a steam ejector (including any spares) would likely occupy a space adjacent to the affected equipment, in a location convenient to the existing piping of the delayed coking units, such as at ground level or on a raised steel platform. Therefore, little to no demolition activities would be expected prior to the installation of a steam ejector system to remove any existing equipment or structures, remove the old piping and electrical connections, and break up the old foundation with a demolition hammer. For these reasons, digging, earthmoving, grading, slab pouring, or paving activities are not anticipated.

Similarly, no construction emissions from site preparation activities such as earthmoving/grading are anticipated because the sites where the coking units exist at each of the affected refineries have already been graded and paved and the placement of either of these technologies would not be expected to require any additional earthmoving or grading.

For the refinery that may be considering installing a compressor, a new foundation is not likely needed to establish footings or structure supports at this facility because the new compressor would be sited at the same location as an existing compressor as a spare~~, which would need to be replaced~~, and this site has an existing concrete pad. Thus, it may not be necessary to dig, cut concrete, or re-pour new footings prior to installing the compressor.

The type of construction-related activities attributable to installing a compressor or steam ejector would consist predominantly of deliveries of equipment, steel, piping, wiring, and other materials, maneuvering the materials within the site via a crane, forklift or truck, and welding.

PROJECT-SPECIFIC CONSTRUCTION IMPACTS: The implementation of the proposed project is anticipated to trigger construction activities associated with the installation of either a compressor or steam ejector system. Construction activities associated with the proposed project would result in emissions of VOC, NOx, SOx, CO, PM10, and PM2.5. Significance determinations are based on the maximum peak daily emissions during the construction period for two refineries under construction within the same 30-day period in year 2014 and for three refineries under construction within the same 30-day period in year 2015. Both of these scenarios provide a "worst-case" analysis of the anticipated peak daily construction emissions. Construction emissions are expected from the following equipment and processes:

- Construction equipment (e.g., aerial lifts, forklifts, cranes, front end loaders, generators, welders, and off-high way trucks, et cetera.)
- Equipment delivery and on-site travel (includes fugitive dust associated with travel on paved roads)
- Heavy-duty diesel trucks
- Construction workers commuting

Using a 1.0 average vehicle ridership, the construction worker labor force would be approximately eight workers for construction activities associated with the installation of one compressor or steam ejector system per refinery. Each worker would generate two one-way vehicle trips per day. Construction worker's travel emissions are based on assuming an estimated 30-mile round trip each day per vehicle (two start-ups per day). The total peak daily emissions that would be attributed to all construction-related activities for the installation of two steam ejector systems at two refineries in year 2014 are approximately 10 pounds of VOC, 39 pounds of CO, 63 pounds of NOx, four pounds of PM10, and four pounds of PM2.5 (see Table 2-3).

TABLE 2-3
Peak Daily Construction Emissions
from the Installation of Two Steam Ejector Systems in 2014

Peak Construction Activity	VOC (lbs/day)	CO (lbs/day)	NOx (lbs/day)	SOx (lbs/day)	PM10 (lbs/day)	PM2.5 (lbs/day)
Off-Road Construction Equipment	4	17	30	0	2	2
On-Road Construction Equipment	0	3	2	0	0	0
Total for 1 Steam Ejector System Installation in 2014	**5**	**20**	**32**	**0**	**2**	**2**
SIGNIFICANCE THRESHOLD	75	550	100	150	150	55
SIGNIFICANT?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**
Total for 2 Steam Ejector System Installations in 2014	**10**	**39**	**63**	**0**	**4**	**4**
SIGNIFICANCE THRESHOLD	75	550	100	150	150	55
SIGNIFICANT?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Similarly, the total peak daily emissions that would be attributed to all construction-related activities for the installation of one, two and three steam ejector systems in year 2015 are summarized in Table 2-4. If three steam ejector systems are installed at three refineries in 2015, the total peak daily emissions would be approximately 13 pounds of VOC, 56 pounds of CO, 88 pounds of NOx, five pounds of PM10, and five pounds of PM2.5.

Lastly, the total peak daily emissions that would be attributed to all construction-related activities for the installation of two steam ejector systems plus one compressor in year 2015 would be approximately 11 pounds of VOC, 48 pounds of CO, 76 pounds of NOx, four pounds of PM10, and four pounds of PM2.5 (see Table 2-5).

TABLE 2-4
Scenario A: Peak Daily "Worst-Case" Construction Emissions from the Installation of Up to Three Steam Ejector Systems in 2015

Peak Construction Activity	VOC (lbs/day)	CO (lbs/day)	NOx (lbs/day)	SOx (lbs/day)	PM10 (lbs/day)	PM2.5 (lbs/day)
Off-Road Construction Equipment	4	16	27	0	1	1
On-Road Construction Equipment	0	3	2	0	0	0
Total for 1 Steam Ejector System Installation in 2015	**4**	**19**	**29**	**0**	**2**	**2**
SIGNIFICANCE THRESHOLD	75	550	100	150	150	55
SIGNIFICANT?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**
Total for 2 Steam Ejector Systems Installations in 2015	**9**	**37**	**58**	**0**	**3**	**3**
SIGNIFICANCE THRESHOLD	75	550	100	150	150	55
SIGNIFICANT?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**
Total for 3 Steam Ejector System Installations in 2015	**13**	**56**	**88**	**0**	**5**	**5**
SIGNIFICANCE THRESHOLD	75	550	100	150	150	55
SIGNIFICANT?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

TABLE 2-5
Scenario B: Peak Daily "Worst-Case" Construction Emissions from the Installation of One Compressor and Two Steam Ejector Systems in 2015

Peak Construction Activity	VOC (lbs/day)	CO (lbs/day)	NOx (lbs/day)	SOx (lbs/day)	PM10 (lbs/day)	PM2.5 (lbs/day)
Off-Road Construction Equipment	2	8	16	0	1	1
On-Road Construction Equipment	**0**	**3**	**2**	**0**	**0**	**0**
Total for 1 Compressor Installation in 2015	**3**	**11**	**18**	**0**	**1**	**1**
SIGNIFICANCE THRESHOLD	75	550	100	150	150	55
SIGNIFICANT?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**
Total for 1 Compressor Installation in 2015	3	11	18	0	1	1
Total for 2 Steam Ejector Systems Installations in 2015 (from Table 2-4)	9	37	58	0	3	3
Total for Installing 2 Steam Ejector Systems plus 1 Compressor in 2015	**11**	**48**	**76**	**0**	**4**	**4**
SIGNIFICANCE THRESHOLD	75	550	100	150	150	55
SIGNIFICANT?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

These numbers include the truck emissions associated with delivering the equipment and associated supplies. Peak construction emissions from the proposed project are calculated based on on-road and off-road vehicle fleet year 2014 and 2015 because these are the earliest possible years construction could occur when taking into consideration the timing of adopting the proposed project combined with the lead time necessary to engineer the design of the equipment for each affected refinery. Should construction occur in later years, the emission factors will not be as conservative as would be for year 2014 and 2015, respectively, since newer fleets are expected to have reduced emissions when compared to older fleets.

Tables 2-4, 2-5, and 2-6 present the results of the SCAQMD staff's construction air quality analysis and lists the total daily construction emissions from construction worker trips and use of equipment for construction.

When comparing construction year 2014 with year 2015 as shown in Tables 2-4, 2-5, and 2-6, the calculations show the worst-case total peak daily construction emissions would occur during year 2015 for the scenario where overlapping of construction of three steam ejector systems at three refineries. However, the emissions for the worst-case scenario do not exceed the SCAQMD's CEQA air quality significance thresholds for any criteria pollutant under either construction scenario. Thus, the project-specific construction emissions that may result from implementing the proposed project are shown to have less than significant air quality impacts during construction. Appendix B contains the spreadsheets with the results, assumptions, and methodologies used by the SCAQMD staff for this analysis.

It should be noted that the air quality construction analysis is a conservative, "worst-case" analysis so the actual construction impacts are not expected to be as great as estimated here. Further, the construction activities are temporary when compared to the permanent projected emission reductions of VOC and other pollutants as a result of the proposed project. Lastly, due to varying production and operation schedules at the affected refineries, the likelihood of the same construction activities occurring on the same day at multiple refineries would be extremely small.

Based upon these considerations, significant air quality impacts during construction are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant air quality impacts during construction were identified, no mitigation measures are necessary or required.

Operational Emissions

PROJECT-SPECIFIC OPERATIONAL IMPACTS: After construction activities are completed, implementation of the proposed project is expected to result in secondary air quality impacts. Specifically, implementation of the proposed project is anticipated to trigger operational activities associated with the operation of either a compressor or steam ejector system. Operation activities associated with the proposed project would result in emissions of VOC, NOx, SOx, CO, PM10, and PM2.5 for operating steam ejector systems and VOC for operating a compressor. Significance determinations are based on the maximum peak daily emissions during operation at four refineries with either four steam ejector systems installed or three steam ejector systems and one compressor installed. Both of these scenarios provide a "worst-case" analysis of the anticipated peak daily operation emissions. Operation emissions are expected from the following equipment and processes:

- Combustion emissions from boilers supplying additional steam to steam ejectors; and,
- Fugitive VOC emissions associated with the operation of a compressor.

Air quality emissions associated with operating steam ejector technology would be expected to be generated because additional steam would be needed to operate the steam ejector. To create more steam, additional fuel would need to be combusted by a boiler, thus, creating combustion emissions. In addition, if Facility C chooses to install a compressor in lieu of a steam ejector system, no combustion emissions would be expected to occur. Instead, fugitive VOC emissions would be expected to occur. Lastly, as no additional employees are anticipated to be needed to operate compressor or steam ejector technology, the existing

work force at each affected refinery is expected to be sufficient. As such, no worker travel emissions are anticipated for the operation of the compressor or steam ejector technology.

The total peak daily emissions that would be attributed to the operation of four steam ejector systems at four refineries would be approximately one pound of NOx, one pound of SOx, one pound of PM10, and one pound of PM2.5 (see Table 2-6).

TABLE 2-6
Scenario A: Peak Daily "Worst-Case" Operation Emissions from the Operation of Four Steam Ejector Systems

Peak Operation Activity	VOC (lbs/day)	CO (lbs/day)	NOx (lbs/day)	SOx (lbs/day)	PM10 (lbs/day)	PM2.5 (lbs/day)
Additional Boiler Firing to provide steam to four steam ejector systems	0	0	1	1	1	1
SIGNIFICANCE THRESHOLD	55	550	55	150	150	55
SIGNIFICANT?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

If instead, one refinery installs a compressor and three refineries install steam ejector systems, the total peak daily emissions that would be attributed to the operation of three steam ejector systems at three refineries and one compressor at one refinery would be approximately seven pounds of VOC, one pound of NOx, one pound of PM10, and one pound of PM2.5 (see Table 2-7).

TABLE 2-7
Scenario B: Peak Daily "Worst-Case" Operation Emissions from the Operation of Three Steam Ejector Systems and One Compressor

Peak Operation Activity	VOC (lbs/day)	CO (lbs/day)	NOx (lbs/day)	SOx (lbs/day)	PM10 (lbs/day)	PM2.5 (lbs/day)
Additional Boiler Firing to provide steam to three steam ejector systems	0	0	1	0	1	1
Fugitive emissions from compressor	7	0	0	0	0	0
Total for Operating 3 Steam Ejector Systems plus 1 Compressor	**7**	**0**	**1**	**0**	**1**	**1**
SIGNIFICANCE THRESHOLD	55	550	55	150	150	55
SIGNIFICANT?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

Operation-related activities are simultaneously expected to reduce emissions while generating emissions due to operation of stationary source equipment. Specifically, the direct air quality effects of full implementation of the proposed project (i.e., after construction activities are completed) are the decrease of VOC emissions by up to 0.36 ton per day (720 pounds per day), PM emissions by up to 0.05 ton per day (102 pounds per day), HAP emissions by up to 0.07 ton per day (140 pounds per day), and methane emissions by up to 1.51 ton per day (3,020 pounds per day). PR 1114 is also anticipated to reduce sulfur emissions as H2S by up to 0.05 ton per day (102 pounds per day).

The anticipated emission reductions that may result from implementing the proposed project are expected to improve the overall air quality in the Basin by enhancing the probability of attaining and maintaining state and federal ambient air quality standards for ozone. Since PR 1114 would result in a reduction of an ozone precursor, VOC, as well as HAP, methane, sulfur and PM emissions, implementing PR 1114 would not violate an air quality standard or contribute to an existing or projected air quality violation. Therefore, the projected emission reductions from implementing PR 1114 are seen as benefits.

Thus, the total daily operational emissions do not exceed any of SCAQMD's CEQA air quality operation emissions significance thresholds. In addition, based on the fact that the proposed project overall is expected to generate a net reduction in VOC, HAP, methane, PM and sulfur emissions during operation, no significant adverse air quality impacts during operation are expected as a result of implementing the proposed project. Appendix B contains the spreadsheets for the proposed project with the results based on the assumptions used by the SCAQMD staff for this analysis.

CUMULATIVE IMPACTS – AIR QUALITY: In general, the preceding analysis concluded that air quality impacts from the construction and operational activities associated with implementing the proposed project would result in less than significant air quality impacts because the analysis demonstrates that the SCAQMD's significance thresholds for construction and operation would not be exceeded for any pollutant. For this reason, air quality impacts are not considered to be cumulatively considerable pursuant to CEQA Guidelines §15064 (h)(1) and therefore, no significant adverse cumulative construction or operation air quality impacts are expected to occur.

The analysis also indicates that, in addition to the overall reduction in VOC emissions, the proposed project will result in less than significant increases of VOC, CO, NOx, SOx, PM10 and PM2.5 emissions during the operational phase of the proposed project. Because anticipated operational emissions would not exceed the project-specific air quality significance thresholds, which also serve as the cumulative significance thresholds, they are not considered to be cumulatively considerable (CEQA Guidelines §15064 (h)(1)). Further, the amount of emission reductions to be achieved by the proposed project for VOC are, at the very least, expected to help meet the emission reduction projections and commitments made in the 2012 AQMP. Even though the proposed project would cause a temporary, but less than significant adverse increase in air emissions during the construction phase and less than significant increases in air emissions during the operation phase, the temporary net increase in construction emissions combined with the total permanent emission reductions projected overall during operation would not interfere with the air quality progress and attainment demonstration projected in the 2012 AQMP. Further, based on regional modeling analyses performed for the 2012 AQMP, implementing control measures

contained in the 2012 AQMP, in addition to the air quality benefits of the existing rules, is anticipated to bring the District into attainment with all national and most state ambient air quality standards by the year 2023. Therefore, cumulative operational air quality impacts from the proposed project, previous amendments and all other AQMP control measures considered together, are not expected to be significant because implementation of all AQMP control measures is expected to result in net emission reductions and overall air quality improvement. This determination is consistent with the conclusion in the 2012 AQMP Final Program EIR that cumulative air quality impacts from all AQMP control measures are not expected to be significant (SCAQMD, 2012). Therefore, there will be no significant cumulative adverse operational air quality impacts from implementing the proposed project.

III. d) Affected facilities are not expected to increase exposure by sensitive receptors to substantial pollutant concentrations from the implementation of PR 1114 for the following reasons: 1) the affected refineries are existing facilities located in industrial areas; 2) the limited construction and operational emission increases of criteria pollutants associated with the proposed installation of either a compressor or steam ejector technology are expected to be offset by the overall reductions in VOC, HAP, PM and sulfur (as H2S) emissions upon implementation of PR 1114 and as such, are concluded to be less than significant. Therefore, no significant adverse air quality impacts to sensitive receptors are expected from implementing PR 1114.

III. e) Historically, the SCAQMD has enforced odor nuisance complaints through SCAQMD Rule 402 - Nuisance. Sulfur compounds such as hydrogen sulfide (H2S) and mercaptans are the primary sources of odors from existing delayed coking operations. Current coking operations divert coke drum vapors to a blowdown/vapor recovery system, so that when a coke drum is depressurized at the end of the coking cycle, emissions (and any associated odors vented to the atmosphere) are minimized. PR 1114 would further assist in minimizing emissions to the atmosphere by requiring the depressurization of coke drums at the end of the coking cycle to be less than two psig. Refinery operators may choose to install compressor or steam ejector technology to achieve the depressurization requirement in PR 1114. The effect of requiring such a low pressure before venting a coke drum to atmosphere would not only reduce emissions, but would also reduce the associated odors, causing the overall odor profile of the affected coking units to improve. Lastly, the operation of construction equipment that may be utilized in order to install either technology is not expected to be a substantial source of odors because diesel fuel needed to operate the construction equipment is required to have a low sulfur content (e.g., 15 ppm by weight or less) in accordance with SCAQMD Rule 431.2 – Sulfur Content of Liquid Fuels. Further, because construction activities to install ejectors or compressors occur within the confines of existing affected facilities, sufficient dispersion of diesel emissions over distance would occur so that odors associated with diesel emissions would not be discernable to offsite receptors. Thus, the proposed project is not expected to create significant adverse objectionable odors, either during construction or during operations. Accordingly, this impact issue will not be further analyzed.

III. f) The proposed project would be required to comply with all applicable SCAQMD, CARB, and USEPA rules and regulations. Thus, the proposed project is not expected to diminish an existing air quality rule or future compliance requirements. Further, adopting and implementing the proposed project enhances existing air pollution control rules that are expected to assist the SCAQMD in its efforts to attain and maintain with a margin of safety

the state and federal ambient air quality standards for ozone and PM2.5 because VOCs are considered to be precursor pollutants that contribute to the formation of ozone and PM2.5. Accordingly the proposed project would not diminish any air quality rules or regulations.

III. g) & h) Changes in global climate patterns have been associated with global warming, an average increase in the temperature of the atmosphere near the Earth's surface, recently attributed to accumulation of GHG emissions in the atmosphere. GHGs trap heat in the atmosphere, which in turn heats the surface of the Earth. Some GHGs occur naturally and are emitted to the atmosphere through natural processes, while others are created and emitted solely through human activities. The emission of GHGs through the combustion of fossil fuels (i.e., fuels containing carbon) in conjunction with other human activities, appears to be closely associated with global warming[8]. State law defines GHG to include the following: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6) (HSC §38505(g)). The most common GHG that results from human activity is CO2, followed by CH4 and N2O.

GHGs and other global warming pollutants are perceived as solely global in their impacts and that increasing emissions anywhere in the world contributes to climate change anywhere in the world. A study conducted on the health impacts of CO2 "domes" that form over urban areas cause increases in local temperatures and local criteria pollutants, which have adverse health effects[9].

The analysis of GHGs is a much different analysis than the analysis of criteria pollutants for the following reasons. For criteria pollutants, the significance thresholds are based on daily emissions because attainment or non-attainment is primarily based on daily exceedances of applicable ambient air quality standards. Further, several ambient air quality standards are based on relatively short-term exposure effects on human health (e.g., one-hour and eight-hour standards). Since the half-life of CO2 is approximately 100 years, for example, the effects of GHGs occur over a longer term which means they affect the global climate over a relatively long time frame. As a result, the SCAQMD's current position is to evaluate the effects of GHGs over a longer timeframe than a single day (e.g., annual emissions). GHG emissions are typically considered to be cumulative impacts because they contribute to global climate effects. GHG emission impacts from implementing the proposed project were calculated at the project-specific level. For example, installation and subsequent operation of compressor and steam ejector technology has the potential to increase the electricity, fuel, and water use which will in turn increase CO2 emissions.

On December 5, 2008, the SCAQMD adopted an interim CEQA GHG Significance Threshold for projects where SCAQMD is the lead agency (SCAQMD, 2008). This interim threshold is set at 10,000 metric tons of CO2 equivalent emissions (MTCO2eq) per year. Projects with incremental increases below this threshold will not be cumulatively considerable.

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8 Solomon, S., D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.). 2007. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007. Cambridge University Press. http://www.ipcc.ch/publications_and_data/ar4/wg1/en/contents.html

9 Jacobsen, Mark Z. "Enhancement of Local Air Pollution by Urban CO2 Domes," Environmental Science and Technology, as describe in Stanford University press release on March 16, 2010 available at: http://news.stanford.edu/news/2010/march/urban-carbon-domes-031610.html.

While the operational-related activities are expected to reduce emissions during the depressurization of coke drums, a simultaneous increase in GHG emissions are expected to occur from the construction and operation of compressor and steam ejector technology. The following analysis mainly focuses on directly emitted CO2 because this is the primary GHG pollutant emitted during the combustion process and is the GHG pollutant for which emission factors are most readily available. CO2 emissions were estimated using emission factors from CARB's EMFAC2007 and Offroad2007 models and USEPA's AP-42. In addition, CH4 and N20 emissions were also estimated and are included in the overall GHG calculations. No other GHGs are expected to be emitted because the proposed project does not affect equipment or operations that have the potential to emit other GHGs such as SF6, HFCs or PFCs.

As discussed earlier in Sections b) and c) of this section, the construction analysis that pertains to the installation of compressor or steam ejector technology as part of implementing the proposed project is expected to generate construction-related CO2 emissions. In addition, based on the type and size of equipment affected by the proposed project, CO2 emissions from the operation of this equipment are likely to increase from current levels due to electricity, fuel and water use.

For the purposes of addressing the GHG impacts of the proposed project, the overall impacts of CO2eq emissions from the project were estimated and evaluated from the earliest possible initial implementation of the proposed project with construction beginning in 2014. Once the proposed project is fully implemented, potential GHG emission reductions would occur and continue through the end of the useful life of the equipment. The analysis estimated CO2eq emissions from all sources subject to the proposed project during construction in 2014 and 2015 and operation thereafter. The beginning of the proposed project was assumed to be no sooner than 2014, since installing compressor and steam ejector technology is assumed to take some advance planning and engineering.

As summarized in Tables 2-9 and 2-10, two scenarios were analyzed: 1) Scenario A: construction and operation of four steam ejector systems; and, 2) Scenario B: construction and operation of three steam ejector systems and one compressor. The source of GHG emissions as analyzed are from construction emissions amortized over 30 years, GHG emissions due to water conveyance (to supply additional water to make additional steam for the steam ejectors), GHG emissions due to energy (by increasing the amount of fuel burned to heat the water and convert it into steam), and, the reduction of methane emissions as a result of implementing the two psig depressurization limit in PR 1114. Appendix B contains the spreadsheets for the proposed project with the results based on the assumptions used by the SCAQMD staff for this analysis.

TABLE 2-8
Scenario A: Overall CO2eq Increases Due to Construction and Operation Activities of 4 Steam Ejector Systems (metric tons/year)[1]

GHG Activity	GHG Emissions Source	Total CO2eq (MT/yr)
Temporary construction activities in 2014[2]	Combustion GHGs in 2014 (diesel/gasoline)	3
Temporary construction activities in 2015[2]	Combustion GHGs in 2015 (diesel/gasoline)	4
Increased energy demand to produce more steam	Combustion GHGs	1,666
Increased water demand to produce more steam[3]	Water Conveyance GHGs	31
Increased wastewater generation from producing more steam[3]	Wastewater Conveyance GHGs	5
Reduced emissions due to 2 psig limit in PR 1114	Reduced CH4 emissions of 1.51 tons/day[4]	-10,498
	TOTAL CO2eq[4]	**-8,788**
	Significance Threshold	10,000
	Exceed Significance?	**NO**

1 1 metric ton = 2,205 pounds
2 GHGs from temporary construction activities are amortized over 30 years.
3 California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
4 A negative number means a reduction in emissions.

TABLE 2-9
Scenario B: Overall CO2eq Increases Due to Construction and Operation Activities of 3 Steam Ejector Systems and 1 Compressor (metric tons/year)[1]

GHG Activity	GHG Emissions Source	Total CO2eq (MT/yr)
Temporary construction activities in 2014[2]	Combustion GHGs in 2014 (diesel/gasoline)	3
Temporary construction activities in 2015[2]	Combustion GHGs in 2015 (diesel/gasoline)	4
Increased energy demand to produce more steam	Combustion GHGs	3,678
Increased water demand to produce more steam[3]	Water Conveyance GHGs	29
Increased wastewater generation from producing more steam[3]	Wastewater Conveyance GHGs	4
Reduced emissions due to 2 psig limit in PR 1114	Reduced CH4 emissions of 1.51 tons/day[4]	-10,498
	TOTAL CO2eq[4]	**-6,780**
	Significance Threshold	10,000
	Exceed Significance?	**NO**

1 1 metric ton = 2,205 pounds
2 GHGs from temporary construction activities are amortized over 30 years.
3 California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF
4 A negative number means a reduction in emissions.

Relative to GHGs, implementing the proposed project is expected to achieve a reduction in GHG emissions. Lastly, PR 1114 is not subject to a GHG reduction plan. Thus, implementation of PR 1114 would not conflict with an applicable plan, policy or regulation adopted for the purpose of reducing GHG emissions.

Thus, the SCAQMD's GHG significance threshold for industrial sources will not be exceeded. For this reason, implementing the proposed project is not expected to generate significant adverse cumulative GHG air quality impacts.

Conclusion

Based upon these considerations, significant air quality and GHG emissions impacts are not expected from implementing PR 1114. Since no significant air quality and GHG emissions impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
IV.	**BIOLOGICAL RESOURCES.** Would the project:				
a)	Have a substantial adverse effect, either directly or through habitat modifications, on any species identified as a candidate, sensitive, or special status species in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☐	☑
b)	Have a substantial adverse effect on any riparian habitat or other sensitive natural community identified in local or regional plans, policies, or regulations, or by the California Department of Fish and Game or U.S. Fish and Wildlife Service?	☐	☐	☐	☑
c)	Have a substantial adverse effect on federally protected wetlands as defined by §404 of the Clean Water Act (including, but not limited to, marsh, vernal pool, coastal, etc.) through direct removal, filling, hydrological interruption, or other means?	☐	☐	☐	☑
d)	Interfere substantially with the movement of any native resident or migratory fish or wildlife species or with established native resident or migratory wildlife corridors, or impede the use of native wildlife nursery sites?	☐	☐	☐	☑
e)	Conflicting with any local policies or ordinances protecting biological resources, such as a tree preservation policy or ordinance?	☐	☐	☐	☑
f)	Conflict with the provisions of an adopted Habitat Conservation plan, Natural Community Conservation Plan, or other approved local, regional, or state habitat conservation plan?	☐	☐	☐	☑

Significance Criteria

Impacts on biological resources will be considered significant if any of the following criteria apply:

- The project results in a loss of plant communities or animal habitat considered to be rare, threatened or endangered by federal, state or local agencies.
- The project interferes substantially with the movement of any resident or migratory wildlife species.
- The project adversely affects aquatic communities through construction or operation of the project.

Discussion

IV. a), b), c), & d) PR 1114 would only affect delayed coking operations at existing petroleum facilities located in heavy industrial areas which have already been greatly disturbed. In general, these areas currently do not typically support riparian habitat, federally protected wetlands, or migratory corridors. Additionally, special status plants, animals, or natural communities are not expected to be found in close proximity to the affected facilities. Areas immediately around the affected delayed coking units subject to PR 1114 are expected to be devoid of all biological activity for safety and fire prevention reasons. Therefore, the proposed project would have no direct or indirect impacts that could adversely affect plant or animal species or the habitats on which they rely in the SCAQMD's jurisdiction. The current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions. A conclusion in the Program Environmental Impact Report (EIR) for the 2012 AQMP was that population growth in the region would have greater adverse effects on plant species and wildlife dispersal or migration corridors in the basin than SCAQMD regulatory activities, (e.g., air quality control measures or regulations). The current and expected future land use development to accommodate population growth is primarily due to economic considerations or local government planning decisions.

IV. e) & f) The proposed project is not envisioned to conflict with local policies or ordinances protecting biological resources or local, regional, or state conservation plans. Land use and other planning considerations are determined by local governments and no land use or planning requirements would be altered by the proposed project. Additionally, the proposed project would not conflict with any adopted Habitat Conservation Plan, Natural Community Conservation Plan, or any other relevant habitat conservation plan, and would not create divisions in any existing communities because all activities associated with complying with the proposed project would occur at existing facilities located primarily in heavy industrial areas, which are not typically subject to Habitat or Natural Community Conservation Plans.

The SCAQMD, as the Lead Agency for the proposed project, has found that, when considering the record as a whole, there is no evidence that the proposed project would have potential for any new adverse effects on wildlife resources or the habitat upon which wildlife depends. Accordingly, based upon the preceding information, the SCAQMD has, on the basis of substantial evidence, rebutted the presumption of adverse effect contained in §753.5 (d), Title 14 of the California Code of Regulations.

Based upon these considerations, significant biological resource impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant biological resource impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
V.	**CULTURAL RESOURCES.** Would the project:				
a)	Cause a substantial adverse change in the significance of a historical resource as defined in §15064.5?	☐	☐	☐	☑
b)	Cause a substantial adverse change in the significance of an archaeological resource as defined in §15064.5?	☐	☐	☐	☑
c)	Directly or indirectly destroy a unique paleontological resource, site, or feature?	☐	☐	☐	☑
d)	Disturb any human remains, including those interred outside formal cemeteries?	☐	☐	☐	☑

Significance Criteria

Impacts to cultural resources will be considered significant if:

- The project results in the disturbance of a significant prehistoric or historic archaeological site or a property of historic or cultural significance to a community or ethnic or social group.
- Unique paleontological resources are present that could be disturbed by construction of the proposed project.
- The project would disturb human remains.

Discussion

V. a) There are existing laws in place that are designed to protect and mitigate potential impacts to cultural resources. For example, CEQA Guidelines state that generally, a resource shall be considered ”historically significant” if the resource meets the criteria for listing in the California Register of Historical Resources, which include the following:

- Is associated with events that have made a significant contribution to the broad patterns of California’s history and cultural heritage;
- Is associated with the lives of persons important in our past;

- Embodies the distinctive characteristics of a type, period, region, or method of construction, or represents the work of an important creative individual, or possesses high artistic values;
- Has yielded or may be likely to yield information important in prehistory or history (CEQA Guidelines §15064.5).

Buildings, structures, and other potential culturally significant resources that are less than 50 years old are generally excluded from listing in the National Register of Historic Places, unless they are shown to be exceptionally important. While the exact age of all of the affected delayed coking units is unknown, there may be some that are older than 50 years. Nonetheless, delayed coking units would not be considered historically significant since they would not have any of the distinctive characteristics of a type, period, region, or method of construction, or represents the work of an important creative individual, or possesses high artistic values. Further, since construction-related activities associated with the implementation of the proposed project are expected to be confined within the existing footprint of the petroleum refineries and focused on the delayed coking units, the proposed project would not adversely impact any existing structures at the petroleum refineries that would be considered historically significant, that have contributed to California history, or that pose high artistic values. Therefore, the proposed project is not expected to cause any impacts to significant historic cultural resources.

V. b), c), & d) Installing equipment to comply with the proposed project would require disturbance of previously disturbed areas at the existing petroleum refineries. However, since construction-related activities are expected to be confined within the existing footprint of these affected facilities, the proposed project is not expected to require physical changes to the environment, which may disturb paleontological or archaeological resources. Furthermore, it is envisioned that these areas are already either devoid of significant cultural resources or whose cultural resources have been previously disturbed. Therefore, the proposed project has no potential to cause a substantial adverse change to a historical or archaeological resource, directly or indirectly destroy a unique paleontological resource or site or unique geologic feature, or disturb any human remains, including those interred outside a formal cemeteries. The proposed project is, therefore, not anticipated to result in any activities or promote any programs that could have a significant adverse impact on cultural resources in the district.

Based upon these considerations, significant adverse cultural resources impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant cultural resources impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VI.	**ENERGY.** Would the project:				
a)	Conflict with adopted energy conservation plans?	☐	☐	☐	☑
b)	Result in the need for new or substantially altered power or natural gas utility systems?	☐	☐	☑	☐
c)	Create any significant effects on local or regional energy supplies and on requirements for additional energy?	☐	☐	☑	☐
d)	Create any significant effects on peak and base period demands for electricity and other forms of energy?	☐	☐	☑	☐
e)	Comply with existing energy standards?	☐	☐	☐	☑

Significance Criteria

Impacts to energy and mineral resources will be considered significant if any of the following criteria are met:

- The project conflicts with adopted energy conservation plans or standards.
- The project results in substantial depletion of existing energy resource supplies.
- An increase in demand for utilities impacts the current capacities of the electric and natural gas utilities.
- The project uses non-renewable resources in a wasteful and/or inefficient manner.

Discussion

The proposed project would reduce emissions of delayed coking operations at five affected refineries. The expected options for compliance are either installing compressor or steam ejector technology. Further, it is expected that the installation and operation of any equipment used to comply with the proposed project would also comply with all applicable existing energy standards.

VI. a) & e) The proposed project is not subject to any existing energy conservation plans. If a facility that is subject to PR 1114 is also subject to energy conservation plans, it is not expected that the proposed project would affect in any way or interfere with that facility's ability to comply with its energy conservation plan or energy standards. As concluded in the discussion in sections b), c) and d) below, the amount of energy that may be needed to implement project construction and operation activities is shown to be at less than significant and, thus, the proposed project would not utilize non-renewable energy resources in a wasteful or inefficient manner.

VI. b), c) & d) In order to achieve the overall net air quality benefit from implementing the proposed project, operators of the affected refineries may choose to install either a compressor or steam ejector technology. Installation and operation of compressor or steam ejector technology to comply with the proposed project is expected to increase demand for energy used for constructing and operating the primary equipment as well as support equipment, such as controllers, et cetera.

During construction, diesel fuel and gasoline may be needed to operate construction equipment and to fuel worker vehicles and trucks. Once construction is completed, in order to operate a steam ejector system, additional steam would be needed. To create more steam, additional fuel would need to be combusted by a boiler. The fuel would be expected to be supplied by the refineries.

Once construction is completed, in order to operate a compressor, if installed, additional electricity would be needed. Any additional electricity required is typically either supplied by each affected facility's cogeneration units, for those that have them, or by the local electrical utility, as appropriate.

Two scenarios were considered for the energy analysis: 1) Scenario A which assumes that four facilities would be installing and operating steam ejector systems; and, 2) Scenario B which assumes that three facilities would be installing and operating steam ejector systems and one facility would be installing and operating a compressor. Energy information, as it relates to construction and operational activities, was derived as part of the air quality and GHG emissions analysis in this chapter and the calculations are shown in Appendix B of this ~~Draft~~ Final EA. Tables 2-11 and 2-12 summarize the estimated impacts on diesel fuel and gasoline usage during construction and fuel gas during operation for Scenarios A and B, respectively.

Since neither Scenario A nor Scenario B of the proposed project exceeds the SCAQMD's energy threshold of one percent of supply for diesel, gasoline, and fuel gas, both scenarios are expected to have less than significant energy impacts due to fuel use.

TABLE 2-10
Scenario A: Fuel Usage Summary
for Steam Ejector Systems Installed at 4 Refineries

Fuel Usage Activity	Total Usage	Units	Significance Threshold: 1% of supply (gal/day)	Units	Percent Increase in Fuel Demand	Significant?
Diesel Fuel Usage during Construction	1,599	gal/day	1,086,000,000	gal/day	0.0147%	NO
Gasoline Usage during Construction	63	gal/day	6,469,000,000	gal/day	0.0001%	NO
Fuel Gas Usage during Operation	0.63	MMgal/day	95	MMgal/day	0.66%	NO

TABLE 2-11
Scenario B: Fuel Usage Summary
for Steam Ejector Systems Installed at 3 Refineries
and 1 Compressor Installed at 1 Refinery

Fuel Usage Activity	Total Usage	Units	Significance Threshold: 1% of supply (gal/day)	Units	Percent Increase in Fuel Demand	Significant?
Diesel Fuel Usage during Construction	1,440	gal/day	1,086,000,000	gal/day	0.0133%	NO
Gasoline Usage during Construction	63	gal/day	6,469,000,000	gal/day	0.0001%	NO
Fuel Gas Usage during Operation	0.56	MMgal/day	95	MMgal/day	0.59%	NO

Tables 2-13 summarizes the estimated electricity usage for Scenarios A and B, respectively. Since neither Scenario A nor Scenario A of the proposed project exceeds the SCAQMD's energy threshold of one percent of supply for electricity usage, both scenarios are expected to have less than significant energy impacts due to electricity use.

TABLE 2-12
Electricity Usage Summary

Scenario	No. of Compressors to be Installed	Instantaneous Electricity Usage (MW)	Significance Threshold: 1% of supply (MW)	Percent Increase (%)	Significant?
A	0	0	8,362	0%	NO
B	1	0.50	8,362	0.01%	NO

Based upon these considerations, significant energy impacts are not expected from implementing PR 1114. Since no significant energy impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VII. GEOLOGY AND SOILS. Would the project:				
a) Expose people or structures to potential substantial adverse effects, including the risk of loss, injury, or death involving:	☐	☐	☐	☑
• Rupture of a known earthquake fault, as delineated on the most recent Alquist-Priolo Earthquake Fault Zoning Map issued by the State Geologist for the area or based on other substantial evidence of a known fault?	☐	☐	☐	☑
• Strong seismic ground shaking?	☐	☐	☐	☑
• Seismic–related ground failure, including liquefaction?	☐	☐	☐	☑
b) Result in substantial soil erosion or the loss of topsoil?	☐	☐	☐	☑
c) Be located on a geologic unit or soil that is unstable or that would become unstable as a result of the project, and potentially result in on- or off-site landslide, lateral spreading, subsidence, liquefaction or collapse?	☐	☐	☐	☑
d) Be located on expansive soil, as defined in Table 18-1-B of the Uniform Building Code (1994), creating substantial risks to life or property?	☐	☐	☐	☑
e) Have soils incapable of adequately supporting the use of septic tanks or alternative wastewater disposal systems where sewers are not available for the disposal of wastewater?	☐	☐	☐	☑

Significance Criteria

Impacts on the geological environment will be considered significant if any of the following criteria apply:

- Topographic alterations would result in significant changes, disruptions, displacement, excavation, compaction or over covering of large amounts of soil.

- Unique geological resources (paleontological resources or unique outcrops) are present that could be disturbed by the construction of the proposed project.
- Exposure of people or structures to major geologic hazards such as earthquake surface rupture, ground shaking, liquefaction or landslides.
- Secondary seismic effects could occur which could damage facility structures, e.g., liquefaction.
- Other geological hazards exist which could adversely affect the facility, e.g., landslides, mudslides.

Discussion

VII. a) Although the proposed project may result in construction activities to install compressor or steam ejector technology for the delayed coking units operation at existing petroleum refineries, little site preparation is anticipated that could adversely affect geophysical conditions in the jurisdiction of the SCAQMD. Southern California is an area of known seismic activity. Structures must be designed to comply with the Uniform Building Code Zone 4 requirements if they are located in a seismically active area. The local city or county is responsible for assuring that a proposed project complies with the Uniform Building Code as part of the issuance of the building permits and can conduct inspections to ensure compliance. The Uniform Building Code is considered to be a standard safeguard against major structural failures and loss of life. The goal of the code is to provide structures that will: 1) resist minor earthquakes without damage; 2) resist moderate earthquakes without structural damage but with some non-structural damage; and, 3) resist major earthquakes without collapse but with some structural and non-structural damage.

The Uniform Building Code is considered to be a standard safeguard against major structural failures and loss of life. The Uniform Building Code bases seismic design on minimum lateral seismic forces ("ground shaking"). The Uniform Building Code requirements operate on the principle that providing appropriate foundations, among other aspects, helps to protect buildings from failure during earthquakes. The basic formulas used for the Uniform Building Code seismic design require determination of the seismic zone and site coefficient, which represent the foundation conditions at the site. The Uniform Building Code requirements also consider liquefaction potential and establish stringent requirements for building foundations in areas potentially subject to liquefaction.

Accordingly, existing buildings and equipment at existing affected facilities are likely to conform to the Uniform Building Code and all other applicable state codes in effect at the time they were constructed. Further, the installation of equipment at existing affected facilities to comply with the proposed project is also expected to conform to the Uniform Building Code and all other applicable state and local building codes.

Thus, the proposed project would not alter the exposure of people or property to geological hazards such as earthquakes, landslides, mudslides, ground failure, or other natural hazards. As a result, substantial exposure of people or structures to the risk of loss, injury, or death involving the rupture of an earthquake fault, seismic ground shaking, ground failure or landslides is not anticipated and will not be further analyzed.

VII. b) Since compressor or steam ejector technology may be installed at existing facilities, a slight possibility exists for temporary erosion resulting from excavating and grading activities, if required, during construction of the proposed project. These activities are expected to be minor since the existing facilities are generally flat and have previously been graded. Further, wind erosion is not expected to occur to any appreciable extent, because operators at dust generating sites would be required to comply with the best available control measure (BACM) requirements of SCAQMD Rule 403 – Fugitive Dust. In general, operators must control fugitive dust through a number of soil stabilizing measures such as watering the site, using chemical soil stabilizers, revegetating inactive sites, et cetera. The proposed project involves the installation of equipment at existing petroleum refineries, so that grading could be required to provide stable foundations. Potential air quality impacts related to grading are addressed elsewhere in this Initial Study (as part of construction air quality impacts). No unstable earth conditions or changes in geologic substructures are expected to result from implementing the proposed project.

VII. c) Since PR 1114 would affect delayed coking operations at existing petroleum refineries, it is expected that the soil types present at the affected facilities would not be further susceptible to expansion or liquefaction. Furthermore, subsidence is not anticipated to be a problem since no excavation, grading, or filling activities would occur at affected facilities. Further, the proposed project would not involve drilling or removal of underground products (e.g., water, crude oil, et cetera) that could produce subsidence effects. Additionally, the affected areas are not envisioned to be prone to landslides or have unique geologic features since the affected facilities are located in heavy industrial areas where such features have already been altered or removed.

Finally, since implementation of PR 1114 would be expected to affect operations at existing facilities, the proposed project would not be expected to alter or make worse any existing potential for subsidence, liquefaction, et cetera.

VII. d) & e) Since the proposed project would affect delayed coking operations at existing petroleum refineries located in industrial zones, it is expected that people or property would not be exposed to new impacts related to expansive soils or soils incapable of supporting water disposal. Further, typically each affected facility has some degree of existing wastewater treatment systems that would continue to be used and would be expected to be unaffected by the proposed project. Sewer systems are available to handle wastewater produced and treated by each affected facility. Each existing facility affected by the proposed project would not require installation of septic tanks or alternative wastewater disposal systems. As a result, the proposed project would not require facility operators to utilize septic systems or alternative wastewater disposal systems. Thus, implementation of the proposed project would not adversely affect soils associated with a septic system or alternative wastewater disposal system.

Based upon these considerations, significant geology and soils impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant geology and soils impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
VIII. HAZARDS AND HAZARDOUS MATERIALS. Would the project:				
a) Create a significant hazard to the public or the environment through the routine transport, use, and disposal of hazardous materials?	☐	☐	☑	☐
b) Create a significant hazard to the public or the environment through reasonably foreseeable upset conditions involving the release of hazardous materials into the environment?	☐	☐	☑	☐
c) Emit hazardous emissions, or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school?	☐	☐	☑	☐
d) Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code §65962.5 and, as a result, would create a significant hazard to the public or the environment?	☐	☐	☐	☑
e) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public use airport or a private airstrip, would the project result in a safety hazard for people residing or working in the project area?	☐	☐	☑	☐
f) Impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan?	☐	☐	☐	☑
g) Expose people or structures to a significant risk of loss, injury or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands?	☐	☐	☐	☑

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
h) Significantly increased fire hazard in areas with flammable materials?	☐	☐	☐	☑

Significance Criteria

Impacts associated with hazards will be considered significant if any of the following occur:

- Non-compliance with any applicable design code or regulation.
- Non-conformance to National Fire Protection Association standards.
- Non-conformance to regulations or generally accepted industry practices related to operating policy and procedures concerning the design, construction, security, leak detection, spill containment or fire protection.
- Exposure to hazardous chemicals in concentrations equal to or greater than the Emergency Response Planning Guideline (ERPG) 2 levels.

Discussion

VIII. a) & b) Delayed coking units are inherently dangerous operations that involve the use of hazardous feed materials and generate hazardous emissions. Operational hazards associated with DCU operations can occur during coke drum switching, coke drum head removal (deheading), and coke cutting. Emergency hazards can occur during coke transfer, processing and storage that can trigger an emergency evacuation due to potential exposures to toxics and dust irritants and burn trauma[10]. To help control these hazards and prevent emergency situations, operators of DCUs follow established USEPA and OSHA safety protocols that contain best management practices for operating the DCUs safely and reliably. Implementation of PR 1114 would not interfere with USEPA and OSHA requirements for the proper safe operation and maintenance of DCUs. In addition, PR 1114 would not create new upset conditions involving the release of hazardous materials into the environment above the existing baseline. Rather, PR 1114, by requiring a lower minimum depressurization level than current operations without requiring a change to the nature, process, or throughput of the affected delayed coking units, would potentially enhance safety by reducing the possibility of explosion due to pressure build up. Thus, the potential changes that may occur as part of implementing PR 1114 (e.g., the installation of compressor or steam ejector technology) would not affect the structural integrity of the affected coke drums.

Operators of the existing refineries have indicated that the construction activities to install a steam ejector system or compressor for the delayed coking units would need to occur prior to a turnaround and for safety reasons, the actual tie-in (final connection) of the equipment

[10] Hazards of Delayed Coker Unit (DCU) Operations, Safety and Health Information Bulletin, Occupational Safety and Health Adminstration (OSHA), SHIB 08-29-03 (C); http://www.osha/gov/dts/shib/shib082903c.html.

would occur during a turnaround (e.g., when the affected delayed coking units are shut down and cooled).

Since delayed coking units typically undergo a turnaround every five years, the process of shutting down the equipment to prepare for construction to accommodate PR 1114, as well as maintenance and any needed repairs, is routine for the operators of the affected refineries. Thus, construction activities that may occur as a result of implementing PR 1114 would not be expected to create any new hazards or increase existing hazards above the existing baseline.

During operation, PR 1114 would not introduce, require, or change the amount of hazardous materials: 1) routinely transported to or from the refineries for use in the DCUs; 2) processed by the DCUs; and, 3) disposed of as hazardous waste at the end of the DCU process. However, PR 1114 may have the effect of reducing emissions vented to the atmosphere, which include HAPs such as H2S. While the reduction of H2S vented to atmosphere would be beneficial for air quality, because H2S is also explosive, a reduction in H2S emissions would lessen the current explosion hazards associated with the operation of delayed coking units.

VIII. c) & e) Construction activities from implementing the proposed project are expected to occur within the existing confines of the affected facilities. However, some of these facilities may be located within one-quarter mile of a sensitive receptor (e.g., a school) or in close proximity to a public/private airport and are located within an airport land use plan. Nonetheless, the installation of either compressor or steam ejector technology would not increase the height of the existing delayed coking units. Further, installation of compressor or steam ejector technology would be required to comply with all appropriate building, land use and fire codes. For these reasons, installation of compressor or steam ejector technology would not interfere with plane flight paths consistent with Federal Aviation Regulation, Part 77 because installation of ejectors or compressors onto DCUs is not expected to increase the existing height profiles of this equipment. Such codes are designed to protect the public from hazards associated with normal operation. Since PR 1114 would not create any new hazards or increase existing hazards above the existing baseline, no significant impacts from use and potential accidental release of acutely hazardous materials, substances and wastes near sensitive receptors and public/private airports are expected to occur. As noted in the preceding discussion, the proposed project is expected to reduce H2S emissions, which is a benefit because H2S is explosive and a HAP. Therefore, the proposed project would not be expected to result in a safety hazard for people residing or working in the area of the affected facilities even within the vicinity of a sensitive receptor or airport.

VIII. d) In the event that compressor technology is installed at an affected facility, construction activities that may occur as part of preparing for a small concrete pad, if needed, may require some limited grading and excavating which could potentially uncover contaminated soils. In the event that any excavated soils contain concentrations of certain substances, such as heavy metals and hydrocarbons, the handling, processing, transportation and disposal of the contaminated soils would continue to be subject to applicable hazardous waste regulations such as Title 22 of the California Code of Regulations and other local and federal rules. Title 22 has multiple requirements for hazardous waste handling, transport and disposal, such as requirements to use approved disposal and treatment facilities, to use certified hazardous waste transporters, and to have manifests for tracking the hazardous

materials. If contaminated soils are encountered during grading and excavating, the soils would need to be removed for proper decontamination and disposal in accordance with SCAQMD Rule 1166 – Volatile Organic Compound Emissions From Decontamination of Soil.

Lastly, if any of the affected facilities are designated pursuant to Government Code §65962.5 as a large quantity generator of hazardous waste, complying with PR 1114 would not alter in any way how the affected facilities manage their hazardous wastes and they would continue to be managed in accordance with all applicable federal, state, and local rules and regulations.

VIII. f) Health and Safety Code §25506 specifically requires all businesses handling hazardous materials to submit a business emergency response plan to assist local administering agencies in the emergency release or threatened release of a hazardous material. Business emergency response plans generally require the following:

- Identification of individuals who are responsible for various actions, including reporting, assisting emergency response personnel and establishing an emergency response team;
- Procedures to notify the administering agency, the appropriate local emergency rescue personnel, and the California Office of Emergency Services;
- Procedures to mitigate a release or threatened release to minimize any potential harm or damage to persons, property or the environment;
- Procedures to notify the necessary persons who can respond to an emergency within the facility;
- Details of evacuation plans and procedures;
- Descriptions of the emergency equipment available in the facility;
- Identification of local emergency medical assistance; and,
- Training (initial and refresher) programs for employees in:
    1. The safe handling of hazardous materials used by the business;
    2. Methods of working with the local public emergency response agencies;
    3. The use of emergency response resources under control of the handler;
    4. Other procedures and resources that will increase public safety and prevent or mitigate a release of hazardous materials.

In general, every county or city and all facilities using a minimum amount of hazardous materials are required to formulate detailed contingency plans to eliminate, or at least minimize, the possibility and effect of fires, explosion, or spills. In conjunction with the California Office of Emergency Services, local jurisdictions have enacted ordinances that set standards for area and business emergency response plans. These requirements include immediate notification, mitigation of an actual or threatened release of a hazardous material, and evacuation of the emergency area.

Emergency response plans are typically prepared in coordination with the local city or county emergency plans to ensure the safety of not only the public (surrounding local communities), but the facility employees as well. The proposed project would not impair implementation of, or physically interfere with any adopted emergency response plan or emergency evacuation plan. The existing facilities affected by the proposed project would typically already have their own emergency response plans in place. However, operators of affected facilities who elect to install compressor or steam ejector technology for their delayed coking units may need to update their emergency response plan. Thus, the proposed project is not expected to impair implementation of or physically interfere with an adopted emergency response plan or emergency evacuation plan, but may require minor changes. As such, this impact issue will not be further analyzed.

VIII. g) The proposed project is not expected to increase the existing risk of fire hazards in areas with flammable brush, grass, or trees since the affected petroleum refineries are located at on existing industrial sites in urban areas where wildlands are not prevalent. In addition, no substantial or native vegetation typically exists on or near the affected facilities (specifically because they could be a fire hazard) so the proposed project is not expected to expose people or structures to wild fires. Thus, risk of loss or injury associated with wildland fires is not expected.

VIII. h) The Uniform Fire Code and California Building Code set standards intended to minimize risks from flammable or otherwise hazardous materials. Local jurisdictions are required to adopt the uniform codes or comparable regulations. Local fire agencies require permits for the use or storage of hazardous materials and permit modifications for proposed increases in their use. Permit conditions depend on the type and quantity of the hazardous materials at the facility. Permit conditions may include, but are not limited to, specifications for sprinkler systems, electrical systems, ventilation, and containment. The fire departments make annual business inspections to ensure compliance with permit conditions and other appropriate regulations. Further, businesses are required to report increases in the storage or use of flammable and otherwise hazardous materials to local fire departments. Local fire departments ensure that adequate permit conditions are in place to protect against potential risk of upset.

As mentioned in the earlier discussion for section VIII a) & b), PR 1114 may have the effect of reducing the amount of H2S vented to atmosphere. Because H2S is explosive, a reduction in H2S emissions would lessen the current explosion hazards associated with the operation of delayed coking units. Thus, PR 1114 may improve the existing fire risk of existing DCU operations.

Based upon the above considerations, significant hazards and hazardous materials impacts are not expected from implementing PR 1114. Since no significant hazards and hazardous materials impacts were identified, no mitigation measures are necessary or required.

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
IX.	**HYDROLOGY AND WATER QUALITY.** Would the project:				
a)	Violate any water quality standards, waste discharge requirements, exceed wastewater treatment requirements of the applicable Regional Water Quality Control Board, or otherwise substantially degrade water quality?	☐	☐	☑	☐
b)	Substantially deplete groundwater supplies or interfere substantially with groundwater recharge such that there would be a net deficit in aquifer volume or a lowering of the local groundwater table level (e.g. the production rate of pre-existing nearby wells would drop to a level which would not support existing land uses or planned uses for which permits have been granted)?	☐	☐	☑	☐
c)	Substantially alter the existing drainage pattern of the site or area, including through alteration of the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in substantial erosion or siltation on- or off-site or flooding on- or off-site?	☐	☐	☑	☐
d)	Create or contribute runoff water which would exceed the capacity of existing or planned storm water drainage systems or provide substantial additional sources of polluted runoff?	☐	☐	☑	☐
e)	Place housing or other structures within a 100-year flood hazard area as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood hazard delineation map, which would impede or redirect flood flows?	☐	☐	☐	☑

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
f)	Expose people or structures to a significant risk of loss, injury or death involving flooding, including flooding as a result of the failure of a levee or dam, or inundation by seiche, tsunami, or mudflow?	☐	☐	☐	☑
g)	Require or result in the construction of new water or wastewater treatment facilities or new storm water drainage facilities, or expansion of existing facilities, the construction of which could cause significant environmental effects?	☐	☐	☑	☐
h)	Have sufficient water supplies available to serve the project from existing entitlements and resources, or are new or expanded entitlements needed?	☐	☐	☑	☐
i)	Result in a determination by the wastewater treatment provider which serves or may serve the project that it has adequate capacity to serve the project's projected demand in addition to the provider's existing commitments?	☐	☐	☑	☐

Significance Criteria

Potential impacts on water resources will be considered significant if any of the following criteria apply:

Water Demand:

- The existing water supply does not have the capacity to meet the increased demands of the project, or the project would use more than 262,820 gallons per day of potable water.
- The project increases demand for total water by more than five million gallons per day.

Water Quality:

- The project will cause degradation or depletion of ground water resources substantially affecting current or future uses.

- The project will cause the degradation of surface water substantially affecting current or future uses.
- The project will result in a violation of National Pollutant Discharge Elimination System (NPDES) permit requirements.
- The capacities of existing or proposed wastewater treatment facilities and the sanitary sewer system are not sufficient to meet the needs of the project.
- The project results in substantial increases in the area of impervious surfaces, such that interference with groundwater recharge efforts occurs.
- The project results in alterations to the course or flow of floodwaters.

Discussion

IX. a), g), h) & i) Operators of facilities affected by the proposed project are expected to install either compressor or steam ejector technology to comply with the requirements in PR 1114. While compressors do not utilize water or steam for operation, operational activities associated with steam ejectors will increase the demand for water (to be converted to steam) and subsequently, will increase the amount of wastewater discharged at each affected facility. As summarized in Table 2-13, neither the operational water demand for Scenario A nor Scenario B would exceed the significance thresholds for potable water and total water. As such, the operational water demand would not be expected to create a significant adverse water demand impact.

TABLE 2-13
Operational Water Demand

Scenario	Water Demand (gal/day)	Significance Threshold: Potable Water (gal/day)	Exceed Significance for Potable Water?	Significance Threshold: Total Water (MMgal/day)	Exceed Significance for Total Water?
A: Steam Ejector Systems Installed at 4 Refineries	23,259	262,820	NO	5	NO
B: Steam Ejector Systems Installed at 3 Refineries and 1 Compressor Installed at 1 Refinery	21,759	262,820	NO	5	NO

As shown in Table 2-13, for the facility operators who choose to employ steam ejector technology, which requires water (as steam) for operation, some of the affected facilities were shown to have a less than significant increase in water demand. To investigate whether the existing water supply has the capacity to meet the increased water demand of the proposed project, previous projects involving potentially significant increases in water demand were shown to have sufficient supply of water during drought conditions (e.g., the November 2010 amendments to the SOx RECLAIM program[11]). Because the increased

[11] Final Program Environmental Assessment for Proposed Amended Regulation XX – Regional Clean Air Incentives Market (RECLAIM), SCAQMD No. 06182009BAR; State Clearinghouse No: 2009061088, Certified November 5, 2010. http://www.aqmd.gov/ceqa/documents/2010/aqmd/finalEA/SOx-RECLAIM/RegXXFinalPEA.pdf

water demand associated with the proposed project is concluded to be less than significant as shown in Table 2-13, existing water supplies are expected to be sufficient. It is important to note that while the affected facilities could increase steam production that would increase water demand, it is also possible that the affected refineries may already have existing amounts of extra steam available such that there would be no increase in water demand. For these reasons, the existing water supply in the district is expected to be sufficient to accommodate the proposed project. Lastly, the relatively small increases in water demand would not be expected to create a need for new or expanded water supply entitlements.

As summarized in Tables 2-15 and 2-16, affected facility operators provided their wastewater discharge limits and on-site treatment capacity. These values were compared to each facility's estimated potential increase in wastewater that may result from implementing Scenario A and Scenario B of the proposed project, respectively. The peak percentage increase from baseline levels when compared to the proposed project was approximately 0.034 percent (Facility E) under both Scenario A and Scenario B. An increase of 25 percent of wastewater generation would trigger a permit revision of the wastewater permit discharge limit and would be considered a significant adverse wastewater impact. Since all of the affected facilities have been shown under both scenarios to have a potential wastewater increase less than 25 percent, no modifications to any existing Industrial Wastewater Discharge Permits are anticipated as a result of the proposed project. Further, the on-site wastewater treatment capacities are adequate to treat any additional wastewater that may be generated as a result of implementing the proposed project. Thus, the operational impacts of the proposed project on each affected facility's wastewater discharge and the Industrial Wastewater Discharge Permit are expected to be less than significant.

Table 2-14
Scenario A: Potential Increases in Wastewater Generation per Facility

Facility ID	Scenario A: Proposed Compliance Method	Potential Increase in Wastewater Generation (gal/day)	Wastewater Permit Discharge Limit[1] (MMgal/day)	On-site Treatment Capacity[2] (MMgal/day)	Percentage Increase Above Discharge Limit (%)	Greater than 25% Increase? (Exceeds CEQA Significance Threshold?)[3]
A	Steam Ejector System	563	7.49	11.52 (max.); 5.76 (avg.)	0.008%	NO
B	Steam Ejector System	2,250	10.8	5.04 (max.); 4.32 (avg.)	0.021%	NO
C	Steam Ejector System	375	7.2	2.88	0.005%	NO
D	Software Upgrade	0	14.4	8.64 (max.); 3.19 (avg. dry weather); 3.25 (avg. wet weather)	0%	NO
E	Steam Ejector System	375	1.1	1.14	0.034%	NO
F	Existing Permit Limit	0	8.8	System 1: 7.2 (max.); and 4.32 (avg.) System 2: 2.88 (max.); and 2.59 (avg.)	0%	NO

[1] Wastewater limits were obtained from each facility's wastewater permit(s). For any facility that has multiple discharge limits (i.e. dry weather, wet weather, etc.), the most conservative limit will be used for the purposes of this comparison.

[2] On-site treatment capacity information was provided by each facility operator. For any facility that has multiple capacities (i.e. dry weather, wet weather, etc.), the most conservative value will be used to determine if the capacity is adequate to handle the potential increase in wastewater treatment.

[3] Significance for wastewater is if the increase is greater than 25% above an individual facility's discharge limit. An increase of 25% or more above the limit would trigger a permit revision.

Table 2-15
Scenario B: Potential Increases in Wastewater Generation per Facility

Facility ID	Scenario B: Proposed Compliance Method	Potential Increase in Wastewater Generation (gal/day)	Wastewater Permit Discharge Limit[1] (MMgal/day)	On-site Treatment Capacity[2] (MMgal/day)	Percentage Increase Above Discharge Limit (%)	Greater than 25% Increase? (Exceeds CEQA Significance Threshold?)[3]
A	Steam Ejector System	563	7.49	11.52 (max.); 5.76 (avg.)	0.008%	NO
B	Steam Ejector System	2,250	10.8	5.04 (max.); 4.32 (avg.)	0.021%	NO
C	Compressor	0	7.2	2.88	0%	NO
D	Software Upgrade	0	14.4	8.64 (max.); 3.19 (avg. dry weather); 3.25 (avg. wet weather)	0%	NO
E	Steam Ejector System	375	1.1	1.14	0.034%	NO
F	Existing Permit Limit	0	8.8	System 1: 7.2 (max.); and 4.32 (avg.) System 2: 2.88 (max.); and 2.59 (avg.)	0%	NO

[1] Wastewater limits were obtained from each facility's wastewater permit(s). For any facility that has multiple discharge limits (i.e. dry weather, wet weather, etc.), the most conservative limit will be used for the purposes of this comparison.

[2] On-site treatment capacity information was provided by each facility operator. For any facility that has multiple capacities (i.e. dry weather, wet weather, etc.), the most conservative value will be used to determine if the capacity is adequate to handle the potential increase in wastewater treatment.

[3] Significance for wastewater is if the increase is greater than 25% above an individual facility's discharge limit. An increase of 25% or more above the limit would trigger a permit revision.

IX. b) Operators of facilities affected by the proposed project are expected to install either compressor or steam ejector technology to comply with the requirements in PR 1114. While compressors do not utilize water or steam for operation, operational activities associated with steam ejectors will increase the demand for water (to be converted to steam). Typically, operators of the affected refineries that would install steam ejectors would access existing sources of water/steam located elsewhere in the refinery and the quality of the steam would need to be suitable for multiple processes within the refinery. While some of the affected refineries may have access to ground water, the use of ground water is limited by water quality, since levels of salinity and well as other contaminants such as soil, rock and other debris could be unacceptably high for use. Thus, the proposed project is not expected to utilize ground water if steam ejector technology is employed. For these reasons, PR 1114 is not expected to cause degradation or depletion of ground water resources substantially affecting current or future uses. Thus, implementation of PR 1114 is not expected to significantly adversely affect the quantity or quality of groundwater in the area of each affected facility. Accordingly, this impact issue will not be further evaluated in this ~~Draft~~ Final EA.

IX. c) & d) Changes to each affected facility's storm water collection systems are expected to be less than significant since most of the changes associated with the proposed project

(e.g., by installing compressor or steam ejector technology) would occur within existing facilities. Further, typically most of the areas likely to be affected by the proposed project are currently paved and are expected to remain paved, so there is not expected to be an increase in the amount of runoff from the affected facilities. Any new units constructed would be curbed and the existing units will remain curbed to contain any runoff. Any runoff occurring will continue to be handled by each affected facility's wastewater system and sent to an on-site wastewater treatment system prior to discharge. The surface water runoff is expected to be handled with each facility's existing wastewater treatment system. Storm water runoff will be collected and discharged in accordance with each facility's discharge permit terms and conditions. Storm water Pollution Prevention Plans may need to be updated, as necessary to reflect operational modifications and included additional Best Management Practices, if required. Further, any construction that may occur as a result of implementing PR 1114 would not alter the course of a stream or river, or substantially increase the rate or amount of surface runoff in a manner that would result in substantial erosion or siltation on- or off-site or flooding on- or off-site because the sites are paved and storm water is directed into the existing wastewater treatment systems. Therefore, less than significant storm water quality impacts are expected to result from the operation of the proposed project. Accordingly, these impact issues will not be further evaluated in this ~~Draft~~ Final EA.

IX. e) Once implemented, PR 1114 is not expected to require additional workers at affected facilities. Further, the proposed project is expected to involve construction activities located within the confines of existing facilities and does not include the construction of any new housing so it would not place new housing in 100-year flood areas as mapped on a federal Flood Hazard Boundary or Flood Insurance Rate Map or other flood delineation map. It is likely that most affected facilities are not located within a 100-year flood hazard area. Any affected facilities that may be located in a 100-year flood area could impede or redirect 100-year flood flows, but this would be considered part of the existing setting and not an effect of the proposed project. Since the proposed project would not require locating new facilities within a flood zone, it is not expected that implementation of the proposed project would expose people or property to any new known water-related flood hazards. As a result, PR 1114 is not expected to expose people or structures to significant flooding risks. Accordingly, this impact issue will not be further evaluated in this ~~Draft~~ Final EA.

IX. f) The proposed project does not require construction of new facilities in areas that could be affected by tsunamis. Of the facilities affected by the proposed project, some are located near the Ports of Long Beach, Los Angeles, and San Pedro. The port areas are protected from tsunamis by the construction of breakwaters. Construction of breakwaters combined with the distance of each facility from the water is expected to minimize the potential impacts of a tsunami or seiche so that no significant impacts are expected. The proposed project does not require construction of facilities in areas that are susceptible to mudflows (e.g., hillside or slope areas). Existing affected facilities that are currently located on hillsides or slope areas may be susceptible to mudflow, but this would be considered part of the existing setting. As a result, the proposed project is not expected to generate significant adverse mudflow impacts. Finally, PR 1114 will not affect in any way any potential flood hazards inundation by seiche, tsunami, or mud flow that may already exist relative to existing facilities. Accordingly, this impact issue will not be further evaluated in this ~~Draft~~ Final EA.

Based upon the above considerations, significant hydrology and water quality impacts are not expected from implementing PR 1114. Since no significant hydrology and water quality impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
X. LAND USE AND PLANNING. Would the project:				
a) Physically divide an established community?	☐	☐	☐	☑
b) Conflict with any applicable land use plan, policy, or regulation of an agency with jurisdiction over the project (including, but not limited to the general plan, specific plan, local coastal program or zoning ordinance) adopted for the purpose of avoiding or mitigating an environmental effect?	☐	☐	☐	☑

Significance Criteria

Land use and planning impacts will be considered significant if the project conflicts with the land use and zoning designations established by local jurisdictions.

Discussion

X. a) The proposed project would not require the construction of new facilities at new locations, but any physical effects that will result from the proposed project, would occur at existing industrial facilities. Thus, implementing the proposed project would not result in physically dividing any established communities.

X. b) & c) There are no provisions in PR 1114 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by implementing the proposed project. Further, the proposed project would be consistent with the typical industrial zoning of the affected facilities. Since PR 1114 would establish lower depressurization requirements for delayed coking units at existing petroleum refineries which are located in heavy industrial settings, any equipment installed to achieve the proposed pressure limit is expected to occur within the confines of these affected facilities.

The proposed project would not affect in any way habitat conservation or natural community conservation plans, agricultural resources or operations, and would not create divisions in any existing communities. Further, no new development or alterations to existing land designations would occur as a result of the implementation of the proposed project.

Therefore, present or planned land uses in the region would not be affected as a result of implementing the proposed project.

Based upon these considerations, significant land use and planning impacts are not expected from implementing PR 1114. Since no significant land use and planning impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XI. MINERAL RESOURCES. Would the project:				
a) Result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state?	☐	☐	☐	☑
b) Result in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan?	☐	☐	☐	☑

Significance Criteria

Project-related impacts on mineral resources will be considered significant if any of the following conditions are met:

- The project would result in the loss of availability of a known mineral resource that would be of value to the region and the residents of the state.
- The proposed project results in the loss of availability of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Discussion

XI. a) & b) There are no provisions in PR 1114 that would result in the loss of availability of a known mineral resource of value to the region and the residents of the state such as aggregate, coal, clay, shale, et cetera, or of a locally-important mineral resource recovery site delineated on a local general plan, specific plan or other land use plan.

Based upon these considerations, significant mineral resource impacts are not expected from implementing PR 1114 and, thus, will not be further analyzed. Since no significant mineral resource impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XII. NOISE. Would the project result in:				
a) Exposure of persons to or generation of permanent noise levels in excess of standards established in the local general plan or noise ordinance, or applicable standards of other agencies?	☐	☐	☑	☐
b) Exposure of persons to or generation of excessive groundborne vibration or groundborne noise levels?	☐	☐	☑	☐
c) A substantial temporary or periodic increase in ambient noise levels in the project vicinity above levels existing without the project?	☐	☐	☑	☐
d) For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public use airport or private airstrip, would the project expose people residing or working in the project area to excessive noise levels?	☐	☐	☑	☐

Significance Criteria

Noise impact will be considered significant if:

- Construction noise levels exceed the local noise ordinances or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three decibels (dBA) at the site boundary. Construction noise levels will be considered significant if they exceed federal Occupational Safety and Health Administration (OSHA) noise standards for workers.
- The proposed project operational noise levels exceed any of the local noise ordinances at the site boundary or, if the noise threshold is currently exceeded, project noise sources increase ambient noise levels by more than three dBA at the site boundary.

Discussion

XII. a), b), c), & d) Modifications or changes associated with the implementation of the proposed project would take place at existing refineries that are located in industrial settings. The existing noise environment at each of the affected refineries is typically dominated by noise from existing equipment onsite, vehicular traffic around the facilities, and trucks entering and exiting facility premises. Construction activities associated with implementing the proposed project may generate some noise associated with the use of construction equipment and construction-related traffic. However, noise from the proposed project is not

expected to produce noise in excess of current operations at each of the existing facilities. Unlike the operation of steam ejector technology, which does not generate noise, the installation and operation of compressor technology would become a new source of noise. Nonetheless, any operator who chooses to install compressor technology at its facility in order to comply with the requirements in PR 1114, it is expected that each affected refinery would continue to comply with all existing noise control laws or ordinances. Further, Occupational Safety and Health Administration (OSHA) and California-OSHA (Cal/OSHA) have established noise standards to protect worker health when noise levels exceed specified noise levels (see for example 29 CFR Part 1910). These potential noise increases are expected to be within the allowable noise levels established by the local noise ordinances for industrial areas, and thus are expected to be less than significant.

Though some of the facilities affected by the proposed project are located at sites within an airport land use plan or within two miles of a public airport, the installation of compressor technology would not expose people residing or working in the project area to the same degree of excessive noise levels associated with airplanes. All noise producing equipment must comply with local noise ordinances and applicable OSHA or Cal/OSHA workplace noise reduction requirements.

Based upon these considerations, significant noise impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant noise impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XIII. POPULATION AND HOUSING. Would the project:				
a) Induce substantial growth in an area either directly (for example, by proposing new homes and businesses) or indirectly (e.g. through extension of roads or other infrastructure)?	☐	☐	☐	☑
b) Displace substantial numbers of people or existing housing, necessitating the construction of replacement housing elsewhere?	☐	☐	☐	☑

Significance Criteria

Impacts of the proposed project on population and housing will be considered significant if the following criteria are exceeded:

- The demand for temporary or permanent housing exceeds the existing supply.
- The proposed project produces additional population, housing or employment inconsistent with adopted plans either in terms of overall amount or location.

Discussion

XIII. a) The construction activities associated with the proposed project at each affected facility are not expected to involve the relocation of individuals, require new housing or commercial facilities, or change the distribution of the population. The reason for this conclusion is that operators of affected facilities who need to perform any construction activities to comply with the proposed project can draw from the existing labor pool in the local southern California area. Further, it is not expected that the installation of compressor or steam ejector technology would require new employees to operate and maintain the equipment. In the event that new employees are hired, it is expected that the number of new employees at any one facility would be small, no more than one or two per refinery. Human population within the jurisdiction of the SCAQMD is anticipated to grow regardless of implementing the proposed project. As a result, the proposed project is not anticipated to generate any significant adverse effects, either direct or indirect, on population growth in the district or population distribution.

XIII. b) Because the proposed project includes modifications and/or changes at existing facilities located in industrial settings, the proposed project is not expected to result in the creation of any industry that would affect population growth, directly or indirectly induce the construction of single- or multiple-family units, or require the displacement of people or housing elsewhere in the district.

Based upon these considerations, significant population and housing impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant population and housing impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XIV. PUBLIC SERVICES. Would the proposal result in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response times or other performance objectives for any of the following public services:				
a) Fire protection?	☐	☐	☐	☑
b) Police protection?	☐	☐	☐	☑
c) Schools?	☐	☐	☐	☑
d) Other public facilities?	☐	☐	☐	☑

Significance Criteria

Impacts on public services will be considered significant if the project results in substantial adverse physical impacts associated with the provision of new or physically altered governmental facilities, or the need for new or physically altered government facilities, the construction of which could cause significant environmental impacts, in order to maintain acceptable service ratios, response time or other performance objectives.

Discussion

XIV. a) & b) If implementation of the proposed project results in the installation of compressor or steam ejector technology, construction activities associated with the installation would occur prior to a scheduled turnaround of the delayed coker unit, all the while continuing current operations elsewhere within the facility. Safety hazards are not expected to occur during installation of compressor or steam ejector technology because the associated construction activities would not involve the use or handling of hazardous materials and the actual tie-in would occur during a scheduled turnaround as explained below. Because the operation of delayed coker units pose existing fire and safety hazards, the tie-in of the equipment after construction is complete would need to occur during a turnaround when the unit is shut down for regular maintenance. Turnarounds are often planned up to two years in advance and are coordinated with safety personnel, both on-site and off-site, such as local fire departments. Thus, on the event of an accident during the turnaround when construction for the tie-in is expected to occur, fire departments are typically first responders for control and clean-up and police may need to be available in the unlikely event that the accident goes beyond perimeter boundaries. Because construction is expected to occur prior to a turnaround and the tie-in of the equipment is expected to occur

during a turnaround when the delayed coking units are offline, the proposed project is not expected to increase the need or demand for additional public services (e.g., fire departments, or police departments) above current levels in the event of an accident during construction.

Lastly, in the event a facility would need to modify its fire permit as a result of construction and an inspection by the fire department would be required, the additional inspections would not increase the need for additional fire department personnel because the modifications would only occur at five facilities. Lastly, even if facility operators install compressor or steam ejector technology at their refineries, the main function of the delayed coking units would not be altered and thus, the probability of accidental releases occurring would not be expected to change from the existing baseline.

XIV. c) & d) As noted in the previous "Population and Housing" discussion, the proposed project is not expected to induce population growth in any way because the local labor pool (e.g., workforce) is expected to be sufficient to accommodate any construction activities that may be necessary at affected facilities and operation of any new equipment is not expected to require additional employees. Therefore, there would be no increase in local population and thus no impacts would be expected to local schools or other public facilities.

The proposed project is expected to result in the use of new equipment to reduce the pressure in delayed coking units during depressurization. Besides permitting the equipment or altering permit conditions by the SCAQMD, there would be no need for other types of government services. The proposed project would not result in the need for new or physically altered government facilities in order to maintain acceptable service ratios, response times, or other performance objectives. There would be no increase in population and, therefore, there would be no need for physically altered government facilities.

Based upon these considerations, significant public services impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant public services impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XV. RECREATION.				
a) Would the project increase the use of existing neighborhood and regional parks or other recreational facilities such that substantial physical deterioration of the facility would occur or be accelerated?	☐	☐	☐	☑

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
b) Does the project include recreational facilities or require the construction or expansion of recreational facilities that might have an adverse physical effect on the environment or recreational services?	☐	☐	☐	☑

Significance Criteria

Impacts to recreation will be considered significant if:

- The project results in an increased demand for neighborhood or regional parks or other recreational facilities.
- The project adversely affects existing recreational opportunities.

Discussion

XV. a) & b) As discussed earlier under the topic of "Land Use and Planning," there are no provisions in the PR 1114 that would affect land use plans, policies, or regulations. Land use and other planning considerations are determined by local governments and no land use or planning requirements will be altered by the proposed requirements in PR 1114. The proposed project would not increase the demand for or use of existing neighborhood and regional parks or other recreational facilities or require the construction of new or expansion of existing recreational facilities that might have an adverse physical effect on the environment because it would not directly or indirectly increase or redistribute population.

Based upon these considerations, significant recreation impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant recreation impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVI. SOLID AND HAZARDOUS WASTE. Would the project:				
a) Be served by a landfill with sufficient permitted capacity to accommodate the project's solid waste disposal needs?	☐	☐	☑	☐

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
b) Comply with federal, state, and local statutes and regulations related to solid and hazardous waste?	☐	☐	☑	☐

Significance Criteria

The proposed project impacts on solid and hazardous waste will be considered significant if the following occurs:

- The generation and disposal of hazardous and non-hazardous waste exceeds the capacity of designated landfills.

Discussion

XVI. a) & b) There are six petroleum refineries that operate delayed coking units that would be subject to the requirements in PR 1114. Of these six, one can demonstrate compliance with PR 1114 because their coke drums, per their permit conditions, can be depressurized to less than two psig through the use of steam ejectors. For the remaining facilities, operators may choose to either install compressor or steam ejector technology to reduce the pressure to less than two psig at the end of the coking cycle. As such, construction activities associated with installing compressor or steam ejector technology may involve some demolition and site preparation/grading/excavating activities that could generate solid waste. Demolition activities could generate demolition waste while site preparation, grading, and excavating could uncover contaminated soils since the affected petroleum refineries affected by the proposed project are located in existing industrial areas.

Excavated soil, if found to be contaminated, will need to be characterized, treated, and disposed of offsite in accordance with applicable regulations. Where appropriate, the soil will be recycled if it is considered or classified as non-hazardous waste or it can be disposed of at a landfill that accepts non-hazardous waste. Otherwise, the material would need to be disposed of at a hazardous waste facility. (Potential soil contamination is addressed in the Hazards and Hazardous Materials discussion in Section VIII. d.)

Solid or hazardous wastes generated from construction-related activities would consist primarily of materials from the demolition and/or alteration of any existing structure to make room for the new equipment to be installed. Construction-related waste, depending on the classification of the waste, would need to be disposed of at a Class II (industrial) or Class III (municipal) landfill.

A Class II landfill can handle wastes that exhibit a level of contamination not considered hazardous, but that are required by the State of California to be managed for disposal to a permitted Class II landfill. For this reason, Class II landfills are specially designed with liners to reduce the risks of groundwater contamination from industrial wastes, also known as California-regulated waste. Similarly, a Class III landfill can handle non-hazardous or

municipal waste. Municipal waste is typically generated through day-to-day activities and does not present the hazardous characteristics of hazardous, industrial, or radioactive wastes.

There are 32 active Class III landfills within the SCAQMD's jurisdiction, many of which have liners that can handle both Class II and Class III wastes. According to the Final Program EIR for the 2012 AQMP (SCAQMD, 2012), total Class III landfill waste disposal capacity in the district is approximately 116,796 tons per day.

Due to the relatively limited scope of construction that may occur in order to comply with the requirements in PR 1114, the amount of solid or hazardous waste that may be generated during construction is expected to be well within the landfill waste disposal capacity available. For this reason, the construction impacts of the proposed project on solid and hazardous waste disposal facilities are expected to be less than significant.

Since operation of compressor or steam ejector technology does not generate any solid or hazardous waste, implementation of PR 1114 is not expected to require additional waste disposal capacity or interfere or undermine a petroleum refinery's ability to comply with existing federal, state, and local regulations for solid and hazardous waste handling and disposal.

Based upon these considerations, significant solid and hazardous waste impacts are not expected from implementing PR 1114, and thus, this topic will not be further analyzed. Since no significant solid and hazardous waste impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVII. TRANSPORTATION AND TRAFFIC. Would the project:				
a) Conflict with an applicable plan, ordinance or policy establishing measures of effectiveness for the performance of the circulation system, taking into account all modes of transportation including mass transit and non-motorized travel and relevant components of the circulation system, including but not limited to intersections, streets, highways and freeways, pedestrian and bicycle paths, and mass transit?	☐	☐	☑	☐

		Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
b)	Conflict with an applicable congestion management program, including but not limited to level of service standards and travel demand measures, or other standards established by the county congestion management agency for designated roads or highways?	☐	☐	☑	☐
c)	Result in a change in air traffic patterns, including either an increase in traffic levels or a change in location that results in substantial safety risks?	☐	☐	☐	☑
d)	Substantially increase hazards due to a design feature (e.g. sharp curves or dangerous intersections) or incompatible uses (e.g. farm equipment)?	☐	☐	☐	☑
e)	Result in inadequate emergency access?	☐	☐	☐	☑
f)	Conflict with adopted policies, plans, or programs regarding public transit, bicycle, or pedestrian facilities, or otherwise decrease the performance or safety of such facilities?	☐	☐	☐	☑

Significance Criteria

Impacts on transportation and traffic will be considered significant if any of the following criteria apply:

- Peak period levels on major arterials are disrupted to a point where level of service (LOS) is reduced to D, E or F for more than one month.
- An intersection's volume to capacity ratio increase by 0.02 (two percent) or more when the LOS is already D, E or F.
- A major roadway is closed to all through traffic, and no alternate route is available.
- The project conflicts with applicable policies, plans or programs establishing measures of effectiveness, thereby decreasing the performance or safety of any mode of transportation.
- There is an increase in traffic that is substantial in relation to the existing traffic load and capacity of the street system.
- The demand for parking facilities is substantially increased.

- Water borne, rail car or air traffic is substantially altered.
- Traffic hazards to motor vehicles, bicyclists or pedestrians are substantially increased.
- The need for more than 350 employees
- An increase in heavy-duty transport truck traffic to and/or from the facility by more than 350 truck round trips per day
- Increase customer traffic by more than 700 visits per day.

Discussion

XVII. a) & b) Construction activities resulting from implementing the proposed project may generate a slight, albeit temporary, increase in traffic in the areas of each affected facility associated with construction workers, construction equipment, and the delivery of construction materials. However, the proposed project is not expected to cause a significant increase in traffic relative to the existing traffic load and capacity of the street systems surrounding the affected facilities as explained in the following paragraphs. Also, the proposed project is not expected to exceed, either individually or cumulatively, the current LOS of the areas surrounding the affected facilities during construction as explained in the following paragraph.

The maximum construction workforce during any 30-day construction period is expected to be approximately eight workers per facility. For a worst-case analysis, three facilities which may need a total of up to 24 workers were assumed to undergo overlapping construction activities in 2015. Even if it is assumed that all 24 construction workers drive alone (which represents an average vehicle ridership equal to 1.0) not all of the workers would be driving to the same facility. It is unlikely that these vehicle trips would substantially affect the LOS at any intersection because the trips would be dispersed over a large area and the workers would not all arrive at the site at the exact same time. Therefore, the construction work force at each affected facility is not expected to significantly increase as a result of the proposed project and construction worker trips would end once construction is completed. Further, the conclusion of no significant transportation impacts based on the workforce is consistent with the transportation analyses in the CEQA documents prepared for six refineries in accordance with the CARB Phase III Reformulated Gasoline requirements[12]. Specifically, the number of construction workers for each of the six projects ranged from

[12]
1. Final EIR for Chevron El Segundo CARB Phase 3 Clean Fuels Project, certified November 30, 2001. (http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/chevron/final/chev_f.html)
2. Final Environmental Impact Report for: Proposed Ultramar Wilmington Refinery - CARB Phase 3 Project, certified December 19, 2001. (http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/ultramar/final/ultEIR_f.html)
3. Final Environmental Impact Report for: Proposed Equilon Enterprises LLC CARB Phase 3 Reformulated Gasoline Project, certified October 15, 2001. (http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/equilon/final/equEIR_f.html)
4. Final Environmental Impact Report for: Mobil CARB Phase 3 Reformulated Gasoline Project, certified October 12, 2001. (http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/mobil/final/mobil_f.html)
5. Final Environmental Impact Report for: ARCO CARB Phase 3/MTBE Phase-out Project, certified May 15, 2001. (http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/arco/finalEIR/arcoFEIR.html)
6. Final Environmental Impact Report for: Proposed Tosco Los Angeles Refinery - Phase 3 Reformulated Fuels Project, certified April 5, 2001. (http://www.aqmd.gov/ceqa/documents/2001/nonaqmd/tosco_rfp/final/toscoEIR_f.html)

approximately 200 to 700 daily construction worker trips and each of these projects was concluded to have no significant transportation impacts

Further, it is not expected that the installation of compressor or steam ejector technology would require new employees to operate and maintain the equipment. In the event that new employees are hired, it is expected that the number of new employees at any one facility would be small, no more than one or two per refinery. Thus, because no new employees are expected to be needed to operate the compressor or steam ejector technology, if installed, the work force at each affected facility is not expected to significantly increase during operations of the proposed project. As a result, no significant increases in operation-related traffic are expected.

XVII. c) Though some of the facilities that would be affected by the proposed project may be located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, actions that would be taken to comply with the proposed project are not expected to significantly influence or affect air traffic patterns because 1) the height and appearance of the existing structures at each affected facility are not expected to change; and, 2) the construction and operation of either compressor or steam ejector technology will be are conducted within the confines of the affected facilities. For these reasons, implementation of PR 1114 would not be expected to affect navigable air space. Thus, the proposed project would not result in a change in air traffic patterns including an increase in traffic levels or a change in location that results in substantial safety risks. Thus, these impacts will not be evaluated further in this ~~Draft~~ Final EA.

XVII. d) & e) The siting of each affected facility is consistent with surrounding land uses and traffic/circulation in the surrounding areas of the affected facilities. Thus, the proposed project is not expected to substantially increase traffic hazards, create incompatible uses at or adjacent to the affected facilities. Further, PR 1114 is not expected to require a modification to circulation, thus, no long-term impacts on the traffic circulation system are expected to occur. The proposed project is not expected to involve the construction of any roadways, so there would be no increase in roadway design feature that could increase traffic hazards. Emergency access at each affected facility is not expected to be impacted by the proposed project because each affected facility is expected to continue to maintain their existing emergency access gates. Thus, these impacts will not be evaluated further in this ~~Draft~~ Final EA.

XVII. f) Construction and operation activities resulting from implementing the proposed project are not expected to conflict with policies supporting alternative transportation since the proposed project does not involve or affect alternative transportation modes (e.g., bicycles or buses) because the construction and operation activities related to the proposed project will occur at existing facilities located solely in established industrial areas.

Based upon these considerations, significant transportation and traffic impacts are not expected from implementing PR 1114. Since no significant transportation and traffic impacts were identified, no mitigation measures are necessary or required.

	Potentially Significant Impact	Less Than Significant With Mitigation	Less Than Significant Impact	No Impact
XVIII. MANDATORY FINDINGS OF SIGNIFICANCE.				
a) Does the project have the potential to degrade the quality of the environment, substantially reduce the habitat of a fish or wildlife species, cause a fish or wildlife population to drop below self-sustaining levels, threaten to eliminate a plant or animal community, reduce the number or restrict the range of a rare or endangered plant or animal or eliminate important examples of the major periods of California history or prehistory?	☐	☐	☐	☑
b) Does the project have impacts that are individually limited, but cumulatively considerable? ("Cumulatively considerable" means that the incremental effects of a project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects)	☐	☐	☑	☐
c) Does the project have environmental effects that will cause substantial adverse effects on human beings, either directly or indirectly?	☐	☐	☑	☐

Discussion

XVIII. a) As discussed in the "Biological Resources" section, PR 1114 is not expected to significantly adversely affect plant or animal species or the habitat on which they rely because the affected equipment is located at primarily existing facilities in industrial areas which have already been greatly disturbed and that currently do not support such habitats. Furthermore, the areas where the affected delayed coking units exist are already either devoid of significant biological resources or whose biological resources have been previously disturbed. Lastly, special status plants, animals, or natural communities are not expected to be found within close proximity to the facilities affected by PR 1114 because the affected refineries are generally devoid of plants and natural communities that could support animals for fire safety reasons.

The proposed project would not require the acquisition of land to comply with the provisions of PR 1114. Also, while implementation of PR 1114 may result in construction activities associated with the installation of compressor or steam ejector technology, these anticipated construction activities are expected to occur entirely with the boundaries of existing affected refineries. Similarly, implementing PR 1114 would not require construction activities in areas where special status plants, animals, or natural communities and important examples of the major periods of California history or prehistory exist. As a result, implementing PR 1114 is not expected to adversely affect in any way habitats that support riparian habitat, are federally protected wetlands, or are migratory corridors. Therefore, these areas would not be expected to be adversely affected by the proposed project.

XVIII. b) Based on the preceding analyses in discussion topics I. through XVII, PR 1114 is not expected to generate any project-specific significant adverse environmental impacts for the following reasons. The environmental topics that were not checked as areas potentially affected by the proposed project (e.g., aesthetics, agriculture and forestry resources, biological resources, cultural resources, geology and soils, hazards and hazardous materials, land use and planning, mineral resources, noise, population and housing, public services, recreation, and, solid and hazardous waste) were found to have 'No Impact' or 'Less Than Significant Impact' and would not be expected to make any contribution to potential cumulative impacts whatsoever. For the environmental topics checked as areas potentially affected by the proposed project (e.g., air quality and GHG emissions, energy, hydrology and water quality, and transportation and traffic), the analysis indicated that project impacts would be less than significant because they would not exceed any project-specific significance thresholds. Based on these conclusions, incremental effects of the proposed project would be minor and, therefore, are not considered to be cumulatively considerable as defined by CEQA Guidelines §15064(h)(1). Since impacts from the proposed project are not considered to be cumulatively considerable, the proposed project has no potential for generating significant adverse cumulative impacts.

XVIII. c) Based on the preceding analyses, PR 1114 is not expected to cause adverse effects on human beings, either directly or indirectly. For the environmental topics that were checked as areas potentially affected by the proposed project (e.g., air quality and GHG emissions, energy, hydrology and water quality, and transportation and traffic), less than significant impacts to air quality and GHG emissions, energy, hydrology and water quality, and, transportation and traffic impacts from implementing PR 1114 were identified.

The net effect of implementing PR 1114 is that VOC emissions from this source category will be reduced up to 0.36 ton per day, PM emissions will be reduced by up to 0.05 ton per day, HAP emissions will be reduced by up to 0.07 ton per day, and methane emissions will be reduced by up to 1.51 tons per day. PR 1114 is also anticipated to reduce sulfur as H2S by up to 0.05 ton per day. These anticipated reductions are expected to provide an overall direct air quality and GHG benefit. Further, the projected VOC emission reductions will assist the SCAQMD's progress in attaining and maintaining the ambient air quality standards for ozone.

Based on the discussion in items I through XVIII, the proposed project is not expected to have the potential to cause significant adverse environmental effects to any environmental topic.

APPENDIX A

PROPOSED RULE 1114 – PETROLEUM REFINERY COKING OPERATIONS

In order to save space and avoid repetition, please refer to the latest version of Proposed Rule 1114 located elsewhere in the Governing Board Package. The version of Proposed Rule 1114 that was circulated with the Draft EA and released on February 28, 2013 for a 30-day public review and comment period ending March 29, 2013 was identified as "V9."

Original hard copies of the Draft EA, which include the draft version of the proposed rule listed above, can be obtained through the SCAQMD Public Information Center at the Diamond Bar headquarters or by calling (909) 396-2039

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APPENDIX B

CONSTRUCTION AND OPERATION CALCULATIONS

LIST OF WORKSHEETS

Worksheet 1: Steam Ejector Installation in Year 2014 ..... B-1
Worksheet 2: Scenario A: Steam Ejector Installation in Year 2015 .... B-4
Worksheet 3: Compressor Installation at 1 Facility in 2015 ..... B-7
Worksheet 4: Scenario B: Construction in 2015 ..... B-10
Worksheet 5: Coke Drum Headspace Estimate..... B-11
Worksheet 6: Operational Water Demand and Wastewater Generation B-12
Worksheet 7: Operational Energy Demand and Air Quality Impacts ... B-16
Worksheet 8: Energy Summary..... B-19
Worksheet 9: GHG Emissions Summary B-21

Steam Ejector Installation in Year 2014

Activity	Days/ wk	Wks/ month	Days/ month	Months	Total Days	Crew Size
Construction	5	4.33	21.67	1	21.67	8
			Total	1	**21.67**	

Construction	Max Equipment Rating	Number	Operating Schedule	Usage Factor	2014 Mobile Source Emission Factors							
Off-Road Equipment Type	**hp**	**Needed**	**(hr/day)**		**VOC (lb/hr)**	**CO (lb/hr)**	**NOx (lb/hr)**	**SOx (lb/hr)**	**PM10 (lb/hr)**	**PM2.5 (lb/hr)**	**CO2 (lb/hr)**	**CH4 (lb/hr)**
Aerial Lift	comp	2	16	0.5	0.0483	0.1877	0.2867	0.0004	0.0184	0.0184	34.7	0.0044
Crane (75 ton)	250	1	8	0.5	0.0979	0.2817	0.9088	0.0013	0.0317	0.0317	112	0.0088
Forklift	comp	1	16	0.5	0.0497	0.2215	0.3551	0.0006	0.0178	0.0178	54.4	0.0045
Generator Set	comp	2	16	0.5	0.0702	0.2974	0.5083	0.0007	0.0296	0.0296	61.0	0.0063
Off-Highway Truck	comp	1	8	0.5	0.1986	0.7438	1.6111	0.0017	0.0767	0.0767	151	0.0179
Welder	comp	2	16	0.5	0.0589	0.2041	0.2436	0.0003	0.0206	0.0206	25.6	0.0053

Incremental Increase in Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Aerial Lift	0.77	3.00	4.59	0.01	0.29	0.29	555.55	0.07	557.01	5.47
Crane (75 ton)	0.39	1.13	3.64	0.01	0.13	0.13	448.64	0.04	449.38	4.42
Forklift	0.40	1.77	2.84	0.00	0.14	0.14	435.17	0.04	435.92	4.28
Generator Set	1.12	4.76	8.13	0.01	0.47	0.47	975.88	0.10	978.01	9.61
Off-Highway Truck	0.79	2.98	6.44	0.01	0.31	0.31	605.72	0.07	607.22	5.97
Welder	0.94	3.27	3.90	0.01	0.33	0.33	409.64	0.08	411.43	4.04
SUBTOTAL	**4**	**17**	**30**	**0**	**2**	**2**	**3431**	**0**	**3439**	**34**

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21
1 metric ton (MT) = 2,205 pounds

Construction		Number	Round- trip Distance	Mileage Rate (miles/ gallon)	2014 Mobile Source Emission Factors							
On-Road Equipment Type	**Fuel**	**Needed**	**(miles/day)**		**VOC (lb/mile)**	**CO (lb/mile)**	**NOx (lb/mile)**	**SOx (lb/mile)**	**PM10 (lb/mile)**	**PM2.5 (lb/mile)**	**CO2 (lb/mile)**	**CH4 (lb/mile)**
Offsite (Construction Worker Vehicle)	gasoline	8	30	20	0.0007	0.0066	0.0007	0.00001	0.0001	0.0001	1.1026	0.0001
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	1	50	4.89	0.0020	0.0085	0.0242	0.00004	0.0012	0.0010	4.2128	0.0001
Offsite (Delivery Truck - Medium Duty)	diesel	1	50	6	0.0019	0.0128	0.0143	0.00003	0.0005	0.0005	2.7985	0.0001
Onsite (Pickup Truck)	gasoline	1	10	20	0.0007	0.0066	0.0007	0.00001	0.0001	0.0001	1.1026	0.0001

Incremental Increase in Combustion Emissions from On-Road Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Offsite (Construction Worker Vehicle)	0.17	1.58	0.16	0.00	0.02	0.01	264.62	0.02	264.94	2.60
Offsite (Flatbed Truck - Heavy-Heavy Duty)	0.10	0.42	1.21	0.00	0.06	0.05	210.64	0.00	210.74	2.07
Offsite (Delivery Truck)	0.09	0.64	0.71	0.00	0.03	0.02	139.92	0.00	140.02	1.38
Onsite (Pickup Truck)	0.01	0.07	0.01	0.00	0.00	0.00	11.03	0.00	11.04	0.11
SUBTOTAL	**0**	**3**	**2**	**0**	**0**	**0**	**626**	**0**	**627**	**6**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21

1 metric ton (MT) = 2,205 pounds

Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq (lb/day)	CO2eq (MT*)
Combustion Emissions from Construction Equipment	4.42	16.90	29.54	0.04	1.67	1.67	3430.59	0.40	3438.97	33.79
Combustion Emissions from On-Road Construction Vehicles	0.37	2.72	2.09	0.01	0.11	0.09	626.21	0.02	626.73	6.16
TOTAL for 1 Facility	**5**	**20**	**32**	**0**	**2**	**2**	**4057**	**0**	**4066**	**40**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

TOTAL for 2 Facilities Overlapping Construction in 2014	**10**	**39**	**63**	**0**	**4**	**4**	**8114**	**1**	**8131**	**80**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Construction Hours for Project	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/project)
Operation of Portable Equipment	347	Aerial Lift	1.77	28.32	613.60	N/A	N/A
Operation of Portable Equipment	87	Crane (75 ton)	5.51	22.04	477.53	N/A	N/A
Operation of Portable Equipment	173	Forklift	10.17	81.36	1762.80	N/A	N/A
Operation of Portable Equipment	347	Generator Set	5.13	82.08	1778.40	N/A	N/A
Operation of Portable Equipment	87	Off-Highway Truck	13.54	54.16	1173.47	N/A	N/A
Operation of Portable Equipment	347	Welder	2.20	35.20	762.67	N/A	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	N/A	12.00	260.00
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	10.22	221.54	N/A	N/A
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	8.33	180.56	N/A	N/A
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	N/A	0.50	10.83
TOTAL for 1 Facility				**322**	**6,971**	**13**	**271**
TOTAL for 2 Facilities Overlapping Construction in 2014				**643**	**13,941**	**25**	**542**

Sources:

1. Off-Road Mobile Emission Factors, Scenario Year 2014

http://www.aqmd.gov/ceqa/handbook/offroad/offroad.html/offroadEF07_25.xls

2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions

http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html/finalAppA.doc

3. On-Road Mobile Emission Factors (EMFAC 2007 v2.3), Scenario Year 2014

http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEF07_26.xls

http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEFHHDT07_26.xls

Scenario A: Steam Ejector Installation in Year 2015

Activity	Days/ wk	Wks/ month	Days/ month	Months	Total Days	Crew Size
Construction	5	4.33	21.67	1	21.67	8
			Total	1	**21.67**	

Construction	Max Equipment Rating	Number	Operating Schedule	Usage Factor	2015 Mobile Source Emission Factors							
Off-Road Equipment Type	hp	Needed	(hr/day)		VOC (lb/hr)	CO (lb/hr)	NOx (lb/hr)	SOx (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	CO2 (lb/hr)	CH4 (lb/hr)
Aerial Lift	comp	2	16	0.5	0.0439	0.1837	0.2670	0.0004	0.0167	0.0167	34.7	0.0040
Crane (75 ton)	250	1	8	0.5	0.0925	0.2713	0.8284	0.0013	0.0286	0.0286	112	0.0083
Forklift	comp	1	16	0.5	0.0459	0.2200	0.3163	0.0006	0.0156	0.0156	54.4	0.0041
Generator Set	comp	2	16	0.5	0.0640	0.2913	0.4717	0.0007	0.0268	0.0268	61.0	0.0058
Off-Highway Truck	comp	1	8	0.5	0.1924	0.5974	1.4932	0.0027	0.0516	0.0516	260	0.0174
Welder	comp	2	16	0.5	0.0534	0.1994	0.2301	0.0003	0.0187	0.0187	25.6	0.0048

Incremental Increase in Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Aerial Lift	0.70	2.94	4.27	0.01	0.27	0.27	555.55	0.06	556.88	5.47
Crane (75 ton)	0.37	1.09	3.31	0.01	0.11	0.11	448.64	0.03	449.34	4.42
Forklift	0.37	1.76	2.53	0.00	0.12	0.12	435.17	0.03	435.86	4.28
Generator Set	1.02	4.66	7.55	0.01	0.43	0.43	975.88	0.09	977.82	9.61
Off-Highway Truck	0.77	2.39	5.97	0.01	0.21	0.21	1040.22	0.07	1041.68	10.24
Welder	0.85	3.19	3.68	0.01	0.30	0.30	409.64	0.08	411.26	4.04
SUBTOTAL	**4**	**16**	**27**	**0**	**1**	**1**	**3865**	**0**	**3873**	**38**

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21
1 metric ton (MT) = 2,205 pounds

Construction		Number	Round- trip Distance	Mileage Rate (miles/	2015 Mobile Source Emission Factors							
On-Road Equipment Type	Fuel	Needed	(miles/day)	gallon)	VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Construction Worker Vehicle)	gasoline	8	30	20	0.0007	0.0061	0.0006	0.00001	0.0001	0.0001	1.1019	0.0001
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	1	50	4.89	0.0018	0.0077	0.0212	0.00004	0.0010	0.0009	4.2090	0.0001
Offsite (Delivery Truck - Medium Duty)	diesel	1	50	6	0.0017	0.0117	0.0129	0.00003	0.0005	0.0004	2.8125	0.0001
Onsite (Pickup Truck)	gasoline	1	10	20	0.0007	0.0061	0.0006	0.00001	0.0001	0.0001	1.1019	0.0001

Incremental Increase in Combustion Emissions from On-Road Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Offsite (Construction Worker Vehicle)	0.16	1.47	0.14	0.00	0.02	0.01	264.46	0.01	264.76	2.60
Offsite (Flatbed Truck - Heavy-Heavy Duty)	0.09	0.38	1.06	0.00	0.05	0.04	210.45	0.00	210.54	2.07
Offsite (Delivery Truck)	0.09	0.58	0.64	0.00	0.03	0.02	140.62	0.00	140.71	1.38
Onsite (Pickup Truck)	0.01	0.06	0.01	0.00	0.00	0.00	11.02	0.00	11.03	0.11
SUBTOTAL	**0**	**3**	**2**	**0**	**0**	**0**	**627**	**0**	**627**	**6**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Combustion Emissions from Construction Equipment	4.09	16.02	27.32	0.04	1.44	1.44	3865.10	0.37	3872.84	38.06
Combustion Emissions from On-Road Construction Vehicles	0.34	2.50	1.85	0.01	0.10	0.08	626.56	0.02	627.04	6.16
TOTAL for 1 Facility	**4**	**19**	**29**	**0**	**2**	**2**	**4492**	**0**	**4500**	**44**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

TOTAL for 2 Facilities Overlapping Construction in 2015	**9**	**37**	**58**	**0**	**3**	**3**	**8983**	**1**	**9000**	**88**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

TOTAL for 3 Facilities Overlapping Construction in 2015	**13**	**56**	**88**	**0**	**5**	**5**	**13475**	**1**	**13500**	**133**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Construction Hours for Project	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/project)
Operation of Portable Equipment	347	Aerial Lift	1.75	28.00	606.67	N/A	N/A
Operation of Portable Equipment	87	Crane (75 ton)	5.51	22.04	477.53	N/A	N/A
Operation of Portable Equipment	173	Forklift	10.02	80.16	1736.80	N/A	N/A
Operation of Portable Equipment	347	Generator Set	5.06	80.96	1754.13	N/A	N/A
Operation of Portable Equipment	87	Off-Highway Truck	13.52	54.08	1171.73	N/A	N/A
Operation of Portable Equipment	347	Welder	2.17	34.72	752.27	N/A	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	N/A	12.00	260.00
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	10.22	221.54	N/A	N/A
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	8.33	180.56	N/A	N/A
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	N/A	0.50	10.83
TOTAL for 1 Facility				**319**	**6,901**	**13**	**271**
TOTAL for 2 Facilities Overlapping Construction in 2015				**637**	**13,802**	**25**	**542**
TOTAL for 3 Facilities Overlapping Construction in 2015				**956**	**20,704**	**38**	**813**

Sources:

1. Off-Road Mobile Emission Factors, Scenario Year 2015

http://www.aqmd.gov/ceqa/handbook/offroad/offroad.html/offroadEF07_25.xls

2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions

http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html/finalAppA.doc

3. On-Road Mobile Emission Factors (EMFAC 2007 v2.3), Scenario Year 2015

http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEF07_26.xls

http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEFHHDT07_26.xls

Compressor Installation at 1 Facility in 2015

Activity	Days/ wk	Wks/ month	Days/ month	Months	Total Days	Crew Size
Construction	5	4.33	21.67	1	21.67	8
			Total	1	21.67	

Construction	Max Equipment Rating	Number	Operating Schedule	Usage Factor	2015 Mobile Source Emission Factors							
Off-Road Equipment Type	hp	Needed	(hr/day)		VOC (lb/hr)	CO (lb/hr)	NOx (lb/hr)	SOx (lb/hr)	PM10 (lb/hr)	PM2.5 (lb/hr)	CO2 (lb/hr)	CH4 (lb/hr)
Aerial Lift	comp	1	8	0.5	0.0439	0.1837	0.2670	0.0004	0.0167	0.0167	34.7	0.0040
Crane (75 ton)	250	1	8	0.5	0.0925	0.2713	0.8284	0.0013	0.0286	0.0286	112	0.0083
Generator Set	comp	2	8	0.5	0.0640	0.2913	0.4717	0.0007	0.0268	0.0268	61.0	0.0058
Off-Highway Truck	comp	1	8	0.5	0.1924	0.5974	1.4932	0.0027	0.0516	0.0516	260	0.0174
Welder	comp	2	8	0.5	0.0534	0.1994	0.2301	0.0003	0.0187	0.0187	25.6	0.0048

Incremental Increase in Combustion Emissions from Construction Equipment	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Aerial Lift	0.18	0.73	1.07	0.00	0.07	0.07	138.89	0.02	139.22	**1.37**
Crane (75 ton)	0.37	1.09	3.31	0.01	0.11	0.11	448.64	0.03	449.34	**4.42**
Generator Set	0.51	2.33	3.77	0.01	0.21	0.21	487.94	0.05	488.91	**4.80**
Off-Highway Truck	0.77	2.39	5.97	0.01	0.21	0.21	1040.22	0.07	1041.68	**10.24**
Welder	0.43	1.59	1.84	0.00	0.15	0.15	204.82	0.04	205.63	**2.02**
SUBTOTAL	**2**	**8**	**16**	**0**	**1**	**1**	**2321**	**0**	**2325**	**23**

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1 and CH4 = 21
1 metric ton (MT) = 2,205 pounds

Construction		Number	Round- trip Distance	Mileage Rate (miles/ gallon)	2015 Mobile Source Emission Factors							
On-Road Equipment Type	Fuel	Needed	(miles/day)		VOC (lb/mile)	CO (lb/mile)	NOx (lb/mile)	SOx (lb/mile)	PM10 (lb/mile)	PM2.5 (lb/mile)	CO2 (lb/mile)	CH4 (lb/mile)
Offsite (Construction Worker Vehicle)	gasoline	8	30	20	0.0007	0.0061	0.0006	0.00001	0.0001	0.0001	1.1019	0.0001
Offsite (Flatbed Truck - Heavy-Heavy Duty)	diesel	1	50	4.89	0.0018	0.0077	0.0212	0.00004	0.0010	0.0009	4.2090	0.0001
Offsite (Delivery Truck - Medium Duty)	diesel	1	50	6	0.0017	0.0117	0.0129	0.00003	0.0005	0.0004	2.8125	0.0001
Onsite (Pickup Truck)	gasoline	1	10	20	0.0007	0.0061	0.0006	0.00001	0.0001	0.0001	1.1019	0.0001

Incremental Increase in Combustion Emissions from On-Road Construction Vehicles	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/project)
Offsite (Construction Worker Vehicle)	0.16	1.47	0.14	0.00	0.02	0.01	264.46	0.01	264.76	2.60
Offsite (Flatbed Truck - Heavy-Heavy Duty)	0.09	0.38	1.06	0.00	0.05	0.04	210.45	0.00	210.54	2.07
Offsite (Delivery Truck)	0.09	0.58	0.64	0.00	0.03	0.02	140.62	0.00	140.71	1.38
Onsite (Pickup Truck)	0.01	0.06	0.01	0.00	0.00	0.00	11.02	0.00	11.03	0.11
SUBTOTAL	**0**	**3**	**2**	**0**	**0**	**0**	**627**	**0**	**627**	**6**

Equation: No. of Vehicles x Emission Factor (lb/mile) x No. of Round-Trips/Day x Round-Trip length (mile) = Offsite Construction Emissions (lb/day)

Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2e (lb/day)	CO2e (MT*)
Combustion Emissions from Construction Equipment	2.25	8.13	15.97	0.03	0.75	0.75	2320.51	0.20	2324.78	22.84
Combustion Emissions from On-Road Construction Vehicles	0.34	2.50	1.85	0.01	0.10	0.08	626.56	0.02	627.04	6.16
TOTAL for 1 Facility	**3**	**11**	**18**	**0**	**1**	**1**	**2947**	**0**	**2952**	**29**
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Construction Hours for Project	Equipment Type	Diesel Fuel Usage (gal/hr)	Total Diesel Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/project)
Operation of Portable Equipment	87	Aerial Lift	1.75	7.00	151.67	N/A	N/A
Operation of Portable Equipment	87	Crane (75 ton)	5.51	22.04	477.53	N/A	N/A
Operation of Portable Equipment	173	Generator Set	5.06	40.48	877.07	N/A	N/A
Operation of Portable Equipment	87	Off-Highway Truck	13.52	54.08	1171.73	N/A	N/A
Operation of Portable Equipment	173	Welder	2.17	17.36	376.13	N/A	N/A
Workers' Vehicles - Commuting	N/A	Light-Duty Vehicles	N/A	N/A	N/A	12.00	260.00
Workers' Vehicles - Offsite Delivery/Haul	N/A	Flatbed Truck	N/A	10.22	221.54	N/A	N/A
Workers' Vehicles - Offsite Delivery/Haul	N/A	Delivery Truck	N/A	8.33	180.56	N/A	N/A
Workers' Vehicles - Onsite Hauling	N/A	Pickup Truck	N/A	N/A	N/A	0.50	10.83
			TOTAL for 1 Facility	**160**	**3,456**	**13**	**271**

Sources:

1. Off-Road Mobile Emission Factors, Scenario Year 2015

http://www.aqmd.gov/ceqa/handbook/offroad/offroad.html/offroadEF07_25.xls

2. PM2.5 Significance Thresholds and Calculation Methodology, Appendix A - Updated CEIDARS Table with PM2.5 Fractions

http://www.aqmd.gov/ceqa/handbook/PM2_5/PM2_5.html/finalAppA.doc

3. On-Road Mobile Emission Factors (EMFAC 2007 v2.3), Scenario Year 2015

http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEF07_26.xls

http://www.aqmd.gov/ceqa/handbook/onroad/onroad.html/onroadEFHHDT07_26.xls

Scenario B: Construction in 2015

Total Construction Emissions for 2 facilities installing steam ejectors overlapping with 1 facility installing a compressor in 2015

Construction Emissions Summary	VOC (lb/day)	CO (lb/day)	NOx (lb/day)	SOx (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	CH4 (lb/day)	CO2eq (lb/day)	CO2eq (MT*)
Subtotal of 2 Facilities Installing Steam Ejectors in 2015	**9**	**37**	**58**	**0**	**3**	**3**	**8983**	**1**	**9000**	**88**
Subtotal of 1 Facility Installing 1 Compressor in 2015	3	11	18	0	1	1	2947	0	2952	29
TOTAL for 3 Facilities Overlapping Construction in 2015	11	48	76	0	4	4	11930	1	11952	117
Significance Threshold	75	550	100	150	150	55	n/a	n/a	n/a	n/a
Exceed Significance?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**n/a**	**n/a**	**n/a**	**n/a**

*1 metric ton (MT) = 2,205 pounds

Incremental Increase in Fuel Usage From Construction Equipment and Workers' Vehicles	Total Diesel Fuel Usage (gal/day)	Total Diesel Fuel Usage (gal/project)	Total Gasoline Fuel Usage (gal/day)	Total Gasoline Fuel Usage (gal/project)
Subtotal of 2 Facilities Installing Steam Ejectors in 2015	**637**	**13,802**	**25**	**542**
Subtotal of 1 Facility Installing 1 Compressor in 2015	**160**	**3,456**	**13**	**271**
TOTAL for 3 Facilities Overlapping Construction in 2015	**797**	**17,259**	**38**	**813**

Coke Drum Headspace Estimate

Refinery	Number of Coke Drums	Coke Drum Diameter (feet)	Coke Drum Height (feet)	Volume[1] per Coke Drum (cubic feet)	Headspace[2] per Coke Drum (cubic feet)	Total Headspace	
A	4	21.5	73	26,503	6,626	26,503	
A	2	21.5	97	35,216	8,804	17,608	
B	4	18	59	15,014	3,753	15,014	
B	4	18	60	15,268	3,817	15,268	
B	4	18	61	15,523	3,881	15,523	
C	4	26	75	39,820	9,955	39,820	
D	4	26	68	36,103	9,026	36,103	
E	2	23	58	24,098	6,024	12,049	
E	2	23	83	34,484	8,621	17,242	
F	6	26	68	36,103	9,026	54,155	
Total	36					6,925	Average Coke Drum Headspace

[1]Coke Drum Volume is calculated as follows:
Volume = π x r x r x h
where:
π is Pi, approximately 3.142
r is the radius of the circular end of the cylinder (equal to one-half of the diameter)
h is the height of the cylinder

[2]assume headspace is 25 percent of the total coke drum volume

Operational Water Demand and Wastewater Generation

Scenario A: 4 facilities installing steam ejectors

Water Demand and Water Conveyance GHGs

Refinery	Number of Coke Drums	Anticipated Method of Complying with PR 1114	number of new ejectors operating at any one time	Time needed to evacuate one drum via Steam Ejector (hr/drum)	Total time needed for steam ejector to operate (hr/day)	Extra steam needed (lb/hr)	Extra Water needed to generate steam (gal/day)	Water Conveyance GHGs: CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2eq (MT/yr)
A	6	steam ejector	1	0.25	1.5	12,500	2,250.90	3.03	0.00002	0.00003	3.0345701
B	12	steam ejector	2	0.25	3	25,000	18,007.20	24.23	0.00014	0.00025	24.276561
C	4	steam ejector	1	0.25	1	12,500	1,500.60	2.02	0.00001	0.00002	2.0230467
D	4	software upgrade	n/a	n/a	n/a	0	0	0.00	0.00000	0.00000	0
E	4	steam ejector	1	0.25	1	12,500	1,500.60	2.02	0.00001	0.00002	2.0230467
F	6	existing permit limit	n/a	n/a	n/a	0	0	0.00	0.00000	0.00000	0
Total	36						23,259	31	0	0	31

Significance Threshold (potable water)	262,820
Exceed Significance?	NO
Significance Threshold (total water)	5,000,000
Exceed Significance?	NO

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1, CH4 = 21, and N2O = 310.
1 metric ton (MT) = 2,205 pounds

Wastewater Generation and Wastewater Conveyance GHGs

Refinery	Number of Coke Drums	Anticipated Method of Complying with PR 1114	number of new ejectors operating at any one time	Time needed to evacuate one drum via Steam Ejector (hr/drum)	Total time needed for steam ejector to operate (hr/day)	Wastewater to be generated (gal/min)	Wastewater to be generated (gal/day)	Wastewater Conveyance GHGs: CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2eq (MT/yr)
A	6	steam ejector	1	0.25	1.5	6.25	562.50	0.76	0.00000	0.00001	0.76
B	12	steam ejector	2	0.25	3	12.50	2,250.00	3.03	0.00002	0.00003	3.03
C	4	steam ejector	1	0.25	1	6.25	375.00	0.50	0.00000	0.00001	0.51
D	4	software upgrade	n/a	n/a	n/a	0	0	0.00	0.00000	0.00000	0.00
E	4	steam ejector	1	0.25	1	6.25	375.00	0.50	0.00000	0.00001	0.51
F	6	existing permit limit	n/a	n/a	n/a	0	0	0.00	0.00000	0.00000	0.00
Total	36						3,563	5	0	0	5

Wastewater Generation

Refinery	Number of Coke Drums	Anticipated Method of Complying with PR 1114	number of new ejectors operating at any one time	Time needed to evacuate one drum via Steam Ejector (hr/drum)	Total time needed for steam ejector to operate (hr/day)	Wastewater to be generated (gal/min)	Wastewater to be generated (gal/day)	Wastewater Permit Discharge Limit[1] (MMgal/day)	Percentage Increase Above Discharge Limit (%)	Greater than 25% Increase? (Exceeds CEQA Significance Threshold?*)
A	6	steam ejector	1	0.25	1.5	6.25	562.50	7.49	0.008	NO
B	12	steam ejector	2	0.25	3	12.50	2,250.00	10.8	0.021	NO
C	4	steam ejector	1	0.25	1	6.25	375.00	7.2	0.005	NO
D	4	software upgrade	n/a	n/a	n/a	0	0	14.4	0	NO
E	4	steam ejector	1	0.25	1	6.25	375.00	1.1	0.034	NO
F	6	existing permit limit	n/a	n/a	n/a	0	0	8.8	0	NO
Total	36						3,563			

[1] Wastewater limits were obtained from each facility's wastewater permit(s). For any facility that has multiple discharge limits (i.e. dry weather, wet weather, etc.), the most conservative limit will be used for the purposes of this comparison.

* Significance for wastewater is if the increase is greater than 25% above an individual facility's discharge limit. An increase of 25% or more above the limit would trigger a permit revision.

Scenario B: 3 facilities installing steam ejectors and 1 facility installing a compressor

Water Demand and Water Conveyance GHGs

Refinery	Number of Coke Drums	Anticipated Method of Complying with PR 1114	number of new ejectors operating at any one time	Time needed to evacuate one drum via Steam Ejector (hr/drum)	Total time needed for steam ejector to operate (hr/day)	Extra steam needed (lb/hr)	Extra Water needed to generate steam (gal/day)	Water Conveyance GHGs: CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2eq (MT/yr)
A	6	steam ejector	1	0.25	1.5	12,500	2,250.90	3.03	0.00002	0.00003	3.03
B	12	steam ejector	2	0.25	3	25,000	18,007.20	24.23	0.00014	0.00025	24.28
C	4	compressor	n/a	n/a	n/a	0	0	0	0	0	0
D	4	software upgrade	n/a	n/a	n/a	0	0	0	0	0	0
E	4	steam ejector	1	0.25	1	12,500	1,500.60	2.02	0.00001	0.00002	2.02
F	6	existing permit limit	n/a	n/a	n/a	0	0	0	0	0	0
Total	36						21,759	29	0	0	29

Significance Threshold (potable water)	262,820
Exceed Significance?	NO
Significance Threshold (total water)	5,000,000
Exceed Significance?	NO

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1, CH4 = 21, and N2O = 310.
1 metric ton (MT) = 2,205 pounds

Wastewater Generation and Wastewater Conveyance GHGs

Refinery	Number of Coke Drums	Anticipated Method of Complying with PR 1114	number of new ejectors operating at any one time	Time needed to evacuate one drum via Steam Ejector (hr/drum)	Total time needed for steam ejector to operate (hr/day)	Wastewater to be generated (gal/min)	Wastewater to be generated (gal/day)	Wastewater Conveyance GHGs: CO2 (MT/yr)	N2O (MT/yr)	CH4 (MT/yr)	Total CO2eq (MT/yr)
A	6	steam ejector	1	0.25	1.5	6.25	562.50	0.76	0.00000	0.00001	0.76
B	12	steam ejector	2	0.25	3	12.50	2,250.00	3.03	0.00002	0.00003	3.03
C	4	compressor	n/a	n/a	n/a	0	0	0	0	0	0
D	4	software upgrade	n/a	n/a	n/a	0	0	0	0	0	0
E	4	steam ejector	1	0.25	1	6.25	375.00	0.50	0.00000	0.00001	0.51
F	6	existing permit limit	n/a	n/a	n/a	0	0	0	0	0	0
Total	36						3,187.50	4	0	0	4

Wastewater Generation

Refinery	Number of Coke Drums	Anticipated Method of Complying with PR 1114	number of new ejectors operating at any one time	Time needed to evacuate one drum via Steam Ejector (hr/drum)	Total time needed for steam ejector to operate (hr/day)	Wastewater to be generated (gal/min)	Wastewater to be generated (gal/day)	Wastewater Permit Discharge Limit[1] (MMgal/day)	Percentage Increase Above Discharge Limit (%)	Greater than 25% Increase? (Exceeds CEQA Significance Threshold?*)
A	6	steam ejector	1	0.25	1.5	6.25	562.50	7.49	0.008	NO
B	12	steam ejector	2	0.25	3	12.50	2,250.00	10.8	0.021	NO
C	4	compressor	n/a	n/a	n/a	0	0	7.2	0	NO
D	4	software upgrade	n/a	n/a	n/a	0	0	14.4	0	NO
E	4	steam ejector	1	0.25	1	6.25	375.00	1.1	0.034	NO
F	6	existing permit limit	n/a	n/a	n/a	0	0	8.8	0	NO
Total	36						3,187.50			

[1] Wastewater limits were obtained from each facility's wastewater permit(s). For any facility that has multiple discharge limits (i.e. dry weather, wet weather, etc.), the most conservative limit will be used for the purposes of this comparison.

* Significance for wastewater is if the increase is greater than 25% above an individual facility's discharge limit. An increase of 25% or more above the limit would trigger a permit revision.

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
12,700 kWh/MMgallons for electricity use for water conveyance - potable water
640 lb CO2/MWh for electricity use due to water/wastewater conveyance
0.0067 lb CH4/MWh for electricity use due to water/wastewater conveyance
0.0037 lb N2O/MWh for electricity use due to water/wastewater conveyance

Operational Energy Demand and Air Quality Impacts

Scenario A: 4 facilities installing steam ejectors

Refinery	Number of Coke Drums	Anticipated Method of Complying with PR 1114	Number of new ejectors to operate at any one time	Time needed to evacuate one drum via Steam Ejector (hr/drum)	Total time needed for steam ejector to operate (hr/day)	Extra steam needed (lb/hr)	Total Extra Steam Needed To Operate Steam Ejectors (lb/day)	Energy needed to produce one pound of steam (BTU/lb)*	Boiler Load	Energy needed to meet increased steam demand (BTU/day)	Heating Value of Fuel Gas (BTU/scf)	Fuel Consumption (scf fuel gas/day)
A	6	steam ejector	1	0.25	1.5	12,500	18,750	1,128	0.75	15,862,500	1,200	13,219
B	12	steam ejector	2	0.25	3	25,000	75,000	1,128	0.75	63,450,000	1,200	52,875
C	4	steam ejector	1	0.25	1	12,500	12,500	1,128	0.75	10,575,000	1,200	8,813
D	4	software upgrade	n/a	n/a	n/a	0	0	n/a	n/a	0	n/a	0
E	4	steam ejector	1	0.25	1	12,500	12,500	1,128	0.75	10,575,000	1,200	8,813
F	6	existing permit limit	n/a	n/a	n/a	0	0	n/a	n/a	0	n/a	0
Total	**36**						**118,750**			**100,462,500**		**83,719**

* Source: Department of Energy, Energy Tips - Benchmark the Fues Cost of Steam Generation, Table 1, at a feedwater temperature of 100 degrees F and an operating pressure of 150 psig.

Boiler Emission Factors (for fuel gas)

VOC (lb/MMBTU)	CO (lb/MMBTU)	NOX (lb/MMBTU)	SOX (lb/MMBTU)	PM10 (lb/MMBTU)	PM2.5 (lb/MMBTU)	CO2 (lb/MMscf fuel burned)	N20 (lb/MMscf fuel burned)	CH4 (lb/MMscf fuel burned)
0.0041	0.0036	0.0110	0.0050	0.0100	0.0100	120,000	0.64	2.3

Refinery	Energy needed to meet increased steam demand (MMBTU/day)	Fuel Consumption (MMscf fuel gas/day)	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	N20 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/yr)
A	16	0.0132	0.07	0.06	0.17	0.08	0.16	0.16	1,586	0.01	0.03	1,590	263
B	63	0.0529	0.26	0.23	0.70	0.32	0.63	0.63	6,345	0.03	0.12	6,358	1,052
C	11	0.0088	0.04	0.04	0.12	0.05	0.11	0.11	1,058	0.01	0.02	1,060	175
D	0	0	0	0	0	0	0	0	0	0	0	0	0
E	11	0.0088	0.04	0.04	0.12	0.05	0.11	0.11	1,058	0.01	0.02	1,060	175
F	0	0	0.00	0	0	0	0	0	0	0	0	0	0
Total	**100**	**0.0837**	**0**	**0**	**1**	**1**	**1**	**1**	**10,046**	**0.05**	**0.19**	**10,067**	**1,666**

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1, CH4 = 21, and N2O = 310.
1 metric ton (MT) = 2,205 pounds

Scenario B: 3 facilities installing steam ejectors and 1 facility installing a compressor

Refinery	Number of Coke Drums	Anticipated Method of Complying with PR 1114	Number of new ejectors to operate at any one time	Time needed to evacuate one drum via Steam Ejector (hr/drum)	Total time needed for steam ejector to operate (hr/day)	Extra steam needed (lb/hr)	Total Extra Steam Needed To Operate Steam Ejectors (lb/day)	Energy needed to produce one pound of steam (BTU/lb)*	Boiler Load	Energy needed to meet increased steam demand (BTU/day)	Heating Value of Fuel Gas (BTU/scf)	Fuel Consumption (scf fuel gas/day)
A	6	steam ejector	1	0.25	1.5	12,500	18,750	1,128	0.75	15,862,500	1,200	13,219
B	12	steam ejector	2	0.25	3	25,000	75,000	1,128	0.75	63,450,000	1,200	52,875
C	4	compressor	n/a	n/a	n/a	0	0	n/a	n/a	0	n/a	0
D	4	software upgrade	n/a	n/a	n/a	0	0	n/a	n/a	0	n/a	0
E	4	steam ejector	1	0.25	1	12,500	12,500	1,128	0.75	10,575,000	1,200	8,813
F	6	existing permit limit	n/a	n/a	n/a	0	0	n/a	n/a	0	n/a	0
Total	**36**						**106,250**			**89,887,500**		**74,906**

* Source: Department of Energy, Energy Tips - Benchmark the Fues Cost of Steam Generation, Table 1, at a feedwater temperature of 100 degrees F and an operating pressure of 150 psig.

Boiler Emission Factors (for fuel oil)

VOC (lb/MMBTU)	CO (lb/MMBTU)	NOX (lb/MMBTU)	SOX (lb/MMBTU)	PM10 (lb/MMBTU)	PM2.5 (lb/MMBTU)	CO2 (lb/MMscf fuel burned)	N20 (lb/MMscf fuel burned)	CH4 (lb/MMscf fuel burned)
0.0041	0.0036	0.0110	0.0050	0.0100	0.0100	120,000	0.64	2.3

Refinery	Energy needed to meet increased steam demand (MMBTU/day)	Fuel Consumption (MMscf fuel gas/day)	VOC (lb/day)	CO (lb/day)	NOX (lb/day)	SOX (lb/day)	PM10 (lb/day)	PM2.5 (lb/day)	CO2 (lb/day)	N20 (lb/day)	CH4 (lb/day)	CO2eq* (lb/day)	CO2eq* (MT/yr)
A	16	0.0132	0.07	0.06	0.17	0.08	0.16	0.16	1,586	0.01	0.03	1,590	263
B	63	0.0529	0.26	0.23	0.70	0.32	0.63	0.63	6,345	0.03	0.12	6,358	1,052
C	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0	0.00	0.00	13,211	2,187
D	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0	0.00	0.00	0	0
E	11	0.0088	0.04	0.04	0.12	0.05	0.11	0.11	1,058	0.01	0.02	1,060	175
F	0	0	0.00	0.00	0.00	0.00	0.00	0.00	0	0.00	0.00	0	0
Total	**90**	**0.0749**	**0**	**0**	**1**	**0**	**1**	**1**	**8,989**	**0.05**	**0.17**	**22,218**	**3,678**

*SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1, CH4 = 21, and N2O = 310.
1 metric ton (MT) = 2,205 pounds

For Refinery C under scenario B, assume one electric 700 h.p. (520 kw) compressor is installed and operating at 95% load.

Refinery	Number of Compressors to be Installed	Compressor Rating (hp)	Compressor Rating (kw)	Compressor Load	Daily Operating Schedule (hr/day)	Annual Operating Schedule (day/yr)	Electricity Use (kWh/day)	Electricity Use (MWh/day)	Fugitive VOC Emission Factor* (lb/source/yr)	Fugitive VOC (lb/yr)
C	1	700	522	0.95	24	365	11,901	12	2,570	2,570

*SCAQMD Annual Emission Reporting Program, Form R3 - Default Emission Factors for Refinery Compressors (used to calculate fugitive emissions)

GHG Emission Factors:
1,110 lb CO2e/MWh for electricity when source of power is not identified
(CEC, September 6, 2007 - Reporting and Verification of Greenhouse Gas Emissions in the Electricity Sector)

Energy Summary

Scenario A: Steam Ejector Systems installed at four refineries

Construction Diesel Fuel Usage Summary	Total Diesel Fuel Usage (gal/day)	Significance Threshold: 1% of supply (gal/day)	Percent Increase (%)	Significant?
TOTAL for 2 Facilities Overlapping Construction in 2014	643	1,086,000,000	0.0059%	NO
TOTAL for 3 Facilities Overlapping Construction in 2015	956	1,086,000,000	0.0088%	NO
TOTAL	**1,599**	**1,086,000,000**	**0.0147%**	**NO**

Construction Gasoline Usage Summary	Total Gasoline Fuel Usage (gal/day)	Significance Threshold: 1% of supply (gal/day)	Percent Increase (%)	Significant?
TOTAL for 2 Facilities Overlapping Construction in 2014	25	6,469,000,000	0.0000%	NO
TOTAL for 3 Facilities Overlapping Construction in 2015	38	6,469,000,000	0.0001%	NO
TOTAL	**63**	6,469,000,000	0.0001%	**NO**

Year 2000 California Energy Commission (CEC) projections. Construction activities in future years would yield similar results.
SCAQMD's energy threshold for both diesel and gasoline is 1% or more of supply.

Operational Fuel Usage Summary	Total Fuel Usage (scf/day)	Total Fuel Usage (MMgal/day)	Significance Threshold: 1% of supply (MMgal/day)	Percent Increase (%)	Significant?
Total Fuel Needed for Boilers to Generate Steam	**83,719**	**0.63**	**95**	**0.66%**	**NO**

US Energy Information Administration, Number and Capacity of Petroleum Refineries, California, 2012
http://www.eia.gov/dnav/pet/PET_PNP_CAP1_DCU_SCA_A.htm

Operational Instantaneous Electricity Summary	Electricity Usage (kWh/day)	Electricity Usage (MWh/day)	Significance Threshold: 1% of supply (MW - instantaneous electricity)	Percent Increase (%)	Significant?
Electricity Needed to Operate Compressor	**0**	**0**	**8362**	**0.00%**	**NO**

Instantaneous Electricity Equation: kW-hr/day x 1 work day/24 hr x 1 MW/1000 kW

Scenario B: Steam Ejector Systems installed at three refineries and one compressor installed at one refinery

Construction Diesel Fuel Usage Summary	Total Diesel Fuel Usage (gal/day)	Significance Threshold: 1% of supply (gal/day)	Percent Increase (%)	Significant?
TOTAL for 2 Facilities Overlapping Construction in 2014	643	1,086,000,000	0.0059%	NO
TOTAL for 3 Facilities Overlapping Construction in 2015	797	1,086,000,000	0.0073%	NO
TOTAL	**1,440**	**1,086,000,000**	**0.0133%**	**NO**

Construction Gasoline Usage Summary	Total Gasoline Fuel Usage (gal/day)	Significance Threshold: 1% of supply (gal/day)	Percent Increase (%)	Significant?
TOTAL for 2 Facilities Overlapping Construction in 2014	25	6,469,000,000	0.0000%	NO
TOTAL for 3 Facilities Overlapping Construction in 2015	38	6,469,000,000	0.0001%	NO
TOTAL	**63**	**6,469,000,000**	**0.0001%**	**NO**

Year 2000 California Energy Commission (CEC) projections. Construction activities in future years would yield similar results.
SCAQMD's energy threshold for both diesel and gasoline is 1% or more of supply.

Operational Fuel Usage Summary	Total Fuel Usage (scf/day)	Total Fuel Usage (MMgal/day)	Significance Threshold: 1% of supply (MMgal/day)	Percent Increase (%)	Significant?
Fuel Needed for Boilers to Generate Steam	**74,906**	**0.56**	**95**	**0.59%**	**NO**

US Energy Information Administration, Number and Capacity of Petroleum Refineries, California, 2012
http://www.eia.gov/dnav/pet/PET_PNP_CAP1_DCU_SCA_A.htm

Operational Instantaneous Electricity Summary	Electricity Usage (MWh/day)	Electricity Usage - Instantaneous (MW)	Significance Threshold: 1% of supply (MW - instantaneous electricity)	Percent Increase (%)	Significant?
Electricity Needed to Operate Compressor	12	**0.50**	**8362**	**0.01%**	**NO**

Instantaneous Electricity Equation: MW-hr/day x 1 work day/24 hr

GHG Emissions Summary

Scenario A: 4 facilities installing steam ejectors

GHG Activity	GHG Emissions Source	Total CO2eq (MT/yr)
Temporary construction activities in 2014 [1]	Combustion GHGs in 2014 (diesel/gasoline)	3
Temporary construction activities in 2015 [1]	Combustion GHGs in 2015 (diesel/gasoline)	4
Increased energy demand to produce more steam	Combustion GHGs	1,666
Increased water demand to produce more steam [2]	Water Conveyance GHGs	31
Increased wastewater generation from producing more steam [2]	Wastewater Conveyance GHGs	5
Reduced emissions due to 2 psig limit in PR 1114	Reduced CH4 emissions of 1.51 tons/day	-10,498
	TOTAL CO2eq	**-8,788**
	Significance Threshold	10,000
	Exceed Significance?	**NO**

Scenario B: 3 facilities installing steam ejectors and 1 facility installing a compressor

GHG Activity	GHG Emissions Source	Total CO2eq (MT/yr)
Temporary construction activities in 2014 [1]	Combustion GHGs in 2014 (diesel/gasoline)	3
Temporary construction activities in 2015 [1]	Combustion GHGs in 2015 (diesel/gasoline)	4
Increased energy demand to produce more steam	Combustion GHGs	3,678
Increased water demand to produce more steam [2]	Water Conveyance GHGs	29
Increased wastewater generation from producing more steam [2]	Wastewater Conveyance GHGs	4
Reduced emissions due to 2 psig limit in PR 1114	Reduced CH4 emissions of 1.51 tons/day	-10,498
	TOTAL CO2eq	**-6,780**
	Significance Threshold	10,000
	Exceed Significance?	**NO**

[1] GHGs from temporary construction activities are amortized over 30 years.

[2] California's Water – Energy Relationship, Table 1-3, Page 11, California Energy Commission, Final Staff Report, CEC-700-2005-011-SF, November 2005. http://www.energy.ca.gov/2005publications/CEC-700-2005-011/CEC-700-2005-011-SF.PDF

GHG Emission Factors:
1 metric ton (MT) = 2,205 pounds
12,700 kWh/MMgallons for electricity use for water conveyance - potable water
640 lb CO2/MWh for electricity use due to water/wastewater conveyance
0.0067 lb CH4/MWh for electricity use due to water/wastewater conveyance
0.0037 lb N2O/MWh for electricity use due to water/wastewater conveyance
SCAQMD Regulation XXVII - Climate Change, Rule 2700 - General, Table 1 - Global Warming Potentials, CO2 = 1, CH4 = 21, and N2O = 310.

APPENDIX C

MARATHON PETROLEUM COMPANY LLC
G-955 COKER DRUM DEPRESSURING PROJECT

Marathon Petroleum Company LLC
REFINING

INITIAL CAPITAL BUDGET
($000's)

Year: 2010 Initial Budget **Organization: Louisiana Refining Division**
G-955 Coker Drum Depressuring Project

Project Summary Sheet

A. Project Title: G-955 Coker Drum Depressuring Project

B. Objective: Environmental

		2010 IN Budget	2009 MY Budget	Change
C. Capital Amount:	Prior to 2010	$ 250	$ 250	$ -
Estimate Quality: A	2010	$ 750	$ 4,000	$ (3,250)
	2011	$ -	$ -	$ -
	2012	$ -	$ -	$ -
	2013	$ -	$ -	$ -
	2014	$ -	$ -	$ -
	Total:	$ 1,000	$ 4,250	$ (3,250)
Capital Authorization Amount		$ 1,000	$ 250	$ 750

Expense Amount: N/A

D. Project Description/Source of Benefits:

The current operation of the Unit 05 Coker includes venting the coke drums directly to the atmosphere after water quenching to the blowdown tower. Since the Blowdown System operates at 15 psig, further depressuring of the coke drums is accomplished by venting the drums to atmosphere before un-heading. This practice is not in compliance with Subpart Ja, which requires the coke drums to be depressured below 5 psig before they can be vented to the atmosphere. Although the existing Coker (Unit 05) is not presently subject to Subpart Ja, subsequent modifications to the unit in the near future could require the unit to meet this regulation.

In order to allow the Unit 5 Coker Unit to meet the Subpart Ja requirement that coke drums vent below 5 psig, the Marathon Project Team first decided to install a Blowdown Vent Gas Compressor to lower the pressure of the blowdown system and hence the coke drums. A Decision Support Package for implementing this concept was approved at the end of 2008, and the total estimated cost of the project was about $4MM.

The Project Team later decided to explore a more cost effective option and contracted ConocoPhillips to design a steam ejector system in place of a Blowdown Vent Gas Compressor. The ejector system designed by ConocoPhillips and Bechtel is capable of lowering the pressure of the blowdown system and the coke drums to below 3 psig in less than 45 minutes, and it discharges the recovered vapor at 22 psig into the inlet of the Fractionator Overhead Fin Fans. The system includes two ejectors that are sized to handle 50% of the nominal design flow. This was done to cover the potentially wide variation and uncertainty in the coke drum vapor flow rate. As a result, only one ejector may be required during operation. The ejector system capacity is 1060scfm (4025lb/hr) of water-saturated non condensable gas, and the motive fluid requirements are 150 psig steam at 8700 lbs/hr. After exploration of this option, the Project Team recommends installing the steam ejector system desgined by ConocoPhillips in the Unit 05 Coker for depressuring the coke drums down to about 3 psi after the quench step. The system includes two steam ejectors and the associated piping, instrumentation, and steel. The total estimated cost to complete the project is $1MM.

E. Financial Benefits: N/A

F. Economics: N/A

G. Attachments:
1. Design and Cost Estimate

Last Revision Date: 08/18/2009

Marathon Petroleum Company LLC
REFINING

INITIAL CAPITAL BUDGET
($000's)

Year: 2010 Initial Budget
G-955 Coker Drum Depressuring Project

Organization: Louisiana Refining Division

Approved Date: 07/29/2009

Marathon Oil Company

Louisiana Refining Division

Project Title/Description: Design of Ejector System for the Coker - Hire Conoco-Phillips to c

Date: 12/11/2008

Unit Name: 05 - Delayed Coker - Dom 7

ERTS Number:

Work Or

DECISION SUPPORT PACKAGE

Conceptual: ☐ **Feasibility:** ☑ **Definition:** ☐

Approval Role	Approval Date	Approved	Reviewed
Accounting Representative	12/12/2008	Yes	BETH DURON
Area Environmental	12/15/2008	Yes	N G (NICOLE) BRIEN
Area Safety Representative	12/12/2008	Yes	MARK BAILEY
Process Area Coordinator	12/12/2008	Yes	MICHAEL ODELL
Process Engineer	12/11/2008	Yes	ANDREW SMITH
Project Area Coordinator	12/12/2008	Yes	PETER TALAVERA
Project Engineer	12/11/2008	Yes	WENDAL VINCENT
Project Sponsor	12/11/2008	Yes	RICHARD HERNANDEZ JR
TA Planning Supervisor	12/12/2008	Yes	MICHAEL HENSCHEN JR
Team Leader	12/15/2008	Yes	K N (KEVIN N.) BASHAM

Project Cost Summary ($000's)

Year	Capital	Expense
2008	0	0
2009	0	70
2010	0	0
Remaining	0	0
Total	0	70

Project Economics

Total Costs ($000's)

ROI (%) 0%

NVP @ 15% 0

Simple Payout (yrs) 0

EII Impact

Date Approved: 12/17/08

Division Manager R D (RICH) BEDELL

Marathon Petroleum Company, LLC
Louisiana Refining Division
Design & Cost Estimate

Distribution | **DATE:** 12/16/2008

OFFICE: LA Refining Division | **FROM:** A. Smith / W. Vincent

SUBJECT: **DESIGN & COST ESTIMATE**

Project #:
Project Title: Design of Ejector System for the Coker

SCOPE
The purpose of this project is to evaluate using a steam ejector system in place of the proposed liquid ring compressor system for reducing pressure at which the coke drums now vent to the atmosphere.

RECOMMENDATION
It is recommended to contract Conoco-Phillips to design a steam ejector system for our existing Coker to reduce the venting pressure of the coke drums from the current 16-18 psi to a 3 psi. The cost of this work will be **$70,000** to be spent in the first and second quarters of 2009. This price includes design man hours as well as travel expenses.

FINANCIAL BENEFITS
The project to install liquid ring compressor systems on both Cokers is estimated to be $7.6 MM. By using ejectors in place of the compressors, there will be an estimated savings of over $4.0 MM in capital expenditures. The steam ejectors although consuming 18,000 lbs per day of 150 lb steam will result in net nergy savings of $131M. There will also be savings in maintenance costs since the ejector system will require much less maintenance than the compressor system.

DISCUSSION

The Team decided to explore the possibility of using ejectors instead of liquid ring compressors after learning that the standard design for Foster Wheeler Coker Units is now to use steam ejectors to reduce the coke drum pressure prior to venting. Steam ejectors were not considered for GME as the Conoco Phillip's standard design is to use liquid ring vent gas compressors. Since then Conoco Phillips has designed an ejector system for Suncor in Canada however this system has not yet been installed. Based on the new NSPS Subpart Ja requirements other refineries are also designing steam ejectors to reduce drum venting pressure such as Hovensa, U.S Virgin Islands and CITGO, Lake Charles.
The proposed steam ejector design will educt the coke drum gas and discharge into the Blow down system. A conservative estimate by Graham Corp. is that the steam ejector will require 11mpph of 150 psig motive steam for an approximate vent gas suction load of 21 mpph at 16-18 psig. The coke drum pressure will be reduced to 3 psig therefore the ejector suction pressure will be <1psig to account for any line losses and the discharge at 18-20 psig so that vent gas stream can get into the blow down system. Based on these preliminary numbers the additional steam requirement and sour water generation will not be significant.
Conoco Phillips was contacted and they proposed a design package that will contain the following deliverables:

1. Design Basis Description
   - Elapsed time, start and end pressures

- Basis for generated steam and vapors
- Description of intended operation

2. Hand marked P&IDs
3. Ejector Data Sheet
4. Control System data for sizing
   - Motive steam flow rate controller, if applicable
   - Spill back flow rate controller, if applicable
5. Line Designation table
   - Pipe class, metallurgy, size
   - Insulation requirements
   - Piping design temperature, pressure
6. Interlock Description

PROJECT EXECUTION

The project can be completed on the run and should not require a unit shutdown.

ACCOUNTING ANALYSIS

The costs associated with the Design of the Ejector System for the Coker (~$70,000) should be expensed since its conceptual process study work to determine a viable design solution.

Solomon Exclusion Information: Excludable; 100% Environmental

Cost Information: Funds associated with this project will be accounted for from within the Tech Services outside engineering department budget.

ENERGY ANALYSIS

There will be a net savings of $131M annually if the steam ejectors are installed instead of the 400hp compressor motor. The Garyville EII will also be reduced by 0.002. The steam ejectors will require 18MPPD of 150# steam costing $46M while the 400HP compressor motor will cost $177M annually. This assumes an electricity cost of $0.0679/kwh and $7/Mlbs for 150# steam.

ENVIRONMENTAL ANALYSIS

Reduction of the coker drum venting pressure in order to reduce atmospheric emissions is required for Subpart Ja compliance and should be implemented as soon as possible. Prior LDEQ approval is not required for the design phase but will be required prior to installation of any equipment.

DISTRIBUTION

R. D. Bedell, S. H. Baker, W. E. Dows, R. J. Dussold, D. L. Ehrhart, R. A. Hernandez, R. G.

Kasubinski, W. M. Kepner, B. J. Levi, D. Roland, N. G. Brien, M. W. Odell, P. G. Talavera

Team Leaders

APPENDIX D

COMMENT LETTERS ON THE DRAFT EA AND RESPONSES TO COMMENTS

Comment Letter #1

(Soboba Band of Luiseno Indians, February 28, 2013)

SOBOBA BAND OF LUISEÑO INDIANS
EST. JUNE 19, 1883

February 28, 2013

Attn: Steve Smith, Ph.D
Program Supervisor
Planning, Rules, and Area Sources
South Coast Air Quality Management District
21865 Copley Drive,
Diamond Bar, CA 91765-4178

Re: Proposed Rule 1114- Petroleum Refinery Coking Operations

The Soboba Band of Luiseño Indians appreciates your observance of Tribal Cultural Resources and their preservation in your project. The information provided to us on said project(s) has been assessed through our Cultural Resource Department, where it was concluded that although it is outside the existing reservation, the project area does fall within the bounds of our Tribal Traditional Use Areas. At this time the Soboba Band does not have any immediate concerns with the proposed project. 1-1

Sincerely,

Joseph Ontiveros
Cultural Resource Director
Soboba Band of Luiseño Indians
P.O. Box 487
San Jacinto, CA 92581
Phone (951) 654-5544 ext. 4137
Cell (951) 663-5279
jontiveros@soboba-nsn.gov

Responses to Comment Letter #1
(Soboba Band of Luiseno Indians, February 28, 2013)

1-1 This comment thanks the SCAQMD for observing Tribal Cultural Resources and their preservation. This comment notifies the SCAQMD that the proposed project was assessed and was determined to fall within the Tribal Traditional Use Areas. Lastly, this comment states that the commenter does not have any immediate concerns with the proposed project. No further response is necessary.

Comment Letter #2

(Western States Petroleum Association, March 29, 2013)

Western States Petroleum Association
Credible Solutions • Responsive Service • Since 1907

VIA ELECTRONIC MAIL

March 29, 2013

Barbara Radlein
Planning, Rule Development, and Area Sources
South Coast Air Quality Management District
21865 Copley Drive
Diamond Bar, CA 91765

Dear Ms. Radlein:

DRAFT ENVIRONMENTAL ASSESSMENT FOR PROPOSED RULE 1114, PETROLEUM REFINERY COKING OPERATIONS

Western States Petroleum Association (WSPA) is a non-profit trade association representing twenty-seven companies that explore for, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California, Arizona, Nevada, Oregon, Washington and Hawaii. WSPA-member companies operate petroleum refineries in the South Coast Air Basin that will be impacted by the final requirements of PR 1114. 2-1

WSPA appreciates the opportunity to submit the following comments on the Draft Environmental Assessment as published on February 28, 2013.

1. Project Background, page 1-4.

A. As correctly stated in the DEA, US-EPA issued requests in 2010 to several out-of-state refineries for source testing of coke drum vent emissions. However, the final results were inconsistent[1] and of variable quality. Consequently (as reported by District Staff at the September 27, 2012 meeting of the PR 1114 Working Group), EPA had little confidence in the test results, and the results were ultimately not useful to either US-EPA or the District. 2-2

[1] Source: "EPA Source Test Results", slide 3 from Staff handout at the September 27, 2012 meeting of the PR 1114 Working Group.

1

Nevertheless, despite its limitations, source testing is the only, even remotely accurate, way to measure the constituents in an atmospheric vent stream. We note that, anecdotally, Staff has stated that "pegged" readings (i.e., values > 100,000 ppm VOC) have been observed when using a hand-held Organic Vapor Analyzer (OVA) to evaluate a coke drum vent stream. An OVA has a flame ionization detector that combusts the sample being studied. However, because a coke drum vent stream is 98-99 percent water vapor (i.e., non-combustible), it would tend to extinguish the flame in the detector, which results in an erroneous "pegged" reading on the instrument. 2-2 Cont'd

B. It needs to be emphasized that the Staff estimates of baseline emissions, and of the potential emission reductions, are far from precise because of the dubious quality and extreme variability of the underlying source testing results. Although Staff has used estimating techniques that are not unreasonable, it is misleading to imply that the emissions estimates are either accurate or reliable as is done in the Draft EA. The Final DEA needs to qualify the estimates of baseline emissions as being only rough estimates. 2-3

2. Project Description, page 1-5.

The description in the Draft EA correctly paraphrases subdivision "c" of the draft proposed rule (Version 9). However, it would be clearer to state that any facility that is unable to comply with the proposed 2 psig requirement is, literally, physically unable to do so. In other words, it is not a matter of any actual or perceived unwillingness to comply. 2-4

3. Technology Overview.

A. Page 1-7.

The word "de-coking" is used consistently throughout this section. However, "de-coking" has a particular meaning in the context of refinery operations, and that meaning is unrelated to the removal of coke from a coke drum. We suggest referring to the coke removal process as "cutting coke", or, simply "coke removal".

The process of removing coke from a coke drum begins with "un-heading" the drum (not "de-heading"). The closures at the top and bottom of the coke drums should be referred to as "heads" (not "lids"). Use of the word "lid" seems to imply something that is lightweight and flimsy, which coke drum heads are definitely not. 2-5

B. Page 1-8.

High pressure water "jets" are used to "cut the coke" from the coke drum. Using the term water "spray" gives a potentially misleading impression of the nature of this process. 2-6

It is inaccurate to state that, "To prevent fugitive dust emissions, the coke slurry is kept moist." A slurry is a mixture of water and solid coke; thus, it is "wet" by definition. It is 2-7

true that, in order to prevent fugitive dust emissions, coke is kept moist throughout its storage life at a facility. 2-7 Cont

Mention is made of "technological advancements" being capable of reducing the length of the coking cycle. The Final EA should specify the nature of any such advancements. 2-8

The statement is made that, "On average, the coke contains nine to 12 percent volatiles and 2.7 percent moisture." We question the low value for average moisture content, and we note that Rule 1158, Storage, Handling, and Transport of Coke, Coal and Sulfur, generally requires that coke be kept moist and it defines "moist" as a minimum of 8.3 percent water (1158(c)(21)). We have no comment on the reported range of values for volatiles, but depending upon the test method(s) used, "volatiles" probably need to be distinguished from "VOCs". 2-9

The Draft EA refers to the coke calcining process but fails to note that coke calcining is not common, and that there is only one such facility in the Basin. The Draft EA correctly reports that high purity (i.e., calcined) petroleum coke can be used to manufacture "anodes". We suggest that it would be helpful for the Final EA to further explain what anodes are. 2-10

Reference (under "Controlling Emissions from Delayed Coking") is made to the fact that "… due to environmental considerations … modern cokers are now designed to recover the vapors … by routing them to the refinery fuel gas system." The Final EA should clearly state that every DCU in the Basin is "modern" in this respect. That is, there are no DCUs that still have blow down system(s) which rely on flaring for the disposition of vented gases. Until the point at which coke drums are vented to the atmosphere, the gases are being recovered and sent to fuel gas treatment systems with the aid of vapor recovery systems, which typically consist of mechanical compressors or steam eductors[2]. Proposed Rule 1114 would increase the recovery of vented gases by establishing a maximum pressure at which drums can be vented to the atmosphere. 2-11

The term "vapor" is used throughout both this section and the Draft EA in general, but it is not always clear what is meant when the term is used. Specifically, although there is some discussion regarding the fact that the "vapors" ultimately vented from coke drums are comprised of steam and other compounds, it should be made clear that the atmospheric vent stream is 98-99 percent water vapor (i.e., steam). 2-12

[2] Steam eductors are sometimes called steam ejectors. The terms are synonymous.

3

C. Page 1-9.

The discussion of potentially cooling a drum down further than what is typically being done now needs to clearly state that this is purely an academic argument. One risk of cooling a drum down too far is the possibility of creating a vacuum inside the drum. Coke drums are not designed to withstand a vacuum, and such a condition could be potentially very damaging to the drum. 2-13

4. Environmental Checklist.

A. Page 2-12.

According to the Draft EA, a coke drum depressurization project implemented at the Unit 5 Coker at the Marathon Petroleum refinery in Louisiana was used as the basis for "worst-case construction assumptions for installing steam ejectors...". However, no justification is presented for using a single project - particularly one at an out-of-state refinery - as a case study for the development of a so-called worst case analysis. 2-14

Further, we note that that a great deal of important information is missing from the Marathon documents that were included in the Draft EA. For example, the costs appear to be the original estimates (as opposed to the final "as-built" costs), there is no mention of the number of drums in Marathon's Unit 5 Coker (thus, it cannot be readily determined how to translate the Marathon project to DCUs in the Basin), etc. 2-15

B. Page 2-13.

The Draft EA asserts (in at least two places) that the typical construction time needed to install a steam ejector system is thirty days per facility, but there is no documentation to support this assumption. Further, it is unclear whether the Draft EA means thirty days per facility, or, thirty days per DCU. 2-16

The Draft EA asserts that, for the installation of either a compressor or ejector system, approximately one year will be needed for the pre-construction/advance planning effort leading up to construction. But, no basis for this estimate has been provided. Although conceptually simple, these will not be insignificant projects. The list of activities enumerated in the Draft EA itself ("engineering analysis of the affected equipment, engineering design of the potential equipment, contracting with a vendor, securing financing, ordering and purchasing the equipment, obtaining permits and clearances, and lining up contractors and workers") convincingly makes the case that these projects will be multi-year programs. Just one aspect of these projects - obtaining SCAQMD permits to construct - is very likely to take close to a year. 2-17

C. Page 2-15.

The Draft EA reports on the results of an inquiry by SCAQMD staff of one manufacturer of steam ejectors regarding the characteristics of a reasonably appropriate steam ejector. We do not find the results of that inquiry to be inconsistent with expectations. However, the emphasis on the steam ejectors conveys a misleading impression of the scope and magnitude of the projects needed to comply with the provisions of the draft rule. Although they are the essential "prime movers", the steam ejectors are virtually the least significant parts of the overall projects. Further, the Draft EA does not report on the number of steam ejectors that might be required at any given DCU. 2-18

D. Page 2-23.

It is stated that, "Sulfur compounds such as hydrogen sulfide and mercaptans are the primary sources of odors from existing delayed coking operations." But the claim is speculative and there is no support offered for it. The Draft EA also refers to minimizing emissions "and any associated odors", which is more factually correct because, to our knowledge, no causative link between coke drum venting and nuisance odors has been established. 2-19

E. Page 2-39.

The discussion states that, "Delayed cokers are inherently dangerous operations that involve the use of hazardous feed materials and generate hazardous emissions." The Draft EA goes on to list examples of so-called operational hazards, emergency hazards, and emergency evacuations. The discussion also suggests that PR 1114 would "potentially enhance safety by reducing the possibility of explosion due to pressure build up". These are strong and very serious, but completely unfounded, assertions. It would be alarmist and irresponsible for the Final EA to include such statements. 2-20

The Draft EA claims that the installation of compressor or steam ejector technology would not affect the structural integrity of the affected coke drums. We believe that this is a generally true statement. However, it also needs to be recognized that, when systems for complying with PR 1114 are installed, appropriate safeguards will be taken by the facilities to ensure that the pressure inside coke drums cannot go negative. Coke drums are not designed to withstand an internal vacuum. 2-21

F. Page 2-40.

Two references are made to the potential reduction of emissions of hydrogen sulfide that are associated with the requirements of PR 1114. Further, it is stated that, because hydrogen sulfide is "explosive", a reduction in hydrogen sulfide emissions "would lessen the ***current*** (emphasis added) explosion hazards associated with the operation of delayed coking units." 2-22

5

These claims are hugely misleading. Although it is true that hydrogen sulfide is combustible, its explosive range in air is from 4 percent to 44 percent[3]. Clearly no such explosion hazard exists when any hydrogen sulfide in the coke drum vent gas is present in concentrations significantly less than four percent, in a stream that is 99 percent water vapor[4]. If it is deemed necessary and appropriate to discuss the issue of current explosion hazards associated with the operation of DCUs, the Final EA must clearly state that such risks are virtually zero, and that the potential projects to comply with Rule 1114 are not expected to change the degree of risk one way or the other. 2-22 Cont'd

WSPA would be glad to discuss these issues with you in greater detail. Please contact me with any questions at (310)678-7782, or, psenecal@wspa.org. 2-23

Sincerely,

Patty Senecal

Patty Senecal
Manager, Southern California Region and Infrastructure Issues

cc: Naveen Berry
David Ono
Eugen Teszler
Laki Tisopolus, Ph.D., P.E.

[3] Gas Data Book - 7th Edition, Matheson Gas Products, 2001.
[4] Preliminary Draft Staff Report for PR 1114, December 2012, page III-2.

6

Responses to Comment Letter #2
(Western States Petroleum Association, March 29, 2013)

2-1 This comment provides background information about the commenter and the relationship between the commenter and facilities affected by PR 1114. This comment also expresses the intent to comment on the Draft EA for PR 1114. No further response to this comment is necessary.

2-2 The commenter refers to the source testing conducted by USEPA and the quality of the final source test results. SCAQMD staff agrees with the comment that the emission data collected from the SCAQMD and USEPA source tests were inconsistent and a clear correlation could not be established. As a result, SCAQMD staff worked with USEPA staff, industry representatives, and the public on alternate methods for establishing an emission inventory based on a theoretical approach, using heat balance equations for a coke drum to derive emission estimates. However, SCAQMD staff's understanding about USEPA's position is that, despite the limited number of source tests, emission factors can be developed for individual delayed coking units and applied on a site-specific basis, as indicated by the following statement from their Emission Estimation Protocol For Petroleum Refineries:

> *"A limited number of source tests have recently been performed on delayed coking unit vents. For facilities that have performed source tests, site-specific emissions factors can be developed and used. It is anticipated that the pollutant emissions will be a function of coking vessel void volume and initial vent pressure; however, for a particular delayed coking unit, these variables are fairly constant and a per cycle emissions rate from the source test can be used[13]."*

With respect to the anecdotal reference to the coke drum Organic Vapor Analyzer (OVA) measurement mentioned by SCAQMD staff, it should be clarified that the statement regarding the high hydrocarbon measurement reading was taken from an open coke drum after it was depressurized, and not from a coke drum ***vent***.

2-3 The commenter claims that it is misleading to imply in the Draft EA that the baseline emission estimates are accurate and reliable. However, the commenter did not provide specific references to where this implication is made in the Draft EA. The commenter also acknowledges that the estimating techniques were not unreasonable.

The rule development process for PR 1114 has been based on the best data available for delayed coking unit operations located within and outside the District. The Draft EA relies upon the data and extensive research provided as part of the rule development process and does not reflect on the accuracy or reliability of the data. Thus, SCAQMD staff believes that the Draft EA accurately represents the baseline emissions as estimates through the following statement: "staff estimates the baseline emissions…et seq." Also, as indicated in Response to Comment 2-2, these estimates were derived from a theoretical calculation of the heat balance for the coke drum. SCAQMD staff, in recognition of the issue regarding

[13] Emission Estimation Protocol for Petroleum Refineries, May 2011, version 2.1.1, RTI International, Section 5.3, p. 5-13. http://www.epa.gov/ttnchie1/efpac/protocol/Emission_Estimation_Protocol_for_Petroleum_Refinerie_052011.pdf.

the quality of the additional data collected, included the following clarification in the Staff Report for PR 1114:

> *"However, the quality of additional data collected left a lot to be desired. Thus over the past six months, staff has worked with U.S. EPA, the refineries, and the public on alternative approaches to estimate emissions from DCUs and has recently reached consensus."*

2-4 The commenter states that the paraphrased project description of subdivision (c) is correct but suggests the addition of a clarification to explain the reason that any facility that is unable to comply with the proposed two psig depressurization requirement in PR 1114 is because the facility is physically unable to comply, and not necessarily unwilling to comply. The project description in the EA has been revised to reflect the situation when a facility is unable to comply due to lack of the necessary equipment by November 1, 2013, as follows:

> *"In the event that a facility is unable to comply with the two psig depressurization limit in paragraph (c)(1), an extra period of time will be allowed, depending on the number of DCUs they operate, to make necessary process and equipment modifications that can be completed during downtime periods for maintenance and repair known as turnarounds."*

2-5 The commenter suggests to replace the word "de-coking," which is a term of art with a specific meaning unrelated to the removal of coke from the drum, with "cutting coke" or "coke removal" instead. The term decoking is mentioned alongside "removing the coke" so its meaning is clear in both the Staff Report and Draft EA. Thus, SCAQMD staff believes the term is appropriate for describing the coke removal process.

Similarly, the commenter suggests replacing the word "de-heading" with "un-heading" when describing the coke removal process. SCAQMD staff believes both terms are synonymous, but that de-heading is more commonly used in reference materials.

Lastly, the commenter suggests referring to the closures at the top and bottom of the coke drums as "heads" in lieu of "lids" because the word "lid" incorrectly implies something lightweight and flimsy. To better reflect the scale of the equipment, the EA has been revised according to the suggestion.

2-6 The commenter mistakenly claims that page 1-8 of the Draft EA states that: "high pressure water "jets" are used to "cut the coke" from the coke drum…" and that using the term water "spray" is misleading. In actuality, the description regarding how high pressure water is applied, begins at the bottom of page 1-7 and continues onto page 1-8 as follows:

> *"Once opened, a high pressure water (about 2000 psi) hydraulic drill is lowered into the drum at the top of the drum and a pilot hole is drilled into the solidified coke toward the bottom of the drum. Subsequently, a bigger rotating drill is lowered back into the drum to cut the coke bed. The high pressure water spray breaks the coke into lumps, allowing the coke to fall through the bottom opening of the coke*

drum into a receiving area such as a pad or a pit located directly below the coke drum."

SCAQMD staff made changes according to the suggested language.

2-7 The commenter states that because slurry is a mixture of water and solid coke and is wet by definition, the following statement on page 1-8 in the Draft EA is inaccurate:

"To prevent fugitive dust emissions, the coke slurry is kept moist."

Instead, the commenter suggests this statement be clarified to say that the "To prevent fugitive dust emissions, coke is kept moist throughout its storage life at a facility."

SCAQMD staff agrees with this clarification. The EA has been revised accordingly.

2-8 The commenter suggests the EA to be revised to include the nature of technological advancements made to reduce the length of the coking cycle. Some of the improvements, apart from the implementation of the control techniques expected under adoption of PR 1114, include technological progress with the design and construction of new coke drums, including improved metallurgy which allows drums to withstand the higher thermal stress resulting from a decreased batch cycle time relative to existing older coke drums. The EA has been revised to reflect the requested clarification.

2-9 The commenter questions the 2.7 percent moisture content of the coke when Rule 1158 requires a minimum of 8.3 percent water. SCAQMD staff agrees that a better representation is a range for petroleum coke moisture of between five and nine percent[14]. The EA has been revised accordingly.

2-10 The commenter suggests that the EA mention that coke calcining is not a common process and that only one coke calcining facility is located in the District. SCAQMD staff agrees with this clarification. The EA has been revised accordingly.

The commenter agrees with the statement that calcined coke is used to manufacture anodes, but also suggests that the EA explain what anodes are. An anode, also known as an electrode, is a device through which electric current flows into an electrical device or circuit. Anodes are used for aluminum production. The EA has been revised to reflect this additional information.

2-11 The commenter states that there are no delayed coking units in the District that have a blow down system that relies on flaring for the venting of gases. Instead, the commenter states that the gases are recovered and sent to fuel gas treatment systems with the aid of vapor recovery systems consisting of either mechanical compressors or steam jectors. The

[14] Comparison of Fuel Properties of Petroleum Cokes and Coals Used in Power Generation, http://web.anl.gov/PCS/acsfuel/preprint%20archive/Files/44_1_ANAHEIM_03-99_0080.pdf, p. 82.

commenter suggests that the EA explain that all delayed coking units in the District are modern in that they route the vapors to the refinery fuel gas system.

SCAQMD staff believes that the description for modern cokers implicitly includes cokers located within the District. In addition, page 1-9 of the Draft EA states the following:

> *"Currently all of the affected DCUs route the head space vapors in the coke drum to a blowdown system."*

In addition, the drums located in the District are required to be vented to a blowdown/flare system through permitting conditions. While the blowdown is primarily routed for fuel gas recovery, in the event of an emergency, the flare system is still available. Thus, no change to the EA is necessary.

2-12 The commenter states that the EA uses the term "vapor" throughout the document but that it is not always clear what is meant by the term. The commenter suggests that the EA clarify the atmospheric vent stream consists of 98 to 99 percent water vapors (e.g., steam). While the description of the drum depressurization and subsequent atmospheric venting in the Draft EA is consistent with the use of the term "vapors" in reference to gas phase constituents in the unvented drum headspace, identifying the moisture content in the atmospheric vent stream in a more descriptive manner may be helpful in clarifying this understanding. As a result, the discussion on page 1-9 of the EA has been revised as follows:

> *"However, once the pressures equalize between the drum and the blowdown system, the only way to depressurize the drum to ambient pressure is to vent <u>the remaining vapors, which primarily consist of steam (roughly 97 percent to 99 percent), from</u> the drum to the atmosphere before drilling of the coke bed can commence."*

2-13 The commenter refers to the discussion on page 1-9 of the EA about potentially cooling a drum down further than what is typically done now and suggests that the EA clarify the discussion to explain that it is a purely academic argument because cooling a drum too much can create a negative pressure vacuum that can cause damage. The discussion to which the commenter is referring is a general discussion about how the coke drum cooling process and the time taken to do so can vary by facility, as follows:

> *"One way to minimize emissions during coke drum venting would be to change the process by increasing the drum cooling time. Waiting longer before opening the coke drum will allow it to cool down further."*

However, the possibility of extending the drum cooling time as a control option has been presented in the EA as being highly unlikely since it would impact productivity, as indicated in the following statement:

> *"However, by increasing the cooling time, there would be a dramatic reduction in the processing throughput… For these reasons, it* ***is impractical and improbable*** *[emphasis added] that refinery operators would choose to allow for additional time for the coke drums to cool."*

While SCAQMD staff recognizes that coke drums are not designed to withstand a negative vacuum, the additional suggested safety precautions, while critical if using a compressor to reduce the pressure in the drum, would not make the extended drum cooling time control option significantly more unlikely.

2-14 The commenter states that no justification was provided in the EA to explain why the coke drum depressurization project at the Marathon Petroleum Refinery in Louisiana was used to establish the worst-case construction assumptions for installing steam ejectors.

When conducting a CEQA analysis, SCAQMD staff draws upon a variety of examples of past projects, when available, for establishing assumptions for determining construction and operational emissions. These past projects provide insight and expertise as to how future projects of a similar nature may proceed, regardless of their location within the United States. The Marathon project was relied upon because it was a solid example of a facility installing steam ejectors on a delayed coking unit at a similar size and scale relative to delayed coking units operating in the District. The goals of the Marathon project were so similar to the goals of PR 1114, the fact that the Marathon project was located in Louisiana and not in the District was not an issue. Further, the Chevron Coke Drum Reliability Project[15] was consulted, but the scale of this project and the corresponding construction assumptions covered much more than depressurization issues (e.g., entire coke drum replacement).

2-15 The commenter claims that important information, such as final "as built" costs and the number of coke drums, were missing from the Marathon documents attached to the EA, and that it cannot be determined how the Marathon project applies to affected facilities that would be subject to PR 1114. For rule development and the staff report, SCAQMD staff relied on cost data provided by the USEPA for the Marathon coker project. USEPA staff used the same information to calculate the cost effectiveness of the recent rule 40 CFR 60 Subpart Ja for delayed cokers. For this reason, SCAQMD staff has applied a similar approach in the staff report for consistency.

Per CEQA Guidelines §15131, economic information may be presented in whatever form the agency desires. Further, CEQA Guidelines §15131 (a) states that the economic effects of a project shall not be treated as significant effects on the environment. For these reasons, cost data is not considered in CEQA analyses. Instead, cost information is contained in a separate socioeconomic analysis document. Thus, the original cost estimates or final "as built" costs were not required for the CEQA analysis and thus, were not included or considered in the EA.

2-16 The commenter states that the EA asserts in at least two places that the typical construction time needed to install a steam ejector system is 30 days per facility, but there is no documentation to support this assumption. SCAQMD staff interviewed representatives from individual refineries within the District and their responses are confidential. However, when the representatives were asked to provide an estimate on construction duration, 30

[15] Chevron Coke Drum Reliability Project, SCH No. 2011101026, November 16, 2012. http://www.aqmd.gov/ceqa/documents/2012/nonaqmd/ChevronCokeDrumProject/FEIR.pdf

days was the response. In addition, SCAQMD staff contacted manufacturers of steam ejectors and their estimates for installation of a steam ejector system were less than 30 days. Using an abundance of caution, the analysis in the EA is based on a 30-day construction schedule. Thus, the assumption for construction duration of 30 days was considered reasonable for installing a steam ejector system at one facility.

The commenter also asks for clarification as to whether the 30-day construction schedule is per facility or 30 days per delayed coking unit. The assumptions in the EA regarding the installation of steam ejectors are based on 30-days per facility per steam ejector system.

2-17 The commenter states that the basis for assuming one year for pre-construction/advance planning has not been provided and that the list of activities involved with the pre-construction planning would seem to take more than one year. The commenter notes that the time needed to obtain SCAQMD Permits to Construct can take up to one year.

While the actual time a refinery may take to conduct pre-construction planning could take longer, especially if other refinery modifications not related to PR 1114 are proposed as part of a larger project, the one-year assumption for pre-construction is for the purpose of determining the worst-case construction impacts. There is nothing in PR 1114 that limits the affected facilities to one year of pre-planning. Rather, the one-year estimate is conservative and for calculation purposes only and certainly does not preclude refinery operators from taking longer, provided that the compliance dates in PR 1114 are met.

2-18 While the commenter acknowledges that the results of an inquiry made to one manufacturer of steam ejectors is not inconsistent with the commenter's expectations, the commenter suggests that SCAQMD's focus on steam ejector technology is misleading about the scope and magnitude of projects to be undertaken by refinery operators to comply with PR 1114. However, the commenter goes on to say that "steam ejectors are virtually the least significant parts of the overall projects." These two comments seem to contradict each other and it is not clear whether the commenter believes the projects are substantial or relatively simple. In any case, the SCAQMD's approach to the CEQA analysis was based on contacting a steam ejector manufacturer as well as conversing with representatives from individual refineries. The responses from the refinery representatives indicated that steam ejectors would be the preferred solution for most facilities to comply with the depressurization requirement in PR 1114. The Draft EA acknowledges the complexity involved with installing steam ejector systems, and has referred to the construction of a steam ejector system as follows:

> *"From a construction point of view, the installation of a compressor or steam ejector technology is a relatively straightforward process. If a facility operator chooses to install either a compressor or steam ejector system, approximately one year will be needed for pre-construction/advance planning activities such as engineering analysis of the affected equipment, engineering design of the potential equipment, contracting with a vendor, securing financing, ordering and purchasing the equipment, obtaining permits and clearances, and lining up contractors and workers."*

The evaluation of the estimated construction related activities is based on the comparative overall coke drum headspace affected, and a correspondingly sized ejector. In addition, page 2-16 of the Draft EA details the construction assumptions that cover the complexity of the installation.

Lastly, in response to the comment that the Draft EA does not report on the number of steam ejectors that may be required at any given delayed coking unit, the commenter is referred to Appendix B. Scenario A assumes that four refineries will install five steam ejector systems and Scenario B assumes that four refineries will install four steam ejector systems.

2-19 The commenter claims the following statement in the Draft EA is speculative and unsubstantiated:

> *"Sulfur compounds such as hydrogen sulfide and mercaptans are the primary sources of odors from existing delayed coking operations."*

Contrary to the comment, there is no speculation about the type of emissions from delayed coking operations. Specifically, coking units produce appreciable quantities of methyl mercaptans[16]. Further, the potential exists for exposure to hazardous gases such as hydrogen sulfide (H2S) during coking operations[17]. A common chemical trait of sulfur compounds and mercaptans is that these substances both have a strong odor, even at part per billion concentrations. The analysis in PR 1114 estimates a reduction in several pollutants, including H2S, and as such, would cause a reduction in the amount of odors potentially generated by delayed coking operations.

2-20 The commenter states that the following discussion on page 2-39 of the Draft EA are unfounded, alarmist assumptions and it is irresponsible to include in the Final EA:

> *"Delayed coking units are inherently dangerous operations that involve the use of hazardous feed materials and generate hazardous emissions. Operational hazards associated with DCU operations can occur during coke drum switching, coke drum head removal (deheading), and coke cutting. Emergency hazards can occur during coke transfer, processing and storage that can trigger an emergency evacuation due to potential exposures to toxics and dust irritants and burn trauma. To help control these hazards and prevent emergency situations, operators of DCUs follow established USEPA and OSHA safety protocols that contain best management practices for operating the DCUs safely and reliably. Implementation of PR 1114 would not interfere with USEPA and OSHA requirements for the proper safe operation and maintenance of DCUs. In addition, PR 1114 would not create new upset conditions involving the release of hazardous materials into the environment above the existing baseline. Rather, PR 1114, by requiring a lower minimum depressurization level than current operations without requiring a change to the nature, process, or throughput of the affected delayed coking units, would*

[16] Emission Estimation Protocol for Petroleum Refineries, May 2011, version 2.1.1, RTI International, Section 5.3, p. 5-13. http://www.epa.gov/ttnchie1/efpac/protocol/Emission_Estimation_Protocol_for_Petroleum_Refinerie_052011.pdf

[17] OSHA Technical Manual, Section IV, Chapter 2, Petroleum Refining Processes; http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html.

potentially enhance safety by reducing the possibility of explosion due to pressure build up. Thus, the potential changes that may occur as part of implementing PR 1114 (e.g., the installation of compressor or steam ejector technology) would not affect the structural integrity of the affected coke drums."

Contrary to the comment, the above discussion is based on information provided in a Safety and Health Information Bulletin from the Occupational Safety and Health Administration (OSHA)[18] about DCU hazards that may result in relatively frequent and serious accidents.

2-21 The commenter agrees with the statement in the Draft EA that the installation of compressor or steam ejector technology would not affect the structural integrity of the affected coke drums but requests the EA to also acknowledge that appropriate safeguards will be employed by the refinery operators to ensure that the pressure inside each coke drum will not go negative, since coke drums are not designed to withstand an internal vacuum. See Response to Comment 2-13.

2-22 The commenter claims the references on page 2-40 of the Draft EA to H2S emissions, the description that H2S is explosive and the claim that the reduction in H2S emissions would lessen the current explosion hazards of delayed coking units, are misleading. The commenter agrees that H2S is combustible, but points out that the explosive range in air is from four percent to 44 percent. The commenter claims that coke drum vent gas is 99 percent water vapors, so no explosion hazard exists since the H2S concentration would be well below four percent. The commenter also claims that the Final EA must clearly state the current explosion hazards are virtually zero and that compliance with PR 1114 will not change the degree of risk one way or another.

The commenter is implying that the coke drum vent gas is always high in water vapors and low in H2S concentration and therefore, there is no chance for explosion. However, as mentioned in Response to Comment 2-20, OSHA's Safety and Health Information Bulletin outlines the hazards associated with DCU operations and paints a completely different picture regarding the potential for explosions, as follows:

"The batch state of the operation (drum switching and coke cutting) presents unique hazards and is responsible for most of the serious accidents attributed to DCUs… 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… DCU workers can be exposed to coke dust and toxic substances in gases and process water around DCU operations… Liquid hydrocarbon escaped from a coke drum can be well above its ignition temperature, presenting a fire hazard… 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 process operations."

[18] Hazards of Delayed Coker Unit (DCU) Operations, Safety and Health Information Bulletin, Occupational Safety and Health Adminstration (OSHA), SHIB 08-29-03 (C); http://www.osha/gov/dts/shib/shib082903c.html.

In addition, SCAQMD staff researched OSHA's accident reports involving delayed coker units and found the following summary of a reported incident as an example of an explosion:

> *"In 1993, employees were working in a coker unit that thermally cracks heavy residual feed through a process called delayed coking. The workers were preparing to switch the feed to the core drum, which necessitated opening and closing a number of valves. Three workers were involved with opening and closing the valve, each working at a different location. As the operation was proceeding, a loud noise was heard and a vapor cloud was observed in the vicinity of the pumps feeding the process. The vapor cloud ignited, fatally burning two of the workers.*[19]*"*

Based on the evidence, it is not correct to claim that the potential existing risk for explosion is virtually zero when there are clearly inherent, substantial, existing hazards associated with DCU operations. No change to the EA will be made.

2-23 This comment provides closing remarks to the letter. No further response to this comment is necessary.

[19] OSHA Safety Hazard Information Bulletin on Chemical Exposures from Industrial Valve and Piping Systems, May 14, 1996, Examples of Accidents; http://www.osha.gov/dts/hib/hib_data/hib19960514.html