Energy Efficiency and Co-Benefits Assessment of Large Industrial Sources

Oil and Gas Production and Mineral Processing Sectors Public Report

California Air Resources Board
Stationary Source Division
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California Environmental Protection Agency
Air Resources Board

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Introduction and Summary

This report summarizes the data provided to the Air Resources Board (ARB or Board) by Oil and Gas Production and Mineral Processing (Oil and Gas/Mineral) facilities subject to the Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities Regulation (EEA Regulation or Regulation).[1] In this section, we provide background information on the EEA Regulation and a short summary of the data provided by Oil and Gas/Mineral facilities.

Following the Introduction and Summary (IS), are two sections which provide a compilation of the information submitted by Oil and Gas/Mineral facilities. This information is aggregated in a manner consistent with ARB regulations. The first section "Part I" is a sector-wide summary of all of the energy efficiency improvement projects identified by all Oil and Gas/Mineral facilities, along with estimated emission reductions and costs. The second section "Part II" summarizes Oil and Gas/Mineral facility-specific information consistent with the public disclosure requirements under California Code of Regulations (CCR) § 95610. Emission inventories, both on a sector-wide and facility-specific basis, are also provided for the 2009 reporting year.

Based on the information provided to ARB, we have the following preliminary observations:

- The five oil and gas production facilities and one mineral processing facility subject to the EEA Regulation identified over 140 energy efficiency improvement projects.
- The total greenhouse gas (GHG) reductions associated with these projects is estimated to be approximately 1.6 million metric tonnes carbon-dioxide equivalent ($MMTCO_2e$) per year.[2]
    - ✓ If fully implemented, the projects would reduce GHG emissions by nearly 25 percent.
    - ✓ Approximately 92 percent of the estimated GHG reductions (1.5 $MMTCO_2e$) are from completed projects, with 27 percent (0.4 $MMTCO_2e$) of these reductions from projects completed before 2010 (and therefore already accounted for in the 2009 emissions inventories) and 73 percent (1.1 $MMTCO_2e$) of the reductions from projects completed during or after 2010.
    - ✓ Approximately 8 percent of the estimated GHG reductions (0.13 $MMTCO_2e$) are from projects that are scheduled (7 percent) or under investigation (1 percent).
- Corresponding reductions of oxides of nitrogen (NO_x) and particulate matter (PM) are 2.24 tons per day (tpd) and 0.5 tpd, respectively, with approximately 60 to 75 percent of the reductions from projects completed before 2010 and 25 to

[1] Title 17, California Code of Regulations, sections 95600 to 95612.

[2] About a quarter of the estimated reductions is from completed projects (27 percent of the 92 percent from completed projects) and already accounted for in the 2009 GHG Mandatory Reporting emissions inventory. The total does not include estimated emission reductions from projects identified as "Not Implementing."

40 percent of the reductions from projects completed during or after 2010, scheduled, or under investigation.

EEA Regulation Background

On July 22, 2010, the Board approved the EEA Regulation. The Regulation requires operators of California's largest industrial facilities to conduct a one-time energy efficiency assessment. The Regulation was approved by the Office of Administrative Law and became effective on July 16, 2011. All California facilities with 2009 GHG emissions equal to or greater than 0.5 $MMTCO_2e$ are subject to the Regulation. Also subject to the requirements are cement plants and transportation-fuel refineries that emitted at least 0.25 $MMTCO_2e$ in 2009.

The Regulation requires facility managers to conduct a one-time assessment of fuel and energy consumption, and provide estimates of GHG, criteria pollutants, and toxic air contaminant (TAC or toxics) emissions. Facilities are further required to identify potential energy efficiency improvements for equipment, processes, and systems that cumulatively account for at least 95 percent of the facility's total GHG emissions. Energy Efficiency Assessment Reports (EEA Reports) were to be filed with the ARB by December 15, 2011. A total of 43 facilities were required to provide an EEA Report. [3]

To fulfill ARB's public disclosure requirements in the EEA Regulation, ARB staff developed five separate "Public Reports" for the following sectors: Refinery, Oil and Gas Production/Mineral Processing, Cement Manufacturing, Power Generation, and Hydrogen Production. The reports summarize, by sector, the information provided in the 43 EEA Reports submitted by the facilities. The reports strike a balance between full public disclosure of the information provided ARB and our responsibility to protect confidential business information pursuant to CCR § 95610. This report is the Public Report for the Oil and Gas/Minerals Sectors.

The Public Reports do not present ARB staff's findings, conclusions, or recommendations. These will be presented in a subsequent report that will include all sectors. We intend to release this subsequent report once we have completed our review and analysis of the information provided in the EEA Report, the reports from the third party reviewer, and other applicable information. We anticipate releasing this subsequent report in 2014.

[3] Staff of the San Francisco State University Industrial Assessment Center is also under contract to provide a third-party review of a subset of the EEA Reports. Nine reports were provided to them to evaluate. The third-party reviews are not yet available and therefore are not reflected in this report.

Summary of EEA Report Data for the Oil and Gas/Mineral Sectors

Five oil and gas production facilities and one mineral processing facility submitted EEA Reports to ARB. Below staff provides a summary of the 2009 GHG emissions for the Oil and Gas/Mineral Sectors, followed by a summary of the potential GHG, criteria pollutant (CP), and toxic air contaminant (TAC or toxics) emission reductions from Completed/Ongoing, Scheduled, and Under Investigation energy efficiency improvement projects identified in the EEA Reports. Also presented are the estimated total one-time capital costs, annual costs, and annual savings associated with the projects. As indicated earlier, additional details are provided in Parts I and II which follow this summary.

GHG Emissions

Table IS-I shows the 2009 GHG emissions in $MMTCO_2e$ from the five oil and gas production facilities and one mineral processing facility subject to the EEA Regulation. This estimate comes from ARB's Mandatory GHG Reporting for 2009. The GHG emission estimates do not include any off-site emissions such as those associated with the production of electricity or steam which is not produced on-site, thus, emissions may not be directly comparable between oil and gas production facilities. As shown in the table, the Oil and Gas/Mineral Sectors total GHG emissions in 2009 were 6.5 $MMTCO_2e$ per year.

Table IS- I: 2009 Greenhouse Gas Emissions for Oil and Gas/Mineral Facilities Subject to EEA Regulation

Facility Name	2009 GHG Emissions ($MMTCO_2e$/year)	Air District
Oil and Gas Production		
Aera - Belridge	1.6	San Joaquin Valley Air Pollution Control District
Aera - MOCO	0.5	
Chevron - Kern River	0.5	
Chevron - Midway Sunset/Cymric	1.8	
Occidental - Elk Hills	0.6	
Subtotal Oil and Gas	5.0	
Mineral Processing		
Searles Valley Minerals	1.5	Mojave Desert Air Quality Management District
Total - Oil & Gas/Mineral	6.5	

Source: Facility EEA Reports

Energy Efficiency Projects and Estimated Potential Emission Reductions

The facility operators of California's five oil and gas production facilities and one mineral processing facility subject to the EEA Regulation identified over 140 energy efficiency improvement projects and designated the project status as:

- Completed/Ongoing,
- Scheduled,
- Under Investigation, or
- Not Implementing.

For the Oil and Gas/Mineral Sectors, many of the projects identified by the different facilities were similar in terms of the equipment impacted and the approach used to improve energy efficiency. Similar projects have been grouped and placed in one of the six "Equipment Category" listed in Table IS-2. Equipment Category refers to the equipment (i.e. boilers) or a grouping of equipment (i.e. electric equipment) that are associated with an oil and gas or minerals process.

Table IS-2 summarizes, by "Equipment Category," the number of projects and the estimated GHG, NOx, and PM emission reductions associated with the projects identified in the EEA Reports. The estimated GHG emission reductions are approximately 1.6 MMTCO2e annually. Approximately a quarter of the GHG emission reductions identified were completed before 2010 and are reflected in the 2009 GHG totals shown in Table IS-1. Three-quarters of the GHG emission reductions are from projects that were completed during or after 2010, scheduled, or under investigation and are not reflected in the 2009 GHG values shown in Table IS-1.

Table IS-2: Estimated GHG and Criteria Pollutants Emission Reductions from Potential Energy Efficiency Improvement Projects*

Equipment Category	Number of Projects*	GHG Reductions per year ($MMTCO_2e$)	NO_x Reductions (tons per day)	PM Reductions (tons per day)
Boiler	45	1.20	0.63	0.11
Thermal, Chemical, and Stationary Combustion Engines	12	0.20	0.44	0.074
Electric Equipment	69	0.20	1.15	0.31
Other Equipment	3	0.004	0.015	0.003
Total	129*	1.59	2.24	0.50

*Includes all reported projects except those identified as Not Implementing.

The estimates in Table IS-2 assume that all of the energy efficiency improvement projects identified in the EEA Reports would be implemented, except for those identified as "Not Implementing." However, implementation of some projects may preclude the implementation of other projects that deal with the same equipment or processes.

Therefore, these estimated reductions do not necessarily represent readily achievable on-site emission reductions.

<u>Costs</u>

Table IS–3 provides a summary of the estimated total one-time capital costs, annual costs, and annual savings for the approximately 129 energy efficiency improvement projects identified in the Oil and Gas/Mineral Sectors EEA Reports. The total estimated one-time costs for all of these projects (except for those identified as “Not Implementing”) are estimated at about $507 million with annual costs of about $18 million. These projects would also result in annual savings of approximately $130 million. These estimates are preliminary. They are not based on detailed engineering and cost analysis that would be required to accurately estimate emission reductions, costs, and timing of the projects.

Table IS-3: Summary of Estimated Costs and Savings for Energy Efficiency Improvement Projects*

Number of Projects	One Time Cost (million $)	Annual Cost (million $/year)	Annual Savings (million $/year)
129	$507	$18	$129

* Includes all projects identified as Completed/Ongoing, Scheduled, or Under Investigation. Does not include projects identified as “Not Implementing.” All values rounded.

In the next two parts of this “Public Report,” we provide more details on the information contained in the Oil and Gas/Mineral Sectors EEA Reports. The information is presented consistent with the public disclosure requirements under CCR § 95610.

Part I provides sector-wide information on the five oil and gas facilities and one mineral facility subject to the EEA Regulation including background information on the Oil and Gas/Mineral sectors; estimates of the GHG, criteria pollutant, and TAC emissions from the Oil and Gas/Mineral facilities; and information on State, federal, and district regulations affecting Oil and Gas/Mineral operations in California. Part I provides, on a sector-wide basis, the energy efficiency improvement projects identified by these facilities in their EEA Reports and the estimated GHG, criteria pollutant, and TAC emission reductions associated with these projects. All information provided, including inventory data as well as identified project costs and benefits, is as reported by the facilities in their EEA Reports. Inventory data may not agree with other published data due to the inclusion of more recent data provided by the facility.

Part II provides specific information about each of the Oil and Gas/Mineral facilities submitting EEA Reports. Within each facility-specific section, there is information on the 2009 emissions for GHG, criteria pollutants, and TACs from the specific facility. There is also a summary of the energy efficiency improvement projects that facility staff identified in their EEA Report. The projects are categorized by Equipment Category and Equipment Sub-type. Equipment Sub-type provides a general description of the types of equipment but does not provide a detailed explanation of each of the 129 projects identified or facility specific variations from the general description. Information about cost and potential emission reductions of GHG, criteria pollutants, and TACs, summed for all the projects (by Equipment Category and Equipment Sub-type), is provided. In compliance with CCR § 95610, the specific details about the individual projects were not presented. While it is not possible to identify the specific details for each project a facility has identified, it is possible to get a good indication of what equipment, what action, and what timeframe for action were considered by referring back to the sector-wide project information in Part I.

Part I – Oil and Gas Production and Mineral Processing Sectors

I.0 Introduction

The information presented in this sector-wide summary is based on EEA Reports submitted by the five oil and gas production facilities and the one mineral processing facility subject to the EEA Regulation. These two sectors were combined because of the similarity of the energy efficiency projects identified and to provide more information on the mineral plant projects without disclosing confidential business information (CBI) pursuant to CCR § 95610. All information provided, including inventory data as well as identified project costs and benefits, is as reported by the facilities in their EEA Reports. Inventory data may not agree with other published data due to the inclusion of more recent data provided by the facility. The format and level of detail of the information presented strikes a balance between full public disclosure of the information provided to ARB and our responsibility to protect confidential business information in a manner consistent with ARB regulations. This report does not present ARB staff's findings, conclusions, or recommendations. These will be presented in a subsequent report that will include all sectors. We intend to release this subsequent report once we have completed our review and analysis of the information provided in the EEA Reports, the reports from the third party reviewer, and other applicable information. We anticipate releasing this subsequent report in 2014.

I.1 Oil and Gas Production and Mineral Processing Sector Description

Table I-1 shows the five oil and gas production facilities and the one mineral processing facility that were required to provide information under the EEA Regulation, along with the air district in which they are located.

Table I-1: Oil/Gas/Mineral Facilities Submitting EEA Reports and Air District Where Located

Facility Name	Facility Type	Air District
Aera - Belridge	Oil and Gas	San Joaquin Valley APCD
Aera - MOCO	Oil and Gas	
Chevron - Kern River	Oil and Gas	
Chevron - Midway Sunset/Cymric	Oil and Gas	
Occidental - Elk Hills	Oil and Gas	
Searles Valley Minerals	Mineral	Mojave Desert AQMD

<u>Overview of Oil and Gas Production</u>

Table I-2 provides the 2009 oil and gas production numbers for the five oil and gas facilities submitting EEA Reports. The total oil production was approximately 270,000 barrels per day (bbl/day); the total gas production was approximately 280,000 million cubic feet per day (Mcf/day). Most of these products are processed and used in California.

Table I-2: Annual Production Capacity California Oil and Gas Facilities

Facility	Oil and Condensate (bbl)	Net Gas (Mcf)
Aera - Belridge	29,737,854	12,411,670
Aera - MOCO	Specifics Not Available	Specifics Not Available
Chevron - Kern River	28,704,046	-
Chevron - Midway Sunset/Cymric	24,989,483	4,211,940
Occidental - Elk Hills	13,738,586	89,726,527
Total	97,169,969	106,350,137

(DOGGR, 2010)

Oil and gas production operations in California began in 1876. Currently California is the fourth largest oil producer in the United States behind Texas, Louisiana, and Alaska. California produces approximately 230 million barrels of crude oil and 270 billion cubic feet of natural gas per year. The majority of the crude oil and natural gas production occurs in Kern County using steam injection due to the characteristics of the heavy oil extracted in the region (DOGGR, 2010).

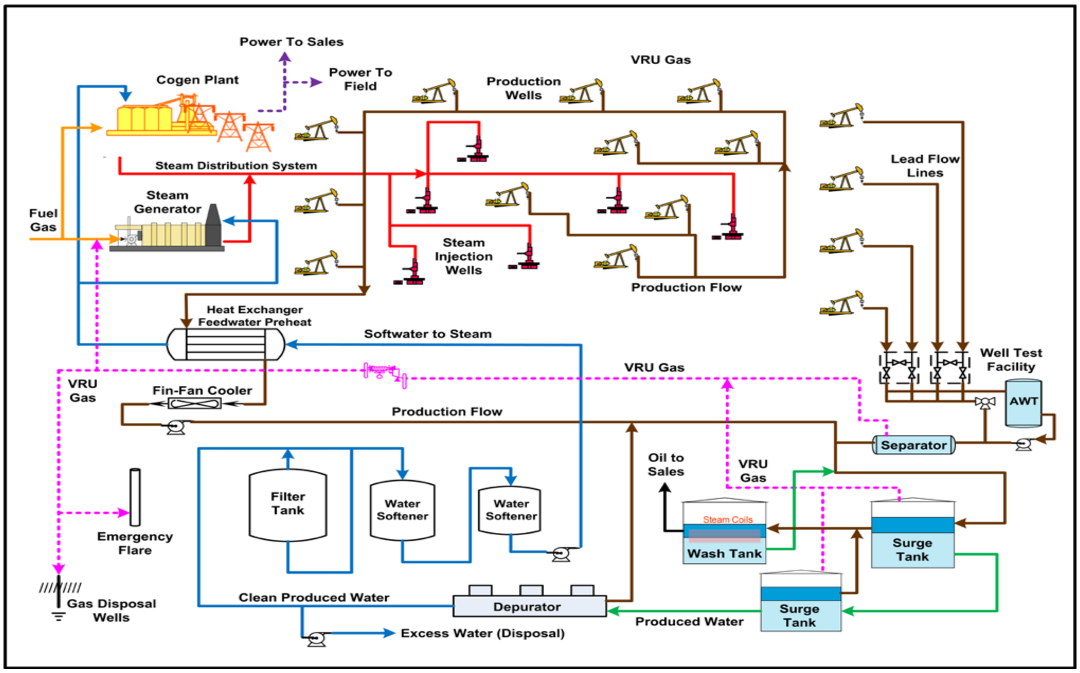
California crude oil consists of approximately 90 percent water and 10 percent oil and gas when it is initially pumped out of the ground. Typical crude oil operations consist of extracting the oil/water emulsion from the geological formation via a mechanical or submergible pump. The emulsion is sent to a separator or a series of separators where the solution is split into three main compounds: water, oil, and gas. The oil and water are transferred into a storage tank to await transfer. The natural gas is processed for sales, used as a fuel gas, or disposed of using a flare or injection well.

Natural gas is produced as either associated or non-associated gas. Associated gas is extracted from a geological formation with crude oil and removed during the separation phase. Non-associated gas is produced from a geological formation without crude oil. California natural gas is mainly associated gas and composed of methane, other light hydrocarbons, carbon dioxide (CO_2), and condensates.

In California, the main contribution of GHG emissions from oil and gas production is from combustion processes associated with the removal and processing of the recovered oil and gas. Combustion emissions produce approximately 93 percent of the GHG emissions from this sector, with fugitive and vented emissions accounting for the remainder. Steam generation produces 87 percent of the total combustion emissions (CARB, 2013). Most of this steam is injected into geological formations to enhance oil recovery. The remainder is used to generate onsite electricity or for process demands.

Steam is injected on either a continuous (flood) or an intermittent (cyclic) basis. Cyclic stimulation is carried out by injecting steam into a producing well for a short period of time. After each steaming cycle, the well is returned to production. Continuous steaming, commonly known as steam flooding or steam drive, is carried out by injecting steam into a reservoir through injection wells. Crude oil was traditionally used as fuel to create the steam used for injection. However, due to federal and state clean-air regulations, almost all production facilities have switched to natural gas combustion. Figure I-1 below illustrates the process involved in a typical oil operation using steam injection.

Figure I-1: Typical Oil Operation Using Steam Injection



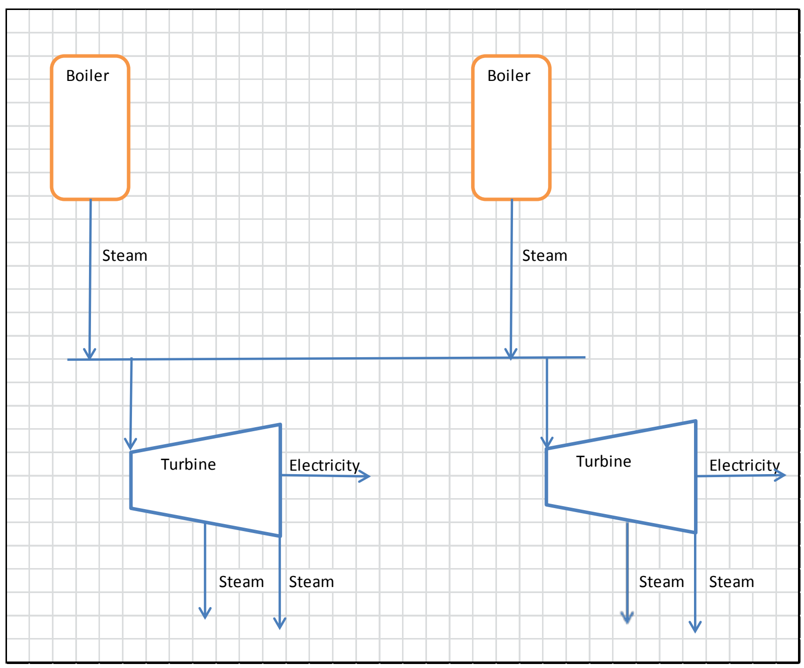
<u>Overview of Mineral Processing</u>

The single mineral processing facility subject to the EEA Regulation is Searles Valley Minerals (SVM). This facility mines nonmetallic materials by using solution mining and various brine processes to produce borax, boric acid, soda ash, and sodium sulfate. Production in Searles Valley began in 1873 with a few tons of Borax and SVM now produces more than 1.7 million tons per year of products. SVM daily ships thousands of tons of high grade material to major manufacturers domestically and around the world. The facility is located at Searles Dry Lake which contains rich deposits of naturally occurring minerals. The brine under the lakebed is approximately 10 times saltier than seawater. This brine holds a diverse supply of minerals. SVM mines the nonmetallic materials from the lakebed by selective crystallization of the brine. The brine solution is pumped from the lake and then through various processes of heating, cooling, thickening, and separating before the final products are produced.

Most of SVM’s emissions are from boilers which produce co-generation steam and power for the facility. The boiler steam is used to process minerals into usable materials and the co-generation energy is used to power ancillary fans and pumps; excess power is sold to the local electricity provider.

The main source of GHG emissions from SVM is the coal-fired boilers in its cogeneration system. Minor sources of GHG emissions include other combustion sources, such as natural gas-fired bleachers and dryers. According to SVM, there are no GHGs released to the atmosphere from the mineral production processes; byproduct CO_2 is separated from the boilers' exhaust stream and is used in the sodium carbonate production, as discussed below. Figure I-2 shows a simplified process-flow diagram for the cogeneration system, the primary process emitting GHG emissions at the SVM plant site. Coal-fired boilers generate steam which is sent to steam turbines generating electricity providing steam at various temperatures and pressures to different production processes throughout the SVM plant.

Figure I-2: Mineral Plant Cogeneration Process Flow



A portion of the boiler exhaust-stack gases are routed to a monoethanolamine (MEA) absorption system where the CO_2 is separated from the exhaust stream. The separated CO_2 is used in the process of precipitating sodium carbonate from the brine solution. The CO_2 is regenerated during the production process and recycled into the system. The addition of CO_2 from the exhaust stack makes up for a small amount of CO_2 leakage from the system. According to SVM, there is no net CO_2 emitted from this production process.

I.2 Emissions and Fuel Use

Emissions

As shown in Table 1-3, GHG emissions from the five oil and gas facilities and one minerals facility were about 6.5 $MMTCO_2e$ in 2009. About 5 $MMTCO_2e$ were from the oil and gas facilities and the remaining 1.5 $MMTCO_2e$ from the mineral processing. This estimate comes from ARB's Mandatory GHG Reporting for 2009. The GHG emission estimates do not include off-site emissions associated with the production of electricity or steam which is not produced on-site.

GHG emissions from oil and gas production in 2009 are down by about 5 percent from 2008 levels and down by 24 percent for all production throughout California from 2000. Oil and gas production throughout California have declined by 24 to 27 percent over this nine year time period. GHG emissions from the mineral processing declined just over 10 percent from 2008 to 2009.

Table I-3: Oil and Gas Production and Mineral Facilities Greenhouse Gas Emissions (2009)

Facility Name	2009 GHG Emissions ($MMTCO_2e$/year)
Aera Belridge	1.6
Aera MOCO	0.5
Chevron Kern River	0.5
Chevron Midway Sunset/Cymric	1.8
Occidental of Elk Hills	0.6
Subtotal Oil and Gas	**5.0**
Searles Valley Minerals	1.5
Total- Oil & Gas/Mineral	**6.5**

Source: Facility EEA Reports

The 2009 estimated criteria pollutant emissions from the five oil and gas production facilities are listed on Table I-4. These emissions are mainly due to natural gas combustion for steam production.

Table I-4: Oil and Gas Production Facilities Total Criteria Pollutant Emissions (2009)

Criteria Pollutant	Total Mass Emissions (tons/day)
Total Organic Gases (TOG)*	1.37
Reactive Organic Gases (ROG)*	2.22
Carbon monoxide (CO)	5.12
Oxides of Nitrogen (NO_x)	6.68
Sulfur Oxides (SO_x)	1.88
Particulate Matter (PM)	2.37

*Some facilities reported total organic gases and others reported reactive organic gases. These totals represent the totals of the reported values.

The 2009 estimated criteria pollutant emissions from the mineral processing facility are listed on Table I-5.

Table I-5: Mineral Facility Total Criteria Pollutant Emissions (2009)

Criteria Pollutant	Total Mass Emissions (tons/day)
Total Organic Gases (TOG)	0.05
Carbon monoxide (CO)	0.36
Oxides of Nitrogen (NO_x)	3.47
Sulfur Oxides (SO_x)	0.24
Particulate Matter (PM)	0.57

Tables I-6 and I-7 show the estimated TAC emissions for the five oil and gas production facilities and one mineral production facility subject to the EEA Regulation, respectively. The emission estimates were provided by the facilities and are primarily based on emissions estimation methodologies used by the local air district in which the facility is located. The TACs reported may vary by local air district such that not all TACs were reported by all the facilities. Also, the Air Toxics "Hot Spots" Information and Assessment Act (AB 2588), enacted in 1987, requires stationary sources to periodically provide more comprehensive reporting, resulting in variations in the TACs reported. These totals represent the totals of the reported values. The TACs are ranked according to potential public health impact based on the combination of mass emissions and cancer potency. The cancer potency factors (CPF) used are approved by California's Office of Environmental Health Hazard Assessment and can be found on the web at http://www.oehha.ca.gov/air/hot_spots/tsd052909.html (OEHHA, 2009)

To identify the toxics pollutants of potential concern, the TACs for each facility were ranked using the reported emissions for each pollutant and their cancer potency factor. Pound for pound, not all pollutants are equal in terms of potential health impacts to the public. Specifically, the ranking (R) for each pollutant is determined by multiplying the reported emissions (E) and the pollutant-specific inhalation cancer potency factor (CPF). The equation for ranking each pollutant is: $R = E \times CPF$.

This method for ranking pollutants is a simplistic tool used to rank the reported emissions according to potential health impacts. All of the pollutants reported for the sector were ranked using the equation above. The ten pollutants with the highest ranking are listed in the table. The location of a pollutant on the list in the table is a combination of the reported emissions and the presence and/or relative magnitude of the CPF. The pollutant with the highest ranking is listed first. While the CPF is typically used in health risk assessments to estimate potential cancer risk; this ranking is not a risk assessment. The list in Table I-6 simply provides a method for placing the reported pollutants in a relative ranking based on mass and the cancer potency of the pollutant.

The 2009 estimated emissions from the top ten TAC's for the five oil and gas production facilities are listed on Table I-6.

Table I-6: Oil and Gas Production Facilities Toxic Air Contaminant Emissions (2009)

Toxic Air Contaminant*	Total mass emissions (pounds/year)
Diesel PM	2,242
1,3-Butadiene	2,010
Formaldehyde	41,226
Benzene	2,756
PAHs	0.8
Acetaldehyde	3,568
Naphthalene	241
Propylene oxide	1,190
Ethyl benzene	653
Chromium, hexavalent	0.001

*Listed in rank order based on mass times cancer potency.

The 2009 estimated emissions from the top ten TAC's from the mineral processing facility are listed on Table I-7.

Table I-7: Mineral Facility Toxic Air Contaminant Emissions (2009)

Toxic Air Contaminant*	Total mass emissions (pounds/year)
Cadmium	25
Arsenic	6
Benzene	500
Formaldehyde	1,810
Chromium, hexavalent	<1
1,3-Butadiene	20
Methylene chloride {Dichloromethane}	2,512
Nickel	7
Acetaldehyde	604
Naphthalene	15

*Listed in rank order based on mass times cancer potency.

Fuel Use

The energy required for the various processes described earlier is supplied from fuel combustion, steam, and electricity. The majority of GHG emissions associated with these facilities are the result of combustion processes. This on-site fuel combustion is used primarily to provide steam and to produce on-site electricity.

Table I-8 shows the total energy use in the oil and gas/mineral production at these facilites in 2009 by fuel type. As shown in the table, 95 percent of the energy usage is from natural gas or coal along with purchased steam, diesel, and kerosene. The oil and gas production facilities primarily use natural gas. This energy is largely obtained from onsite energy sources. Coal is the primary energy source at the mineral plant. The coal is used to produce both electricity and steam. Additional electricity and steam are purchased. The remaining 5 percent of energy use is electricity.

Table I-8: 2009 Energy Used by Oil and Gas Production and Mineral Processing by Fuel Type

Fuel Type	Energy Consumed (MMBtu)	Percent Total Energy Consumed
Natural Gas/Coal/Other*	107,590,000	95
Electricity	5,881,000	5
Total	113,471,000	100

* Other: Includes purchased steam, diesel, and kerosene.

I.3 Regulatory Requirements

Oil and gas production and mineral processing facilities in California subject to the EEA Regulation are also subject to a variety of State, local, and federal air pollution control regulations and emissions reduction programs. These regulations and programs are mainly designed to reduce criteria and toxic air emissions.

All six of the facilities discussed in this report are subject to ARB's Mandatory Reporting Regulation (MRR), Cap-and-Trade (C&T) Regulation, and Cost of Implementation Fee Regulation. In addition, California's air quality management and air pollution control districts develop, implement, and enforce specific criteria and toxic pollutant regulations and programs at the local level. The U.S. EPA develops criteria and toxic pollutant regulations and programs at the federal level. Below is a brief summary of the ARB's MMR, C&T, and Cost of Implementation Fee regulations. Also provided is a table of local air district regulations for the districts in which the reporting facilities are located as well as a list of federal regulations. The discussion below focuses on some of the key air-related regulations and program impacting these facilities. However, it is not a complete listing of all of the state, local, and federal air regulations or programs that these facilities are required to meet.

California GHG Regulations

Mandatory Reporting of GHG Emissions Regulation (title 17, CCR, sections 95100 to 95158)

In January 2012, amendments to the Mandatory Reporting of GHG Emissions Regulation became effective. The 2012 amendments implemented minor but necessary revisions to the reporting regulation. In the revised regulation, onshore petroleum and natural gas production are identified as a source category that is subject to the regulation (subarticle 5). The revised regulation affects all petroleum and natural gas production facilities in California where GHG emissions from their stationary combustion and process emission sources equal or exceed 10,000 MTCO2e annually or GHG emissions from their stationary combustion, process, fugitive and vented emissions equal or exceed 25,000 MTCO2e annually. These amendments clarified the GHG emissions to be reported. The Mandatory Reporting Regulation was amended in 2013 to further support benchmarking, allocation of allowances, and the covered emissions calculation under the Cap-and-Trade Regulation, as well as to ensure that reported GHG emissions data is accurate and complete in order to support California's other climate and GHG reduction programs. These amendments became effective January 1, 2014. For more information about the Mandatory Reporting of GHG Emissions Regulation, please go to http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm

Cap-and-Trade Regulation (title 17, CCR, sections 95801 to 96022)

Cap-and-Trade is one of the strategies California will use to reduce GHG emissions. The program will help California meet its goal of reducing GHG emissions to 1990 levels by 2020. Under Cap-and-Trade, an overall limit on GHG emissions from capped sectors has been established by the Cap-and-Trade Program and facilities subject to the cap will be able to trade compliance instruments (allowances and offsets). Oil and gas production and mineral production facilities are subject to the Cap-and-Trade Regulation and will have to either reduce on-site GHG emissions or obtain GHG compliance instruments equal to their compliance obligation. For more information about the Cap-and-Trade Program, please go to http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm

Cost of Implementation Fee Regulation (title 17, CCR, sections 95200 to 95207)

The AB 32 Cost of Implementation Fee Regulation was finalized on June 17, 2010 and became effective on July 17, 2010. Amendments were adopted in 2011 and 2012 to better align it with the Mandatory Reporting Regulation and the Cap-and-Trade Regulation. AB 32 authorized ARB to adopt a schedule of fees to be paid by sources of GHG emissions. Money collected from these fees will be used to fund the State's costs of implementing AB 32. Entities subject to these fees include large natural gas distributors and large users of natural gas including refineries, suppliers and importers of gasoline and diesel fuel, electricity importers and in-state generating facilities, facilities that combust coal and petroleum coke, and cement manufacturers. There are approximately 300 facilities subject to this fee.

Fees are determined based on the annual budget for the program and the cost to repay start-up loans. The regulation is designed so that invoices are sent after the budget is approved ensuring that each year ARB collects only the amount authorized to run the program and repay the startup loans. The fees are based on a uniform cost for each metric ton of carbon dioxide subject to the regulation. This uniform cost is referred to as the Common Carbon Cost (CCC) and is calculated as the total amount of funding to be collected divided by the total number of emissions subject to the regulation. For more information about the Cost of Implementation Fee Regulation, please go to: http://www.arb.ca.gov/cc/adminfee/adminfee.htm.

Districts Criteria and Toxic Pollutant Regulations and Programs

Tables I-9 and I-10 below lists the key district criteria regulations affecting oil and gas production and mineral processing plants. In addition, these facilities are subject to district permitting regulations and air toxics reporting programs.

Table I-9: District-Specific Rules Affecting Oil and Gas Production

District	Local Rules	Subject	Rule
San Joaquin Valley APCD	Regulation I	General Provisions	
	Regulation IV	Prohibitions	
	R4304		Equipment Tuning Procedures For Boilers, Steam Generators, and Process Heaters
	R4305		Boilers, Steam Generators, and Process Heaters - Phase 2
	R4306		Boilers, Steam Generators, and Process Heaters - Phase 3
	R4307		Boilers, Steam Generators, and Process Heaters - 2.0 MMBtu/hr to 5.0 MMBtu/hr
	R4308		Boilers, Steam Generators, and Process Heaters - 0.075 MMBtu/hr to 2.0 MMBtu/hr
	R4311		Flares
	R4320		Advanced Emission Reduction Options For Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr
	R4351		Boilers, Steam Generators, and Process Heaters - Phase 1
	R4401		Steam-Enhanced Crude Oil Production Wells
	R4402		Crude Oil Production Sumps
	R4403		Components Serving Light Crude Oil or Gases at Light Crude Oil and Gas Production Facilities and Components of Natural Gas Processing Facilities
	R4404		Heavy Oil Test Station - Kern County
	R4405		NO_x Emissions From Existing Steam Generators Used In Thermally Enhanced Oil Recovery - Central/Western Kern County Fields
	R4406		Sulfur Compounds From oilfield Steam Generators - Kern County
	R4407		In-situ Combustion Well Vents
	R4409		Components at Light crude Oil Production Facilities, Natural Gas Production Facilities, and Natural Gas Processing Facilities
	Regulation VIII	Fugitive PM10 Prohibitions	

Table I-10 District-Specific Rules Affecting Mineral Processing Plants

District	Local Rules	Subject	Rule
Mojave Desert AQMD	Regulation I	General Provisions	
	Regulation II	Permits	
	Regulation IV	Prohibitions	401 Visible emissions 402 Nuisance 403 Fugitive Dust 403.1 Fugitive Dust Control for the Searles Valley Planning Area 404 Particulate Matter – Concentration 405 Solid Particulate Matter – Weight 406 Specific Contaminants 407 Liquid and Gaseous Contaminants 409 Combustion Contaminants 431 Sulfur Content of Fuels 474 Fuel Burning Equipment 476 Steam Generating Equipment 480 Natural Gas Fired Control Devices
	Regulation XI	Source Specific Standards	1159 Stationary Gas Turbines
	Regulation XII	Federal Operating Permits	
	Regulation XIII	New Source Review	
	Regulation XIV	Emission Reduction Credit Banking	
	Regulation XV	Emission Standards for Specific Toxic Air Contaminants	1520 Control of Toxic Air Contaminants From Existing Sources

<u>Federal Regulations</u>

The following section provides a list of federal regulations for oil and gas and mineral processing.

Oil and Gas Production:

1) 40 Code of Federal Regulations (CFR) Part 60
   Oil and Natural Gas Sector: New Source Performance Standards

2) 40 CFR Part 63
   Oil and Natural Gas Sector: National Emission Standards for Hazardous Air Pollutants

3) 40 CFR Part 98
   Mandatory Greenhouse Gas Reporting

Mineral Processing:

1) 40 CFR Part 60, Subpart OOO-Standards of Performance for Nonmetallic Mineral Processing Plants, Subpart D-Standards of Performance for Fossil-Fuel-Fired Steam Generators, Subpart Db-Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, Subpart GG-Standards of Performance for Stationary Gas Turbines

2) 40 CFR Part 63 for Mineral Processing, Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

3) 40 CFR Part 98
   Mandatory Greenhouse Gas Reporting

4) 40 CFR Part 268
   Hazardous Waste Recycling: Land Disposal Restrictions

5) 40 CFR Part 148
   Hazardous Waste Injection Restrictions

I.4 Energy Efficiency Improvement Opportunities

The information provided in Tables I-11 through I-17 was compiled by staff using information provided in the EEA Reports prepared by the managers of the five oil and gas production facilities and one mineral production facility subject to the EEA Regulation. All projects that were identified as Completed/Ongoing, Scheduled, or Under Investigation are included in the tables. Projects that were identified as Not Implementing were not included. Each table covers a broad category of equipment or processes identified by the table title and referred to as “Equipment Category.” Table I-10 lists the “Equipment Category” for Tables I-11 through I-17 along with a brief description of the types of projects in each specific category.

As noted in Section I.5, discussed later in the report, over 90 percent of the projects identified in this section have already occurred or will occur over the next few years. Additionally, approximately 24 percent of all reductions occurred prior to 2010.

Table I-10: Listing of Equipment Categories and Project Descriptions of Types of Projects

Table Number	Equipment Category	Description of the Types of Projects
Table I -11	Boilers	Projects associated with cogeneration, steam, and combined cycle plants.
Table I -12	Thermal Equipment	Projects dealing with direct combustion thermal equipment such as flares and heaters/treaters.
Table I -13	Chemical	Projects dealing with chemical processing plants.
Table I -14	Stationary Combustion Engines	Projects dealing with stationary reciprocating engines.
Table I -16	Electric	Projects dealing with drives, pumps, motors, and compressors.
Table I -17	Other	Projects dealing with piping and storage tanks.

Within each of the Tables I-11 through I-17, the projects are assigned to an “Efficiency Improvement Method” group (column 1). The Efficiency Improvement Method is the approach, action or mechanism that would result in energy efficiency improvements, and are as follows:

- Same but more efficient technologies
- Investment in new technologies
- Improvement in process control
- Improvement in energy management and monitoring
- Changes in maintenance practices
- Changes in management systems
- Research and development
- Changes in staff operation
- Energy measurement and monitoring

The information associated with each “Efficiency Improvement Method” represents numerous potential projects. A more detailed description of the types of projects associated with the “Efficiency Improvement Method” is provided in Tables I-11 through I-17 under the column entitled “Project Description.” The emissions and cost data provided are a summation of the data provided for all the projects under the specific “Efficiency Improvement Method” grouping. The estimated GHG emission reductions associated with the projects, capital costs, annual costs, and annual savings estimated by the facilities are also provided. These estimated benefits were usually based on the fuel savings realized. Where projects have been grouped, the reported values are a summation of all the projects represented by the listing. In addition, estimates of the NO_x and PM co-benefits are provided. These estimates provide a general idea of what co-benefits might be achieved by implementing the reported projects. The information is arranged so as to provide the maximum transparency of the information reported and at the same time protect the confidential business information the facilities provided.

The information provided in Tables I-11 through I-17 is preliminary and not based on detailed engineering and economic analyses for all the projects.

Boiler Projects

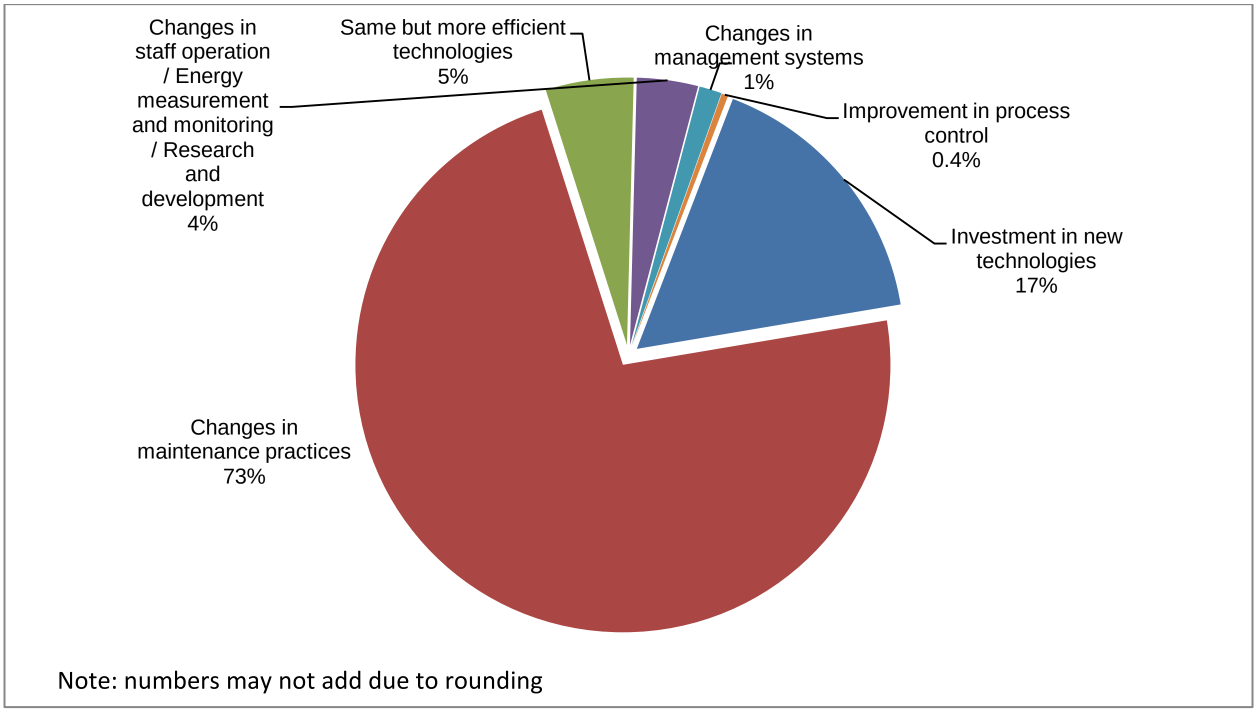
Table I-11 provides information on energy efficiency improvement projects related to boilers at Oil and Gas/Mineral facilities. A total of 45 boiler-related projects were identified by this sector. The total potential GHG emission reductions for these projects – provided in the third column of the table – are about 1.2 $MMTCO_2e$. The total potential NOx and PM reductions associated with these projects would be 0.63 tons per day and 0.11 tons per year, respectively. Total one-time capital costs, associated annual costs, and associated annual savings are also presented in this table. The total potential one-time costs for all of these projects are $250 million and annual costs estimated at about $5 million. These projects would also result in an annual saving of approximately $90 million.

Table I-11: Boiler Projects - Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year)	One Time Cost ($)	Annual Cost ($/year)	Annual Savings ($/year)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Investment in new technologies	Replacing steam generators with new, more efficient steam generators; Installing new cogeneration units.	197,494	139,995,000	2,870,000	25,796,000	0.478	0.025
Changes in maintenance practices	Installing insulation on steam lines and removing scale buildup.	870,760	13,786,000	1,813,000	51,625,000	0.104	0.063
Same but more efficient technologies	Retrofitting steam generators; Restoring cogeneration units.	63,546	85,559,000	-	6,203,000	0.038	0.015
Changes in staff operation / Energy measurement and monitoring / Research and development	Removing steam lines no longer in use; Shutting down cogeneration units not in use; Assessing viability of alternative energy sources.	44,070	304,000	-	4,163,000	0.005	0.003
Changes in management systems	Installing monitoring systems.	16,163	7,927,000	298,000	1,506,000	0.004	0.002
Improvement in process control	Reducing oxygen to burners and re-routing feedwater.	4,729	2,600,000	-	442,000	0.003	0.001
Total		1,196,761	250,171,000	4,981,000	89,735,000	0.63	0.11

The greatest potential GHG reductions from boiler-related projects would come from changes in maintenance practices and investment in new technologies. Maintenance practices are projects designed to improve boiler efficiency including installing insulation and removing scale build up in steam lines. Investments in new technologies include replacing steam generation and cogeneration units, new more efficient steam generators, and cogeneration units. Figure I-3 shows the distribution of potential GHG emission reductions by efficiency improvement method.

Figure I-3: Boiler Projects – Distribution of Potential GHG Reductions by Efficiency Improvement Method



Thermal Equipment, Chemical Processes, and Stationary Combustion Engine Projects

Tables I-12 through I-14 provide information on potential energy efficiency improvement projects related to thermal equipment, chemical processes, and stationary combustion engines at Oil and Gas/Mineral facilities. There are 12 projects identified for this sector in these categories. Table I-15 provides the total costs and benefits for these three categories. ARB staff aggregated the projects in these three categories in order to protect confidential business information. The total potential GHG emission reductions for these projects - provided in the third column of the table - are about 196,000 $MTCO_2e$. The total potential NOx and PM reductions associated with these projects would be 0.44 tons per day and 0.07 tons per day, respectively. Totals for one-time capital costs, associated annual costs, and associated annual savings are also presented in this table. The total potential one-time costs for all of these projects are $58 million with annual costs estimated at about $238,000. These projects would also result in an annual saving of approximately $17 million.

Table I-12: Thermal Equipment Projects - Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year CO2e)	One-Time Costs ($)	Annual Costs ($/year)	Annual Savings ($/year)	Potential NO_x Reduction (tons/day)	Potential PM Reduction (tons/day)
Changes in management systems	Design changes that allow decommissioning of heater/treaters.	39,300	$46,215,000	$0	$4,264,000	0.04	0.016
Investment in new technologies	Flare upgrades.	CBI	CBI	CBI	CBI	CBI	CBI

CBI - Confidential Business Information pursuant to CCR § 95610

Table I-13: Chemical Projects - Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year CO2e)	One-Time Costs ($)	Annual Costs ($/year)	Annual Savings ($/year)	Potential NO_x Reduction (tons/day)	Potential PM Reduction (tons/day)
Research and development	Pilot test using alternative technology	CBI	CBI	CBI	CBI	CBI	CBI

CBI - Confidential Business Information pursuant to CCR § 95610

Table I-14: Stationary Combustion Engines Projects - Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year)	One Time Cost ($)	Annual Cost ($/year)	Annual Savings ($/year)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Investment in new technologies	Replace with electric	CBI	CBI	CBI	CBI	CBI	CBI
Improvement in process control / Same but more efficient technologies	Upgrade engines /Consolidate equipment	9,120	823,000	0	875,000	0.008	0.003

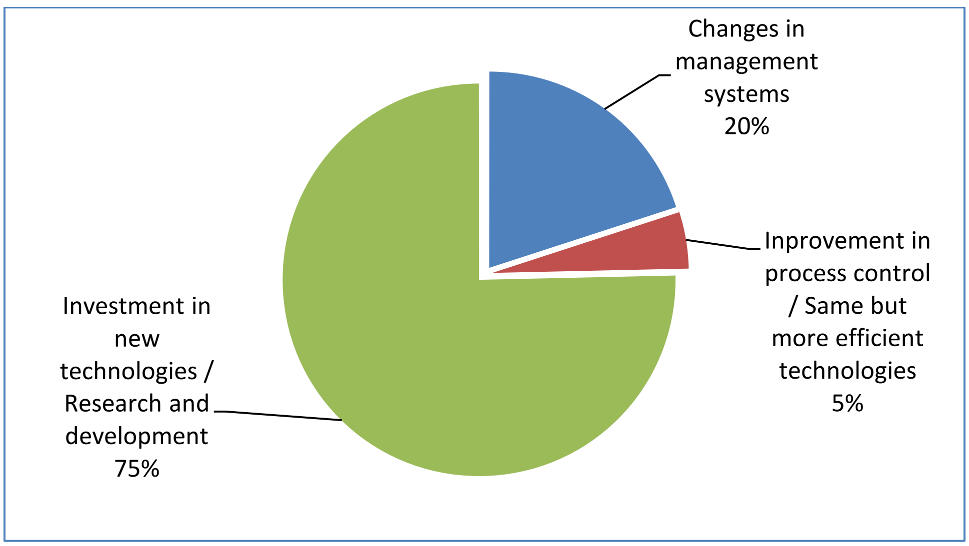
CBI - Confidential Business Information pursuant to CCR § 95610

Table I-15: Aggregated Totals for Thermal, Chemical, and Stationary Combustion Engine Projects

TOTAL	Potential GHG Reductions (metric tons/year CO2e)	One-Time Costs ($)	Annual Costs ($/year)	Annual Savings ($/year)	Potential NO_x Reduction (tons/day)	Potential PM Reduction (tons/day)
	196,461	58,194,000	238,000	17,402,000	0.443	0.074

The greatest potential GHG reductions from thermal equipment, chemical projects, and stationary combustion engines at Oil and Gas/Mineral facilities would come from investment in new technologies for stationary combustion engines. These projects primarily dealt with replacement with electric. Figure I-4 shows the distribution of potential GHG reductions by efficiency improvement method for all three categories of thermal equipment, chemical projects, and stationary combustion engines projects.

Figure I-4: Thermal Equipment, Chemical Projects, and Stationary Combustion Engines Projects – Distribution of Potential GHG Reductions by Efficiency Improvement Method



*Projects were grouped together to protect confidential business information per CCR § 95610.

Electric Projects

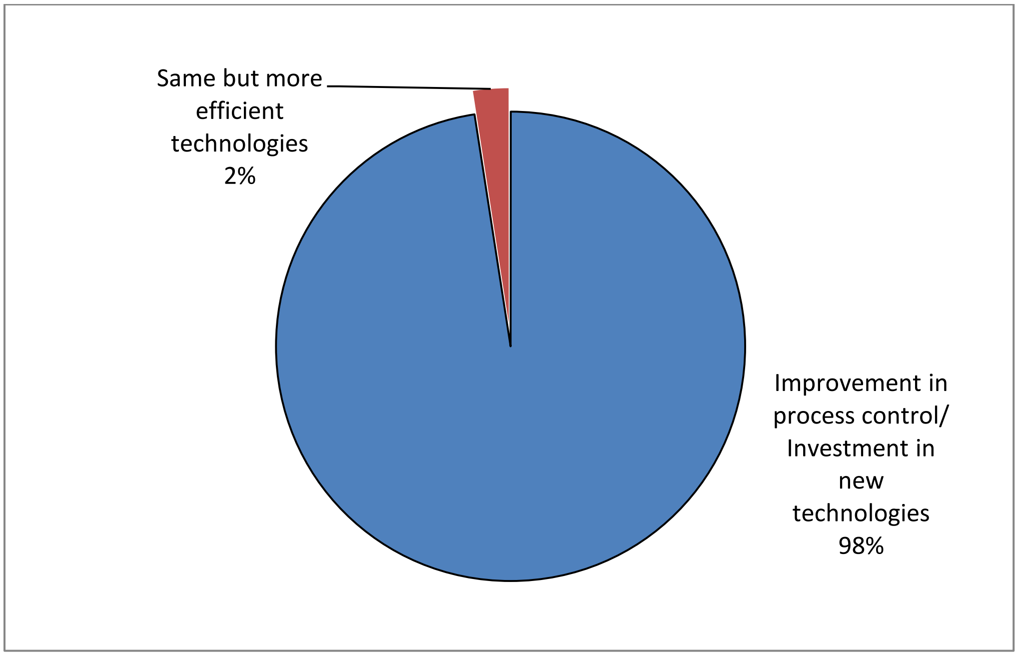
Table I-16 provides information on potential energy efficiency improvement projects related to electric equipment at Oil and Gas/Mineral facilities. There are 69 projects identified by facility managers for this category. The total potential GHG emission reductions for these projects - provided in the third column of the table - are about 195,000 $MTCO_2e$. The total potential NOx and PM reductions associated with these projects would be approximately 1.2 tons per day for NOx and 0.3 tons per day for PM. The total potential one-time costs for all of these projects are approximately $149 million with annual costs estimated at about $13 million. These projects would also result in an annual saving of approximately $18 million.

Table I-16: Electric Projects - Estimated Emission Reductions and Costs

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year)	One Time Cost ($)	Annual Cost ($/year)	Annual Savings ($/year)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Improvement in process control/ Investment in new technologies	Installing variable system drives, variable frequency drives, pump controllers; Selectively shutting off production areas and re-route gas through system; Installing higher efficiency pumps; Install high efficiency electric compressors.	190,558	140,428,000	12,905,000	16,885,000	1.15	0.31
Same but more efficient technologies	Retrofitting pumps and motors	4,794	8,097,000	11,700	1,263,000	0.0046	0.0006
Total		195,352	148,525,000	12,917,000	18,148,000	1.15	0.31

The greatest potential GHG reductions from electric equipment projects at Oil and Gas/Mineral facilities would come from improvements in process control and investment in new technologies. These improvements include installing variable system drives, variable frequency drives, pump controllers, selectively shutting off production areas and re-routing, and installing higher efficiency pumps and compressors. Figure I-5 shows the distribution of GHG benefits for the different energy efficiency improvement methods.

Figure I-5: Electrical Equipment Projects – Distribution of Potential GHG Reductions by Efficiency Improvement Method



Other Equipment Types Projects

Table I-17 provides information on potential energy efficiency improvement projects related to other equipment types at Oil and Gas/Mineral facilities. This equipment category includes piping and storage tanks. There are 3 projects identified for this category. The total potential GHG emission reductions for these projects - provided in the third column of the table - are about 4,000 $MTCO_2e$. The total potential NOx and PM reductions associated with these projects would be 0.015 tons per day for NOx and 0.0034 tons per day PM. The total potential one-time costs for all of these projects are about $50 million with annual costs estimated at $44,000. These projects would also result in an annual saving of approximately $4 million.

Table I-17: Other Equipment Type Projects

Efficiency Improvement Method	Project Description	Potential GHG Reductions (metric tons/year CO2e)	One-Time Costs ($)	Annual Costs ($/year)	Annual Savings ($/year)	Potential NO_x Reduction (tons/day)	Potential PM Reduction (tons/day)
Same but more efficient technologies / Investment in new technologies	Piping and CO2 recovery systems; water pipeline replacement	3,970	$49,746,000	$43,600	$3,836,000	0.015	0.0034

The energy efficiency improvement method identified for this equipment category was using the same but more efficient technologies and investment in new technologies. These projects include upgrading piping and storage tanks.

Summary

Table I-18 summarizes, by “Equipment Category,” the number of projects and the estimated GHG, NOx, and PM emission reductions associated with the energy efficiency improvement projects identified in the EEA Reports. The estimated GHG emission reductions are approximately 1.6 MMTCO2e annually.

Table I-18: GHG and Criteria Pollutants Emission Reductions from Potential Energy Efficiency Improvement Projects*

Equipment Category	Number of Projects	GHG ($MMTCO_2e$)	NOx (tons per day)	PM (tons per day)
A. Boiler	45	1.20	0.63	0.11
B. Thermal Equipment / Chemical / Stationary Combustion Engines	12	0.20	0.44	0.074
C. Electric	69	0.20	1.15	0.31
D. Other Equipment	3	0.004	0.015	0.003
Total	**129**	**1.59**	**2.24**	**0.50**

*Includes all reported projects except those identified as Not Implementing.

Figure 1-6 shows pictorially the relative contribution of each equipment category to the total GHG reductions. As shown in the figure, the equipment category with the greatest potential GHG emission reduction is “Boiler.”

Figure I-6 Potential Statewide Oil and Gas Production/Mineral Processing GHG Emissions Reductions by Equipment Category

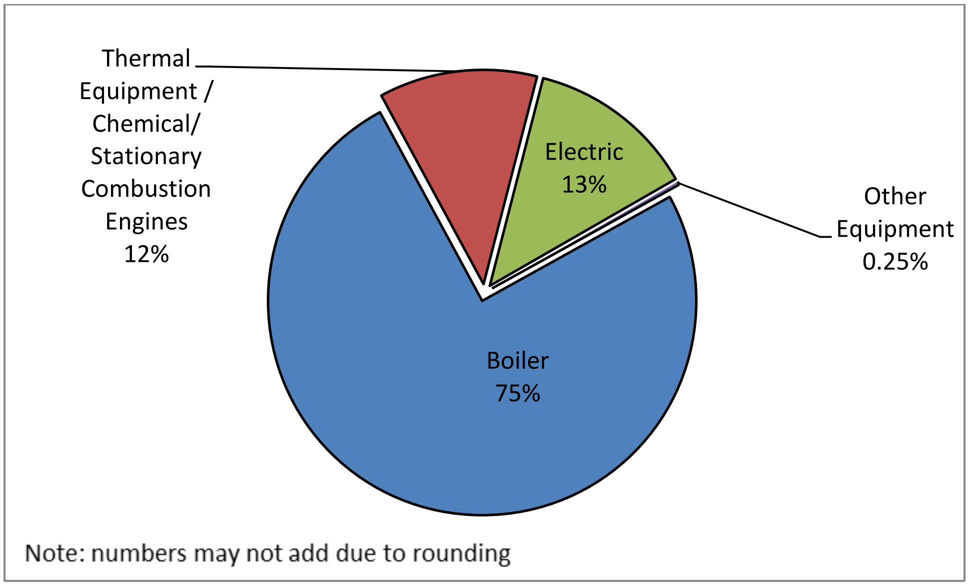


Table I-19 provides a summary of the estimated total one-time capital costs, annual costs, and annual savings for the 129 potential energy efficiency improvement projects identified in the Oil and Gas/Mineral Sectors EEA Reports. The total potential one-time costs for all of these projects (except for those identified as "Not Implementing") are just over $500 million with annual costs of about $18 million. These projects would also result in an annual saving of about $130 million. These estimates are preliminary. They are not based on detailed engineering and cost analysis that would be required to accurately estimate emission reductions, costs, and timing of the projects.

Table I-19: Summary of Estimated Costs and Savings for Energy Efficiency Improvement Projects*

Number of Projects	One Time Cost (million $)	Annual Cost (million $/year)	Annual Savings (million $/year)
129	507	18	129

*Includes all projects identified as Completed/Ongoing, Scheduled, or Under Investigation. Does not include projects identified as "Not Implementing"

I.5 Implementation Status of Energy Efficiency Improvement Opportunities

Many of the projects identified in Section I-4 have already occurred or will occur over the next few years. Oil and Gas Production/Mineral Processing facilities subject to the EEA Regulation identified 149 energy efficiency improvement projects and assigned these projects to one of four categories:

- Completed/Ongoing
- Scheduled
- Under Investigation or
- Not Implementing

Only 20 of the approximately 149 projects were identified as not being implemented. Table I-20 shows the estimated GHG, NO_x, and PM emission reductions associated with the energy efficiency improvement projects identified in the EEA Reports by project status—completed, ongoing, scheduled, or under investigation. The reductions associated with the Completed/Ongoing projects were divided into two subcategories based on if the projects were completed before 2010 or during/after 2010. This was done to avoid double counting of GHG emission reductions since reductions occurring before 2010 should already be reflected in the 2009 GHG Mandatory Reporting.

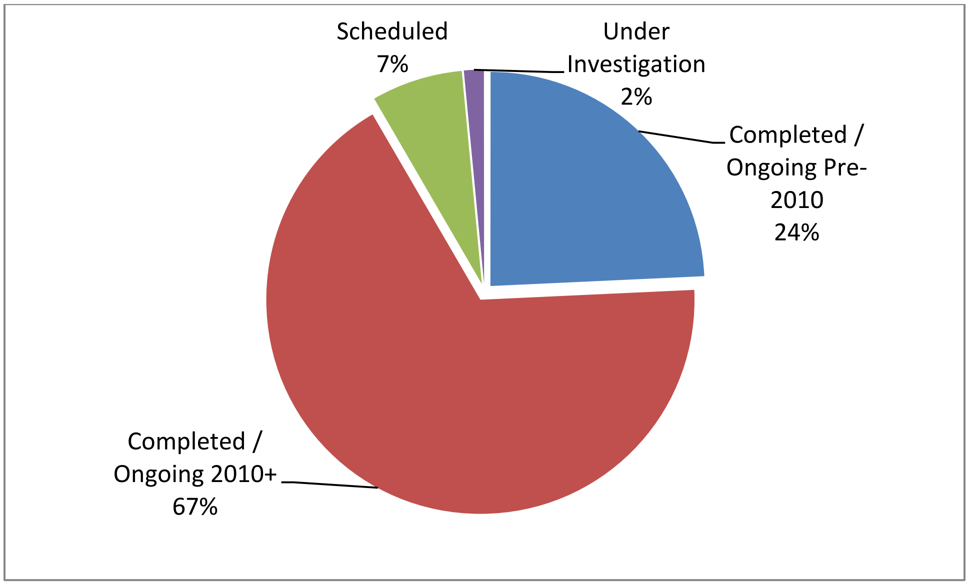
Table I-20: Estimated GHG, NO_x, and PM Emission Reductions by Project Status

Project Status	**GHG Reductions** MMTCO2e /year (% of total)	**NOx Reductions** (tons/day) (% of total)	**PM Reductions** (tons/day) (% of total)
Completed/Ongoing Pre-2010	0.39 (27%)	1.72 (79%)	0.31 (69%)
Completed/Ongoing 2010+	1.07 (73%)	0.45 (21%)	0.14 (31%)
Completed/Ongoing Total	1.46 (92%)	2.17 (97%)	0.45 (91%)
Scheduled	0.11 (7%)	0.06 (3%)	0.04 (7%)
Under Investigation	0.02 (1%)	0.01 (1%)	0.01 (2%)
Subtotal Pre-2010	0.39 (24%)	1.72 (77%)	0.31 (62%)
Subtotal 2010+	1.21 (76%)	0.53 (23%)	0.19 (38%)
Total	1.59	2.24	0.50

Two things of note in Table I-20 are that over 90 percent of the estimated GHG reductions come from Completed/Ongoing projects and that about 24 percent of all estimated GHG reductions occurred before 2010. This is shown pictorially in Figure I-7. Similarly, over 90 percent of the identified NO_x and PM emission reductions are associated with projects that are either completed or ongoing, however, 60 to

80 percent of the identified PM and NOx emission reductions are thought to be reflected in the reported 2009 emissions inventories. Approximately 20 to 40 percent of the identified NOx and PM reductions will further reduce the emissions reported for 2009, if completed.

Figure I-7. Estimated GHG Reduction by Project Status



It should be noted, that the estimated reductions assume that all of the energy efficiency improvement projects identified in the EEA Reports will be implemented, except for those identified as "Not Implementing." This assumption is accurate for projects that were reported as Completed/Ongoing, which make up over 90 percent of the estimated GHG, NO_x, and PM reductions. However, implementation of some projects reported as Scheduled or Under Investigation may preclude the implementation of other projects that deal with the same equipment or processes. Therefore, these estimated reductions do not necessarily represent readily achievable on-site emission reductions. As stated in the Introduction and Summary, ARB staff will be developing a subsequent report that will include all sectors. We intend to release this subsequent report once we have completed our review and analysis of the information provided in the EEA Reports, the reports from the third party reviewer, and other applicable information. We anticipate releasing this subsequent report in 2014

References:

(CARB, 2013) California Air Resources Board. 2007 Oil and Gas Industry Survey Results, Final Report (Revised), October 2013.

(DOGGR, 2010) California Department of Conservation Division of Oil, Gas, and Geothermal Resources. 2009 Annual Report of the State Oil and Gas Supervisor. 2010.

(OEHHA, 2009) Technical Support Document for Cancer Potency Factors: Methodologies for derivation, listing of available values and adjustments to allow for early life stage exposures, California Environmental Protection Agency Office of Environmental Health Hazard Assessment Air Toxicology and Epidemiology Branch, May 2009.

Part II – Facility Specific Information for Oil and Gas Production/Mineral Processing

II.0 Introduction

Part II of this report provides specific information about each of the five oil and gas facilities and the one mineral facility submitting EEA Reports. Each facility has a separate section that provides information on the 2009 emissions for GHG, criteria pollutants, and TACs from the specific facility and a summary of the potential energy efficiency improvement projects that facility staff identified in their EEA Report. The projects are grouped by timing (Completed/Ongoing, Scheduled, or Under Investigation). The projects are then listed by Equipment Category and Equipment Sub-type. All information provided, including inventory data as well as identified project costs and benefits, is as reported by the facilities in their EEA Reports. Inventory data may not agree with other published data due to the inclusion of more recent data provided by the facility.

Equipment Sub-type provides a general description of the types of equipment affected by the improvement project but does not provide a detailed explanation of each of the 149 projects identified or facility-specific variations from the general description. Information about cost and potential emission reductions of GHG and criteria pollutants, summed for all the projects (by Equipment Category and Equipment Sub-type), is provided. In compliance with the confidentiality requirement under CCR § 95610, the specific details about the individual projects were not presented. While it is not possible to release the specific details for each project a facility has identified, it is possible to get a good indication of what equipment, what action(s), and timeframe were considered by referring back to the sector-wide project information in Part I and specifically Tables I-10 through I-17.

II.1 Aera Belridge

General Information

The Aera Belridge facility is located northwest of Bakersfield in Kern County and covers an area of approximately 55 square miles. Aera Belridge produces approximately 85,000 barrels of crude oil per day. The heavy oil is produced from the Tulare formation and light oil from the Diatomite formation.

Emissions

The Aera Belridge facility emitted approximately 1.6 $MMTCO_2e$ in 2009. The majority of emissions from this facility can be attributed to steam generators and cogeneration units. Table II-1 provides the 2009 GHG emissions reported by Aera Belridge in compliance with ARB's GHG Mandatory Reporting Regulation.

Table II-1: Aera Belridge 2009 GHG Emissions

Pollutant	2009 Annual Emissions ($MMTCO_2e$)
GHG	1.57

The 2009 criteria pollutant emission totals for this facility are listed in table II-2.

Table II-2: Aera Belridge 2009 Criteria Pollutant Emissions

Criteria Pollutant Type	2009 Annual Emissions (tons/year)
Reactive Organic Gasses (ROG)	53
Carbon Monoxide (CO)	157
Oxides of Nitrogen (NOx)	172
Oxides of Sulfur (SOx)	7.5
Particulate Matter (PM_{10})	40.7

Table II-3 lists the top ten TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-3: Aera Belridge 2009 Top Ten Prioritized Toxic Air Contaminant Emissions

Toxic Pollutant Type	2009 Annual Emissions (lbs/year)
PAHs (total)	10
Benzene	241
Formaldehyde	801
Naphthalene	115
Ethyl benzene	523
Diesel PM	3
Acetaldehyde	256
Acrolein	103
Toluene	884
Hexane	9,742

* Listed in rank order based on mass times cancer potency

Energy Efficiency Improvement Options

Tables II-4 itemizes the projects that were identified for the Aera Belridge facility. These projects are categorized by equipment type and by project status – Completed/Ongoing or Under Investigation. Table II-5 lists projects that the facility is not implementing. The emissions and cost information are reported in Table II-4 as the sum for all the projects within each equipment category. In compliance with the confidentiality requirement under CCR § 95610, a detailed explanation of how the specific project improves energy efficiency is not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-10 through I-17 in Part I of this report. Additionally, categories that contain fewer than three projects are designated as "CBI" in compliance with CCR § 95610. These projects are included in the total list of projects provided in the previous section.

The Aera Belridge reported that it has identified four projects as Completed/Ongoing. These projects are estimated to reduce GHG emissions by about 40,000 metric tons annually. In addition, these Completed/Ongoing projects are estimated to reduce both NO_x and PM by approximately 0.019 tpd and 0.008 tpd, respectively. These Completed/Ongoing projects are estimated to cost $2.7 million in one-time costs, with additional $1.4 million in annual costs. Aera Belridge has estimated that these projects will save $3.8 million annually.

The Aera Belridge also identified three projects as Under Investigation. The Under Investigation projects could potentially further reduce GHG emissions by 12,700 metric tons annually and NO_x and PM by 0.006 tpd and 0.002 tpd, respectively. These projects are estimated to cost approximately $392,000 in one-time costs, with additional $392,000 in annual costs. The facility estimated that these projects will save approximately $1.2 million annually.

Table II-4: Aera Belridge Energy Efficiency Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Boilers	Boiler for steam	4	39,800	2,669,000	1,421,000	3,755,000	0.019	0.008
Under Investigation	Boilers	Boiler for steam / Boiler for cogeneration	3	12,700	392,000	392,000	1,200,000	0.006	0.002
		Total	7	52,500	3,060,000	1,813,000	4,955,000	0.025	0.010

The Aera Belridge also identified 13 projects as not being implemented due to not being cost effective. These projects are listed in Table II-5. The Equipment Category, Equipment sub-type, number of projects, and a brief description of the reason the projects were not being implemented are listed in Table II-5.

Table II-5: Aera Belridge Energy Efficiency Options Reported as Not Being Implemented

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Reason Why Project Not Being Implemented
Not Being Implemented	Boilers	Boiler for steam / Boiler for cogeneration	7	Not cost effective
	Stationary Combustion Engines	Stationary reciprocating - other	1	Not cost effective
	Electric	Electric motors - pumps and fans / Other	5	Not cost effective

II.2 Aera Moco

General Information

The Aera Energy LLC, MOCO facility (Aera MOCO) is located outside of Bakersfield in Kern County. The Aera MOCO facility produced approximately 3 million barrels of crude oil in 2009.

Emissions

Table II-6 provides the 2009 GHG emissions reported by Aero MOCO in compliance with ARB's GHG Mandatory Reporting Regulation.

Table II-6: Aera MOCO 2009 GHG Emissions

Pollutant	2009 Annual Emissions ($MMTCO_2e$)
GHG	0.51

The 2009 criteria pollutant emissions for this facility are listed in Table II-7.

Table II-7: Aera MOCO 2009 Criteria Pollutant Emissions

Criteria Pollutant Type	2009 Annual Emissions (tons/year)
Reactive Organic Gasses (ROG)	15
Carbon Monoxide (CO)	1
Oxides of Nitrogen (NOx)	65
Oxides of Sulfur (SOx)	1
Particulate Matter (PM_{10})	9

Table II-8 lists the top ten TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-8: Aera MOCO 2009 Top Ten Prioritized Toxic Air Contaminant Emissions

Toxic Pollutant Type	2009 Annual Emissions (lbs/year)
Benzene	49
Formaldehyde	105
Ethyl benzene	58
Naphthalene	3
Acetaldehyde	26
Acrolein	23
Toluene	225
Hexane	39
Propylene	4,509
Xylenes (mixed)	168

* Listed in rank order based on mass times cancer potency

Energy Efficiency Improvement Options

Tables II-9 itemizes the projects that were identified for the Aera MOCO facility. These projects are categorized by equipment type and by project status – either Completed/Ongoing or Under Investigation. The emissions and cost information are reported as the sum for all the projects within each equipment category. In compliance with the confidentiality requirement under CCR § 95610, a detailed explanation of how the specific project improves energy efficiency is not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-10 through I-17 in Part I of this report. Additionally, categories that contain fewer than three projects are designated as "CBI" in compliance with CCR § 95610. These projects are included in the total list of projects provided in the previous section.

The Aera Moco reported that it has identified three projects as Completed/Ongoing. These projects are estimated to reduce GHG emissions by a total of 1,400 metric tons annually. In addition, these Completed/Ongoing projects are estimated to reduce both NO_x and PM by 0.0005 tons per day and 0.0003 tons per day, respectively. These Completed/Ongoing projects are estimated to cost $183,000 in one-time costs with no annual costs. Aera Moco has estimated that these projects will save $129,000 annually.

The Aera Moco facility also identified one project as Under Investigation. No specific costs or GHG benefit data are provided for this project listed as Under Investigation. The data could not be aggregated in such a way to protect confidential nature of the data. However, this project was included in the full list of possible projects in Tables I-10 through I-17 in Part I of this report.

Table II-9: Aera Moco Energy Efficiency Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Boilers	Boiler for steam	3	1,400	183,000	0	129,000	0.0005	0.0003
Under Investigation	Boilers	Boiler for steam	1	CBI	CBI	CBI	CBI	CBI	CBI

CBI - Confidential Business Information pursuant to CCR § 95610

The Aera Moco facility also identified 7 projects as not being implemented due to not being cost effective and having permitting barriers. These projects are listed in Table II-10. The Equipment Category, Equipment sub-type, number of projects, and a brief description of the reason the projects were not being implemented are listed in Table II-10.

Table II-10: Aera Moco Energy Efficiency Options Reported as Not Being Implemented

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Reason Why Project Not Being Implemented
Not Being Implemented	Boilers	Boiler for steam / Boiler for cogeneration	6	Not cost effective and/or permitting barriers
	Electric	Electric motors - pumps and fans	1	Not cost effective and/or permitting barriers

II.3 Chevron Kern River

General Information

The Chevron U.S.A., Kern River Asset facility is located in Kern County north of Bakersfield and is in the San Joaquin Valley Air Pollution Control District. The Chevron Kern River facility produces mostly heavy crude oil and natural gas through thermally enhanced oil wells.

Steam flood operations at this facility use both cyclic and steam drive production wells. Cyclic production wells cycle between steam injection and crude oil production. Steam drive production wells are not steamed directly but are influenced by dedicated steam injection wells in the vicinity.

Emissions

Chevron Kern River emitted 0.54 $MMTCO_2e$ in 2009. The majority of emissions can be attributed to steam generators and cogeneration units. The cogeneration unit supplies all the electricity needed onsite as well as exporting some to the local utility. Table II-11 provides the 2009 GHG emissions reported by Chevron Kern River in compliance with ARB's GHG Mandatory Reporting Regulation.

Table II-11: Chevron Kern River 2009 GHG Emissions

Pollutant	2009 Annual Emissions ($MMTCO_2e$)
GHG	0.54

The 2009 criteria pollutant emissions for this facility are listed in table II-12.

Table II-12: Chevron Kern River 2009 Criteria Pollutant Emissions

Criteria Pollutant Type	2009 Annual Emissions (tons/year)
Toxic Organic Gasses (TOG)	180
Carbon Monoxide (CO)	68
Oxides of Nitrogen (NOx)	89
Oxides of Sulfur (SOx)	31
Particulate Matter (PM_{10})	102

Table II-13 lists the top ten TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-13: Chevron Kern River 2009 Top Ten Prioritized Toxic Air Contaminant Emissions

Toxic Pollutant Type	2009 Emissions (lbs/year)
Diesel PM	1,994
Propylene oxide	1,152
Formaldehyde	703
Benzene	115
Ethylene dibromide {EDB}	<1
Ethylene dichloride {EDC}	<1
p-Dichlorobenzene	<1
Methanol	2,515
Phenanthrene	6
1,2,4,-Trimethylbenzene	1

* Listed in rank order based on mass times cancer potency

Energy Efficiency Improvement Options

Table II-14 itemizes the projects identified for the Chevron Kern River facility. These projects are categorized by equipment type and by project status - Completed/Ongoing or Under Investigation. The facility management did not identify any projects that it was not implementing. The emissions and cost information are reported as the sum for all the projects within each equipment category. In compliance with the confidentiality requirement under CCR § 95610, a detailed explanation of how the specific project improves energy efficiency is not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-10 through I-17 in Part I of this report. Additionally, categories that contain fewer than three projects are designated as “CBI” in compliance with CCR § 95610. These projects are included in the total list of projects provided in the previous section.

This facility’s management identified 43 projects as Completed/Ongoing and two projects as Under Investigation. The Completed/Ongoing projects are estimated to reduce GHG emissions by 641,000 metric tons annually. In addition, these projects are estimated to reduce NOx and PM by approximately 0.9 and 0.3 tons per day, respectively. These projects are estimated to cost approximately $102 million in one-time costs, with an additional $137,000 in annual costs. Chevron Kern River estimated that these projects will save approximately $32 million annually.

Chevron Kern River also identified two projects as Under Investigation. No specific costs or GHG benefit data provided for the two projects listed as Under Investigation. These data could not be aggregated in such a way to protect the confidential nature of the data. However, these projects were included in the full list of possible projects in Tables I-10 through I-17 in Part I of this report.

There were no projects identified as not being implemented.

Table II-14: Chevron Kern River Energy Efficiency Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Boilers	Boiler for steam / Boiler for cogeneration	10	587,280	18,246,000	137,000	24,910,000	0.025	0.021
	Electric / Other	Electric motors - pumps and fans / Other	33	53,818	83,373,000	-	7,170,000	0.87	0.27
Under Investigation	Boilers	Boiler for steam / Boiler for cogeneration	2	CBI	CBI	CBI	CBI	CBI	CBI
Total for Completed/Ongoing projects			43	641,109	101,619,000	137,000	32,080,000	0.90	0.29

CBI - Confidential Business Information pursuant to CCR § 95610

II.4 Chevron Midway Sunset/Cymric

General Information

The Chevron U.S.A., Midway Sunset/Cymric facility is located in the Temblor Thermal Area in the western portion of Kern County and is subject to the San Joaquin Valley Air Pollution Control District's oversight. The Midway Sunset/Cymric facility produces mostly heavy crude oil and natural gas through thermally enhanced oil wells. The natural gas produced with this crude is low quality. Some light crude oil is produced at this facility with higher quality natural gas. All of the natural gas produced is used onsite.

Steam flooding operations at this facility use both cyclic and steam drive production wells. Cyclic production wells cycle between steam injection and crude oil production. Steam drive production wells are not steamed directly but are influenced by dedicated steam injection wells in the vicinity.

Emissions

In 2009, Chevron Midway Sunset/Cymric emitted 1.83 $MMTCO_2e$. The majority of emissions from this facility can be attributed to steam generators or cogeneration units. Electricity produced from cogeneration units is used onsite, with some exported to the local utility. Table II-15 provides the 2009 GHG emissions reported by Midway Sunset/Cymric in compliance with ARB's GHG Mandatory Reporting Regulation.

Table II-15: Chevron Midway Sunset/Cymric 2009 GHG Emissions

Pollutant	2009 Annual Emissions ($MMTCO_2e$)
GHG	1.83

The 2009 criteria pollutant emissions for this facility are listed in Table II-16.

Table II-16: Chevron Midway Sunset/Cymric 2009 Criteria Pollutant Emissions

Criteria Pollutant Type	2009 Annual Emissions (tons/year)
Toxic Organic Gasses (TOG)	301
Carbon Monoxide (CO)	147
Oxides of Nitrogen (NOx)	495
Oxides of Sulfur (SOx)	562
Particulate Matter (PM_{10})	505

Table II-17 lists the top ten TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-17: Chevron Midway Sunset/Cymric 2009 Top Ten Prioritized Toxic Air Contaminant Emissions

Toxic Pollutant Type	2009 Emissions (lbs/year)
Diesel PM	245
Benzene	850
Naphthalene	123
Formaldehyde	423
PAHs (total)	<1
Acetaldehyde	189
Ethyl benzene	71
Chromium, hexavalent	<1
Propylene oxide	38.0
Arsenic	<1

* Listed in rank order based on mass times cancer potency

Energy Efficiency Improvement Options

Tables II-18 itemizes the projects identified for Chevron Midway Sunset/Cymric facility. These projects are categorized by equipment type and by project status - Completed/Ongoing or Scheduled. This facility's managers did not identify any projects as Under Investigation or Not Implementing. The emissions and cost information are reported as the sum for all the projects within each equipment category. In compliance with the confidentiality requirement under CCR § 95610, a detailed explanation of how the specific project improves energy efficiency is not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-10 through I-17 in Part I of this report. Additionally, categories that contain fewer than three projects are designated as "CBI" in compliance with CCR § 95610. These projects are included in the total list of projects provided in the previous section.

This facility's management identified 45 projects as Completed/Ongoing. These Completed/Ongoing projects are estimated to reduce GHG by 426,000 metric tons annually. In addition, these projects are estimated to reduce NOx and PM by approximately 0.2 and 0.08 tons per day, respectively. These projects are estimated to cost approximately $136 million in one-time costs, with an additional $228,000 in annual costs. Chevron Midway Sunset/Cymric estimated that these projects will save approximately $41 million annually.

Chevron Midway Sunset/Cymric also identified two projects as Scheduled. No specific costs or GHG benefit data are provided for the two projects listed as Scheduled. These projects could not be aggregated in such a way to protect the confidential nature of the data. However, these projects were included in the full list of possible projects in Tables I-10 through I-17 in Part I of this report.

There were no projects identified as not being implemented.

Table II-18: Chevron Midway Sunset/Cymric Energy Efficiency Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Boilers	Boiler for steam / Boiler for cogeneration	13	338,694	63,027,000	161,000	31,909,000	0.093	0.047
	Electric	Electric motors - pumps and fans / other	27	39,205	26,208,000	67,000	3,816,000	0.036	0.012
	Stationary Combustion Engines / Thermal Equipment	Stationary reciprocating - other / Other direct combustion thermal equipment	5	47,611	46,311,000	0	5,065,000	0.047	0.019
Scheduled	Boilers	Boiler for steam / boiler for cogeneration	2	CBI	CBI	CBI	CBI	CBI	CBI
Total for Completed/Ongoing projects			45	425,510	135,546,000	228,000	40,790,000	0.18	0.078

CBI - Confidential Business Information pursuant to CCR § 95610

II.5 Occidental of Elk Hills

General Information

Occidental of Elk Hills, Inc., (Occidental of Elk Hills) located outside of Bakersfield in Kern County, is subject to the San Joaquin Air Pollution Control District's oversight. In 2009, this facility produced approximately 13 million barrels of crude oil and 100 billion cubic feet of natural gas (DOGGR, 2010). Occidental of Elk Hills, Inc. produces light crude oil and high quality associated gas. The natural gas is processed through several gas plants before it is sold to the local utility.

Emissions

Table II-19 provides the 2009 GHG emissions reported by Occidental of Elk Hills in compliance with ARB's GHG Mandatory Reporting Regulation.

Table II-19: Occidental of Elk Hills 2009 GHG Emissions

Pollutant	2009 Annual Emissions ($MMTCO_2e$)
GHG	0.60

In addition, the facility reported the following emissions of criteria pollutants as shown in table II-20.

Table II-20: Occidental of Elk Hills 2009 Criteria Pollutant Emissions

Criteria Pollutant Type	2009 Annual Emissions (tons/year)
Reactive Organic Gasses (ROG)	503
Carbon Monoxide (CO)	1,362
Oxides of Nitrogen (NOx)	351
Oxides of Sulfur (SOx)	<1
Particulate Matter (PM_{10})	2

Table II-21 lists the TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-21: Occidental of Elk Hills 2009 Prioritized Toxic Air Contaminant Emissions

Toxic Pollutant Type	2009 Annual Emissions (lbs/year)
1,3-Butadiene	2,010
Formaldehyde	39,195
Benzene	1,500
Acetaldehyde	3,096
PAHs (total)	246
Acrolein	330
Toluene	1,482
Propylene	29,259
Xylenes (mixed)	3,236

* Listed in rank order based on mass times cancer potency

Energy Efficiency Improvement Options

Tables II-22 itemizes the projects that were identified for the Occidental of Elk Hills facility. These projects are categorized by equipment type and by project status – either completed/ongoing or scheduled. The emissions and cost information are reported as the sum for all the projects within each equipment category. In compliance with the confidentiality requirement under CCR § 95610, a detailed explanation of how the specific project improves energy efficiency is not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-10 through I-17 in Part I of this report. Additionally, categories that contain fewer than three projects are designated as "CBI" in compliance with CCR § 95610. These projects are included in the total list of projects provided in the previous section.

This facility's management has identified 18 energy-efficiency projects as Completed/Ongoing. These projects are estimated to reduce GHG emissions by 265,000 metric tons annually. In addition, these projects are estimated to reduce NOx and PM by approximately 0.9 and 0.07 tons per day, respectively. These Completed/Ongoing projects are estimated to cost $185 million in one-time costs, with additional $16 million in annual costs. The Occidental of Elk Hills facility has estimated that these projects will save $30 million annually.

The Occidental of Elk Hills facility has also identified two projects as Scheduled. No specific costs or GHG benefit data provided for these two projects listed as Scheduled. These two projects could not be aggregated in such a way to protect confidential nature of data. However, these projects were included in the full list of possible projects in Tables I-10 through I-17 in Part I of this report.

There were no projects identified as not being implemented.

Table II-22: Occidental of Elk Hills Energy Efficiency Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Boilers	Boiler for cogeneration	4	26,700	87,148,000	2,840,000	12,282,000	0.27	0.00
	Stationary Combustion Engines	Stationary reciprocating - other	4	132,300	8,906,000	238,000	10,727,000	0.36	0.04
	Electric / Thermal Equipment	Other direct combustion thermal equipment / Electric motors - pumps and fans / other / HVAC & refrig equipment	10	106,400	89,351,000	12,840,000	7,132,000	0.26	0.03
Scheduled	Boilers	Combined cycle plant	1	CBI	CBI	CBI	CBI	CBI	CBI
	Stationary Combustion Engines	Stationary reciprocating - other	1	CBI	CBI	CBI	CBI	CBI	CBI
Total for Completed/Ongoing projects			18	265,400	185,405,000	15, 916,000	30,141,000	0.89	0.07

CBI - Confidential Business Information pursuant to CCR § 95610

Reference:

(DOGGR, 2010) California Department of Conservation Division of Oil, Gas, and Geothermal Resources. 2009 Annual Report of the State Oil and Gas Supervisor. 2010.

II.6 Searles Valley Minerals

Information

The Searles Valley Minerals (SVM) facility, located in the California desert southwest of Death Valley, is subject to the Mojave Desert Air Quality Management District's oversight. The facility started production in 1873 with a few tons of Borax and now produces more than 1.7 million tons per year of products. Products include Borax, boric acid, soda ash, and salt. SVM employs about 700 workers for operating power and production facilities which cover a 339 acre area. SVM owns or leases more than 25,000 acres of land for its entire operation. SVM ships thousands of tons of high grade material daily to major manufacturers in 52 countries. The facility is located at Searles Lake which contains rich deposits of naturally occurring minerals. The brine under the lakebed is 10 times saltier than seawater. This brine holds a diverse supply of minerals. SVM mines the nonmetallic materials from the lakebed by selective crystallization of the brine. The brine solution is pumped from the lake and then through various processes for heating, cooling, thickening and separating before the final product is produced.

SVM is composed of three facilities, the Argus, Trona, and Westend facilities. The Argus processing plant produces soda ash as its main product. The Argus utilities plant includes the 55 megawatt coal-fired cogeneration plant that provides steam and electricity to the Argus production plant, Trona facility, and steam to the Westend facility. Electricity from the Argus plant is distributed to the other facilities to power electric pumps, fans, chillers, and compressors. Approximately, 20% of the electricity generated by the Argus utility plant is sold to Southern California Edison. The Trona facility utilizes steam and electricity from the Argus utilities plant to produce PYROBOR, Borax, and boric acid. The Westend facility utilizes steam from the Argus utility plant to produce Borax and sodium sulfate. The facility also purchases electricity from Southern California Edison and receives steam from ACE cogeneration.

Emissions

SVM emitted 1.5 $MMTCO_2e$ in 2009. The GHG emission sources at SVM include coal-fired boilers, coal storage, emergency diesel fire pump and generators, and other small combustion sources, including natural gas used for dryers, burners, and for starting and supplementing the coal-fired boilers. SVM operates a co-generation plant that produces both electricity and steam and accounts for 95% of the facility's GHG emissions. Boiler steam produced is used to process the minerals into usable materials. Cogeneration energy is used to power ancillary fans and pumps. Excess power is sold to the local electricity provider.

Table II-23 provides the 2009 GHG emissions reported by SVM in compliance with ARB's GHG Mandatory Reporting Regulation.

Table II-23: SVM 2009 GHG Emissions

Pollutant	2009 Annual Emissions ($MMTCO_2e$)
GHG	1.5

In addition, the facility reported the following emissions of criteria pollutants as shown in table II-24.

Table II-24: SVM 2009 Criteria Pollutant Emissions

Criteria Pollutant Type	2009 Annual Emissions (tons/year)
Toxic Organic Gasses (TOG)	20
Carbon Monoxide (CO)	133
Oxides of Nitrogen (NOx)	1,265
Oxides of Sulfur (SOx)	86
Particulate Matter (PM_{10})	207

Table II-25 lists the top ten TACs ranked according to the combined mass TAC emissions and cancer potency factor, as described in Section 1.2.

Table II-25: SVM 2009 Top Ten Prioritized Toxic Air Contaminant Emissions

Toxic Pollutant Type	2009 Annual Emissions (lbs/year)
Cadmium	25
Arsenic	6
Benzene	500
Formaldehyde	1,810
Chromium, hexavalent	0.040
1,3-Butadiene	20
Methylene chloride {Dichloromethane}	2,512
Nickel	7
Acetaldehyde	604
Naphthalene	14

Energy Efficiency Improvement Options

Tables II-26 itemizes the six energy-efficiency projects that were identified for the SVM facility. These projects are categorized by equipment type and by project status – completed, scheduled, or under investigation. The emissions and cost information are reported as the sum for all the projects within each equipment category. In compliance with the confidentiality requirement under CCR § 95610, a detailed explanation of how the specific project improves energy efficiency is not provided in this table. However, expanded project descriptions can be referenced for various Equipment Categories and Equipment Sub-types in Tables I-10 through I-17 in Part I of this report. Additionally, categories that contain fewer than three projects are designated as "CBI" in compliance with CCR § 95610. These projects are included in the total list of projects provided in Part I of this report.

SVM reported that it has identified two projects as Completed/Ongoing, two projects as Scheduled, and two projects as Under Investigation. No specific costs or GHG benefit data are provided for these projects. These data could not be aggregated in such a way to protect the confidential nature of the data. However, summed values for all six projects are provided in the table and these projects were included in the full list of possible projects in Tables I-10 through I-17 in Part I of this report. These projects are estimated to reduce GHG emissions by approximately 102,000 metric tons annually. In addition, these projects are estimated to reduce NOx and PM by approximately 0.22 and 0.03 tons per day, respectively. These projects are estimated to cost $19 million in one-time costs, with additional $86,000 in annual costs. The SVM facility has estimated that these projects will save about $10 million annually.

There were no projects identified as not being implemented.

Table II-26: SVM Energy Efficiency Options Reported as Completed/Ongoing, Scheduled, or Under Investigation

Timing	Equipment Category	Equipment Sub-type	Number of Projects	Estimated GHG Reduction (Metric tons per year)	One Time Cost ($)	Annual Cost ($)	Annual Savings ($)	Potential NOx Reduction (tons/day)	Potential PM Reduction (tons/day)
Completed / Ongoing	Other / Boilers	Other / Boiler for steam	2	CBI	CBI	CBI	CBI	CBI	CBI
Scheduled	Other / Chemical	Other / Chemical processing plant	2	CBI	CBI	CBI	CBI	CBI	CBI
Under Investigation	Boilers	Boiler for cogeneration	1	CBI	CBI	CBI	CBI	CBI	CBI
	Electric	Electric motors - pumps and fans	1	CBI	CBI	CBI	CBI	CBI	CBI
Total for All Projects			6	102,350	19,092,000	86,000	9,610,000	0.223	0.026

CBI - Confidential Business Information pursuant to CCR § 95610