TABLE OF CONTENTS

5. Environmental Information 5.1-1

5.1 Air Quality 5.1-1
5.1.1 Affected Environment 5.1-4
5.1.1.1 Climatology 5.1-4
5.1.1.2 Existing Air Quality 5.1-5
5.1.2 Environmental Consequences 5.1-9
5.1.2.1 Construction Criteria Pollutant Emissions 5.1-9
5.1.2.2 Construction Greenhouse Gas Emissions 5.1-11
5.1.2.3 Operational Criteria Pollutant Emissions 5.1-11
5.1.2.4 Operational Greenhouse Gas Emissions 5.1-32
5.1.2.5 Dispersion Modeling Methodology 5.1-37
5.1.2.6 Compliance with Ambient Air Quality Standards 5.1-50
5.1.2.7 Impact on Air Quality-Related Values in Class I Areas 5.1-54
5.1.3 Alternatives 5.1-54
5.1.4 Cumulative Impacts Analyses 5.1-56
5.1.5 Mitigation Measures 5.1-57
5.1.5.1 Construction Mitigation Measures 5.1-57
5.1.5.2 Operational Emissions Offsets 5.1-58
5.1.6 Laws, Ordinances, Regulations, and Standards 5.1-58
5.1.6.1 Ambient Air Quality Standards 5.1-59
5.1.6.2 Prevention of Significant Deterioration Requirements 5.1-60
5.1.6.3 Acid Rain Program Requirements 5.1-60
5.1.6.4 New Source Performance Standards 5.1-61
5.1.6.5 Federal Climate Change Programs 5.1-61
5.1.6.6 Federally Mandated Operating Permits 5.1-61
5.1.6.7 California Power Plants Siting Requirements 5.1-62
5.1.6.8 California Climate Change Programs 5.1-62
5.1.6.9 Air Toxic “Hot Spots” Program 5.1-62
5.1.6.10 Determination of Compliance, Authority to Construct, and Permit to Operate 5.1-63
5.1.6.11 San Joaquin Valley Air Pollution Control District Requirements 5.1-63
5.1.6.12 SJVAPCD Climate Change Action Plan 5.1-63
5.1.6.13 SJVAPCD Rules and Regulations 5.1-64
5.1.7 Involved Agencies and Agency Contacts 5.1-68
5.1.8 Permits Required and Permit Schedule 5.1-68
5.1.9 References 5.1-69

TABLE OF CONTENTS

Tables

Table 5.1-1 Temperature and Precipitation Data for Buttonwillow Station
Table 5.1-2 Ambient Ozone Levels at Shafter–Walker Street Station, 2009–2011
Table 5.1-3 Ambient PM_{10} Levels at Bakersfield—5558 California Avenue, 2008–2010
Table 5.1-4 Ambient $PM_{2.5}$ Levels at Bakersfield—5558 California Avenue, 2008–2010
Table 5.1-5 Ambient CO Levels at Bakersfield—Golden State Highway, 2007–2009
Table 5.1-6 Ambient NO_2 Levels at Shafter–Walker Street Station, 2009–2011
Table 5.1-7 Ambient SO_2 Levels at Fresno—First Street, 2009–2011
Table 5.1-8 Estimated Daily Maximum Construction Emissions of Criteria Pollutants
Table 5.1-9 Estimated Annual Maximum Construction Emissions of Criteria Pollutants
Table 5.1-10 Estimated Emissions of GHG Pollutants, Entire Construction Period
Table 5.1-11 Maximum short-term emissions from CTG/HRSG and coal dryer stack during normal on-peak operations
Table 5.1-12 CTG/HRSG and Coal Dryer Maximum Annual Operation Emissions
Table 5.1-13 CTG/HRSG and Coal Drying Stack Emissions During Start-Up and Shut-Down
Table 5.1-14 Total Combined Annual Criteria Pollutant Emissions
Table 5.1-15 Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas
Table 5.1-16 Duration and Criteria Pollutant Emissions for Commissioning of the Gasifier and Balance of Plant
Table 5.1-17 Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen-Rich Fuel
Table 5.1-18 Duration and Criteria Pollutant Emissions for Commissioning of the Manufacturing Complex
Table 5.1-19 On-Site Trucks and Trains by Period
Table 5.1-20 Operational Transportation Emissions Related to the Project
Table 5.1-21 Carbon Dioxide Venting Scenarios
Table 5.1-22 HECA Maximum Annual CO_2e Emissions
Table 5.1-23 HECA Annual CO_2e Emissions for SB 1368 Emission Performance Standard
Table 5.1-24 Greenhouse Gas Emissions Associated with the Mobile Sources During Project Operations
Table 5.1-25 Maximum Modeled Criteria Pollutant Impacts Due to Construction Emissions
Table 5.1-26 Project Operations Modeling Impacts Compared with Significant Impact Levels and Monitoring Concentrations
Table 5.1-27 AERMOD Modeling Results for Project Operations
Table 5.1-28 SCREEN3 Fumigation Modeling Results for Project Operations
Table 5.1-29 Commissioning Modeling Results
Table 5.1-30 Alternative 2 (Truck Transportation) On-Site Maximum Trucks by Period Greenhouse Gas Emissions Associated with the Mobile Sources During Project Operations for Alternative 2 (Truck Transportation)
Table 5.1-31 Onsite and Offsite Transportation Emissions from Alternative 2 (Truck Transportation) by Air Basin
Table 5.1-32 Difference in Annual Emissions Between Transportation Alternatives 1 (Rail) and 2 (Truck) Transportation
Table 5.1-33 Greenhouse Gas Emissions Associated with the Mobile Sources During Project Operations for Alternative 2 (Truck Transportation)

Table 5.1-34 Laws, Ordinances, Regulations, and Standards—Air Quality
Table 5.1-35 Relevant Ambient Air Quality Standards
Table 5.1-36 Attainment Status for Kern County with Respect to Federal and California Ambient Air Quality Standards
Table 5.1-37 PSD Emission Threshold Triggers for New Stationary Sources
Table 5.1-38 Prevention of Significant Deterioration Allowable Increments ($\mu g/m^3$)
Table 5.1-39 Proposed BACT for the Project
Table 5.1-40 Involved Agencies and Agency Contacts

Figures

Figure 5.1-1 Near-Field Model Receptor Grid
Figure 5.1-2 Far-Field Model Receptor Grid
Figure 5.1-3 Locations of Maximum Predicted Ground Level Pollutant Concentrations for the Operational Project Area

Appendices

Appendix E-1 Seasonal and Annual Wind Roses
Appendix E-2 Construction Criteria Pollutant and Greenhouse Gas Emissions
Appendix E-3 Operational Criteria Pollutant Emissions
Appendix E-4 Responses to $PM_{2.5}$ Cooling Tower Data Requests from CEC and USEPA
Appendix E-5 Offsite Operational Transportation Emissions
Appendix E-6 Operational Greenhouse Gas Emissions
Appendix E-7 NO_2 1-Hour Regional Analysis
Appendix E-8 Commissioning Scenario Emissions and Modeling Results
Appendix E-9 Fumigation Modeling Results
Appendix E-10 Offset Package
Appendix E-11 Criteria Pollutant BACT Analysis
Appendix E-12 Operational Transportation Emissions for Alternative 2
Appendix E-13 CO_2 Vent Study
Appendix E-14 Response to CEC Data Request 32

This page intentionally left blank.

5.1 AIR QUALITY

Hydrogen Energy California LLC (HECA LLC) is proposing an Integrated Gasification Combined Cycle (IGCC) polygeneration project (HECA or Project). The Project will gasify a fuel blend of 75 percent coal and 25 percent petroleum coke (petcoke) to produce synthesis gas (syngas). Syngas produced via gasification will be purified to hydrogen-rich fuel, and used to generate a nominal 300 megawatts (MW) of low-carbon baseload electricity in a Combined Cycle Power Block, low-carbon nitrogen-based products in an integrated Manufacturing Complex, and carbon dioxide (CO_2) for use in enhanced oil recovery (EOR). CO_2 from HECA will be transported by pipeline for use in EOR in the adjacent Elk Hills Oil Field (EHOF), which is owned and operated by Occidental of Elk Hills, Inc. (OEHI). The EOR process results in sequestration (storage) of the CO_2.

Terms used throughout this section are defined as follows:

- **Project or HECA.** The HECA IGCC electrical generation facility, low-carbon nitrogen-based products Manufacturing Complex, and associated equipment and processes, including its linear facilities.

- **Project Site or HECA Project Site.** The 453-acre parcel of land on which the HECA IGCC electrical generation facility, low-carbon nitrogen-based products Manufacturing Complex, and associated equipment and processes (excluding off-site portions of linear facilities), will be located.

- **OEHI Project.** The use of CO_2 for EOR at the EHOF and resulting sequestration, including the CO_2 pipeline, EOR processing facility, and associated equipment.

- **OEHI Project Site.** The portion of land within the EHOF on which the OEHI Project will be located and where the CO_2 produced by HECA will be used for EOR and resulting sequestration**.**

- **Controlled Area.** The 653 acres of land adjacent to the Project Site over which HECA will control access and future land uses.

This introduction provides brief descriptions of both the Project and the OEHI Project. Additional HECA Project description details are provided in Section 2.0. Additional OEHI Project description details are provided in Appendix A-1 of this Application for Certification (AFC) Amendment.

HECA Project Linear Facilities

The HECA Project includes the following linear facilities, which extend off the Project Site (see Figure 2-7, Project Location Map):

- **Electrical transmission line.** An approximately 2-mile-long electrical transmission line will interconnect the Project to a future Pacific Gas and Electric Company (PG&E) switching station east of the Project Site.

- **Natural gas supply pipeline.** An approximately 13-mile-long natural gas interconnection will be made with PG&E natural gas pipelines located north of the Project Site.

- **Water supply pipelines and wells.** An approximately 15-mile-long process water supply line and up to five new groundwater wells will be installed by the Buena Vista Water Storage District (BVWSD) to supply brackish groundwater from northwest of the Project Site. An approximately 1-mile-long water supply line from the West Kern Water District (WKWD) east of the Project Site will provide potable water.

- **Coal transportation.** HECA is considering two alternatives for transporting coal to the Project Site:

  - **Alternative 1, rail transportation.** An approximately 5-mile-long new industrial railroad spur that will connect the Project Site to the existing San Joaquin Valley Railroad (SJVRR) Buttonwillow railroad line, north of the Project Site. This railroad spur will also be used to transport some HECA products to market.

  - **Alternative 2, truck transportation.** An approximately 27-mile-long truck transport route via existing roads from an existing coal transloading facility northeast of the Project Site. This alternative was presented in the 2009 Revised AFC.

OEHI Project

OEHI will be installing the CO_2 pipeline from the Project Site to the EHOF, as well as installing the EOR Processing Facility, including any associated wells and pipelines needed in the EHOF for CO_2 EOR and sequestration. The following is a brief description of the OEHI Project, which is described in more detail in Appendix A of this AFC Amendment:

- **CO_2 EOR Processing Facility.** The CO_2 EOR Processing Facility and 13 satellites are expected to occupy approximately 136 acres within the EHOF. The facility will use 720 producing and injection wells: 570 existing wells and 150 new well installations. Approximately 652 miles of new pipeline will also be installed in the EHOF.

- **CO_2 pipeline.** An approximately 3-mile-long CO_2 pipeline will transfer the CO_2 from the HECA Project Site south to the OEHI CO_2 EOR Processing Facility.

For the purposes of all Air Quality analyses, impacts were determined outside of both the Project Site and the Controlled Area. HECA LLC will own both the Project Site and the Controlled Area, and will have control over public access and future land use. All temporary construction equipment laydown and parking, including construction parking, offices, and construction laydown areas, will be located on the Project Site and the Controlled Area.

The analysis included in this section focuses on the HECA Project as well as the CO_2 pipeline associated with the OEHI Project. The analysis of the CO_2 EOR Processing Facility associated with the OEHI Project is included in in Sections 4.3, Air Quality and 4.18, Greenhouse Gas Emissions, of Appendix A-1 of this AFC Amendment.

This analysis of the potential air quality impacts of the Project was conducted according to California Energy Commission (CEC) power plant siting requirements (CEC, 1997 and 2006). It also addresses U.S. Environmental Protection Agency (USEPA) Prevention of Significant Deterioration (PSD) requirements and San Joaquin Valley Air Pollution Control District (SJVAPCD) permitting requirements for Determination of Compliance/Authority to Construct The analysis is reported as follows:

- Section 5.1.1, Affected Environment, describes the local environment surrounding the Project Site. Meteorological data, including wind speed and direction (i.e., wind roses), temperature, relative humidity, and precipitation are discussed, and ambient concentrations for the appropriate criteria pollutants are summarized.

- Section 5.1.2, Environmental Consequences, evaluates the Project's air quality impacts from emissions of nitrogen oxide (NO_X), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOCs), particulate matter less than 10 microns in diameter (PM_{10}), and particulate matter less than 2.5 microns in diameter ($PM_{2.5}$). Emission estimates are presented for these pollutants and greenhouse gases (GHGs) for Project construction and operation over a range of operating modes, including start-up and shut-down. The modeling analysis conducted for nitrogen dioxide (NO_2), CO, SO_2, $PM_{2.5}$, and PM_{10} is presented. Transportation emissions in this section are estimated for coal transportation Alternative 1 (rail transportation).

- Section 5.1.3, Alternatives, presents a discussion of coal transportation Alternative 2 (truck transportation), and associated air emissions and impacts.

- Section 5.1.4, Cumulative Impacts Analyses, examines the potential impact from any significant emission sources within a 6-mile radius of the Project Site that have been recently permitted or are in the process of being permitted and are not yet operational.

- Section 5.1.5, Mitigation Measures, describes the Project's emission offsets and construction mitigation measures.

- Section 5.1.6, Laws, Ordinances, Regulations, and Standards, describes all applicable laws, ordinances, regulations, and standards (LORS). Section 5.1.5 also provides a summary of the best available control technology (BACT) analysis for the Project.

- Section 5.1.7, Involved Agencies and Agency Contacts, lists the agency contacts used to conduct the air quality assessment.

- Section 5.1.8, Permits Required and Permit Schedule, lists the permits required and provides a permit schedule.

- Section 5.1.9, References, lists the references used to conduct the air quality assessment.

Some air quality data are presented in other sections of this AFC Amendment, including an evaluation of toxic air pollutants (see Section 5.6, Public Health), an evaluation of the CO_2 vent impacts on worker safety (see Section 5.7, Worker Safety and Appendix E-13, CO_2 Vent Study),

and information related to the fuel characteristics, heat rate, and expected capacity factor of the Project (see Section 2, Project Description).

5.1.1 Affected Environment

This section describes the regional climate and meteorological conditions that influence transport and dispersion of air pollutants and the existing air quality within the Project region. The data presented in this section are representative of the Project Site as well as the Controlled Area, described below.

The Project Site is in a predominantly agricultural area of Kern County, approximately 2 miles northwest of the unincorporated community of Tupman, and approximately 7 miles west of the outermost edge of the city of Bakersfield. The Project Site is within Section 10 of Township 30 South, Range 24 East, in Kern County.

The Project Site consists of approximately 453 acres near Tupman in Kern County, as shown on Figure 2-4, Site Plan. HECA LLC also has control over an additional 653 acres of land adjacent to the Project Site, herein referred to as Controlled Area. HECA LLC will own this property and have control over public access and future land use. For the purposes of this air quality analysis, impacts were determined outside of both the Project Site and the Controlled Area combined.

5.1.1.1 Climatology

The California Air Resources Board (CARB) has divided California into regional air basins according to topographic drainage features. The Project Site is located near the unincorporated community of Tupman, Kern County, within the jurisdiction of the San Joaquin Valley Air Basin (SJVAB).

SJVAB, which is approximately 250 miles long and 35 miles wide, is the second largest air basin in the state. Air pollution, especially the dispersion of air pollutants, is directly related to a region's topographic features. The SJVAB is defined by the Sierra Nevada Mountains in the east (8,000 to 14,000 feet in elevation), the Coast Range in the west (averaging 3,000 feet in elevation), and the Tehachapi Mountains in the south (6,000 to 8,000 feet in elevation). The valley opens to the sea at the Carquinez Strait, where the San Joaquin–Sacramento Delta empties into San Francisco Bay.

The SJVAB has an inland Mediterranean climate, averaging more than 260 sunny days per year. The valley floor is characterized by warm, dry summers and cooler winters. Long-term average temperature and precipitation data have been collected at Buttonwillow, the surface meteorological station nearest to the Project Site; they are presented in Table 5.1-1. Average low and high temperatures during the summer vary from the high 60s to the mid-90s, respectively, in degrees Fahrenheit (ºF). Summer precipitation is extremely low due to the strong stationary high-pressure system located off the coast that prevents most weather systems from moving through the area. The Project Site receives an average of 6 inches of rain annually. During the winter, average low and high temperatures vary from the mid-30s to the mid-50s, respectively. About 80 percent of the precipitation in the area occurs from November through March, generally in association with storm systems that move through the region.

Large climatic variations occur within relatively short distances, given the nature of the surrounding topography. These zones may be classified as valley, mountain, and desert. The overall climate, however, is warm and semi-arid.

The annual and seasonal wind roses for the Bakersfield Meadows Field Airport for 2006 through 2010 are presented in Appendix E-1, Seasonal and Annual Wind Roses. Winds for all seasons and all years blow predominantly from the sector between northwest and north, although the directional pattern is more variable during the fall and winter seasons.

5.1.1.2 Existing Air Quality

Ambient air quality standards have been set by both the federal government and the state of California to protect public health and welfare with an adequate margin of safety. Pollutants for which National Ambient Air Quality Standards (NAAQS) or California Ambient Air Quality Standards (CAAQS) have been set are often referred to as "criteria" air pollutants. The term is derived from the comprehensive health and damage effects review that culminates in pollutant-specific air quality criteria documents, which preceded the NAAQS and CAAQS standard setting. These standards are reviewed on a legally prescribed frequency and revised as new health and welfare effects data warrant.

Each NAAQS or CAAQS is based on a specific averaging time over which the concentration is measured. Different averaging times are based upon protection of short-term, high-dosage effects or longer-term, low-dosage effects. NAAQS may be exceeded once or more per year depending upon the pollutant and averaging time. CAAQS are not to be exceeded.

Air quality monitoring data representing existing air quality in the Project area were obtained from the USEPA AirData (USEPA, 2012) and the CARB-California Air Quality Data website (CARB, 2012). The maximum concentration recorded at these monitoring stations over the most recent 3-year period available will be used as a conservative representation of existing air quality conditions at the Project Site.

The monitoring station in the county that is closest to the Project Site is the Shafter–Walker Street Station, within 13 miles (21 kilometers) from the Project Site. This station measures ozone (O_3) and NO_X, and is the most representative of the background conditions near HECA. Further justification for use of the background data from this station can be found in Appendix E-7, NO_2 1-Hour Regional Analysis.

The Bakersfield—5558 California Avenue station is the next closest and that measures all pollutants except SO_2 and CO. This station is located approximately 20 miles (32 kilometers) to the east of the Project site. This station provides the best representation of the background for PM_{10} and $PM_{2.5}$ for the area near HECA. Plus this is the only station that measures PM with adequate data capture within the San Joaquin Valley in Kern County.

The Bakersfield—Golden State Highway station is the only station in Kern County that measures CO. This station was closed early in 2010, thus the most recent measurements available for this station are for 2007–2009 as 2010 data did not have suitable data capture. The only station in the SJVAB that monitors SO_2 is the CARB station at First Street in Fresno, located approximately

102 miles (164 kilometers) to the north. Sulfur dioxide data have only been recorded in Fresno County for 6 of the last 10 years (2003, 2007, 2008, 2009, 2010, 2011), a practice that is justified by the low levels that have been recorded for this pollutant when measurements have been made.

Air quality measurements taken at these stations are presented in Tables 5.1-2 through 5.1-7. These tables show the pollutant levels recorded for the previous 3-year periods, as available. For the air quality impact analysis, the maximum background concentration from the most recently available 3 years from the most representative monitoring station was used.

The monitoring data indicate that the air is in compliance with all federal NAAQS and CAAQS for NO_2, CO, and SO_2 for all averaging periods. However, the monitoring data indicate that the NAAQS and/or the CAAQS are periodically exceeded for O_3, PM_{10}, and $PM_{2.5}$.

Ozone (O_3). Ozone occurs in two layers of the atmosphere. The layer surrounding the earth's surface is the troposphere. Here, ground level O_3 is an air pollutant that damages human health, vegetation, and many common materials. It is a key ingredient of urban smog. The troposphere extends to a level about 10 miles up, where it meets the second layer, the stratosphere. In contrast, the beneficial or stratospheric O_3 layer extends upward from about 10 to 30 miles and protects life on earth from the sun's harmful ultraviolet rays.

Ground level O_3 is what is known as a photochemical pollutant. Significant O_3 formation generally requires an adequate amount of precursors in the atmosphere and several hours in a stable atmosphere with strong sunlight.

Ozone is a regional air pollutant. It is generated over a large area and is transported and spread by wind. O_3, the primary constituent of smog, is the most complex, difficult to control, and the most pervasive of the criteria pollutants. Unlike other pollutants, O_3 is not emitted directly into the air by specific sources. O_3 is created by sunlight acting on other air pollutants (called precursors), specifically NO_X and VOCs. Sources of precursor gases to the photochemical reaction that form O_3 number in the thousands. Common sources include consumer products, gasoline vapors, chemical solvents, and combustion products of various fuels. Originating from gas stations, motor vehicles, large industrial facilities, and small businesses such as bakeries and dry cleaners, the O_3-forming chemical reactions often take place in another location, catalyzed by sunlight and heat. High O_3 concentrations can form over large regions when emissions from motor vehicles and stationary sources are carried hundreds of miles from their origins.

SJVAB is designated as an extreme non-attainment area for federal 8-hour O_3, and non-attainment for state 1-hour and 8-hour O_3. Table 5.1-2 shows that the federal 8-hour O_3 AAQS of 0.075 part per million (ppm) has been frequently exceeded in the past 3 years at the Shafter–Walker Street Station, and that the federal 1-hour O_3 AAQS of 0.12 ppm (a standard revoked by USEPA on 15 June 2005) has not been exceeded in the last 3 years at the Shafter–Walker Street Station. The more stringent 1-hour CAAQS of 0.09 ppm has been exceeded a number of times in the past 3 years at the Shafter–Walker Street Station.

Particulate Matter (PM_{10} and $PM_{2.5}$). PM_{10} refers to particles less than or equal to 10 microns in aerodynamic diameter. $PM_{2.5}$ refers to particles less than or equal to 2.5 microns in aerodynamic diameter and are a subset of PM_{10}. Particulate matter pollution consists of very

small liquid and solid particles floating in the air. Some particles are large or dark enough to be seen as soot or smoke. Others are so small they can be detected only with an electron microscope. Particulate matter is a mixture of materials that can include smoke, soot, dust, salt, acids, and metals. Particulate matter also forms when gases emitted from motor vehicles and industrial sources undergo chemical reactions in the atmosphere.

In the western U.S., there are sources of PM_{10} in both urban and rural areas. PM_{10} and $PM_{2.5}$ are emitted from stationary and mobile sources, including diesel trucks and other motor vehicles; power plants; industrial processing; wood-burning stoves and fireplaces; wildfires; dust from roads, construction, landfills, and agriculture; and fugitive windblown dust. Because particles originate from a variety of sources, their chemical and physical compositions vary widely.

SJVAB is designated as a federal and state non-attainment area for $PM_{2.5}$. The basin was designated as a federal attainment area for PM_{10} in 2008, however the basin is state non-attainment for PM_{10}. Table 5.1-3 shows that the 24-hour average CAAQS of 50 micrograms per cubic meter ($\mu g/m^3$) for PM_{10} has been frequently exceeded in the Bakersfield area. The 24-hour average PM_{10} NAAQS of 150 $\mu g/m^3$ was exceeded only once within the past 3 years.

The state annual average presented in Table 5.1-3 is an annual geometric mean of all measurements. The national annual average is an annual arithmetic average of the four arithmetic quarterly averages (the federal PM_{10} annual standard was revoked on September 22, 2006).

The annual and 24-hour $PM_{2.5}$ data are presented in Table 5.1-4. The 3-year average, 98th percentile is above the federal AAQS of 35 $\mu g/m^3$. The 3-year average, arithmetic mean is above the California AAQS of 12 $\mu g/m^3$.

Carbon Monoxide (CO). Carbon monoxide is emitted by mobile and stationary sources as a result of incomplete combustion of hydrocarbons or other carbon-based fuels. CO is an odorless, colorless, air pollutant gas that is highly reactive.

Carbon monoxide is a by-product of motor vehicle exhaust, which contributes more than two-thirds of all CO emissions nationwide. In cities, automobile exhaust can cause as much as 95 percent of all CO emissions. These emissions can result in high concentrations of CO, particularly in local areas with heavy traffic congestion. Other sources of CO emissions include industrial processes and fuel combustion in sources such as boilers and incinerators. Despite an overall downward trend in concentrations and emissions of CO, some metropolitan areas still experience high levels of CO.

SJVAB is designated as an attainment area for CO. The data in Table 5.1-5 show that the measured concentrations of CO are all below the applicable federal and California standards.

Nitrogen Oxides (NO_X). Nitrogen oxides are a family of highly reactive gases that are a primary precursor to the formation of ground level O_3, and react in the atmosphere to form acid rain. NO_X is emitted from the use of solvents and combustion processes in which fuel is burned at high temperatures, principally from motor-vehicle exhaust and stationary sources, such as electric utilities and industrial boilers. NO_2, a brownish gas, is a strong oxidizing agent that reacts in the air to form corrosive nitric acid, as well as toxic organic nitrates.

SJVAB is designated as an attainment area for NO_2. The data in Table 5.1-6 show that the measured concentrations of NO_2, are all below the applicable federal and California standards.

Sulfur Dioxide (SO_2). Sulfur dioxide is a colorless, irritating gas formed primarily by the combustion of sulfur-containing fossil fuels. Historically, in the late 1970s in the SJVAB portion of Kern County, SO_2 was a pollutant of concern, but with the successful application of regulations, the levels have been reduced significantly.

SJVAB is designated as an attainment area for SO_2. The data in Table 5.1-7 show that the measured concentrations of SO_2 are all below the applicable federal and California standards. Neither CARB or EPA report 3-hour SO_2 monitoring values, however, the maximum SO_2 3-hour background concentration at the Fresno monitoring station was 0.010 ppm from 2007–2009 (CARB AQMIS, 2009).

Other Pollutants

Volatile Organic Compounds (VOCs). VOCs includes all hydrocarbons except those exempted by CARB. Therefore, VOCs are a set of organic gases based on state rules and regulations. Reactive organic gases (ROG) are similar to VOCs in that they include all organic gases except those exempted by federal law. The list of compounds exempt from the definition of VOCs is included by the SJVAPCD and is presented in District Rule 1102. Both VOCs and ROGs are emitted from incomplete combustion of hydrocarbons or other carbon-based fuels. Combustion engine exhaust from automobiles and trucks, oil refineries, and oil-fueled power plants are the primary sources of hydrocarbons. Another source of hydrocarbons is evaporation from petroleum fuels, solvents, dry cleaning solutions, and paint.

Sulfates (SO_3 and SO_4). Sulfates are the fully oxidized ionic form of sulfur. Sulfates occur in combination with metal and/or hydrogen ions. In California, emissions of sulfur compounds occur primarily from the combustion of petroleum-derived fuels (e.g., gasoline and diesel fuel) that contain sulfur. This sulfur is oxidized to SO_2 during the combustion process and subsequently converted to sulfate compounds in the atmosphere. The conversion of SO_2 to sulfates takes place comparatively rapidly and completely in urban areas of California due to regional meteorological features.

Lead (Pb). Lead is a metal that is a natural constituent of air, water, and the biosphere. Lead is neither created nor destroyed in the environment, so it essentially persists forever. Lead was used until recently to increase the octane rating in auto fuel. Since gasoline-powered automobile engines were a major source of airborne Pb through the use of leaded fuels, and the use of leaded fuel has been mostly phased out, the ambient concentrations of Pb have dropped dramatically. Kern County no longer monitors Pb in the ambient air of the SJVAB.

Hydrogen Sulfide (H_2S). Hydrogen sulfide is associated with geothermal activity, oil and gas production, refining, sewage treatment plants, and confined animal feeding operations. It has a characteristic rotten-egg odor.

5.1.2 Environmental Consequences

This section describes the analyses conducted to assess the potential air quality impacts from the Project. Impacts from the Project are considered significant if, when combined with background ambient levels, they will cause an exceedance of an ambient air quality standard, or contribute to an existing exceedance, or if by themselves, they will exceed an applicable PSD significant impact amount. Emissions estimates for both construction and operation of the Project are presented. Dispersion model selection and setup are also described (i.e., emissions scenarios and release parameters, building wake effects, meteorological data, and receptor locations), and analysis results are presented.

5.1.2.1 Construction Criteria Pollutant Emissions

The primary emission sources during construction will include heavy construction equipment, construction vehicles, and fugitive dust from disturbed areas due to grading, excavating, and construction of Project structures. Different areas within the Project Site will be disturbed at different times during the 49-month overall construction period (42 months of site preparation and construction and up to 18 months of commissioning and start-up, with overlap). Estimated land disturbance for major construction activities is summarized in Chapter 2, Project Description.

Construction emissions were calculated from sources in three different categories: on-site sources; sources associated with linear construction (e.g., pipelines, transmission line, rail spur, etc.); and off-site sources. On-site sources include construction equipment, delivery trucks entering the site, and commuter vehicles entering and exiting the site. Linear sources include all construction equipment required for the total linear construction. Off-site sources include worker commuter vehicles and delivery trucks while traveling off site. Trip distances were based on the assumption that workers and delivery trucks are traveling within Kern County.

The schedule of equipment needed during construction and the estimated number of pieces of equipment that would operate during each month of the construction effort is presented in Section 2, Project Description and Appendix E-2, Construction Criteria Pollutant and Greenhouse Gas Emissions. Emissions from equipment will occur over a 49-month construction and commissioning period. The list of fueled equipment needed during each month of the construction effort served as the basis for estimating pollutant emissions throughout the term of construction and helped to identify the periods of probable maximum short-term emissions.

Construction equipment and vehicle exhaust emissions were estimated using equipment lists and construction scheduling information provided by the Project design engineering firm. Mass emissions of criteria pollutants from diesel-fueled construction equipment and vehicles were estimated using equipment specific emission factors from the California Air Resources Board OFFROAD 2007 model (CARB, 2007a). Emission factors specific to Kern County in calendar year 2013 were used. Emission factors for on-road vehicles are based on EMFAC2007 emission factors (CARB, 2007b). While EMFAC2011 was released in September 2011, it is not yet approved by EPA for use in federal projects for NEPA and federal conformity analyses; thus, emission factors from EMFAC2007 were applied. The emissions from the construction phase of the Project will be subject to the General Conformity Rule, as discussed further in

Section 5.1.2.3. Assumptions used in calculating Project construction emissions include a 49-month construction and commissioning period; 22 construction days per month; and a single-shift workday.

Project emissions are calculated to include all on-site and linear source emissions. The month in which Project emissions are a maximum is Month 6 for PM_{10} and $PM_{2.5}$ and Month 17 for CO, VOC, NO_X and SO_X. Activities in the Month 6 include bulldozing, grading, importing fill, and material handling. Activities in the Month 17 primarily include building construction and construction of off-site linears.

The maximum annual Project emissions were based on the worst 12 consecutive months of the construction period. For PM_{10} and $PM_{2.5}$ this occurred in Months 1 through 12; for CO, VOC, NO_X and SO_X this occurred in Months 13 through 24 of construction. For each pollutant, maximum short-term (daily) Project emissions are shown in Table 5.1-8, and maximum annual Project emissions are shown in Table 5.1-9.

For purposes of modeling, maximum emissions periods were determined using only on-site sources. Linear sources are spread out over a large distance (approximately 39 miles); pollutants will be well dispersed and not have a significant impact on a given receptor. Considering only on-site sources, maximum short-term and annual emissions of PM_{10} and $PM_{2.5}$ occurs in Month 6 and Months 1 through 12, respectively. For CO, NO_X, and SO_X emissions, the month in which short-term on-site emissions reach a maximum is Month 24. The worst-case annual on-site emissions are in Months 20 through 31. On-site emissions used in dispersion modeling are shown in Appendix E-2, Construction Criteria Pollutant and Greenhouse Gas Emissions, and calculated based on the assumptions outlined below:

- Fugitive dust emissions resulting from on-site soil disturbances were estimated using USEPA AP-42 emission factors for dirt piling, grading, bulldozing and dirt-pushing, and travel on unpaved roads. A dust control efficiency of 67 percent for Project Site and linear construction activities was assumed to be achieved for these activities by frequent watering and speed control. Estimated land disturbance for major construction activities is summarized in Section 2, Project Description.

- Emissions from on-road delivery trucks and worker commute trips were estimated using trip generation information presented in Section 2.7.4, Combined Construction Traffic, and emission factors provided by the EMFAC2007 model for on-road vehicles. Construction workers were assumed to commute to the Project Site from locations within Kern County.

- Emissions from off-road construction equipment were estimated using emission factors from the OFFROAD 2007 model. Emission factor selection was based on the type of equipment and the reported horsepower. Emissions were based on the number of pieces of equipment in a given month (from the construction schedule) and an assumed 10-hour work day.

Detailed spreadsheets are provided in Appendix E-2, Construction Criteria Pollutant and Greenhouse Gas Emissions, which have calculations of emissions from all Project construction activities and equipment, as well as the data and assumptions used for the calculations. Table 5.1-8 presents the estimated maximum daily Project on-site, linear, and off-site

construction emissions. Table 5.1-9 presents the estimated annual maximum Project on-site, linear and off-site construction emissions.

Construction Criteria Pollutant Emissions associated with OEHI EOR

Construction emissions associated with the OEHI Project are analyzed in Section 4.3, Air Quality, of Appendix A-1 of this AFC Amendment. The primary emission sources during construction will include heavy construction equipment, construction personnel vehicle use, and fugitive dust from disturbed areas due to grading, excavating, and construction of OEHI Project facilities. Different areas within the OEHI Project Site will be disturbed at different times during the 20-year construction phase of the proposed OEHI Project. To minimize emissions from the construction phase, OEHI will implement SJVAPCD Regulation VIII dust mitigation measures to reduce PM_{10} impacts to a level considered less than significant. Emission calculations and Project details can be found in the Appendix A.

5.1.2.2 Construction Greenhouse Gas Emissions

Construction GHG emissions were calculated by using a combination of emission models and emission factors. These models included EMFAC2007, OFFROAD 2007, and California Climate Action Registry (CCAR) General Reporting Guidance (CCAR, 2009). Each model calculates emissions for a different type of source. The equipment inventory, assumptions, and all data used to calculate construction-related GHG emissions are included in Appendix E-2, Construction Criteria Pollutant and Greenhouse Gas Emissions.

Construction GHG emissions are generated by construction equipment and construction vehicles, as well as commuter vehicles and delivery trucks. A summary of Project related GHG emissions over the entire construction period is presented in Table 5.1-10.

Construction GHG Emissions associated with OEHI EOR

Construction GHG emissions associated with the OEHI Project are analyzed in Section 4.18, Greenhouse Gas Emissions, of Appendix A-1 of this AFC Amendment. The primary sources of the OEHI Project GHG emissions during the construction phase are anticipated to be vehicle emissions and construction equipment. Emission calculations and Project details can be found in Appendix A. The analysis contained in Appendix A concludes that GHG emissions associated with the construction of the OEHI Project will not result in a significant adverse impact

5.1.2.3 Operational Criteria Pollutant Emissions

Operational Emissions—Stationary Sources

The Project is an Integrated Gasification Combined Cycle (IGCC) polygeneration project that will produce low carbon baseload electricity, low carbon nitrogen–based products in an integrated Manufacturing Complex, and CO_2 for EOR. The Gasification Block will feature a Mitsubishi Heavy Industries (MHI) oxygen-blown dry feed gasifier, Shift, Low Temperature Gas Cooling (LTGC), Mercury Removal, Acid Gas Removal (AGR), Sulfur Recovery, Tail Gas Treating, EOR CO_2 Compression Units and associated utilities to produce hydrogen-rich fuel.

Sulfur and mercury components will be removed, and CO_2 will be captured and compressed for EOR and resulting sequestration.

The Combined Cycle Power Block will generate approximately 405 MW of gross power and will provide approximately 300 MW output of low-carbon baseload electricity. The Power Block will feature one MHI 501GAC® combustion turbine generator (CTG) that will be fueled with hydrogen-rich fuel from the gasification plant, and natural gas as a backup fuel; a heat-recovery steam generator (HRSG) with duct firing on a combination of hydrogen-rich fuel and PSA off-gas; and a condensing steam turbine-generator.

The Manufacturing Complex is an integrated complex that will produce approximately 1 million tons per year of nitrogen-based products, including urea, UAN and anhydrous ammonia, to be used in agricultural, transportation, and industrial applications. Process units used in producing the low-carbon, nitrogen-based products are the PSA, Carbon Dioxide Purification and Compression, Ammonia Synthesis, Urea, Urea Pastillation and Storage, Nitric Acid, Ammonium Nitrate, Urea Ammonium Nitrate Units, and associated utilities.

The operational emissions from the Project are mainly generated from the combustion of the hydrogen-rich fuel in the Combined Cycle Power Block. Other emission sources are outlined below. Each emission source can be categorized with the Power Block, Gasification Block, Manufacturing Complex, or ancillary equipment as follows.

Power Block	Gasification Block	Manufacturing Complex	Ancillary Equipment
• Combustion Turbine (MHI 501GAC®) • Power Block Cooling Tower	• Coal Dryer • Auxiliary Boiler • Gasification Flare • Sulfur Recovery Unit (SRU) Flare • Rectisol® Flare • Tail Gas Thermal Oxidizer • ASU and Process Cooling Towers • CO_2 Vent • Material Handling Dust collection (Feedstock)	• Nitric Acid Unit • Urea Absorbers • Urea Pastillation • Ammonium Nitrate Unit • Ammonia Synthesis Unit Start-Up Heater • Material Handling Dust collection (Urea)	• Two Emergency Diesel Generators • Emergency Diesel Firewater Pump

Plant Start-Up

This section describes a typical plant-wide start-up that would occur after the commissioning phase. The commissioning and initial start-up of the facility is described later in the commissioning section. HECA LLC anticipates that one to two plant start-ups/shut-downs will be necessary for annual maintenance. This sequence assumes that all the necessary utility and support systems are already in service (plant-distributed control system, fire protection and other

safety systems, electrical switchyard and in-plant electrical distribution, water treatment, natural gas, steam, instrument and plant air, purge nitrogen, etc.).

The IGCC takes 4 to 6 days from cold start to export of low-carbon power. The following summarizes the start-up sequences. Note that if the IGCC is being restarted after a short outage, when the equipment is still close to operating conditions, the durations of each step will be much shorter than indicated below.

Air Separation Unit Start-Up

The Air Separation Unit (ASU) will require 3 to 4 days to start up and reach full capacity. Because the ASU operates at cryogenic conditions, the start-up sequence includes an extensive cool down and drying period. During this time, the main air compressor and booster air compressor will be operated to provide the auto refrigeration necessary to cool and dry the ASU. Near the end of the start-up sequence, the ASU will begin producing liquid oxygen (LOX) and liquid nitrogen. The LOX is stored to provide a backup oxygen supply to cover a compressor trip or other short ASU outage. The liquid nitrogen storage is provided as a backup supply for the purge nitrogen system. Once the ASU is producing enough oxygen to operate the gasifier, the LOX pumping and vaporization system can be started to make high-pressure oxygen vapor available to the Gasification Unit.

AGR Start-Up

The AGR Unit is assumed to be ready to start (purged with nitrogen and with start-up methanol levels established in the circulating system). Methanol circulation is started and the refrigeration system is started to begin cooling the methanol to operating temperature (approximately minus 40°F). This sequence is expected to take about 2 days and will complete at about the same time that sufficient oxygen is available to start the gasifier.

SRU Start-Up

The SRU is a single train with an oxygen-enriched reaction furnace (thermal reactor) and two modified Claus reactor stages. The SRU reaction furnace is refractory lined. After an extended outage, both the refractory and the SRU catalyst require a gradual heating program that will take about 3 days for initial curing and dryout, and 1 day on subsequent start-ups. The heating is provided by firing natural gas with air in the reaction furnace. The combustion products flow through the reaction furnace, catalyst beds and boilers to the tail gas thermal oxidizer. During the refractory dryout/cure period, the hydrogenation reactor in the TGTU will also be preheated. The hydrogenation reactor catalyst requires pre-sulfiding prior to being put into operation, which will be timed to complete when the SRU is feed-ready and the gasifier is feed-ready.

Gasification Block Start-Up

The MHI gasifier is a dry-feed system and the gasification reaction zone is protected by a membrane wall. This design reduces the amount of time needed to warm the gasifier (as compared to a refractory lined vessel) when preparing the gasifier for start-up. Natural gas will be burned in air inside the gasifier to provide heat during initial warm-up and will be sent to the gasification flare.

Once the gasifier is up near operating temperature the natural gas will be partially oxidized with O_2 which makes a low sulfur syngas. The pressure and flow is then ramped up to allow the start-up of the shift/LTGC and Rectisol® units. Initially the unshifted syngas will be sent to the gasification flare. Once the shift reactors are functioning then the shifted syngas will be sent to the gasification flare. The venting location will then be moved downstream of the Rectisol® absorber and hydrogen-rich fuel will go to the gasification flare. The flaring will continue during the gasifier's transition from natural gas to coal/coke until the hydrogen-rich fuel can be sent to the gas turbine.

The shift reactors require warm up and pre-sulfiding before sour syngas (containing hydrogen sulfide) can be introduced. The shift reactor catalyst is heated by circulating hot nitrogen across the catalyst beds for about 2 days. The nitrogen is heated indirectly with a high-pressure steam heater. Once the catalyst is hot, a small amount of sulfur containing compound is added to the circulating nitrogen. The pre-sulfiding is completed when traces of sulfur are detected in the effluent of the second shift reactor. The shift reactors are then placed in a hot standby condition and ready for feed.

The CO_2 compression system will be purged and ready to compress CO_2. The CO_2 compressor start-up sequence will be timed to coincide with the time the AGR Unit is producing CO_2 in sufficient quantity to allow sustained operation of the CO_2 compressor.

When the gasifier reaches operating temperature, and the gasifier system has been purged with nitrogen, the gasifier can be started by introducing oxygen to gasify the natural gas, then switching to the coal/petcoke-blend feedstock. Produced raw syngas is sent to Gasification Flare until the system pressure and flow are stabilized. During start-up, the syngas sent to flare is either produced from natural gas or treated in the AGR Unit and will be essentially sulfur-free.

Syngas is diverted through the shift reactors and LTGC sections and then to the AGR Unit. The circulating solution in the AGR Unit then begins absorbing the CO_2 in the syngas. Once the CO_2 concentration in the rich solution reaches the required level, the flash drums will begin separating CO_2 vapor. This CO_2 will be washed to remove any traces of methanol and vented at the Rectisol® flare until the flow rate is increased and then vented through the CO_2 vent.

Once sufficient hydrogen-rich fuel production is available, the MHI 501GAC® combustion turbine can initiate a switch to 100 percent hydrogen-rich fuel. At this point, the gasifier start-up is complete and operation begins.

Also at this point, the start-up of the PSA and Ammonia Plant is initiated, a process that takes 1 to 2 days. Subsequently, the Urea Plant start-up is initiated over a second 24-hour process.

Power Block Start-Up

The MHI 501GAC® and the MHI steam turbine are on a common shaft, with the common generator located between the combustion turbine (CT) and steam turbine (ST). A clutch is provided between the ST and the generator to allow the CT to start-up independently of the ST. The clutch is disengaged during the following CT start-up sequence.

Once all the start-up permissives are met, the MHI 501GAC® CT start signal is given and the generator is used as a motor to rotate the combustion turbine and accelerate it until the operation is self-sustaining (static start). The CT compressor is first partially loaded to provide enough air flow and duration to purge the HRSG. Following the purge, natural gas is introduced into the CT combustors, resulting in the CT operation to become self-sustaining and the discontinuation of the static start. Natural gas is required to start-up the combustion turbine. When the combustion turbine reaches 3,600 revolutions per minute (RPM), or "full speed, no load," it is synchronized with the electrical grid, and the main breaker is closed. Shortly after the CT is synchronized, it is loaded to a minimum or "spinning reserve" load. All the preceding steps are executed automatically by the CT's control computer system. At this point the HRSG begins warming up and rapidly begins to produce steam. The steam is initially vented, and as pressure builds in the steam system, the atmospheric vents close and the steam flow is diverted to the surface condenser. Once dry superheated steam is available at the ST, the ST start-up sequence can be initiated. The ST can then be accelerated to 3,600 RPM to match speed with the generator shaft. Once the speeds are synchronized, the clutch can be engaged and both the CT and the ST will supply shaft work to the generator. The steam turbine metal temperatures determine how quickly the steam turbine can be loaded. The cold start sequence requires the CT to operate at reduced load (below the emission compliance level) for up to 4 hours. During this time, the CT load is slowly increased to match the steam temperature to the ST metal temperature to heat the ST while minimizing thermal stress. Once the CT reaches the required load, steam is introduced to control nitrogen oxide formation. Once the SCR catalyst reaches the required temperature, ammonia injection is initiated and the HRSG stack emissions will fall to the required compliance levels. The CT can then be loaded normally to base load and the ST will reach a load based on the available steam.

Ammonia Synthesis Unit Start-Up

The Ammonia Synthesis Unit will require about 2 days to start-up and reach full capacity for a cold start-up. First, the circulation of high pressure boiler feedwater through the waste heat boiler, and that of cooling water through the appropriate heat exchangers is started. Then, the syngas compressor is started up and its speed slowly increased with hydrogen and nitrogen feeds. The initial period is used for purging the system and venting the gas (essentially hydrogen and nitrogen) via the flare system in the IGCC complex. The synthesis loop pressure is increased by increasing the compressor speed and syngas flow rate. The start-up heater is switched on to raise the converter catalyst bed temperatures. As the catalyst bed temperature is increased, the exothermic ammonia synthesis reaction starts taking place and ammonia is produced. As the synthesis loop pressure and the converter temperatures are increased, the ammonia refrigeration compressor is brought on line. The chilling provided by this system is used to separate the ammonia product from the main gas stream. The unconverted gas is recycled back to the syngas compressor.

The operating temperatures of the ammonia synthesis converter and the ammonia chillers are next optimized. The start-up heater is then shut down. Then, the synthesis loop pressure is brought to design conditions by increasing the syngas compressor speed and feed rates. At this point, the Ammonia Synthesis Unit is operating at its design capacity and producing cold liquid, warm liquid, and vapor ammonia product streams.

Urea Unit Start-Up

For a cold-start up, the Urea Unit will require about 18 hours to reach full capacity. First, the circulation of cooling water through the appropriate heat exchangers is started. The CO_2 Compressor and the Air Blower are then brought on line at low speed and the CO_2 and air are circulated through the following high pressure vessels:

- High Pressure (HP) Stripper
- Urea Reactor
- HP Carbamate Condenser
- HP Scrubber

The initial period is used for purging the system and venting CO_2 at the urea absorber stacks. Then, the CO_2 compressor speed is increased and the above mentioned vessels are pressurized with CO_2. Medium pressure (385 psig) steam is then introduced in the HP Stripper to raise the temperature of the system. Steam condensate from the HP Stripper is flashed at low pressure (60 psig) to provide steam for users at this level.

Pressurized liquid ammonia stream is introduced into the Urea Reactor to react with the CO_2 stream. The liquid product stream from the Urea reactor consists of urea, carbamate, water, and excess ammonia. This liquid stream is routed to the HP Stripper where carbamate and excess ammonia are separated and recycled to the Urea Reactor with the incoming CO_2 feed stream. The bottoms product from the HP Stripper is urea solution containing over 50 weight percent urea. The urea solution is routed to downstream units for further concentration. A 70 weight percent urea solution is first produced in the LP Rectifier and the Flash Vessel. This solution is stored in the intermediate solution tank. From this tank it is pumped to the vacuum separators/ evaporators to produce either the 80 weight percent urea stream for use in the UAN complex, or a greater than 99 weight percent urea melt stream for use in the Pastillation Unit.

UAN Unit Start-Up

From a typical cold-start up, the UAN Unit will require about 12 hours to reach full capacity. The UAN Unit consists of a Nitric Acid Unit, Ammonium Nitrate Unit, and a UAN blending unit. It is assumed that both the upstream Ammonia Unit and the Urea Unit are operating normally before the UAN Unit is started-up. The start-up sequence will consist of the following:

- Start-up of the Nitric Acid Unit
- Start-up of the Ammonium Nitrate Unit
- Start-up of the Urea Ammonium Nitrate Blending Unit

Start-Up of the Nitric Acid Unit

Circulation of boiler feedwater is first started through the Waste Heat Boiler. Then, the air compressor is started up and air is used to pressurize the system consisting of the Ammonia Converter, Tail Gas Heater, Absorber, and all associated heat exchangers. The ammonia vapor stream from the battery limits is then slowly introduced and fed to the Ammonia Converter. A highly exothermic reaction of ammonia with air takes place over platinum catalyst to produce a

mixture of nitric oxide (NO) and water vapor. The resulting high temperature gas from the Ammonia Converter then flows through a heat recovery system consisting of Expander Gas Heater, Waste Heat Boiler, Tail Gas Heater, and Air Heater. The cooled gas is then routed to the Absorber where it is mixed with air to reoxidize the NO to NO_2. The vapor stream is contacted with feedwater in the Absorber column to produce nitric acid of the desired strength. The overhead from the Absorber is tail gas which is heated in a series of exchangers before being routed to the Tail Gas Expander for power recovery. The tail gas is treated in a catalytic system for NO_X emission control before being vented. The nitric acid product is routed to the Nitric Acid Surge tank for use as feed to the Ammonium Nitrate Unit.

Start-Up of the Ammonium Nitrate Unit

The feeds for the Ammonium Nitrate Unit are nitric acid and ammonia vapor. Ammonium Nitrate (75 to 83 weight percent) is produced in the Neutralizer by the reaction between ammonia vapor and nitric acid. The ammonia vapor is mixed with the nitric acid with a sparger system in the bottom of the Neutralizer.

The heat of reaction in the Neutralizer boils off steam which passes overhead in the Scrubber. The function of the scrubber is to condense the right amount of steam to control the concentration of the product ammonium nitrate solution from the Neutralizer. The overhead vapors from the Neutralizer/Scrubber are further cooled and scrubbed of residual ammonia in the vent scrubber before being vented. The collected condensate is returned to the Absorber. The resultant ammonium nitrate solution is routed to the UAN Blending facility.

Start-Up of the UAN Blending Unit

The feeds to this unit are 80 weight percent urea solution from the Urea Unit and the ammonium nitrate solution from the Ammonium Nitrate Unit. These two streams are blended in the UAN Mix Tank to produce the UAN solution.

Operating Emissions

This section describes steady-state operations, and the start-up/shut-down operations and associated emissions from each source at HECA. The emissions from these sources will be minimized through implementation of BACT as outlined in Section 5.1.6.13.

Power Block CTG/HRSG

The most significant emission source of the Project will be the CTG/HRSG train. The MHI 501GAC® combustion turbine and steam turbine generator will provide approximately 405 MW gross output to produce approximately 300 MW of reliable, low-carbon baseload electricity. Exhaust gas from the turbine section is ducted through the HRSG to generate high-energy steam which produces additional electricity in the steam turbine. Some of the exhaust gas is also ducted from the HRSG to the Gasification Block to dry the feedstock and will be discharged at the coal dryer stack in that process block. Remaining exhaust gas at the HRSG is discharged through the HRSG stack. The combustion system is designed for operation on hydrogen-rich fuel. The combustion system is also equipped with separate fuel nozzles for natural gas-firing during start-up, shut-down, and equipment outages. The combustion system is designed to

achieve low NO_X emissions while injecting nitrogen diluent and combusting hydrogen-rich fuel. When operating on natural gas, water is injected for NO_X control. Natural gas is used during start-up and shut-down of the combustion turbine and during periods of unplanned equipment outages (up to 2 weeks per year).

The combustion turbine exhaust gas, supplemental hydrogen-rich fuel for duct-firing, and PSA off-gas for duct-firing are used as energy input into the HRSG. A selective catalytic reduction (SCR) system is installed in the HRSG to reduce emissions of nitrogen oxides (NO_X) to meet BACT requirements. An oxidation catalyst is also installed in the HRSG to reduce CO and VOC emissions to permit requirements. The HRSG stack is provided with a continuous emission monitoring systems (CEMS) to verify compliance with applicable air permit requirements. The CTG/HRSG will operate in a compliance load range of 70 to 100 percent.

Coal Dryer

The MHI gasification system includes equipment to grind and dry the feedstock. The blended feedstock is stored in silos. The feedstock then flows to the grinding mills where the particle size is reduced to that required for transport into the gasifier and simultaneously dried. The heat source for feedstock drying is hot turbine exhaust gas from the HRSG. After drying the feedstock, the drying gasses flow through a dust collection system then to the atmosphere. The dried feedstock flows to intermediate storage bins from which it is transported into the gasifier.

Power Block CTG/HRSG and Coal Dryer Operating Emissions

During operations and some phases of the start-up and shut-down activities, a portion of the HRSG flue gas will be diverted to the feedstock drying area, filtered through a baghouse, then exhausted from the coal dryer stack. As a result, the emissions from these two stacks are interconnected. The HRSG flue gas that is diverted to the coal dryer has emissions already controlled by the oxidation catalyst and SCR. This exhaust stream is further controlled with a baghouse before being exhausted to the atmosphere through the coal dryer stack.

Maximum short-term operational emissions from the CTG/HRSG and coal dryer were determined from a comparative evaluation of potential emissions corresponding to on-peak and off-peak operating conditions. The criteria pollutant emission rates were provided by the turbine vendor and the design engineers for two load conditions (on-peak and off-peak) and three ambient temperatures (39ºF, 65ºF, and 97ºF) when firing syngas and one load condition (off-peak) when firing natural gas. The maximum short-term operational emissions from the CTG/HRSG and coal dryer when combusting syngas and the CTG/HRSG when operating on natural gas are presented below in Table 5.1-11. Emissions for all operating cases are presented in Appendix E-3, Operational Criteria Pollutant Emissions.

The long-term operational emissions from the CTG/HRSG and coal dryer were estimated by summing the emissions contributions from on-peak operating conditions, including duct-firing (for average ambient condition of 65ºF), CTG/HRSG start-up/shut-down conditions and maximum natural gas usage. These annual emissions of air pollutants for the CTG/HRSG and coal dryer have been calculated based on the expected operating schedule of 8,000 hours of operations, two start-ups and shut-downs per year and 2 weeks of natural gas operations. These emissions are presented in Table 5.1-12.

CTG/HRSG Start-Up and Shut-Down Emissions

Because start-up and shut-down events typically have higher emission rates than operating conditions, they are incorporated into the short- and long-term emissions estimates for the CTG/HRSG for modeling purposes. The CTG will initially be started up using natural-gas fuel, then shifted to syngas as the syngas becomes available, and conversely during a shut-down as syngas production decreases, the CTG will be operated on natural gas. Therefore, the expected emissions and duration of start-up and shut-down events summarized in Table 5.1-13 reflect the emissions from both natural gas and syngas.

Because hours that include start-up and shut-down events will have higher NO_X, CO, and VOC emissions than the normal operating condition with fully functioning SCR and CO oxidation catalyst, they were incorporated (as applicable) into the worst-case short- and long-term emissions estimates in the air quality dispersion modeling simulations for these pollutants.

Power-Block, ASU, and Process Cooling Towers

Power-block heat rejection will consist of a steam surface condenser, cooling tower, and cooling water system. The heat rejection system receives exhaust steam from the low-pressure steam turbine and condenses it to water for reuse. Approximately 95,500 gallons per minute (gpm) of water will be circulated in the power-block cooling tower.

The ASU cooling tower is located in the ASU unit near the cooling loads. The ASU cooling tower has separate pumps and piping systems and is operated independently of the other cooling water systems. The ASU cooling tower circulation rate is approximately 45,000 gpm.

The major heat rejection duties associated with the process cooling tower are from the CO_2 compressor and the AGR refrigeration unit. Cooling water is also supplied to the Gasification, Shift, LTGC, SRU/TGTU, SWS, and Manufacturing Complex as well as other miscellaneous users. The process cooling tower is collocated with the power-block cooling tower. Each tower has a separate cooling-water basin, pumps, and piping system, and operates independently. The process tower circulation rate is about 163,000 gpm.

The cooling water circulates through each of the mechanical draft-cooling towers, which use electric motor-driven fans to move the air into contact with the flow of the cooling water. The heat removed in the condenser will be discharged by heating the air, and through evaporation of some of the cooling water. Maximum drift; that is, the fine mist of water droplets entrained in the warm air leaving the cooling tower, will be limited to 0.0005 percent of the circulating water flow.

For the Power Block and process cooling towers, circulating water could range from 3,000 to 9,000 ppm total dissolved solids (TDS) depending on makeup water quality and tower operation. Therefore, PM_{10} emissions would vary proportionately. For emission calculation purposes, it is assumed that 9,000 ppm TDS are in the circulating cooling water. The cooling equipment in the ASU requires significantly lower dissolved solids in the circulating water than the rest of the plant, thus a maximum of 2,000 ppm TDS are in the circulating ASU cooling water.

The cooling tower total PM emissions are based on the maximum expected total dissolved solids in the cooling water, annual circulating water rate, and the use of a high-efficiency drift eliminator. It is conservatively estimated that total PM emitted from the cooling tower will be equal to PM_{10} in diameter, and the quantity of PM emissions that are equal to $PM_{2.5}$ will be 60 percent of the PM_{10} emissions (a fraction or ratio of 0.6). The basis for the ratio used is described in Response to Data Request 18 (URS, 2009b), and also in "Applicant Comments On The Preliminary Determination Of Compliance For The Hydrogen Energy California (HECA) Project (08-AFC-8)," which is provided in Appendix E-4, Responses to $PM_{2.5}$ Cooling Tower Data Requests from CEC and USEPA.

Annual emissions from the Power Block, ASU and process cooling tower are presented in Table 5.1-14. Hourly and annual emissions and calculation details are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Auxiliary Boiler

The auxiliary boiler will provide steam to facilitate CTG start-up and for other industrial purposes. The auxiliary boiler will be designed to burn pipeline-quality natural gas at the design maximum fuel flow rate of 213 MMBtu/hour (higher heating value). The auxiliary boiler emissions are based on an annual capacity of 25 percent maximum load operation, or 466 billion Btu per year.

The NO_X emissions will be controlled with the installation of SCR and additional flue gas recirculation if necessary. The NO_X emissions are based on 5 parts per million volumetric dry (ppmvd) at 3 percent oxygen (O_2) with installation of SCR. Carbon monoxide emissions are based on 50 ppmvd at 3 percent O_2. Ammonia emissions are based on 5 ppmvd at 3 percent O_2. SO_2 emissions are based on the sulfur content of the natural gas. PM_{10}, $PM_{2.5}$, and VOC emissions are based on vendor-supplied emission factors.

A summary of auxiliary boiler emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Gasification, SRU, and Rectisol® Flares

During gasifier start-up, unprocessed/unreacted vent gas is vented to the flaring system. The Gasification Block will operate a gasification flare to safely dispose of gases during gasifier start-up and unplanned power plant upsets or equipment failures. The gasification flare may operate approximately 28 hours per year for start-up and shut-down events.

There will be an SRU flare installed to safely dispose of gas emissions from the AGR source during start-up (after passing via a scrubber), or to oxidize releases during emergency or upset events. The SRU may flare for up to 40 hours per year during plant start-ups.

The Rectisol® flare will be used to safely dispose of low-temperature gas streams during start-up, shut-down, and unplanned upsets or emergency events. The Rectisol® flare may be used for off-specification CO_2 during gasifier start-up or shut-down events. It is expected that a maximum of 40 hours per year of flaring for this purpose would be required by this flare.

During operations, the three flares will have pilot flames that will operate continuously. Emissions from the flares are generated from the continual operation of the natural gas fired pilots and from periodic vent gases that are oxidized during planned start-up/shut-down of the Gasification Block. The annual emissions from each flare were estimated by adding the emissions from continual use of the pilot plus the planned use during gasifier start-up/shut-down events.

A summary of each flare emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Tail Gas Thermal Oxidizer

Associated with the operation of the sulfur recovery process, the Project will incorporate a thermal oxidizer on the tail-gas treating unit (TGTU). The thermal oxidizer will serve as a control device to oxidize any remaining H_2S (after scrubbing) and other vent gas that is generated during start-up, shut-down, and times of non-delivery of CO_2 product. In addition, miscellaneous oxidizing streams from the gasification area (e.g., atmospheric tank vents and miscellaneous equipment vents) are directed to the thermal oxidizer during operation to prevent nuisance odors. The thermal oxidizer operates at high temperatures, and provides sufficient residence time in order to ensure essentially complete destruction of reduced sulfur compounds like H_2S to SO_2. The thermal oxidizer fires natural gas continually to reach and maintain the required operating temperature for proper thermal destruction. Pollutant emissions are generated from the firing of natural gas and the periodic oxidation of vent gas during SRU start-up. A summary of the tail gas oxidizer emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Carbon Dioxide Vent

The CO_2 vent stack will allow for start-up and intermittent emergency venting of produced CO_2 when the CO_2 compression, transportation, or injection system is unavailable. The CO_2 vent will enable the Project to operate, rather than be disabled, by brief periods when the CO_2 injection system is unavailable, and in doing so, prevents gasifier shut-down and subsequent gasifier restart with associated emissions.

A 260-foot stack height was chosen to satisfy HECA's inherently safe design practices to minimize ground-level CO_2 concentrations in the event of a CO_2 vent under very low wind speeds. The physical height of the CO_2 vent stack of 79.3 meters (260 feet) is within the calculated Good Engineering Practice (GEP) height.

The CO_2 vent exhaust stream will be nearly 100 percent CO_2, with small amounts of CO, VOC and H_2S. A summary of the maximum annual CO_2 vent stack emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Ammonia Synthesis Unit Start-Up Heater

The high-purity hydrogen stream, from the Pressure Swing Adsorption (PSA) Unit, and nitrogen, from the ASU, are combined in an exothermic ammonia synthesis reaction that takes place at

high temperature and high pressure across an iron-based catalyst. There is a large degree of heat integration within the Ammonia Synthesis Unit, and the substantial heat of reaction is recovered and used to generate steam. Cold liquid ammonia is stored in a tank at atmospheric pressure.

There are no normal operating emissions from the ammonia synthesis unit. However, a start-up heater (natural gas-fired) is used to heat the catalyst during a cold start of the unit. A 55-MMBtu/hr natural-gas–fired start-up heater is provided in the ammonia synthesis unit to raise the catalyst-bed temperatures during initial plant commissioning or during start-up after a long period of plant shut-down. The annual heat input for this heater is not expected to exceed 7,700 MMBtu higher heating value, which is equivalent to approximately 140 hours of operation at full capacity.

The heater will use a low-NO_X burner to control emissions to 9 ppmvd at 3 percent O_2. Carbon monoxide emissions are based on 50 ppmvd at 3 percent O_2. PM_{10}, $PM_{2.5}$ and VOC emissions are based on vendor-supplied emission factors. SO_2 emissions are based on 12.65 ppmv total sulfur in pipeline natural gas.

A summary of the ammonia synthesis unit start-up heater emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Urea Absorbers

The purified and compressed CO_2 and the liquid ammonia are reacted in the Urea Unit to create a concentrated urea solution, which is pumped to the Urea Pastillation Unit. Lower-concentration urea solution is produced as a feedstock to the urea ammonia nitrate (UAN) Solution Plant. Vacuum evaporator/separator systems are used to produce the required urea solutions.

The off-gases from the urea synthesis process, consisting of inerts (CO_2, nitrogen, and water) present in the CO_2 feed, process air and unreacted ammonia are cleaned before being vented in the HP scrubber, which operates at an elevated pressure. The off-gases are scrubbed first with process water, and second with clean cold water. In this way, nearly all of the ammonia is scrubbed from the gas. Low pressure off-gases are cleaned in the low-pressure (LP) scrubber, which operates at close to atmospheric pressure. Here, the off-gas is scrubbed with clean cold water to reduce the ammonia content in the vent.

The only emissions associated with the HP and LP Urea Absorbers are ammonia, which are reduced by the wet scrubber. Emissions from the HP and LP Urea Absorbers are presented in Section 5.6, Public Health. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions, and Appendix M, Public Health and Safety.

Urea Pastillation Unit

The pastillation process is used to convert the urea melt into high-quality pastilles. This process is enclosed with a hood, passed through a baghouse, then vented. Limited ammonia and urea dust, which is classified as $PM_{10}/PM_{2.5}$, are emitted from this source. The HECA pastillation process $PM_{10}/PM_{2.5}$ emissions will be limited to a grain loading of 0.001 gr/dscf by the

baghouse. A summary of the Urea Pastillation Unit emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Nitric Acid Unit

Nitric acid production is a three-step process consisting of ammonia oxidation, NO oxidation and absorption. Tail gas from the absorber column will be cleaned before being discharged by catalytic decomposition and reduction of both N_2O and NO_X.

The N_2O emissions are treated in a tertiary reduction system, based on its location at the end of the tail gas heat recovery system. Primary and secondary reduction occurs in the nitric acid unit equipment without any catalysis simply by the high process temperature. In the tertiary reduction, a reducing catalyst that uses high temperature rather than a reducing agent, converts 95 percent of the remaining N_2O emission to molecular nitrogen (N_2) and NO. The NO_X emissions (including the NO formed in the N_2O converter) are then reduced in one or more selective catalytic reduction (SCR) units, with injected ammonia as a reducing agent, as is typical for NO_X control in flue gas systems. Total NO_X emissions from this unit will not exceed 0.2 lb/ton of dry nitric acid or 15 ppmv NO_X. The HECA nitric acid plant will have an ammonia emission limit of 5 ppm due to slip from the SCR.

A summary of the nitric acid unit emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Ammonium Nitrate Unit

Ammonia and nitric acid are the feedstocks to the ammonium nitrate unit, which makes the ammonium nitrate solution. The ammonium nitrate unit vent stream contains water vapor and residual ammonium nitrate solution mist that is not removed by the demisting system. If this vent stream with mist is emitted directly to the atmosphere, the mist droplets would evaporate and result in PM emissions. These particulate emissions are substantially reduced by routing the vent stream to a water scrubbing system before discharge to the atmosphere. This vent scrubber condenses the vapor into condensate which then absorbs the previously entrained mist droplets. The condensate stream is either recycled to the neutralizer or mixed with cooling tower blowdown for treatment and disposal. The HECA Project will use a near total condensing vent scrubbing system and the scrubber vent particulate emissions will be less than 0.2 lb/hr. All PM emissions are assumed to be $PM_{2.5}$ or smaller.

A summary of the ammonium nitrate unit emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Material Handling Dust collection

Particulate matter emissions are associated with the material handling of the feedstock, petcoke and coal, urea, and gasification solids. These operations include bulk material unloading, loading, belt conveying, belt transfer points, silo loading, and feedstock crusher, all controlled with a system of baghouses. Coal and petcoke will be stored in a storage building with separate coal and petcoke storage piles. The transfer conveyors are fully enclosed to control fugitive dust.

Urea pastilles are stored in four buildings that are fully enclosed with roofing and siding. All PM emissions are assumed to be $PM_{2.5}$ or smaller.

A summary of the material handling system emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Fugitive Emissions

Fugitive emissions of VOC, CO, NH_3, H_2S, and trace HAPs and GHGs may occur in some areas of the facility due to leaks in the piping and components. Fugitive emissions are associated primarily with the Gasification Block and the Manufacturing Complex. A leak detection and repair (LDAR) program will be implemented in select process areas to maximize emission reductions. LDAR is the primary established method for controlling fugitive emissions from various pieces of equipment, such as valves and seals.

Potential fugitive VOC emissions from piping components were estimated using the U.S. EPA guidance, *Protocol for Equipment Leak Emission Estimates* (USEPA, 1995c). The emission factors used in the calculations are for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) factors and are presented in Table 7 of the U.S. EPA guidance document. A LDAR program will be implemented on select process areas with the largest toxic air contaminant (TAC) and VOC fugitive emissions. Because the fugitive emission factors were based on factors for SOCMI facilities, the LDAR program implemented at this facility will meet the National Emission Standard for Hazardous Air Pollutants (NESHAPs) regulations, which are traditionally used at SOCMI facilities.

HECA LLC proposes to apply the LDAR program to the following areas in the Gasification Block, Area #1 (methanol), Area #5 (propylene), Area #7 (hydrogen sulfide [H_2S]–laden methanol), Area #8 (CO_2-laden methanol), Area #9 (acid gas), and Area #10 (ammonia-laden gas), and all portions of the Manufacturing Complex. These areas were selected because they had the largest uncontrolled emissions for methanol, propylene, hydrogen sulfide and ammonia. The following compounds were included as VOCs (not all compounds are found in the gas in each process area): methanol, propylene, COS, and hydrogen cyanide.

A summary of the fugitive emissions is presented in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions, with additional details in Appendix M, Public Health and Safety.

Emergency Generator Engines and Firewater Pump Engine

The Project will include two 2,922-horsepower standby diesel generators and one 556-horsepower standby firewater pump, located adjacent to the firewater tank. The diesel engines will exclusively combust ultra-low sulfur (15 ppm) No. 2 diesel fuel.

The 2,922-horsepower diesel engines are installed in an outdoor enclosure and will be connected to the 480-volt (V) switchgear. The switchgear supplies essential service power to critical lube oil and cooling pumps, gasification and auxiliary steam systems, gasification quench system, station battery chargers, uninterruptible power supply (UPS), heat tracing, control room and emergency exit lighting, and other critical plant loads. Emissions were estimated based on

hourly manufacturers' emission rates, as well as USEPA interim Tier 4 emissions standards for 2011 and newer model equipment. Sulfur dioxide emissions were estimated using ultra-low sulfur diesel fuel containing 15 ppm sulfur. The annual emissions from these engines are based on a maximum non-emergency use rate of 50 hours of operation per year each for the emergency generator engines, and 100 hours of operation per year for the fire pump engine. Emissions estimates for the three diesel engines are shown in Table 5.1-14. Emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Total Combined Facility-Wide Emissions

The total combined annual emissions from all stationary emission sources of the Project are shown in Table 5.1-14.

Commissioning

Construction is initially scheduled by area and major equipment erection. Later construction transitions to completion by system in order to support turnover to the commissioning team.

The commissioning period of the Project is expected to be completed within 16 months from mechanical completion. Commercial operation will start when the commissioning and start-up activities are completed, and the licensor/contractor guarantees and milestones have been achieved.

Commissioning is completed by system, with the utilities (fire protection, power, water, natural gas, steam, etc.) completed first. Commissioning the utility and support systems includes electric power, water treating, natural gas, and cooling tower, as well as the safety systems that will be needed to support initial operations of the equipment. Commissioning the Diesel Firewater Pump and the Emergency Diesel Generators will produce air emissions during initial operation and testing.

The major process units will be commissioned in a sequence that begins with the feed-producing units and ends with the product-producing units and systems.

The major Gasification Block units consume electrical power. The Power Block also must be reliable before commissioning on hydrogen-rich fuel begins. For these reasons, the Power Block will be commissioned ahead of the Gasification Block. The commissioning for the Project will require four distinct phases, which are described in the following sections.

Power Block Commissioning on Natural Gas

The Power Block will be initially commissioned on natural gas. The MHI 501GAC® uses diffusion combustors with water injection, rather than dry-low nitrogen oxide combustors. The following list briefly describes the steps for commissioning on natural gas:

- First fire
- Initial CT run-in
- Support of steam blows
- Initial steam turbine roll

- Nitrogen oxide tuning with steam injection
- Installation of SCR and oxidation catalyst
- CEMS drift test and source testing
- Power Block functional testing
- Water wash and Power Block performance testing and continuous operation test

The emissions associated with the sequence above are shown in Table 5.1-15.

The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. An estimation of 1,129 hours of operation during commissioning of the CTG/HRSG on natural gas with partially abated emissions is expected. Fuel flow monitoring will be conducted for all tests.

HECA LLC will make every effort to minimize emissions of CO, VOCs, and NO_X during the commissioning period (SO_2 and PM will be the same or less than operations); however, not all of the equipment to abate these emissions will be fully operational at the start of the commissioning period.

Once it has been installed, the oxidation catalyst will abate CO and VOC emissions from the gas turbine and the duct burners because it is essentially a passive device. Although the SCR catalyst is in some cases able to be installed prior to initial start-up of the combustion turbine, it may not be installed until later in the commissioning period, after completion of steam blows, which could deposit debris and otherwise damage the catalyst. The SCR catalyst may not be installed at the same time as the oxidation catalyst. Nitrogen oxide emissions from the gas turbine and the duct burners may be only partially abated during times that the gas-turbine burners are being tuned and the SCR system is being tested.

Commissioning emissions were very conservatively estimated as worst case by assuming that the control efficiency of the applicable abatement systems is essentially zero during significant portions of the commissioning phase. The CEMS will also be undergoing commissioning at this time. Once the CEMS is commissioned, it will record emissions of NO_X and CO. Emissions of SO_2 and PM_{10} may be quantified by using emission factors based on fuel flow.

Gasification Block and Balance of Plant Commissioning

The following description includes the commissioning activities that are expected to have air emissions. The description assumes that the major utility support systems are already operational (power distribution, firewater, power plant and instrument air, water treatment, steam, boiler feedwater, etc.). The key activities and events are listed below:

- Testing diesel generators
- Testing diesel firewater pump
- Auxiliary boiler initial firing and burner tuning
- Auxiliary boiler source testing
- Auxiliary boiler operation to support gasification commissioning (typically when the Power Block is not operating)
- Operation of the Power Block in support of Gasification Block commissioning

- Cooling tower operation supporting the ASU, Combined Cycle Power Block, and Gasification Block (process cooling tower)
- Gasification flare testing and operation in support of Gasification Block commissioning
- Rectisol® flare testing and operation in support of AGR Unit commissioning
- SRU Flare testing and operation in support of Gasification Block commissioning
- Gasifier testing and operation
- Testing and operation of the AGR, SRU, and Tail Gas Compression Unit
- Testing the SRU thermal oxidation
- Venting CO_2 to support the testing and operation of the AGR and CO_2 compression system

The emissions associated with the sequence above are shown in Table 5.1-16.

The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. Fuel flow monitoring will be conducted for all tests.

Power Block Commissioning on Hydrogen-Rich Fuel

The Power Block will require additional testing and nitrogen oxide tuning with hydrogen-rich fuel. The testing will cover the range of allowable load ranges. The Power Block will be commissioned first on natural gas. The oxidation catalysts are assumed to be in service and active when the HRSG operating temperature is sufficient. The SCR catalyst and ammonia injection system are assumed to be operating whenever the SCR catalyst temperature is in the required range and operation is sufficiently stable. Ammonia injection may be off-line during the initial phases of nitrogen oxide tuning. The key activities and events that are expected to produce air emissions are listed below:

- Start-up, shut-down, and standby operation of MHI 501GAC® on natural gas
- CT nitrogen oxide tuning on 100 percent hydrogen-rich fuel
- CT nitrogen oxide tuning on part load
- Water wash and performance testing on hydrogen-rich fuel
- Duct burner testing on hydrogen-rich fuel
- Duct burner testing on PSA off-gas (if available)
- Source testing on hydrogen-rich fuel across the load range
- Functional testing including fuel transfers and load changes
- IGCC performance test
- IGCC operational reliability test

The emissions associated with the sequence above are shown in Table 5.1-17. The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. An estimation of 1,182 hours of operation during commissioning of the CTG/HRSG on hydrogen-rich fuel with partially abated emissions is expected. Fuel-flow monitoring will be conducted for all tests.

Manufacturing Complex Commissioning

The Manufacturing Complex is comprised of several plants and support systems. High-purity hydrogen and high-purity nitrogen are feedstocks to the Ammonia Synthesis Unit, which produces anhydrous ammonia. Anhydrous ammonia and high-purity CO_2 are feedstocks to the Urea Unit. The Urea Unit produces approximately 99 weight percent urea solution that feeds the Urea Pastillation Unit, as well as 80 weight percent urea solution that feeds the Urea Ammonium Nitrate (UAN) Unit. Anhydrous ammonia is the feedstock for the Nitric Acid Unit and the Ammonium Nitrate Unit. The 80 weight percent urea solution and ammonium nitrate solution are feedstocks to the UAN Unit. The key commissioning activities and events that are expected to produce air emissions through the use of fired heaters or flare systems are listed below:

- PSA Units 1 and 2 including PSA off-gas compression (brief flaring of hydrogen and PSA off-gas)
- High-purity hydrogen compression and nitrogen compression (brief flaring of hydrogen)
- Test HRSG PSA off-gas duct burner system (if not already completed)
- Test Ammonia Synthesis Unit (use of start-up heater, brief flaring during catalyst reduction, and recycle compressor testing)
- Build ammonia storage inventory
- CO_2 purification and purified CO_2 compression (brief venting of CO_2)
- Test Urea Unit (HP loop passivation and heating)
- Test Urea Pastillation Unit (functional testing including particulate control systems)
- Test Nitric Acid Unit (tail gas nitrous oxide abator)
- Test Ammonium Nitrate Unit (ammonium nitrate vent scrubber)
- Test Urea Ammonium Nitrate (UAN) Unit (neutralizer overhead cleanup scrubber)
- Manufacturing Complex performance testing
- IGCC and Manufacturing Complex functional dispatch testing
- Plant-wide performance test
- Plant-wide reliability demonstration

The emissions associated with the sequence above are shown in Table 5.1-18. The duration of all tests may be affected by unforeseen events, and therefore can only be estimated in advance. An estimation of 3,388 hours of operation during commissioning from the combination of all Manufacturing Complex sources is expected.

Operational Emissions—Mobile Sources

Mobile Source Emissions—On-Site

On-site truck and train trip emissions were incorporated in the dispersion modeling for CEQA purposes. Trucks and trains delivering feedstock and removing products would travel to the Project Site on a regular basis. The maximum number of truck and train trips by period is summarized in Table 5.1-19. This section describes the emissions from the transportation associated with coal transportation Alternative 1 (rail transportation).

The petcoke trucks would enter the plant from Station Road, at Tupman Road, and then proceed south to the truck-unloading station. At the truck-unloading area, each truck would idle for no more than 5 minutes while unloading, then loop back around through the truck scales and wash rack to exit the plant onto Station Road. The product trucks and trains are loaded in the product loading area, located in the center of the Project site. The product trucks would also enter and exit the plant from Station Road at Tupman Road and pass through the truck scales and wash rack.

Coal will be transported to the site by train and some of the product will be transported off-site via train. The trains would enter and exit the northwest corner of the site near Dairy Road and Adohr Road. The train feedstock unloading and product loading stations are located in the center of the Project Site. In addition to the feedstock and product trains, there will be one dedicated switching engine on-site to move either the feedstock or product rail cars. The following section provides a breakdown of the transportation needs by product.

Emissions associated with the truck movement were calculated using heavy-heavy duty diesel truck emission factors for all trucks except the Operations and Maintenance trucks, which were calculated with the light-heavy-duty gasoline and diesel factors, from the CARB on-road emissions model EMFAC2007. The 2007 version of EMFAC was used to calculate all on-road vehicle emissions as this version of the model has been approved by EPA for use in projects that require EPA review, such as NEPA's analysis and federal conformity determination that will be conducted for HECA.

Emission factors from EMFAC2007 are provided in terms of grams per mile, which were converted to grams per second for the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) dispersion model, based on the distance traveled and the number and frequency of truck trips. EMFAC2007 factors vary depending on the calendar year for which the model is run, because the emission factors reflect adopted CARB engine and fuel standards, and are also based on the vehicle fleet age and composition. The vehicle fleet used by EMFAC2007 is based on an analysis of California Department of Motor Vehicles (DMV) registration data, which vary by calendar year and geographic area. Thus, EMFAC2007 runs for earlier calendar years will produce higher emission factors because of older, higher-polluting vehicles still in the vehicle fleet.

The anticipated Project commercial operation date is 2017. HECA LLC will use a fleet of delivery trucks that are model year 2010 or newer, thus EMFAC2007 emissions factors for vehicles for calendar year 2010 were used in the emission calculations.

The emissions factors for criteria pollutants for line-haul and switch locomotives were obtained from the USEPA document "Technical Highlights: Emission Factors for Locomotives" for Tier 3 engines (USEPA, 2009). On-site feedstock and product train emissions were calculated assuming the majority of the time the line-haul engines will operate in Notch 1 or idling, therefore emissions were conservatively estimated for Notch 1 horsepower. The percentage of total engine horsepower used at Notch 1 was obtained from the "Port of Long Beach Air Emissions Inventory for 2007," which was based on data derived from EPA (Port of Long Beach, 2009). Emissions from the switching engine were based on EPA Tier 3 emission factors and maximum switching engine horsepower of 260 hp.

The on-site Project related mobile emissions are summarized in Table 5.1-20. On-site transportation emissions and calculations are included in Appendix E-3, Operational Criteria Pollutant Emissions.

Mobile Source Emissions—Off-Site

This section describes the emissions from the transportation associated with coal transportation Alternative 1 (rail transportation). The Project will gasify a blend of 75 percent coal and 25 percent petcoke to produce a hydrogen-rich gas which will be used to produce low-carbon nitrogen-based products and electricity in a Combined Cycle Power Block. Western sub-bituminous coal will be supplied from mines in New Mexico and transported by rail. The coal trains travel through New Mexico, Arizona, Mojave Desert Air Quality Management District (MDAQMD), Eastern Kern Air Pollution Control District (EKAPCD), to the HECA facility in SJVAPCD. Petcoke most likely will be supplied from refineries in the Los Angeles or Santa Maria areas and transported by trucks. Therefore, the petcoke trucks travel in SJVAPCD and SCAQMD.

As a polygeneration facility, the Project is designed to produce several types of products. The products that will be shipped off-site by either truck or train include:

- **Degassed liquid sulfur.** Most of the sulfur will be transported by truck to existing buyers but some will also be transported by rail (approximately 75 percent by truck and 25 percent by rail). Rail is expected to travel on routes only within SJVAPCD and trucks would travel in both SJVAPCD and SCAQMD.
- **Gasification solids.** Most of the gasifier solids will be transported by rail for beneficial reuse by regional industries. A smaller portion can be transported to nearby industries by truck. It is estimated that movements would be approximately 75 percent by rail and 25 percent by truck. Rail is expected to travel on routes in SJVAPCD, EKAPCD and MDAQMD and trucks would travel within SJVAPCD.
- **Ammonia.** Although ammonia is an intermediate for the on-site production of urea pastilles and urea ammonium nitrate, some may be sold directly, rather than using it for urea or UAN production. It is estimated that 75 percent will be transported by truck and 25 percent by rail. Both rail and trucks would be routed only within SJVAPCD.
- **Urea pastilles.** Urea pastilles are small solid "pellets" of urea. The estimated movements are 75 percent by rail and 25 percent by truck. Rail is expected to travel through SJVAPCD, Sacramento Metro area, Yuba City-Marysville area, Chico area, and other areas in northern California, Oregon and Washington. Trucks would be routed only within SJVAPCD.
- **Urea ammonium nitrate (UAN).** The UAN solution is expected to be sold to regional users. The estimated movements are 50 percent by rail and 50 percent by truck. Both rail and trucks would be routed only within SJVAPCD.

In addition, trucks carrying chemical shipments, the ZLD solids and miscellaneous equipment would travel to and from the Project Site to various facilities in Kern County. All truck and train routes are calculated to be round-trip routes, and are differentiated by the air basin in which they occur to aid in the conformity determination calculations which are presented in Appendix E-5,

Offsite Operational Transportation Emissions. For purposes of the conformity determinations, it should be noted that not all of the affected air districts are non-attainment for the same pollutants. Further refinements will be conducted to ensure that only emissions in each non-attainment area are included in the conformity emission inventory.

Emissions associated with the truck movement were calculated using heavy-heavy duty diesel truck emission factors obtained from the CARB on-road emissions model EMFAC2007 for model year 2010, as described in the on-site truck emission calculations. Emissions associated with workers commuting to the Project were estimated using EMFAC2007 for a fleet mix of model years from 1971–2015 for light-duty automobiles and trucks. Fugitive road dust from trucks and worker vehicles was included in the inventory.

The emissions factors for criteria pollutants for line-haul and switch locomotives were obtained from the USEPA document "Technical Highlights: Emission Factors for Locomotives" for Tier 3 engines" (USEPA, 2009). Off-site feedstock and product train emissions were calculated based on the weight of the material shipped, the miles travelled, and the fuel consumption emission factor in ton-mile/gallon for 2009 Class I rail freight from the Association of American Railroads "Railroad Facts" (AAR, 2012).

As expected the majority of the transportation related emissions are in the San Joaquin Valley air basin. The off-site Project related emissions by air basin are summarized in Table 5.1-20. Off-site transportation emissions and calculations are included in Appendix E-5, Offsite Operational Transportation Emissions.

General Conformity

The General Conformity Rule ensures that the actions taken by federal agencies in non-attainment and maintenance areas do not interfere with a state's plan to meet national standards for air quality. The purpose of the General Conformity Rule is to ensure that federal activities do not cause or contribute a new violation of NAAQS and ensure that attainment of the NAAQS is not delayed. Therefore, federal entities are required to find that the total direct or indirect emissions from the federal action will conform to the purpose of the State Implementation Plan (SIP) or not otherwise interfere with the state's ability to attain and maintain the NAAQS. The General Conformity Rule may be implemented in coordination with and as part of the National Environmental Policy Act (NEPA) environmental review process. The proposed HECA Project is federally funded by the U.S. Department of Energy and is therefore subject to NEPA and the General Conformity Rule.

CO, PM_{10}, $PM_{2.5}$, SO_2, and O_3 precursor (NO_X and VOC) emissions during construction and operations are subject to General Conformity requirements. Stationary source emissions are controlled by the SJVAPCD permit and are considered to comply with the SIP; therefore, the stationary source emissions are not included in the General Conformity analysis. The USEPA created *de minimis* emission levels for each criteria pollutant to limit the need to conduct conformity determinations for federal projects with minimal emission increases. The attainment status of the project area determines the *de minimis* levels that are applicable for a project. When the total direct and indirect emissions from a proposed project are below the *de minimis* levels, the project would not be subject to a conformity determination.

Applicability is based on direct and indirect emissions from the proposed HECA Project, which include off-site truck and rail transportation, on-site truck and rail transportation, and the commuting of worker vehicles. As noted in the *Mobile Source Emissions – Off-site* section, the Project related vehicles travel through many air quality control regions (AQCR) in California (SJVAPCD, SCAQMD, EKAPCD, MDAQMD, Sacramento Metro area, Yuba City-Marysville area, Chico area), Oregon, Washington, Arizona, and New Mexico. A list of these AQCR, their attainment status and the associated conformity thresholds is provided in Table 5.1-20 and Appendix E-5, Offsite Operational Transportation Emissions.

Emissions allocated to each AQCR were calculated along the transportation routes according to the length of the route and are shown in Table 5.1-20 and Appendix E-5, Offsite Operational Transportation Emissions. It should be noted that not each of the affected air districts is non-attainment for the same non-attainment pollutants. Further refinements will be conducted to ensure only emissions in each non-attainment area are included in the conformity emission inventory. The estimated annual emission rates in each AQCR were compared to the applicability *de minimis* thresholds. The estimated emission increase due to transportation in most areas, except the NO_X emission increase in SJVAPCD, is less than the conformity *de minimis* levels. The NO_X emission increase due to the proposed Project operation associated with transportation in SJVAPCD is greater than the *de minimis* level of 10 tons per year (TPY). In addition, NO_X and VOC emissions during Project construction exceed the *de minimis* level of 10 TPY. Therefore, a conformity determination will be prepared by HECA LLC and reviewed by SJVAPCD for NO_X and VOC as precursors to ozone.

Operational Criteria Pollutant Emissions associated with OEHI EOR

Permitted emissions associated with the OEHI Project include emissions from new equipment installed for the purpose of CO_2 EOR and will include process heaters, tanks, fugitive ROG emissions from permitted equipment at the CO_2 EOR Processing Facility, and emissions from maintenance activities conducted on emergency use only equipment (i.e., diesel engines used for fire pumps). Diesel emergency engine testing is expected to occur 12 hours per year per engine. The emergency use only flares do not include maintenance allowance since the flares have to be removed from service in order to conduct such maintenance. Mobile source emissions are limited to on-road vehicle emissions from operational phase employees transiting between area residences and the OEHI Project Site.

OEHI will implement mitigation in the form of BACT and LDAR, plus emissions reduction credits (ERCs) will be provided, as required, to offset emission increases from permitted sources ensuring that impacts from emissions are less than significant. Emission calculations and Project details can be found in the Section 4.3, Air Quality, of Appendix A of this AFC Amendment. The analysis contained in Appendix A-1 concludes that emissions from the operation of the OEHI Project will not result in a significant adverse impact.

5.1.2.4 Operational Greenhouse Gas Emissions

Operational Greenhouse Gas Emissions—Stationary Sources

The GHG emissions presented in this section reflect the following key Project objectives:

- to provide dependable, low carbon baseload electricity;
- to help meet future electrical power needs and to support a reliable power grid that is an essential component to meeting California's GHG reduction goals for 2020 and beyond; and
- to mitigate impacts related to climate change by dramatically reducing GHG emissions relative to those emitted from conventional power generation and nitrogen-based product manufacturing by capturing and sequestering CO_2 emissions.

GHG emissions from HECA sources are minimized through implementation of GHG BACT as described in Section 5.1.6.13. GHG emissions were estimated for three operating scenarios, as described below:

- Early operations, which are expected to last approximately 2 years, during which time hydrogen-rich fuel availability will be approximately 65 to 75 percent. During this period, all sources are expected to be operated at maximum operating conditions, including two plant start-ups and shut-downs. The CO_2 vent is included with maximum permitted venting emissions of up to 504 hours at full capacity.
- Mature operations, which is expected to occur after the first 2 years of commercial operation when the hydrogen-rich fuel availability will be approximately 85 percent. At this stage, significantly less venting is expected to occur, thus CO_2 vent emissions are estimated based on approximately 10 days of venting at 50 percent capacity (or 120 hours of venting at 100 percent capacity). All other sources are operated at maximum operating conditions, including two plant startups and shutdowns.
- Expected mature operations occurs during the same period as mature operations. In this scenario, emissions are estimated based on maximum operating conditions for all sources for a year, including two start ups and shut downs, but no CO_2 venting. Emissions from operation of the CTG/HRSG on syngas are included; no natural gas use is included, except for startup and shutdown.

The CO_2 vent stack will allow for startup and intermittent emergency venting of produced CO_2 when the CO_2 compression, transportation, or injection system is unavailable. The CO_2 vent exhaust stream will be nearly all CO_2; thus, total exhaust flow was used to determine the CO_2 emissions.

Venting durations during early and mature operations were determined based on the following types of events that could occur over any 1-year period. These events include: (A) Gasification Block cold start-ups; (B) unplanned outages of the CO_2 compressor; (C) unplanned outages of the CO_2 pipeline; and (D) CO_2 Off-Taker unable to accept. The scenarios shown in Table 5.1-21 were developed as a conservative estimate of the venting that may be required during the early operations and for mature operations. Safe operation of the HECA Project is a key factor in considering whether to shut down the gasifier during short, unplanned CO_2 transportation system events. Shutting down the entire Gasification Block and restarting it increases the risk of upsets and must be considered when evaluating whether to vent CO_2 or shut down the Gasification Block.

The GHG emissions from the CTG/HRSG and coal dryer were estimated based on the composition of the syngas and PSA off-gas, the quantity of each to be used annually and a methane destruction rate of 98 percent.

Emissions of CO_2, CH_4, and N_2O from combustion of natural gas in the CTG/HRSG, auxiliary boiler, gasification flare, SRU flare, Rectisol® flare pilot, thermal oxidizer, and ammonia synthesis start-up heater were estimated using emission factors from of the California Climate Action Registry (CCAR) General Reporting Protocol Version 3.1 (Jan 2009). To calculate the N_2O emissions from the CTG/HRSG and coal dryer during combustion of syngas and PSA off-gas the CCAR natural gas emission factor was used even though actual emissions are expected to be lower than from the combustion of natural gas.

Emissions at the Rectisol® flare were based on the gas stream composition, which is high in CO_2, upstream of the Rectisol® unit since the unit may not be fully operational during a gasifier start-up or shut-down events.

Fugitive emissions of CO_2 may occur in some areas of the facility due to leaks in the piping and components. These emissions will be minimized through implementation of a LDAR program. Detailed emissions calculations are presented in Appendix M, Public Health and Safety.

CO_2 is used in the process of making urea and will be emitted from the urea absorber vents. Emission calculations are based on data provided by Project design engineers.

Nitric acid production is a three-step process consisting of ammonia oxidation, NO oxidation and absorption. Tail gas from the absorber column will be cleaned before being discharged by catalytic decomposition and reduction of both nitrous oxide (N_2O) and NO_X. The N_2O emissions are treated in a tertiary reduction system, based on its location at the end of the tail gas heat recovery system. Primary and secondary reduction occurs in the nitric acid unit equipment without any catalysis simply by the high process temperature. In the tertiary reduction, a reducing catalyst that uses high temperature rather than a reducing agent, converts 95 percent of the remaining N_2O emission to molecular nitrogen (N_2) and NO. The only GHG emission associated with the nitric acid unit are N_2O. Emissions were estimated based on nitric acid production a vendor supplied emission factor and the destruction efficiency.

The circuit breakers will also have the potential to emit a very small amount of GHG, sulfur hexafluoride (SF_6). Circuit breakers do not emit SF_6 directly, but they do have the potential for fugitive emissions (leaks). The circuit breakers will be designed to have a leakage rate of at most 0.5 percent annually. Emissions are based on the amount of SF_6 in each circuit breaker and the leakage rate.

Emergency generators and firewater pump engines emissions of CO_2, CH_4, and N_2O were estimated using diesel emission factors from of the CCAR General Reporting Protocol Version 3.1 (January 2009).

Table 5.1-22 presents the annual CO_2e emissions from all stationary sources at HECA in metric tons (tonnes) during the early operations phase.

For comparison to the SB 1368 Greenhouse Gases Emission Performance Standard, GHG emissions and electricity production were calculated following CEC's "Regulations Establishing and Implementing a Greenhouse Gases Emission Performance Standard for Local Publicly Owned Electric Utilities" (CEC, 2012).

The SB 1368 emission calculations include only the annual GHG emissions from each fuel used in any component directly involved in electricity production or associated with the sequestration of CO_2. Emissions from electricity production come from the CTG/HRSG and coal dryer when burning syngas, PSA off-gas and natural gas, and SF_6 from the circuit breakers. Emissions associated with the CO_2 sequestration include the CO_2 vent and fugitives from CO_2 preparation for sequestration. HECA will provide OEHI with sequestration ready CO_2. No additional compression or processing would be needed to sequester the CO_2 after it leaves HECA. The SB 1368 emission calculations do not include emissions associated with the Gasification Block (flares, thermal oxidizer), Manufacturing Complex (ammonia synthesis plant start-up heater, urea absorbers, nitric acid unit), auxiliary boiler, emergency generators, fire pump, and vehicles.

The net electricity production calculated for SB 1368 compliance for hydrogen-rich fuel generation includes the net power exported plus the power used on-site in the Manufacturing Complex minus the steam generated from the ammonia production unit. The net power exported (267 MW) is presented in Table 2-10 in Section 2, Project Description. Approximately 58 MW of power will be used in the Manufacturing Complex, and about 5 MW of steam generated in the ammonia production unit will be added to the HRSG. Thus, the net electricity production for SB 1368 for hydrogen-rich fuel generation is 320 MW. The net electricity production for natural-gas generation is 300 MW (presented in Table 2-10).

Table 5.1-23 presents the CO_2e emissions for SB 1368 compliance for the three scenarios: early operations, which include the maximum permitted emissions for all Project emission sources; mature operations, which includes less CO_2 venting than the early operation scenario; and expected mature operations on hydrogen-rich fuel. CO_2 equivalent emissions from the electricity production at HECA are approximately 230 lb/MWh during expected mature operations on hydrogen-rich fuel. The maximum CO_2e emissions during early operations, including emissions from natural-gas operation, startup, shutdown, and CO_2 venting, would be approximately 400 lb/MWh.

These maximum emissions are less than one-half of those from a typical natural-gas combined-cycle power plant. In summary, the Project's GHG emissions will be well below the 1,100 lb CO_2/MWh threshold requirement of SB 1368 and the New Source Performance Standards (NSPS) of 1,000 lb CO_2/MWh threshold proposed by USEPA.

GHG emissions and calculations associated with the operation of HECA are included in Appendix E-6, Operational Greenhouse Gas Emissions.

Operational Greenhouse Gas Emissions—Mobile Sources

Mobile Source Emissions—On-Site

This section describes the emissions from the transportation associated with coal transportation Alternative 1 (rail transportation). On-site vehicle GHG emissions are based on the same data as the criteria pollutants emissions described earlier. The emission factors for CO_2 from EMFAC2007 were used for the on-road vehicles. The emission factors for N_2O and CH_4 are based on Table C.4 in the California Climate Action Registry (CCAR) General Reporting Protocol Version 3.1 (January 2009) for diesel and gasoline fueled trucks.

The CO_2 emission factors for switching and line-haul locomotives for Tier 3 emissions were used (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH_4 and N_2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) were used for locomotives.

On-site transportation GHG emissions are presented in Table 5.1-24 and calculation details are included in Appendix E-6, Operational Greenhouse Gas Emissions.

Mobile Source Emissions—Off-Site

This section describes the emissions from the transportation associated with coal transportation Alternative 1 (rail transportation). Off-site vehicle GHG emissions are based on the same data as the criteria pollutants emissions described earlier. The emission factors for CO_2 from EMFAC2007 were used for the on-road vehicles. The emission factors for N_2O and CH_4 are based on Table C.4 in the California Climate Action Registry (CCAR) General Reporting Protocol Version 3.1 (January 2009) for diesel and gasoline fueled trucks.

The CO_2 emission factors for switching and line-haul locomotives for Tier 3 emissions were used (40 CFR Part 1033, EPA Switch and Line-haul Locomotive Emission Standards). CH_4 and N_2O factors are from California Climate Action Registry General Reporting Protocol Version 3.1 (January 2009), Table C.6 (Methane and Nitrous Oxide Emission Factors for Non-Highway Vehicles) were used for locomotives.

Off-site transportation GHG emissions are presented in Table 5.1-24 and calculation details are included in Appendix E-6, Operational Greenhouse Gas Emissions.

Operational GHG Emissions Associated with OEHI EOR

During the operational phase of the OEHI Project there will be various stationary, mobile, and indirect sources. Indirect sources refer to emissions of CO_2e produced as a result of generating electrical power consumed by the Project. Of the total estimated operational CO_2e emissions, approximately 79 percent would be from indirect sources (e.g., consumption of electric power not generated as part of the OEHI Project). Emission calculations and Project details can be found in Section 4.18, Greenhouse Gas Emissions of Appendix A-1 of this AFC Amendment,

which concludes that GHG emissions from the operation of the OEHI Project will not result in a significant adverse impact.

The entire EOR process occurs within a specially-designed, closed system. During operations, there is no venting or emissions of CO_2 to the atmosphere. CO_2 is a valuable commodity, and there is significant financial incentive for EOR operators to closely monitor and contain all of the injected CO_2. Additionally, OEHI has studied potential leakage pathways, and determined that there are no identified leakage pathways that would result in significant loss of CO_2 to the atmosphere.

DOE's National Energy Technology Laboratory released a report titled "Carbon Dioxide Enhanced Oil Recovery" (DOE-NETL, 2009), in which DOE specifically addressed the question, "Won't the CO_2 be released when the oil is produced?" DOE's answer is found on page 23: "No. Any CO_2 that is produced along with oil and natural gas is captured and re-injected. The company operating the EOR project bought the CO_2 and expects to re-inject it if any is produced, to maximize its value. It only has value when it is used to remove oil from the rock formation underground, so there is a strong economic motivation to collect it for re-injection, either in the current Project or another. When a CO_2 EOR flood is finished, the CO_2 that remains underground stays there. Monitoring efforts can be put into place to make sure that is true."

5.1.2.5 Dispersion Modeling Methodology

The purpose of the air quality impact analyses is to evaluate whether or not criteria pollutant emissions resulting from the Project will cause or contribute significantly to a violation of a California or National AAQS. Mathematical models, designed to simulate the atmospheric transport and dispersion of airborne pollutants, are used to quantify the maximum expected impacts of Project emissions for comparison with applicable regulatory criteria. Potential impacts of toxic air contaminant emissions from the Project are evaluated in Section 5.6, Public Health and Safety.

Separate criteria pollutant modeling analyses were conducted to address the air quality effects of emissions from Project construction activities and operations, because these activities will occur at different times. Impacts from construction activities include fugitive dust from road travel and excavation of disturbed areas, and exhaust combustion products from diesel- and gasoline-fueled construction equipment and vehicles. The impacts from operations will be associated with the operation of the Gasification Block, Power Block, Manufacturing Complex, material handling, ancillary equipment, and, for CAAQS, mobile sources. Impacts from commissioning the Project are also analyzed.

The air quality modeling methodology described in this section has been documented in formal modeling protocols, which have been submitted for comment to CEC, SJVAPCD, and USEPA Region IX. The modeling protocols formally submitted and docketed are as follows:

- Air Quality Modeling Protocol for the HECA Power Project, Kern County, California, February, 2009 (URS, 2009a)

- Modeling Protocol for Parameter Selection Specific to the 1-hour NO_2 NAAQS Regional Modeling for the HECA Project, January 20, 2011 (URS, 2011)

- Modeling Protocol Supplement for the HECA Project (URS, 2012)

The modeling approaches used to assess various aspects of the Project's potential impacts to air quality are discussed below and follow the techniques outlined in the modeling protocols. Modeling input and output files will be submitted electronically with this AFC Amendment.

Model and Model Option Selections

The impacts of Project operations on criteria pollutant concentrations in receptor areas within approximately 6 miles (10 kilometers) from the Project Site and Controlled Area were evaluated using the AERMOD (Version 12060). Similarly, construction impacts were evaluated at receptor areas within 1 kilometer using AERMOD. AERMOD is appropriate for this AFC Amendment because it has the ability to assess dispersion of emission plumes from multiple point, area, or volume sources in flat, simple, and complex terrain, and to use sequential hourly meteorological input data. The regulatory default options were used, including building and stack tip downwash, default wind speed profiles, exclusion of deposition and gravitational settling, consideration of buoyant plume rise, and complex terrain.

Compliance with SJVAPCD Rule 2201 modeling requirements for attainment pollutants will be demonstrated by modeling the maximum ground level concentrations of the Project at any receptor and adding conservative background concentrations, based on recent data from the most representative air quality monitoring stations. The Project will not be considered to cause or contribute to a near-field ambient air quality violation unless impacts from these sources combined with the background concentration exceed the most stringent AAQS.

Note that emissions reduction credits will be obtained by HECA LLC to offset Project emissions increases of the following pollutants: NO_X, VOC, PM_{10}, and SO_2 as these pollutants are above the SJVAPCD emission offset triggering levels specified in the District's Rule 2201. No credit was taken for emission offsets in the modeling analysis.

Evaluation of construction, commissioning, and operational NO_2 concentrations (1-hour and annual averaging times) was accomplished using the ozone limiting method Plume Volume Molar Ratio Method (PVMRM) option in AERMOD. The PVMRM option accounts for the role of ambient O_3 in limiting the conversion of emitted NO_X—which occurs mostly in the form of nitrogen oxides (NO)—to NO_2, the pollutant regulated by ambient standards. The input data to the AERMOD-PVMRM model were provided by SJVAPCD and include representative hourly O_3 monitoring data for the years corresponding to the meteorological input record.

To evaluate whether urban or rural dispersion parameters should be used in model simulations, an analysis of land use adjacent to the Project Site was conducted in accordance with Section 8.2.8 of the *Guidelines on Air Quality Models* (USEPA, 2003), and Auer (1978), USEPA AERMOD implementation guide (USEPA, 2004), and its addendum (USEPA, 2006). Based on the Auer land use procedure, more than 50 percent of the area within an approximately 2-mile (3-kilometer) radius of the Project is classified as rural. Because the Auer classification scheme

requires more than 50 percent of the area within the approximately 2-mile (3-kilometer) radius around a proposed new source to be non-rural for an urban classification, the rural mode will be used in the AERMOD modeling analyses.

Building Wake and Good Engineering Practice

The effects of building wakes (i.e., downwash) on plumes from the Project's operational sources were evaluated in accordance with USEPA guidance (USEPA, 1985). Data on the buildings on the Project Site that could potentially cause plume downwash effects for the sources were determined for different wind directions using the USEPA Building Profile Input Program–Prime (BPIP-Prime) (Version 04274).

As defined in *Guideline for Determination of Good Engineering Practice Stack Height* (USEPA, 1985), GEP is defined as the height necessary to ensure that emissions from a stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies, or wakes that may be created by the source itself, nearby structures, or nearby terrain obstacles.

All stacks in the HECA Project will be less than or equal to the GEP default height of 65 meters, except for the coal dryer, three flares, and the CO_2 vent. The heights of these stacks are as follows:

- Coal Dryer: 92.9 meters
- SRU Flare, Gasification Flare, Rectisol® Flare: 76.2 meters
- CO_2 Vent: 79.2 meters.

BPIP Prime has been run to determine the GEP height for each stack. The output of this model shows that the GEP for the three flares is 65 meters, for the coal dryer is 223.91 meters, and lastly the CO_2 vent is 223.90 meters. BPIP files will be provided with this application.

GEP is calculated based on the following equation:

$$Hg = H + 1.5 * L$$

where: Hg = GEP stack height (in meters)
H = height of the nearby structure (in meters)
L = lesser dimension of the height or projected width of the nearby structure (in meters)

The largest structure near these stacks is the gasifier building, which is 92.9 meters high and 27.7 × 82.8 meters in length × width, respectively. Therefore, L = 87.3 meters, H = 92.9 meters, and Hg = 223.9 meters.

The gasifier building is located at a distance within five times L (436.5 meters) from the CO_2 vent and the coal dryer; therefore, GEP for these stacks is calculated based on the gasifier building dimensions. The heights of the coal dryer and CO_2 vent are thus well below the GEP height of 223.9 meters.

The flares are located upwind of the gasification building along its shorter axis, thus L = 27.7 meters and Hg = 134.5 meters. The flares are not within 5 times L (138.5 meters) of the gasification structure or any other structure that is large enough to create downwash for the flares in BPIP Prime. It is important to note that the flares will be built at 76.2 meters tall for safety from a project engineering perspective. However, a 65-meter stack height, or GEP, was used to calculate specific effective stack heights for each flare modeling scenario based on the flare's heat release rate during that modeling scenario. The effective stack height is the height of the stack plus the height above the stack where the flare flame ends and a plume can begin. The effective stack parameters were calculated using the SCREEN3 technique, and were input into the AERMOD model (USEPA, 1995b). Therefore, the lower 65 meter stack height was used as the stack height in the calculation of the effective stack heights for the flares, rather than the actual stack height. Appendix E-3, Operational Criteria Pollutant Emissions, presents the effective stack parameters for the flares.

The results of the BPIP-Prime analysis were included in the AERMOD input files to enable downwash effects to be simulated. Input and output files for the BPIP-Prime analyses are included in the electronic files submitted with this AFC Amendment.

Meteorological Data

Meteorological data suitable for direct input to AERMOD were obtained from the SJVAPCD website. Hourly surface data for calendar years 2006 through 2010 were obtained from the SJVAPCD at the Bakersfield Airport meteorological station, located on the northern end of the city of Bakersfield, within 20 miles (32.2 kilometers) east-northeast of the Project Site. These data have been pre-processed by the SJVAPCD with the Oakland upper-air data to create an input data set specifically tailored for input to AERMOD. The SJVAPCD prepared these data specifically for use at locations such as the Project Site.

The meteorological data recorded at Bakersfield Airport are acceptable for use at the Project Site for two reasons: proximity and terrain similarity. The Bakersfield Airport is the closest full-time meteorological recording station to the Project Site. The terrain immediately surrounding the Project Site can be categorized as a fairly flat, or gradually sloping rural area in a region with developed oil wells. The terrain around the Bakersfield Airport also consists of relatively flat, or gradually sloping rural or suburban areas. Thus, the land use and the location with respect to near-field terrain features are similar. Both are located in areas of medium surface roughness (as opposed to low surface roughness like bodies of water or grassy prairies, or high surface roughness like highly urbanized cities or forests). Both locations are on the valley floor and are at approximately the same elevation. Additionally, there are no significant terrain features separating the Bakersfield Airport from the Project Site that would cause significant differences in wind or temperature conditions between these respective areas. Therefore, the 5 years of meteorological data selected from the Bakersfield Airport were determined to be representative for the purposes of evaluating the Project's air quality impacts.

Seasonal and annual wind roses based on the 5 years of Bakersfield Airport surface meteorological data are provided in Appendix E-1, Seasonal and Annual Wind Roses. Winds for all seasons and all years blow predominantly from the sector between northwest and north, although the directional pattern is more variable during the fall and winter seasons.

Receptor Locations

The property line extends around the perimeter of the Project Site and Controlled Area. The receptor grids used in the AERMOD modeling analyses for operational sources were as follows:

- 25-meter spacing along the property line and extending from the property line out 100 meters;
- 50-meter spacing from 100 to 250 meters beyond the property line;
- 100-meter spacing from 250 to 500 meters beyond the property line;
- 250-meter spacing from 500 meters to 1 kilometer beyond the property line;
- 500-meter spacing from 1 to 2 kilometers beyond the property line; and
- 1,000-meter spacing from 2 to 10 kilometers beyond the property line.

Figures 5.1-1, Near-Field Model Receptor Grid, and 5.1-2, Far-Field Model Receptor Grid, show the placement of near-field and far-field receptor points, respectively. Terrain heights at receptor grid points were determined from U.S. Geological Survey National Elevation Dataset (NED) files. During the refined modeling analysis for operational Project emissions, if a maximum predicted concentration for a particular pollutant and averaging time was located within the portion of the receptor grid with spacing greater than 25 meters, a supplemental dense receptor grid was placed around the original maximum concentration point, and the model was rerun. The dense grid used 25-meter spacing and extended to the next grid point in all directions from the original point of maximum concentration. The only dense refined receptor grid needed occurred for 24-hour SO_2 operational modeling, where a dense grid was placed in the hills southwest of the Project site. Details may be seen in the modeling files included in the electronic files submitted with this AFC Amendment.

Consistent with accepted practice, this AERMOD receptor grid, with the additional dense nested grid points, was determined to best balance the need to predict maximum pollutant concentrations and optimizing model run time.

Because construction emission sources release pollutants to the atmosphere from small equipment exhaust stacks or from soil disturbances at ground level, maximum predicted construction impacts for all pollutants and averaging times will occur within the first kilometer from the Project Site boundary. Accordingly, only the portion of the above-described grid out to a distance of 1 kilometer was used for construction modeling.

Construction Impacts Modeling

Section 5.1.2.1, Construction Emissions, details the development of the Project construction emissions estimates over the 49-month construction and commissioning period. An Excel spreadsheet was created to estimate pollutant emissions from construction activities, with separate worksheets for equipment exhaust and fugitive dust emissions on a month by month basis. Emissions from worker commuter trips to and from the Project Site during the construction period were also included. All emissions were based on the estimated monthly number of workers and pieces of equipment operating at the Project Site, per the construction schedule provided in Appendix E-2, Construction Criteria Pollutant and Greenhouse Gas

Emissions. For modeling purposes, all construction activities were assumed to occur during a 10-hour work day.

As discussed in Section 5.1.2.1, maximum short-term and annual emissions were determined using monthly emissions from on-site sources. Periods of maximum emissions of PM_{10} and $PM_{2.5}$ occurred in Month 6, and the worst 12-month period occurred during Months 1 through 12. For CO, NO_X, and SO_X emissions, the month in which short-term on-site emissions reach a maximum is Month 24. The worst-case annual emissions are in Months 20 through 31. On-site emissions used in dispersion modeling are shown in Appendix E-2, Construction Criteria Pollutant and Greenhouse Gas Emissions.

Source emissions were calculated by means of the model inputs spreadsheet in Appendix D. Fugitive dust emissions from vehicles, on-site equipment and earth moving activities are represented in AERMOD as area sources. Combustion exhaust emissions from vehicles and on-site equipment are represented as point sources. By using point sources, the PVMRM version of the AERMOD dispersion model can be used to calculate NO_2 emissions. To apply the PVMRM option in AERMOD to predict NO_2 concentrations, hourly O_3 data are required. Hourly O_3 data recorded at the SJVAPCD Kern County Shafter–Walker Street monitoring station for the same 5 years as the input meteorological data were used in this analysis. Due to the short duration of construction activities, the variability of equipment usage, and the statistical nature of the NO_2 and SO_2 1-hour NAAQS, construction impacts will not be compared to these standards. Construction impacts will be compared to the NO_2 and SO_2 1-hour CAAQS.

Total exhaust emissions from a given source category (e.g., "worker vehicles") were divided by the number of point sources used in the model to obtain an emission rate of pounds per hour per source. Stack parameters based on the average horsepower of equipment were obtained from "Risk Management Guidance for the Permitting of New Stationary Source Diesel-Fueled Engines" (CARB, 2000). Fugitive emissions, represented as area sources, were divided by the size of the modeled area source to obtain an emission rate of grams per second per meter-squared.

Sensitivity Modeling

For all pollutants and averaging times, screening modeling was performed with maximum emissions and the most conservative stack parameters for each source, regardless of whether all equipment will run at the same time in this worst-case stack parameter and emission configuration. This methodology was performed to determine conservative worst-case off-site impacts without the need of sensitivity modeling for each piece of equipment or time period. Often times, each source will not run at the same time with their worst-case stack parameters and emissions. For example, the emergency ancillary equipment (generators, firewater pump) will not be tested all at the same time during a start-up sequence. However, if the most conservative impact scenario complied for the CAAQS and NAAQS, the equipment was kept in the modeling with maximum emissions and the most conservative stack parameters to eliminate the need for sensitivity modeling iterations.

More refined modeling was completed for several pollutants to more accurately depict the activities occurring concurrently for short averaging times. Sensitivity modeling was completed

for CO 1-hour, and it was determined that the CTG/HRSG shutting down scenario (20 percent load burning natural gas) gave higher impacts than the CTG/HRSG starting up scenario. However, the maximum CO 8-hour impact scenario was determined to occur during CTG/HRSG start-up mode when other sources are operating for that duration of time.

It was determined that the coal dryer gave higher short-term SO_2 impacts in operations mode than in start-up or shut-down mode, while all other maximum pollutant impacts for the coal dryer occurred during coal dryer start-up mode. Maximum PM_{10}, $PM_{2.5}$ 24-hour, and NO_2 1-hour CAAQS impacts occur for a plant start-up period rather than during operations or shut down mode. Finally, maximum NO_2 1-hour NAAQS impacts occur when the CTG/HRSG and coal dryer are operating in on-peak power mode rather than off-peak power mode.

Further details on worst-case modeling scenarios for each pollutant and averaging time are described in Section 5.1.2.5.10.

Fumigation Modeling

Fumigation can occur when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Especially on sunny mornings with light winds, the heating of the earth's surface causes a layer of turbulence, which grows in depth over time and may intersect an elevated exhaust plume. The transition from stable to unstable surroundings can rapidly draw a plume down to ground level and create relatively high pollutant concentrations for a short period. Typically, a fumigation analysis is conducted using the USEPA model SCREEN3 when the Project Site is rural and the stack height is greater than 10 meters.

A fumigation analysis was performed using SCREEN3 to calculate concentrations from inversion breakup fumigation. A unit emission rate was used (1 gram per second) in the fumigation modeling to obtain a maximum unit concentration (X/Q) and the model results were scaled to reflect expected Project emissions for each pollutant. Inversion breakup fumigation concentrations were calculated for 1-hour averaging times. Hourly model predictions are conservative, because inversion breakup fumigation is a transitory condition that would most likely affect a given receptor location for only a few minutes at a time.

Atmospheric conditions that could cause fumigation typically do not last for long periods, therefore due to the statistical nature of the NO_2 and SO_2 1-hour NAAQS, fumigation impacts will not be compared to these standards. Fumigation impacts will be compared to the NO_2 and SO_2 1-hour CAAQS, plus the 1-hour CO CAAQS.

Because SCREEN3 only models the impacts from one source, the model was run for each of the main sources: the CTG/HRSG, coal dryer, tail-gas thermal oxidizer, and the nitric acid plant operating with parameters and emission rates used in the maximum short-term impact scenarios as described below in Section 5.1.2.5.10.

Fumigation impacts were determined for each source then conservatively summed over all sources using peak predicted fumigation concentrations regardless of location. Further details on fumigation modeling can be found in Appendix E-9, Fumigation Modeling Results.

SIL Modeling

HECA is designated PSD for three criteria pollutants: CO, NO_2, and PM_{10}. A project's impacts may be compared to the significant impact levels (SILs) as a screening modeling exercise that helps determine whether the project may cause or contribute to a violation of the NAAQS. If the modeled impact is below the SIL, then refined modeling is not required. CO, PM_{10}, and NO_2 annual SILs are compared to highest first high modeled value, while the NO_2 1-hour SIL is compared to the multiyear average first high 1-hour concentration at any receptor. Only stationary sources at the HECA Project were modeled in comparison to the SILs; on-site mobile sources were excluded as they are not considered for PSD/NAAQS modeling.

NAAQS/CAAQS Modeling

Refined modeling analyses were performed to estimate off-site criteria pollutant impacts from operational emissions of the Project. The modeling was performed as described in the previous sections, using 5 years of hourly meteorological input data. Modeling was conducted for directly emitted NO_X, SO_X, CO, PM_{10}, and $PM_{2.5}$. No modeling was conducted for secondarily formed pollutants such as O_3 from NO_X or VOC, or $PM_{2.5}$ from NO_X, SO_X, VOC, or NH_3. O_3 modeling is not required, because the annual Project emissions of VOC are less than the SER (see Table 5.1-37). Models and modeling techniques to accurately estimate secondarily formed $PM_{2.5}$ from individual sources do not currently exist; thus, only directly emitted $PM_{2.5}$ was analyzed.

All new Project sources were modeled with the worst-case impact scenario corresponding to each averaging time (see Section 5.1.2.5.10). Emission rate calculations and assumptions used for all pollutants and averaging times are documented in Appendix E-3, Operational Criteria Pollutant Emissions.

NO_2 1-Hour NAAQS Modeling

NO_2 1-hour impacts from the Project stationary sources were predicted to be over the SIL; therefore, a refined NO_2 1-hour analysis was performed. Several modeling protocols and discussions with USEPA and SJVAPCD were held in preparation for this analysis.

In addition to techniques described in the January 20, 2011 "Modeling Protocol for Parameter Selection Specific to the 1-Hour NO_2 NAAQS Regional Modeling for the Hydrogen Energy California (HECA) Project," HECA LLC conducted the NO_2 1-hour NAAQS analysis incorporating guidance from three documents, the USEPA "Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard" (USEPA, 2011); CAPCOA "Modeling Compliance of The Federal 1-Hour NO_2 NAAQS" (CAPCOA, 2011); and SJVAPCD "Assessment of Non-Regulatory Option in AERMOD Specifically OLM and PVMRM" (SJVAPCD, 2010).

A full description of the NO_2 1-hour NAAQS refined modeling methodology and analysis can be found in Appendix E-7, NO_2 1-Hour Regional Analysis.

Modeling Scenarios

Operations Emission Scenarios for Modeling

Often times, worst-case impact scenarios do not necessarily align with worst-case emissions. Stack parameter variability for different equipment can change the overall estimated impacts on a per pollutant basis. Another defining variable that determines maximum impact scenarios is whether equipment is operating simultaneously, and in what operating mode. The following subsections describe the worst-case modeling scenarios per pollutant and averaging time. Supporting calculations and documentation may be found in Appendix E-3, Operational Criteria Pollutant Emissions.

CO 1-hour

The maximum CO 1-hour impact scenario occurs when the CTG/HRSG is shutting down at 20 percent load burning natural gas during which time the coal dryer and the auxiliary boiler are not operating. The Tail Gas Thermal Oxidizer and CO_2 vent both have process venting, while all three flares are in pilot mode. CO fugitives from the gasification, shift, AGR, SRU, and sour water areas are also included. Emergency equipment was not included in this scenario, as it will not be testing during shut-down. Mobile sources are not included for comparison to the NAAQS, while all mobile sources are included for comparison to the CAAQS.

CO 8-hour

The maximum CO 8-hour impact scenario occurs during a plant start-up when the CTG/HRSG and coal dryer are starting up, plus a number other sources are operating or starting. For 0.5 hours the CTG/HRSG operates at 20 percent load on natural gas, for 2 hours the CTG/HRSG and coal dryer operate at 40 percent load on natural gas, and for the remaining portion of the 8-hour period operate at 40 percent load on syngas. The Tail Gas Thermal Oxidizer is in start-up mode with maximum SRU waste gas disposal for the entire 8-hour duration. All flares are flaring in start-up mode. The Rectisol® and SRU flares are flaring at maximum hourly start-up rates. The gasification flare is flaring shifted syngas for 5 hours, with the remaining 3 hours at pilot operations. The CO_2 vent has maximum process venting, and the auxiliary boiler is also operating with maximum short-term emissions. The ammonia start-up heater is operating during 5 of the 8 hours in this start-up scenario. Emergency equipment was not included in this scenario, as it will not be testing during start-up. CO fugitives from the gasification, shift, AGR, SRU, and sour water areas are also included. Mobile sources are not included for comparison to the NAAQS, while all mobile sources are included for comparison to the CAAQS.

NO_2 1-hour CAAQS

The maximum NO_2 1-hour CAAQS impact scenario occurs when the CTG/HRSG and coal dryer are starting up in 40 percent load natural gas mode, with the tail gas thermal oxidizer and ammonia start-up heater are also in start-up mode. All flares are in start-up mode with maximum heat release flaring. The auxiliary boiler and nitric acid plant are operating during this time at peak emission rates. Both emergency generators and the emergency diesel firewater pump are conservatively testing during this hour. It is important to note that all sources were modeled at maximum emission rates, sources with intermittent emissions did not use annualized 1-hour rates

for the CEQA CAAQS modeling. Finally, all mobile sources are conservatively operating during this time frame.

NO_2 1-hour SIL and NAAQS

The maximum NO_2 1-hour NAAQS impact scenario for the SIL and NAAQS analyses occurs when the CTG/HRSG and coal dryer are operating in on-peak (Case 1) power mode. Start-up emissions for the CTG/HRSG are limited to 105 hours per year, while shut-down emissions are limited to 18 hours per year. Start-up emissions for the coal dryer are limited to 104 hours per year, with shut-down emissions at 8 hours per year. Annualized maximum 1-hour NO_2 start-up/shut-down emission rates for these two sources are lower than their normal NO_2 1-hour rates, therefore, the maximum on-peak power normal NO_2 1-hour emission rates for the CTG/HRSG and coal dryer were used for the NO_2 1-hour SIL and NAAQS analyses. Similarly, the SRU flare and tail gas thermal oxidizer have maximum impacts during operations with pilot and process vent disposal, respectively, rather than during an annualized start-up period. The auxiliary boiler and nitric acid unit operations were included at their peak hourly emission rate. The Rectisol® and gasification flares were included with maximum annualized start-up flaring emission rates, which are higher than their normal rates during pilot mode. The ammonia plant start-up heater also was included with an annualized start-up 1-hour NO_2 emission rate. Finally, all three ancillary diesel engines including the two emergency diesel generators and firewater pump are included in the NO_2 1-hour SIL and NAAQS modeling with annualized emission rates. Mobile sources are not included in this modeling scenario.

NO_2 Annual

Maximum annual emissions for all NO_X emitting sources were included in the annual modeling scenarios. Maximum annual emissions include operating emissions plus all start-ups and shut-downs associated with each source. The CTG/HRSG and coal dryer use Case 5 stack parameters, while the flares use effective stack parameters based on each flare's annualized heat release rate. All other sources are modeled with normal operating stack parameters. Mobile sources are not included for comparison to the NAAQS, while the maximum annual amount of mobile sources are included for comparison to the CAAQS.

PM_{10} and $PM_{2.5}$ 24-hour

The maximum PM_{10} and $PM_{2.5}$ 24-hour impact occurs when the CTG/HRSG and coal dryer are operating in start-up mode. Stack parameters for these sources used flow rates based on a start-up at 40 percent load on syngas, because most of the 24-hour start-up period would operate in this mode. Similarly, the tail gas thermal oxidizer and all flares were included with maximum emissions during start-up. All three cooling towers (ASU, Power Block and Process) are operating at maximum 24-hour PM_{10} and $PM_{2.5}$ emission rates. The auxiliary boiler is not operating during this time, as it is not expected to operate while the CTG is operating. Both emergency generators are testing for 1 hour in the 24-hour period, while the emergency diesel firewater pump is testing for 2 hours during the 24-hour period. The emergency equipment maximum daily emissions were spread evenly across all hours in the day in AERMOD. The ammonia start-up heater is operating in start-up mode. All sources associated with the manufacturing plant with PM emissions are operating, including the ammonium nitrate unit, and

the urea pastillation stack; and all material handling sources are operating as well, which include all coal/coke, urea, and gasification solids storage and handling systems. Emission source release points for material handling may be found in Appendix E-3, Operational Criteria Pollutant Emissions. Mobile sources are not included for comparison to the NAAQS, while the maximum daily number of mobile sources are included for comparison to the CAAQS.

PM_{10} and $PM_{2.5}$ Annual

Maximum annual emissions from all PM emitting equipment were modeled for the annual modeling scenarios. Maximum annual emissions include operating emissions plus all start-ups and shut-downs associated with each source. The CTG/HRSG and coal dryer use Case 5 stack parameters and emissions, while the flares use effective stack parameters based on each flare's annualized heat release rate. All other sources are modeled with normal operating stack parameters. Mobile sources are not included for comparison to the NAAQS, while the maximum annual number of mobile sources is included for comparison to the CAAQS.

SO_2 1-hour, 3-hour, 24-hour

Maximum SO_2 short term impacts occur when the CTG/HRSG is operating at 80 percent load on natural gas, which is the highest SO_2 emission rate for the CTG/HRSG, conservatively mixed with the lowest exhaust flow rate (Case 2) that occurs during CTG/HRSG operations in off-peak power mode. Conversely, the coal dryer has the highest short-term SO_2 emissions during off-peak power, combined with the lowest flow exhaust rate. Although these two sources will not operate in their worst-case mode at the same time, SO_2 short term modeling was completed as described above to minimize the need for several sensitivity runs. The tail gas thermal oxidizer, the ammonia start-up heater, and all three flares are operating with maximum short-term start-up emission rates. Both emergency generators and the emergency diesel firewater pump are conservatively testing for all averaging times. The two emergency generators are both testing for 1 hour in the 24-hour period, while the emergency diesel firewater pump is testing for 2 hours during the 24-hour period. The maximum daily emissions of the emergency equipment were spread evenly across all hours in the day in AERMOD. All sources were modeled with maximum emission rates, sources with intermittent emissions did <u>not</u> use annualized 1-hour rates for the CEQA CAAQS or NAAQS 1-hour modeling. Mobile sources are not included for comparison to the NAAQS, while the maximum number of mobile sources is included for comparison to the CAAQS.

H_2S 1-hour

The maximum H_2S 1-hour impact scenario occurs when the CO_2 vent is venting at maximum short-term H_2S emission rates. H_2S fugitives from the gasification, shift, AGR, SRU, and sour water areas are also included.

Commissioning Emission Scenarios for Modeling

Project engineers provided a number of commissioning emission scenario that represent the worst-case combination of emissions from various sources during the commissioning period. These emission scenarios were modeled with AERMOD to predict the maximum impact during commissioning.

Due to the short duration of commissioning activities, the variability of equipment usage, and the statistical nature of the NO_2 and SO_2 1-hour and $PM_{2.5}$ 24-hour NAAQS, commissioning impacts will not be compared to these standards. Commissioning impacts will be compared to the NO_2 and SO_2 1-hour and $PM_{2.5}$ 24-hour CAAQS. Commissioning impacts will also be compared to the CO 1- and 8-hour, and SO_2 3- and 24-hour AAQSs.

Construction activities and commissioning activities overlap, although construction activities will be winding down and commissioning activities can be scheduled such that the emissions from the combination of these activities will be minimal. Therefore, modeling was not conducted with the overlapping emissions. Appendix E-8, Commissioning Scenario Emissions and Modeling Results presents the emissions from each source associated with each scenario. Below is a brief description of the scenarios examined.

Case 1

This scenario reflects the testing of either of the two emergency diesel generator engines while the Power Block cooling tower operates at reduced or no load. This scenario occurs early in the commissioning sequence when utility and support systems are being commissioned. The modeling analyses were conducted for SO_2 (1-hour and 24-hour), NO_2 (1-hour), CO (1-hour and 8-hour), and PM_{10} (24-hour).

Case A

This scenario reflects initial, "first fire" operation of the combustion turbine on natural gas at 20 percent load before the SCR and oxidation catalyst are operational. The Power Block cooling tower is also operating at reduced load. The modeling analysis was conducted for CO only, as this case represents the worst-case CO emission rates scenario, while the emissions of other pollutants are overlapped with other scenarios.

Case B

This scenario reflects operation of the combustion turbine on natural gas at 80 percent load before the SCR and oxidation catalysts are operational. This scenario is expected to occurring during tuning the water injection rates for NO_X control. The modeling analyses were conducted for SO_2 and NO_2 since the emissions of other pollutants are overlapped with other scenarios. Case B is the worst-case NO_2 emission rate scenario.

Case A2

This scenario occurs during initial operation of the gasifier at 50 percent load while flaring sweet, unshifted syngas in the Gasification Flare. The gasifier operation is supported by Power Block operation (HRSG and coal dryer) on natural gas at 80 percent load, operation of all three cooling towers, and the Tail Gas Thermal Oxidizer. The modeling analyses were conducted for NO_2, CO, and PM_{10}. This case represents the worst-case PM_{10} emission scenario. SO_2 emissions are overlapped with, or less conservative, than other scenarios; therefore, this case was not modeled for SO_2.

Case B2

This scenario is similar to Case A2 and occurs later in the start-up sequence when shifted syngas is being sent to the Gasification Flare. This scenario anticipates a potential excursion in the SO_2 emissions from the Tail Gas Thermal Oxidizer that could occur briefly before the tail gas is recycled to the shift converters. All three cooling towers would be operated. The modeling analysis was conducted for SO_2 only, as this represents the worst-case SO_2 scenario, while the emissions of other pollutants are overlapped with other scenarios.

Case C2

This scenario occurs with gasifier operation at 50 percent load while flaring hydrogen-rich fuel gas in the Gasification Flare. This reflects a transitional period before the gas turbine can switch to hydrogen-rich fuel and CO_2 is vented before the CO_2 compressor is ready to send CO_2 to OEHI for EOR. The gasifier operation is supported by Power Block operation at 80 percent load on natural gas. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. The modeling analysis was conducted for CO only, since the emissions of other pollutants are overlapped with other scenarios.

Case D2

This scenario occurs with gasifier operation at 50 percent load while commissioning the hydrogen purification (PSA unit). A combination of mostly hydrogen rich gas plus PSA off-gas is being sent to the Gasification Flare. CO_2 is being sent to OEHI for EOR. The Power Block is operated at 80 percent load on natural gas. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. The modeling analysis was conducted for NO_2 only, since the emissions of other pollutants are overlapped with other scenarios.

Case E2

This scenario occurs with gasifier operation at 50 percent load and gas turbine operation at 40 percent load which requires some surplus hydrogen-rich fuel to be sent to the gasification flare. This would occur following the gas turbine switch from natural gas to hydrogen rich gas. CO_2 may need to be vented during this transition period. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. The modeling analysis was conducted for NO_2 and CO.

Case A3

This scenario occurs during commissioning of the Ammonia and Urea units when purified hydrogen is flared and purified CO_2 is vented before it can be converted to products. The CO content of the CO_2 stream is assumed to be higher than normal, but the flow rate is much lower than normal, so the emission rate is less than normal operations. The Gasification Block and support systems are operating normally. The Power Block is operated at 100 percent load on hydrogen-rich fuel. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. No modeling analysis was conducted

since the emission rates of all pollutants are overlapped or covered with other scenario (specifically Case B3).

Case B3

This scenario is similar to Case A3 plus the ammonia synthesis start-up heater is also operating. The modeling analyses were conducted for SO_2, NO_2, and CO.

Case C3

This scenario occurs during commissioning of the Nitric Acid unit. The Gasification Block, Ammonia and Urea units are operating normally. The NO_X abator on the Nitric Acid unit is being commissioned and the NO_X level could potentially reach 200 ppm during the initial phase of NO_X tuning. The Power Block is operated at 100 percent load on hydrogen-rich fuel. Thermal oxidizer would be operated to support the miscellaneous process vent disposal. All three cooling towers would be operated. The modeling analyses were conducted for NO_2 and PM_{10}.

5.1.2.6 Compliance with Ambient Air Quality Standards

Air dispersion modeling was performed according to the methodology described in Section 5.1.2.5, Dispersion Modeling Methodology. This was done to evaluate the maximum increase in ground-level pollutant concentrations resulting from Project emissions to compare to applicable SILs, and to compare the maximum predicted impacts, including background pollutant concentrations, with applicable short-term and long-term CAAQS and NAAQS. The impacts from construction activities and operations were analyzed separately because they will occur during different time periods. The same 5-year record of hourly meteorological data described in Section 5.1.2.5.3 was used in the AERMOD modeling to evaluate both construction and operational impacts.

In evaluating both construction and operational impacts, AERMOD was used to predict the increases in criteria pollutant concentrations at all receptor locations due to Project emissions only. Next, the maximum modeled incremental increases for each pollutant and averaging time were added to the maximum background concentrations, based on air quality data collected at the most representative monitoring stations during the last 3 years available. These background concentrations are presented and discussed in Section 5.1.1.2, Existing Air Quality. The resulting total pollutant concentrations were then compared with the most stringent CAAQS or NAAQS.

Construction Impacts

Section 5.1.2.1, Construction Emissions, described that emissions of CO, NO_X and SO_X, reach worst-case emission conditions for the purpose of analyzing peak short-term impacts to local air quality from on-site sources in Month 24 of the construction schedule. Annual impacts for these pollutants were modeled with all on-site emissions that would occur during the 12 months of construction from Month 20 to Month 31, since this period has the highest estimated emissions of the construction schedule. For PM_{10} and $PM_{2.5,}$ emissions reach a short-term maximum in

Month 6 of the construction schedule, and the worst 12-month period is Months 1 through 12. Results of the Project construction modeling are presented in Table 5.1-25.

Due to the short duration of construction activities, the variability of equipment usage, and the statistical nature of the NO_2 and SO_2 1-hour NAAQS, construction impacts will not be compared to these standards. Construction impacts will be compared to the NO_2 and SO_2 1-hour CAAQS.

As reflected in the construction modeling results presented in Table 5.1-25, high PM_{10} and $PM_{2.5}$ background concentrations have been recorded frequently at representative monitoring stations during recent years. Kern County is currently classified as non-attainment for $PM_{2.5}$ (both federal and state) and non-attainment for PM_{10} (state only). Because of the land use characteristics of this area, it is highly probable that these conditions result primarily from high wind episodes and mobile pollution sources. The predicted contributions of the construction activities are less than the most stringent AAQS, but have the potential to temporarily contribute to existing violations of the state and federal PM_{10} and $PM_{2.5}$ standards if construction occurs during a period of high background concentrations. The modeling analyzed the worst-case emissions from construction equipment and fugitive dust, incorporating standard mitigation control efficiencies. HECA LLC will implement a rigorous mitigation program to minimize fugitive dust and construction equipment exhaust. Because of the conservative nature of the modeling, implementation of mitigation measures, the short duration of construction activities, and variability of equipment usage, it is expected that impacts from PM would be less than predicted in the modeling, and would be less than significant.

AERMOD with PVMRM predicted maximum 1-hour and annual NO_2 concentrations due to Project construction emissions which, when added to conservative background values from the nearest monitoring stations, are below the 1-hour California standard. Predicted maximum impacts for CO and SO_2 are also less than the most stringent ambient standards.

Operational Impacts

As described previously, emission scenarios used in the AERMOD simulations for the Project operations were selected to ensure that the maximum potential impacts will be addressed for each pollutant and averaging time corresponding to an AAQS. The emissions and scenarios used for each pollutant and averaging time are explained and quantified in Sections 5.1.2.3 and 5.1.2.5.10, and in Appendix E-3, Operational Criteria Pollutant Emissions. This subsection describes the maximum predicted operational impacts of the Project for the operating conditions described in the modeling scenarios discussion above. Commissioning impacts, which will occur on a temporary, one-time basis and will not be representative of normal operations, were addressed separately, as described in Section 5.1.2.6.3.

Maximum operational impacts were compared to both Significant Impact Levels (SILs) for applicable pollutants, and to the CAAQS and NAAQS. Several of the SILs, CAAQS, and NAAQS have distinctions between them regarding: the type of sources to be included in the comparison with the standard; and the exceedance criteria regarding whether the highest first high impact or a statistical modeled concentration is to be compared with each standard. The following subsections will summarize the modeled operational impacts from HECA.

SIL Modeling

HECA is a PSD Project for CO, NO_2, and PM_{10}. These pollutants are in attainment in the Project area, and annual HECA Project emissions are greater than the PSD Significant Emission Rates for these pollutants. Therefore, screening modeling to determine whether HECA operational impacts may cause or contribution to a violation of the NAAQS for these pollutants may be compared to their Class II Significant Impact Levels (SILs). If estimated Project impacts do not exceed the SILs, then the impacts are considered to not contribute significantly to any violation of the NAAQS, exempting HECA from more refined cumulative analyses. For SIL modeling, only permitted stationary sources are included in the modeling analyses. Table 5.1-26 summarizes maximum impacts from HECA compared with the applicable SILs.

PM_{10} 24-hour, PM_{10} Annual, CO 8-hour, and NO_2 Annual modeled impacts due to Project operations are less than the SILs. Although the maximum CO 1-hour impact is greater than the SIL of 2,000 micrograms per cubic meter ($\mu g/m^3$), the following Subsection 5.1.2.6.2.2 presents the refined modeling which shows that when the maximum modeled concentration from HECA operations are added to a conservatively high CO ambient background value, the impact is well below either the CO 1-hour CAAQS or NAAQS.

Section 5.1.2.5.8 described how HECA sources were modeled in comparison to the NO_2 1-hour interim SIL. In this initial impact analysis, several receptors exceeded the NO_2 1-hour SIL of 4 ppb (7.55 $\mu g/m^3$). Therefore, a cumulative assessment was completed following procedures outlined in several modeling guidance documents, agency discussions, and HECA modeling protocols. In the next section and in Appendix E-7, NO_2 1-Hour Regional Analysis, further information is given regarding the cumulative analysis completed for the 1-hour NO_2 NAAQS.

Significant Monitoring Concentrations (SMCs) are applicable to PSD pollutants only, and are compared to the same modeled pollutant concentrations from the Project as were compared to the SILs. SMCs are higher than SILs. HECA estimated impacts are lower than all applicable SMCs, therefore, monitoring is not required. No SMC exists for NO_2 1-hour.

NAAQS/CAAQS Modeling

Table 5.1-27 summarizes the maximum predicted criteria pollutant concentrations due to Project emissions. This table also shows that the modeled impacts due to the Project emissions, in combination with conservative background concentrations, will not cause a violation of any the CAAQS or NAAQS, and will not significantly contribute to the existing violations of the federal and state PM_{10} and $PM_{2.5}$ standards. In addition, as described later, all of the Project's operational emissions of PM_{10}, NO_X, VOCs, and SO_X will be offset to ensure a net air quality benefit. $PM_{2.5}$ emissions will be mitigated by the PM_{10} ERCs, because $PM_{2.5}$ is a subset of PM_{10}. All of the ERCs used to offset PM_{10} were from combustion sources; thus, the majority of the emission reductions are both PM_{10} and $PM_{2.5}$. Therefore, because all of the PM emissions will be offset, impacts of PM_{10} and $PM_{2.5}$ would be less than significant.

Because NO_2 impacts from HECA exceeded the 1-hour SIL, a cumulative impact assessment was completed to determine whether the Project would cause or contribute to any modeled violations of the NAAQS. HECA sources were combined with nearby sources and modeled in AERMOD with PVMRM, and hourly NO_2 ambient background concentrations were added to the hourly model predictions. Appendix E-7, NO_2 1-Hour Regional Analysis, contains the

modeling approach, background air quality, emission sources modeled, and modeling result details for the regional analysis. Table 5.1-27 presents the highest of the modeled 5-year average of the 98th percentile of the maximum 1-hour daily concentration (design value) at any receptor, which complies with the 1-hour NO_2 NAAQS. This analysis demonstrates that HECA would not cause or contribute to any modeled violations, as the total design value predicted from the HECA sources, the nearby regional sources and background measured concentrations of NO_2 are less than the NAAQS.

Figure 5.1-3, Locations of Maximum Predicted Ground Level Pollutant Concentrations from HECA Operations, shows the locations of the maximum predicted operational impacts for all pollutants and averaging times, as these vary by pollutant and averaging time. All peak annual impacts occur on the eastern boundary of the property line, along with the peak CO 1-hour impact, and the NO_2 1-hour CAAQS and NAAQS impacts. The peak PM_{10} and $PM_{2.5}$ 24-hour, H_2S 1-hour, and CO 8-hour all occur on the western boundary of the property line. All maximum SO_2 short term impacts occur in the hills to the southwest of the Project Site, approximately 3.5 kilometers from the southern boundary of the property line.

Fumigation

The predicted peak concentrations from inversion fumigation from Project emissions, including background, are predicted to be below the applicable 1-hour CAAQS, and are presented in Table 5.1-28. Therefore, fumigation modeling complies with all applicable 1-hour ambient air quality standards.

Commissioning

Table 5.1-29 shows the results of the model simulations for the commissioning of the HECA Project. The tabulated impacts are the highest concentrations predicted for each pollutant and averaging time examined from all of the commissioning scenarios.

Table 5.1-29 demonstrates that when the maximum incremental commissioning impacts are added to applicable background concentrations and compared with the most stringent state or national AAQSs, no violations of the applicable standards for these pollutants are predicted to occur.

Effects on Visibility from Plumes

Modern combined-cycle power plants burning gaseous fuel emit particulate matter at levels far below the concentration corresponding to visible smoke. Combustion sources also emit water vapor that sometimes may condense in the atmosphere to form visible plumes. However, the generally warm, dry conditions in Kern County are not conducive to lengthy visible stack plumes. A visible plume analysis was performed for the Project and presented in the AFC that showed visible plumes were infrequent. Data are provided regarding the moisture content of the CTG/HRSG and coal dryer stacks, along with data regarding cooling towers exhaust in Section 5.11, Visual Resources. New visible plume analyses were not conducted as the ambient conditions at the site have not changed to make it more conducive for plume development.

Odor Impacts

Modeling was conducted to determine the concentration of H_2S at the property line. This modeling showed that the concentration predicted was less than the CAAQS (see Table 5.1-27), which is equivalent to the odor detection threshold; thus, H_2S odors will not be detectable beyond the property line.

Ammonia emissions from stationary and fugitive sources were included in the Health Risk Assessment (HRA) modeling for the Project, which is presented in Section 5.6, Public Health. The Office of Environmental Health Hazard Assessment acute reference exposure level for ammonia is lower than the odor detection threshold for ammonia. Therefore, since the total acute health index was predicted to be less than significant, the ammonia concentration will be below the odor detection level. Thus, ammonia odors will not be detectable beyond the property line.

5.1.2.7 Impact on Air Quality-Related Values in Class I Areas

The nearest Class I Area (i.e., national parks and wilderness areas) to the HECA Project is San Rafael Wilderness Area, approximately 60 kilometers away. The next nearest Class I Area is Domelands Wilderness Area which is about 105 kilometers away, while Sequoia National Park is 120 kilometers away. As identified in the February 2012 HECA modeling protocol supplement, the Federal Land Managers' Air Quality Related Values Work Group (FLAG) guidance from 2010, FLAG provides a method to determine if projects greater than 50 kilometers from a Class I Area need to conduct analyses in the Class I Area (NPS, 2010). This screening method is based on the sum of the annualized daily emissions of PM_{10}, NO_2, SO_2, and H_2SO_4 emissions divided by the distance to the nearest Class I Area (Q/d). The Q/d value for the HECA Project for the San Rafael Wilderness Area is approximately 5, which is less than the screening threshold of 10; therefore, HECA did not prepare Class I Area analyses for this AFC Amendment. Q/d values for the Domelands Wilderness Area and Sequoia National Park Class I Areas are less than 3. U.S. Forest Service confirmed on April 18, 2012, that a revised AQRV analysis would not be required for the HECA Project.

It should be noted that in the previous PSD application, HECA prepared Class I Area analyses for the San Rafael Wilderness Area, all of which showed less-than-significant impacts. The emissions of the newly revised HECA Project have decreased or stayed similar; thus, HECA impacts should decrease or remain similar, and impacts from the HECA Project in Class I Areas would remain less than significant.

5.1.3 Alternatives

Alternative 1 (rail transportation) has been analyzed and presented in Section 5.1.2. A discussion of the implications of the No Project Alternative has been provided in Section 6, Alternatives. Below is a discussion of the impacts associated with Alternative 2 (truck transportation).

Under Alternative 2, truck transport would be via existing roads from an existing coal transloading facility northeast of the Project Site. The truck route distance is approximately 26.5 miles.

Under this alternative, the on-site railroad spur would not be developed. Therefore, there would be no trains on-site for feedstock delivery or product removal. Coal would be transported via trucks on existing roads from an existing coal transloading facility in the town of Wasco, northeast of the Project Site. All product would be transported by truck.

The main difference between Alternatives 1 and 2 is the approximately 5-mile railroad spur that would connect the Project Site to the existing SJVRR Buttonwillow railroad line, north of the Project Site, would not be built; thus, no feedstock or product would be transported to the site via train. The coal would still be transported from New Mexico via train, but would be offloaded at the transloading facility in Wasco, then trucked to the site. All product would be transported off-site by truck. There are no changes to the stationary sources.

The coal train will travel approximately 7 miles extra in SJVAPCD to get to the transloading facility. The coal truck route distance from the transloading facility in Wasco to HECA is approximately 26.5 miles. All product truck routes will remain the same as Alternative 1 (rail transportation), with increased truck volume to account for the lack of trains.

The maximum number of trucks that will travel on site by period in Alternative 2 (truck transportation) is summarized in Table 5.1-30.

Emissions were estimated for the on-site and off-site vehicles transporting feedstock and products. Emission factors and calculation techniques outlined in Section 5.1.2.3.2 were also used to estimate the emissions from the vehicles for Alternative 2 (truck transportation).

Table 5.1-31 presents the on-site and off-site transportation emissions from Alternative 2 (truck transportation) by air basin. Transportation emissions and calculations for Alternative 2 (truck transportation) are included in Appendix E-12, Operational Transportation Emissions for Alternative 2. Table 5.1-32 presents the difference in the off-site transportation emissions from Alternative 2 (truck transportation) to Alternative 1 (rail transportation) by air basin.

Transportation-related emissions decrease in EKAPCD, MDAQMD, Sacramento Metro, Yuba City-Marysville, and Chico areas; remain the same in Arizona and New Mexico; and increase slightly in SCAQMD. In SJVAPCD—the air district where the Project is located—emissions decrease for all pollutants except PM_{10}. PM_{10} increases slightly, 2 tons per year, due solely to the increase in fugitive road dust from the increased volume of trucks. Vehicle exhaust emissions decrease significantly in Alternative 2 (truck transportation).

On-site emissions decrease for all pollutants except PM_{10}, which increases slightly, 0.08 ton per year, from fugitive road dust. PM_{10} modeling for comparison to the 24-hour NAAQS does not include emissions associated with mobile sources; therefore, there would not be any change in modeled impacts compared to Alternative 1 (rail transportation).

Modeling for PM_{10} 24-hour and annual impacts from Alternative 2 (truck transportation) compared to the CAAQS was not conducted, because the emission increase is less than

0.1 percent of the total Project emissions modeled. Thus, the impacts are not expected to change significantly. Modeling for all other pollutants was not conducted, because the impacts are expected to decrease due to the decrease in emissions.

Air quality impacts for Alternative 2 (truck transportation) would be approximately the same or lower than predicted for Alternative 1 (rail transportation); thus, the emissions from Alternative 2 (truck transportation) will have a less-than-significant impact on air quality.

GHG emissions associated with the vehicles transporting feedstock and products for Alternative 2 (truck transportation) were estimated using emission factors and calculation techniques outlined in Section 5.1.2.4.2. GHG emissions from the on-site and off-site transportation for Alternative 2 (truck transportation) are presented in Table 5.1-33, and calculation details are included in Appendix E-12, Operational Transportation Emissions for Alternative 2. The GHG emissions, reported as CO_2e, increase by less than 100 tonnes per year for Alternative 2 (truck transportation), versus Alternative 1 (rail transportation). This will not have a significant impact on the total Project GHG emissions.

5.1.4 Cumulative Impacts Analyses

Under certain circumstances, CEQA requires consideration of a project's cumulative impacts (CEQA Guidelines Section 15130). A "cumulative impact" consists of an impact that is created as a result of the combination of the project under review together with other projects causing related impacts (CEQA Guidelines Section 15355). CEQA requires a discussion of the cumulative impacts of a project when the project's incremental effect is cumulatively considerable (CEQA Guidelines Section 15130[a]). "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects (CEQA Guidelines Section 15065 [a][3]).

When the combined cumulative impact associated with a project's incremental effect and the effects of other projects is not significant, further discussion of the cumulative impact is not necessary (CEQA Guidelines Section 15130[a]). It is also possible that a project's contribution to a significant cumulative impact is less than cumulatively considerable and thus not significant (CEQA Guidelines Section 15130[a]).

The discussion of cumulative impacts should reflect the severity of the impacts and their likelihood of occurrence, but the discussion need not provide as great a level of detail as is provided for the effects attributable to the project under consideration (CEQA Guidelines Section 15130[b]). The discussion should be guided by standards of practicality and reasonableness (CEQA Guidelines Section 15130[b]).

A cumulative impact analysis starts with a list of past, present, and probable future projects within a defined geographical scope with the potential to produce related or cumulative impacts (CEQA Guidelines Section 15130[b]). Factors to consider when determining whether to include a related project include the nature of the environmental resource being examined, the location of the project, and its type (CEQA Guidelines Section 15130[b]). Depending on its location and type, not every project on this list is necessarily relevant to the cumulative impact analysis for each environmental topic.

The purpose of the air quality cumulative analysis is to assess whether the combined effects of the Project and other permitted emission sources within a 6-mile radius of the Project Site would cause or contribute to a violation of any AAQS. For purposes of this analysis, a de minimis emission threshold of 5 tons/per year was applied in addition to the 6-mile radius threshold to determine the list of related projects. To obtain a list of other permitted sources, SJVAPCD was contacted and a public records request was submitted in 2009. SJVAPCD responded with a list of sources, all of which emit less than the 5 tons/year threshold for any single criteria pollutant.. This list is provided in Appendix E-14, Response to CEC Data Request 32. SJVAPCD was again contacted in 2011, and no sources have been permitted in the past few years, or will be permitted in the foreseeable future, within 6 miles of the Project Site with emissions greater than 5 tons/year. Therefore, since no nearby sources were identified, cumulative modeling for CEQA was not conducted.

OEHI prepared a cumulative air quality analysis for the OEHI Project, which is set forth in Section 4.3 of Appendix A-1 of this AFC Amendment, and concludes that emissions from the construction and operation of the OEHI Project will not result in a significant adverse cumulative impact to air quality.

5.1.5 Mitigation Measures

5.1.5.1 Construction Mitigation Measures

The Project will implement all of the SJVAPCD and CEC recommended mitigation measures outlined below, to control emissions during the construction phase of the Project from both fugitive dust and equipment combustion exhaust when feasible.

AIR-1. The following mitigation measures are proposed to control fugitive dust emissions during construction of the Project:

- Stabilize the main access roads through the facility with crushed rock or gravel for the purposes of dust control;
- Use of either water application, chemical dust suppressant application, or other suppression technique to control dust emissions from on-site unpaved road travel and unpaved parking areas;
- Cover all trucks hauling soil, sand, and other loose materials or require all such trucks to maintain at least 2 feet of freeboard;
- Limit traffic speeds on all unpaved site areas to 15 miles per hour;
- Install sandbags or other erosion control measures to prevent silt runoff to roadways;
- Replant vegetation in disturbed areas as quickly as possible;
- Inspect and wash as necessary vehicle tires prior to exiting construction site onto paved roadways; and

- Mitigate fugitive dust emissions from wind erosion on areas disturbed by construction activities (including storage piles) by application of either water, chemical dust suppressant, or other suppression technique.

AIR-2. The following mitigation measures are proposed to control exhaust emissions from the diesel heavy equipment used during construction of the Project:

- Properly maintain and tune engines to the engine manufacturer's specifications;
- Limit the engine idle time to not more than 5 minutes for diesel heavy construction equipment that does not need to idle as part of their normal operation;
- Use low sulfur and low aromatic fuel meeting California standards for motor vehicle diesel fuel; and
- Use low-emitting gas and diesel engines meeting state and federal emissions standards (Tiers II and III) for construction diesel engines with a rating of 50 horsepower or higher,

5.1.5.2 Operational Emissions Offsets

In accordance with SJVAPCD rules, as well as CEC policy, the Project is required to provide emission offsets in the form of ERC for increases in emissions of non-attainment pollutants and their precursors in excess of specified thresholds that will result from the operation of the Project on a pollutant-specific basis. Appendix E-10, Offset Package, presents a discussion of the ERCs procured for the Project and how these comply with the requirements of each agency.

The Project will participate in the GHG Cap and Trade program to be implemented under the California regulation AB 32. CARB will provide allowances to electric utilities, which will be sold to power providers such as HECA. These allowances will decline annually, so projects can also purchase offsets if sufficient allowances are not available.

5.1.6 Laws, Ordinances, Regulations, and Standards

USEPA has ultimate responsibility for ensuring, pursuant to the Clean Air Act Amendments of 1990 (CAAA), which areas of the U.S. meet, or are making progress toward meeting, the federal AAQS. The state of California falls under the jurisdiction of USEPA Region IX, which is headquartered in San Francisco. USEPA requires that all states submit SIPs for non-attainment areas that describe how the federal AAQS will be achieved and maintained. Attainment plans must be approved by CARB before they are submitted to USEPA.

Regional or local air quality management districts (or air districts), such as SJVAPCD are responsible for preparation of plans for attainment of federal and state standards. CARB is responsible for overseeing attainment of the CAAQS, implementation of nearly all phases of California's motor vehicle emissions program, and oversight of the operations and programs of the regional air districts.

Each air district is responsible for establishing and implementing rules and control measures to achieve air quality attainment within its district boundaries. The air district also prepares an air quality management plan (AQMP) that includes an inventory of all emission sources within the district (both man-made and natural), a projection of future emissions growth, an evaluation of current air quality trends, and an assessment of any rules or control measures needed to attain the AAQS. This AQMP is submitted to CARB, which then compiles AQMPs from all air districts within the state into the SIP. The responsibility of the air districts is to maintain an effective permitting system for existing, new, and modified stationary sources, to monitor local air quality trends, and to adopt and enforce such rules and regulations as may be necessary to achieve the AAQS.

Applicable LORS related to the potential air quality impacts from the Project are described below, and shown in Table 5.1-34. These LORS are administered (either independently or cooperatively) by the SJVAPCD, USEPA Region IX, CEC, and CARB. The area of responsibility for each of these agencies is described below. This Section 5.1, Air Quality and Section 5.6, Public Health, outline how the Project will comply with these LORS.

5.1.6.1 Ambient Air Quality Standards

USEPA, in response to the federal CAA of 1970, established federal AAQS in Title 40 CFR Part 50. The federal AAQS include both primary and secondary standards for six "criteria pollutants." These criteria pollutants are O_3, CO, NO_2, SO_2, particulate matter, and Pb. Primary standards were established to protect human health, and secondary standards were designed to protect property and natural ecosystems from the effects of air pollution.

The 1990 CAAA established attainment deadlines for all designated areas that were not in attainment with the federal AAQS. In addition to the federal AAQS described above, a new federal standard for $PM_{2.5}$ and a revised O_3 standard were promulgated in July 1997. The new federal standards were challenged in a court case during 1998. The court required revisions in both standards before USEPA can enforce them. The U.S. Supreme Court upheld an appeal of the District Court decision in February 2001. These issues were resolved and the 1-hour O_3 standard revoked in 2005, while the revised $PM_{2.5}$ standard was made effective in 2006. In 2010 a new 1-hour SO_2 standard was implemented and the SO_2 24-hour and annual standards were revoked. The 3-hour secondary standard for SO_2 remains unchanged. The state of California has adopted CAAQS that are in some cases more stringent than the federal AAQS. The state and federal AAQS relevant to the Project are summarized in Table 5.1-35.

USEPA, CARB, and the local air pollution control districts determine air quality attainment status by comparing local ambient air quality measurements from the state or local ambient air monitoring stations with the federal and state AAQS. Those areas that meet ambient air quality standards are classified as "attainment" areas; areas that do not meet the standards are classified as "non-attainment" areas. Areas that have insufficient air quality data may be identified as unclassifiable areas. These attainment designations are determined on a pollutant-by-pollutant basis. The area around the Project Site is classified as attainment with respect to the NAAQS for NO_2, PM_{10}, CO, and SO_2, and non-attainment for O_3 and $PM_{2.5}$. With respect to CAAQS, the area around the Project Site is classified as attainment for NO_2, CO, sulfates, Pb, H_2S, and SO_2, and non-attainment for O_3, PM_{10}, and $PM_{2.5}$. Nitrogen dioxide and SO_2 are regulated as PM_{10}

precursors, and NO_2 and VOCs as O_3 precursors. Table 5.1-36 presents the attainment status (both federal and state) for SJVAB.

As mentioned above, both USEPA and CARB are involved with air quality management in the SJVAB, area along with SJVAPCD.

5.1.6.2 Prevention of Significant Deterioration Requirements

In addition to the AAQS described above, the federal PSD program has been established to protect deterioration of air quality in those areas that already meet NAAQS. The PSD program specifies allowable concentration increases for attainment pollutants due to new emission sources. These increases allow economic growth while preserving the existing air quality, protecting public health and welfare, and protecting Class I areas. The PSD regulations require major stationary sources to undergo a pre-construction review that includes an analysis and implementation of BACT, a PSD increment consumption analysis, an ambient air quality impact analysis, and analysis of AQRVs (impacts on visibility). Effective July 2011, a source that emits more than 100,000 TPY of CO_2e is also considered a major stationary source. The Project is subject to these requirements.

The significant emission PSD triggers for all pollutants are as shown in Table 5.1-37. Project emissions of CO, NO_X, and PM_{10} are above these PSD triggers, thus HECA LLC must demonstrate through modeling that such emissions will not interfere with the attainment or maintenance of the applicable NAAQS and will not cause an exceedance of the applicable PSD increments shown in Table 5.1-38. Modeling showed that NO_X annual and PM_{10} 24-hour and annual impacts are below the PSD SILs, thus they are also below the increments listed in Table 5.1-38. For all Project emissions, HECA LLC must demonstrate through modeling that the increase in emissions will not interfere with the attainment or maintenance of the NAAQS, which HECA LLC did, and is described in Section 5.1.2.6.

Project emissions of CO_2 are above the PSD applicability threshold; thus, a GHG BACT analysis must be conducted to ensure that GHG emissions are minimized and Project efficiency is maximized.

5.1.6.3 Acid Rain Program Requirements

Title IV of the CAAA applies to sources of air pollutants that contribute to acid rain formation, including certain sources of SO_2 and NO_X emissions. The SJVAPCD has been delegated the authority by USEPA to administer Title IV requirements under its Title V Operating Permit program in Regulation II. Title IV is implemented by USEPA under 40 CFR 72, 73, and 75. The Acid Rain Program provisions of 40 CFR Part 72, Subparts A through I, are incorporated in SJVAPCD Rule 2540. Allowances of SO_2 emissions are set aside in 40 CFR 73. Sources subject to Title IV are required to obtain SO_2 allowances, to monitor their emissions, and obtain SO_2 allowances when a new source is permitted. Sources such as the Project that use fossil-derived fuel are required to comply with the acid rain program requirements. Under this program, HECA LLC is subject to the following requirements:

- Submittal of an Acid Rain permit application
- Remain in compliance with SO_2 and NO_X limitations/allowances
- Preparation and maintenance of an Acid Rain Compliance Plan
- Installation and maintenance of emission monitoring system.

The Project is a new facility; therefore, an Acid Rain Permit application will be submitted to SJVAPCD at least 24 months before the date of initial operation of the unit.

To meet the NO_X and SO_2 requirements, the Project must estimate SO_2 and NO_X emissions, and monitor NO_X emissions with certified CEMSs.

5.1.6.4 New Source Performance Standards

NSPS have been established by USEPA to limit air pollutant emissions from certain types of new and modified stationary sources. The NSPS regulations are contained in 40 CFR 60, and cover nearly 70 source categories. CTG/HRSG is regulated under Subpart Da.

In general, local emission limitation rules or BACT requirements are more restrictive than the NSPS requirements. A case-by-case applicability of NSPS regulations for the sources is further discussed in the BACT analysis in Appendix E-11, Criteria Pollutant BACT Analysis.

5.1.6.5 Federal Climate Change Programs

On April 13, 2012, the USEPA proposed the first Clean Air Act NSPS for emissions of CO_2 from future power plants (Standards for Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units). EPA is proposing that new fossil-fuel-fired power plants meet an output-based standard of 1,000 pounds of CO_2 per megawatt-hour (lb CO_2/MWh gross). This rule is currently in the public comment phase and it is unclear when the rule will be finalized.

USEPA issued the Mandatory Reporting of Greenhouse Gases Rule which requires reporting of GHG data and other relevant information from large sources and suppliers in the United States. The purpose of the rule is to collect accurate and timely GHG data to inform future policy decisions. In general, the Rule is referred to as 40 CFR Part 98 (Part 98). Implementation of Part 98 is referred to as the Greenhouse Gas Reporting Program.

5.1.6.6 Federally Mandated Operating Permits

Title V of the CAAA requires USEPA to develop a federal operating permit program that is implemented under 40 CFR 70. This program is administered by SJVAPCD under Regulation II, Rule 2520. Each major source, Phase II acid rain facility, and other source types designated by USEPA must obtain a Part 70 permit. Permits must contain emission estimates based on potential-to-emit, identification of all emission sources and controls, a compliance plan, and a statement indicating each source's compliance status. The permits must also incorporate all applicable federal, state, or SJVAPCD orders, rules, and regulations.

Because the Project will constitute a new stationary source, HECA LLC will submit a complete Title V permit application for a Title V permit to operate within 12 months after Project start-up.

5.1.6.7 California Power Plants Siting Requirements

Under CEQA, CEC has been charged with assessing the environmental impacts of each new power plant and considering the implementation of feasible mitigation measures to prevent potential significant impacts. CEQA Guidelines (Title 14, California Administrative Code, §15002[a][3]) state that the basic purpose of CEQA is to "prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible."

CEC's siting regulations require that, except under certain conditions, a new power plant can only be approved if the project complies with all federal, state, and local air quality rules, regulations, standards, guidelines, and ordinances that govern the construction and operation of the project. A project must demonstrate that project emissions will be appropriately controlled to mitigate significant impacts from the project and that it will not jeopardize attainment and maintenance of the AAQS. Cumulative impacts, impacts due to pollutant interaction, and impacts from non-criteria pollutants must also be considered.

5.1.6.8 California Climate Change Programs

Assembly Bill 32 (AB 32) requires the CARB to enact standards that will reduce GHG emissions to 1990 levels by 2020. AB 32 requires the CARB to assign emissions targets to each sector in the California economy and to develop regulatory and market methods to ensure compliance. Emission targets have been established in the CCR Title 20 §2902 – 2904. Additionally, Senate Bill 1368 is a state regulation that has set limits on GHG emissions from utilities. CEC is currently considering whether to modify the current requirements of SB 1368. SB 1368 set an emission performance standard for baseload generation owned by, or under long-term contract to publicly owned utilities, of 1,100 lb/MWh of CO_2. The Project will comply with the current version of SB 1368.

The GHG cap and trade regulation under AB 32 became effective January 2012 with a compliance date beginning January 1, 2013. Companies are not given a specific limit on their GHG emissions but must supply a sufficient number of allowances to cover their annual emissions. As the cap declines each year, the total number of allowances issued in the state drops, requiring companies to find the most cost-effective and efficient approaches to reducing their emissions. CARB will provide allowances to industrial sources during the initial period (2013–2014), and those that need additional allowances to cover their emissions can purchase them on the market. Electric utilities will also be given allowances to be sold to power providers such as the Project.

5.1.6.9 Air Toxic "Hot Spots" Program

As required by the California Health and Safety Code §44300, all facilities with criteria air pollutant emissions in excess of 10 tons per year are required to submit air toxic "Hot Spots" emissions information. The operational Project will be required to provide quantitative

information to the SJVAPCD on the Project's emissions of toxic air contaminants. This requirement is applicable only after the start of operation. Section 5.6, Public Health, demonstrates that the Project's emissions of toxic air contaminants impacts from the Project will be less than significant.

5.1.6.10 Determination of Compliance, Authority to Construct, and Permit to Operate

Under Regulation II, Rule 2010, 2070, and 2201, the SJVAPCD administers the air quality regulatory program for the construction, alteration, replacement, and operation of new power plants. As part of the AFC process, the Project will be required to obtain a pre-construction Determination of Compliance (DOC) from the SJVAPCD. Regulation II, Rule 2201 incorporates other SJVAPCD rules that pertain to sources that may emit air contaminants through the issuance of air permits (i.e., ATC and Permit to Operate [PTO]). This permitting process allows the SJVAPCD to adequately review new and modified air pollution sources to ensure compliance with all applicable prohibitory rules and to ensure that appropriate emission controls are used. An ATC allows for the construction of the air pollution source and remains in effect until the PTO application is granted, denied, or cancelled. Projects that are reviewed under the CEC application process must obtain an ATC from the local air district (in this case, SJVAPCD) prior to construction of the new power plant. For power plants under the siting jurisdiction of CEC, the SJVAPCD issues a DOC in lieu of an ATC. The DOC is incorporated into the CEC license. The ATC remains in effect until the PTO application is granted, denied, or cancelled. Once the Project commences operations and demonstrates compliance with the DOC, SJVAPCD will issue a PTO. The PTO specifies conditions that the air pollution source must meet to comply with other air quality standards, and will incorporate applicable DOC requirements. An application for the DOC will be submitted to the SJVAPCD simultaneously with the filing of this AFC Amendment.

5.1.6.11 San Joaquin Valley Air Pollution Control District Requirements

The SJVAPCD has been delegated responsibility for implementing the federal, state, and local regulations on air quality in Kern County to achieve and maintain both state and federal air quality standards; implementing permit programs established for the construction, modification, and operation of sources of air pollution; enforcing air pollution statutes, regulations and prohibitory rules governing non-vehicular sources; and developing programs to reduce emissions from indirect sources. The Project is subject to SJVAPCD regulations that apply to new sources of emissions, to the prohibitory regulations that specify emissions standards, and to the requirements for evaluation of air pollutant impacts for both criteria and toxic air pollutants. The following sections include the evaluation of the Project's compliance with the applicable SJVAPCD requirements.

5.1.6.12 SJVAPCD Climate Change Action Plan

In December 2009, the SJVAPCD adopted the "Guidance for Valley Land-use Agencies in Addressing GHG Emission Impacts for New Projects under CEQA" and the district policy "Addressing GHG Emission Impacts for Stationary Source Projects under CEQA When Serving as the Lead Agency" (SJVAPCD 2009a, 2009b). The guidance and policy rely on the use of performance based standards, otherwise known as Best Performance Standards, to assess

significance of project specific GHG emissions on global climate change during the environmental review process, as required by CEQA. This policy applies to projects for which the SJVAPCD has discretionary approval authority over the project and the SJVAPCD serves as the lead agency for CEQA purposes. For this Project, CEC is the lead agency and quantification of GHG emissions is used to determine compliance with adopted regional, statewide or local GHG reductions plans. As such, the SJVAPCD Climate Change Plan performance based standards are not applicable to this Project.

5.1.6.13 SJVAPCD Rules and Regulations

Rule 1080, Stack Monitoring

Outlines facility requirements for continuous monitoring equipment from any facility emitting pollutants for which emission limits have been established. The project will be constructed and operated to comply with the requirements of Rule 1080.

Rule 1081, Source Sampling

Outlines facility design requirements for source sampling from any facility emitting pollutants for which emission limits have been established. The project will be constructed and operated to comply with the requirements of Rule 1081.

Rule 1100, Equipment Breakdown

This rule details the notification and corrective action requirements necessary in an equipment breakdown situation. As operator of the Project, the Applicant will comply with these requirements.

Rule 2010, Permits Required

An ATC and PTO will be required for the Project. The Applicant will submit the required application materials for these permits to SJVAPCD.

Rule 2201, New and Modified Stationary Source Review

This rule outlines the emission standards, the offset requirements and conditions, the required demonstrations that the new source or modification will not cause or contribute to violations of the ambient air quality standards, procedures for power plants under CEC process, methods for calculating project emissions, and required air quality analysis procedures. Compliance with the specific provisions of this rule is discussed below.

Section 4.1, BACT. An Applicant must apply BACT to any new or modified emissions unit that has a potential to emit 2.0 pounds per day or more of any criteria pollutant. The SJVAPCD maintains a list of current BACT standards for specific source categories, which is posted on the District's website. Appendix E-11, Criteria Pollutant BACT Analysis, provides a formal BACT evaluation for the Project emissions of criteria pollutants. The proposed BACT levels for each

Project source are shown in Table 5.1-39, Proposed BACT for the Project, and incorporated in the emission calculations.

The Project will produce low-carbon baseload electricity and nitrogen based products by capturing CO_2 and transporting it for EOR and sequestration, thus controlling GHG emission to levels substantially below that of other fossil fuel power plants. The GHG BACT analysis has been prepared and submitted to USEPA with the HECA PSD permit application, this analysis will be amended to incorporate Project revisions and submitted with the revised PSD permit application.

Section 4.5, Emissions Offset Requirements. This section of Rule 2201 requires that offsets be provided for a new stationary source with a potential to emit equal to or exceeding the levels shown in the ERC analysis presented in Appendix E-10, Offset Package. Appendix E-10, Offset Package, describes the methods for determining the quantities of emission reduction credits needed to offset emissions from the Project. HECA LLC has already procured sufficient ERCs to mitigate Project emissions of non-attainment pollutant and their precursors.

Section 4.14, Ambient Air Quality Standards. Emissions from a new or modified Stationary Source may not cause or make worse the violation of an AAQS. Modeling used for the purposes of demonstrating compliance with this rule must be consistent with the requirements contained in the most recent edition of USEPA's *Guidelines on Air Quality Models,* unless the Air Pollution Control Officer finds that such model is inappropriate for use. After making such a finding, the Air Pollution Control Officer may designate an alternate model only after allowing for public comments and only with the concurrence of CARB or the USEPA.

As described in Section 5.1.2.6, Modeling Results—Compliance with Ambient Air Quality Standards, an air quality modeling analysis has been conducted to demonstrate that the Project will not cause or make worse the violation of any air quality standard.

Section 5.8, Power Plants. This section applies to all power plants proposed to be constructed in the SJVAPCD and for which a Notice of Intention or AFC has been accepted by CEC. It describes the actions to be taken by SJVAPCD to provide information to CEC and CARB to ensure that the project will conform to the District's rules and regulations. After the application has been submitted to CEC and other responsible agencies, including SJVAPCD, the Air Pollution Control Officer is required to conduct a DOC review. This determination consists of a review identical to that which would be performed if an application for an ATC had been received for the power plant. If the information contained in the AFC does not meet the requirements of this regulation, then the Air Pollution Control Officer is required to so inform CEC within 20 calendar days following receipt of the AFC. In such an instance, the AFC is considered to be incomplete, and is returned to the Applicant for re-submittal.

Section 6.0, Certification of Conformity. This section describes how a new or modified source that is subject to the requirements of Rule 2520 may choose to apply for a certificate of conformity with the procedural requirements of 40 CFR Part 70 for a Federal Operating Permit. A certificate of conformity will allow changes authorized by the ATC permit to be incorporated in the Part 70 permit as administrative permit amendments.

Rule 2520, Federally Mandated Operating Permits

Provides an administrative mechanism for issuing operating permits for new and modified sources of air contamination accordance with the federal requirements of 40 CFR Part 70. Under this rule, the Project will be required to obtain an operating permit, because it will include emission units that are subject to recently promulgated NSPS, and because it will also require an acid rain permit.

Rule 3010/3020, Permit Fees

This rule and the fee schedules in Rule 3020 establish the filing and permit review fees for specific types of new sources, as well as annual renewal fees and penalty fees for existing sources.

Rule 3110, Air Toxics Fees

This rule applies to facilities subject to the requirements of the Air Toxics "Hot Spots" Information and Assessment Act (§§ 44340 and 44383 of the California Health and Safety Code) and to facilities subject to NESHAPs issued pursuant to §112 of the federal CAA.

Rule 3135, Dust Control Plan Fee

This rule recovers the District's cost for reviewing Dust Control Plans and conducting site inspections to verify compliance with such plans.

Rule 3170, Federally Mandated Ozone Non-Attainment Fee

The purpose of this rule is to satisfy requirements specified in §185 and §1 82(f) of the CAA. This rule applies to major sources of NO_X and VOCs. The fees required pursuant to this section are additional to the permit fees and other fees required under other Rules and Regulations. This rule will cease to be effective when the Administrator of USEPA designates the SJVAPCD to be in attainment of the federal 1-hour standard for O_3. The Project will be a major source under either the federal or SJVAPCD definitions, and is subject to Rule 3170.

Rule 4001, New Source Performance Standards

This rule incorporates the federal NSPS from 40 CFR Part 60.

Rule 4002, National Emission Standards for Hazardous Air Pollutants

This rule incorporates the federal NESHAPs from Part 61 and Part 63, Chapter I, Subchapter C, Title 40 CFR.

Rule 4101, Visible Emissions

This rule applies to the opacity of discharges from any single source. Emissions from the sources of the Project will be below threshold opacity levels described in this rule.

Rule 4102, Nuisance

This rule states that there shall be no discharge of such quantities of any pollutant or material which could cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause or have a natural tendency to cause injury or damage to business or property.

Rule 4201, Particulate Matter Concentration

This rule applies to the discharge of particulate matter into the atmosphere. The relevant limit for the Project is expressed in Rule 4201, which states that no person shall release or discharge into the atmosphere from any single-source operation dust, fumes, or total suspended particulate matter, in excess of 0.1 grain per dry standard cubic foot of natural gas as determined by the following test methods: Particulate matter concentration – USEPA Method 5; Stack gas velocity – USEPA Method 2; Stack gas moisture – USEPA Method 4. The Project natural gas sources will easily comply with this requirement, with a maximum PM_{10} emission rate of approximately 0.045 grain per dry standard foot of natural gas consumption.

Rule 4301, Fuel-Burning Equipment

This rule limits the emission levels of NO_X, SO_2, and fuel combustion contaminants (particulates) from any fuel-burning equipment unit. The specific limits are 140 pounds per hour of NO_X, calculated as NO_2, 200 pounds per hour of SO_2, 0.1 grain per cubic foot of gas calculated to 12 percent of CO_2 at dry standard conditions, and 10 pounds per hour of combustion contaminants.

Rule 4703, Stationary Gas Turbines

This rule limits the NO_X and CO emissions from gas turbines with ratings greater than 0.3 MW. NO_X emissions concentrations shall be averaged over a 3-hour period using consecutive 15-minute sampling periods, or if CEMS are used, all applicable requirements of 40 CFR Part 60 must be met.

Rule 4801, Sulfur Compounds

This rule limits the emissions of sulfur compounds to less than 0.2 percent by volume on a dry basis averaged over 15 consecutive minutes by using USEPA Method 8 and CARB Methods 1 through 100.

Rule 8021, Construction, Demolition, Excavation, Extraction, and Other Earthmoving Activities

This rule limits fugitive dust emissions from construction, demolition, excavation, extraction, and other earthmoving activities such that opacity levels are kept to no more than 20 percent.

Rule 8041, Carryout and Trackout

This rule requires the limiting of carryout and trackout dust emissions from sites and is applicable to construction of the project.

Rule 8051, Open Areas

This rule applies to any open area of 3.0 acres or more in rural areas with at least 1,000 square feet of disturbed surface area. Dust emissions must be kept below 20 percent opacity.

Rule 8061, Paved and Unpaved Roads

This rule limits the emission of fugitive dust from roads to no more than 20 percent opacity through different control measures. Depending on traffic levels, the road must meet certain width requirements.

Rule 8071, Unpaved Vehicle/Equipment Traffic Areas

This rule limits the emission of fugitive dust to no more than 20 percent opacity through different control measures.

Rule 9110, General Conformity

This rule specifies the criteria and procedures for determining the conformity of federal actions with the SJVAPCD's air quality implementation plan. Provisions of 40 CFR parts 6 and 51 are included in this rule.

On November 30, 1993, the USEPA promulgated a set of regulations known as the General Conformity regulations (40 CFR 51 Subpart W) that include procedures and criteria for determining whether a proposed federal action would conform to the applicable SIPs. The General Conformity Rule affects air pollutant emissions associated with actions that are federally funded, licensed, permitted, or approved, and ensures emissions do not contribute to air quality degradation or prevent the achievement of state and federal air quality goals.

The proposed HECA Project is federally funded by Department of Energy, therefore it is subject to NEPA and the General Conformity Rule.

5.1.7 Involved Agencies and Agency Contacts

Agencies and individuals contacted in connection with the air quality assessment of the Project are detailed in Table 5.1-40.

5.1.8 Permits Required and Permit Schedule

The ATC permitting process that would otherwise apply is superseded in the case of CEC power plant licensing projects by the DOC process, which is its functional equivalent. CEC's final decision on this AFC Amendment will serve as the principal approval required to ensure that the

Project's impacts to air quality would be within acceptable levels. However, a PTO would be awarded following SJVAPCD confirmation that the Project has been constructed to operate as described in the permit applications. The SJVACPD review and approval process is expected to occur on a schedule within the overall CEC AFC Amendment review process.

USEPA will require a PSD permit be in place prior to the start of some elements of the construction. The USEPA review and approval process is expected to occur on a schedule within the overall CEC AFC Amendment review process.

5.1.9 References

AAR (Association of American Railroads), 2012. *Class I Rail Freight Fuel Consumption and Travel*. Available at http://www.bts.gov/publications/national_transportation _statistics/html/table_04_17.html. Accessed April 13, 2012.

Auer, August H., Jr., 1978. American Meteorological Society. Journal of Applied Meteorology, 17(5): 636–643. *Correlation of Land Use and Cover with Meteorological Anomalies*. May 1978.

CAPCOA (California Air Pollution Control Officers Association), 2011. *Modeling Compliance of The Federal 1-Hour NO_2 NAAQS*, October 27, 2011.

CARB (California Air Resources Board), 2000. *Risk Management Guidance for the Permitting of New Stationary Source Diesel-Fueled Engines*. October 2000.

CARB (California Air Resources Board), 2007a. *Off-Road Emissions Inventory, OFFROAD2007 Model*. Available at http://www.arb.ca.gov/msei/offroad/offroad.htm. Accessed April 13, 2012.

CARB (California Air Resources Board), 2007b. *Mobile Source Emission Inventory, EMFAC2007 Model*. Available at http://www.arb.ca.gov/msei/onroad/ latest_version.htm. Accessed April 13, 2012.

CARB (California Air Resources Board) *Aerometric Data Analysis & Management (ADAM), 2012. Top 4 Air Quality Data Summaries*, http://www.arb.ca.gov/adam/topfour/ topfour1.phpl. Accessed April 13, 2012.

CCAR (California Climate Action Registry), 2009. *California Climate Action Registry General Reporting Protocol*, ver. 3.1. January 2009.

CEC (California Energy Commission), 1997. *Regulations Pertaining to the Rules of Practice and Procedure and Plant Site Certification*. Title 20, California Code of Regulations. Chapters 1, 2, and 5.

CEC (California Energy Commission), 2006. *Rules of Practice and Procedure and Power Plant Site Certification Regulations Revisions*, 04-SIT-2. December 14.

CEC (California Energy Commission), 2012. *Regulations Establishing and Implementing a Greenhouse Gases Emission Performance Standard for Local Publicly Owned Electric Utilities, Chapter 11. Greenhouse Gases Emission Performance Standard, Article 1, Section 2900 et seq.*, http://www.energy.ca.gov/emission_standards/regulations/ Chapter11_Article1_SB 1368_Regulations.PDF. Accessed April 10, 2012.

DOE-NETL (Department of Energy–National Energy Technology Laboratory), 2009. *Carbon Dioxide Enhanced Oil Recovery – Untapped Domestic Energy Supply and Long Term Carbon Storage Solution. DOE/NETL Oil and Natural Gas Technologies, Exploration, and Production Report – CO_2 EOR Primer*. September 2009.

NPS (National Park Service), 2010. *Federal Land Managers' Air Quality Related Values Work Group (FLAG), Phase I Report – Revised (2010)*. October.

Port of Long Beach, 2009. *Port of Long Beach Air Emissions Inventory – 2007*. http://www. polb.com/civica/filebank/blobdload.asp?BlobID=6029. Accessed April 13, 2012.

SJVAPCD (San Joaquin Valley Air Pollution Control District), 2009a. *Guidance for Valley Land-use Agencies in Addressing GHG Emission Impacts for New Projects under CEQA*. December 17, 2009.

SJVAPCD (San Joaquin Valley Air Pollution Control District), 2009b. *Addressing GHG Emission Impacts for Stationary Source Projects under CEQA When Serving as the Lead Agency*. December 17, 2009.

SJVAPCD (San Joaquin Valley Air Pollution Control District), 2010. *Assessment of Non-Regulatory Option in AERMOD Specifically OLM and PVMRM*. September 2010.

URS Corporation, 2009a. *Air Quality Modeling Protocol for the Hydrogen Energy California (HECA) Project, Kern County*. Prepared by URS for San Joaquin Valley Air Pollution Control District, California Energy Commission, U.S. Environmental Protection Agency Region IX, and National Park Service. February, 2009.

URS Corporation, 2009b. *Reponses to CEC Data Requests Set One – Nos. 1 Through 132,* Revised Application for Certification (08-AFC-8). November 2009.

URS Corporation, 2010. *Reponses to CEC Data Requests Set One (Nos. 1, 2, 11, 17, 31b, 32, 33, 36, 64f, 85 through 90, and 125 through 132),* Revised Application for Certification (08-AFC-8). January 2010.

URS Corporation, 2011. *Modeling Protocol for Parameter Selection Specific to the 1-hour NO_2 NAAQS Regional Modeling for the HECA Project*. Prepared by URS for U.S. Environmental Protection Agency, Region IX. January 20, 2011

URS Corporation, 2012. *Modeling Protocol Supplement for the HECA Project*. Prepared by URS for U.S. Environmental Protection Agency Region IX, California Energy Commission, and San Joaquin Valley Air Pollution Control District. February 21, 2012.

USEPA (U.S. Environmental Protection Agency), 1985. *Guideline for Determination of Good Engineering Stack Height (Technical Support Document for the Stack Height Regulation*) (Revised), EPA-450/4-80-023R. Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina. June 1985.

USEPA (U.S. Environmental Protection Agency), 1995b. *SCREEN3 Model User's Guide*. EPA-454/B-95-004. September 1995.

USEPA (U.S. Environmental Protection Agency), 1995c. *Protocol for Equipment Leak Emission Estimates*. EPA-453/R-95-017. November 1995.

USEPA (U.S. Environmental Protection Agency), 2003. *Guidelines on Air Quality Models*.

USEPA (U.S. Environmental Protection Agency), 2004. *User's Guide for the AMS/EPA Regulatory Model – AERMOD*. EPA454-B-03-001. September 2004.

USEPA (U.S. Environmental Protection Agency), 2006. *Addendum to User's Guide for the AMS/EPA Regulatory Model-AERMOD*. December 2006.

USEPA (U.S. Environmental Protection Agency), 2009. *Technical Highlights: Emission Factors for Locomotives*. EPA-420/F-09-025. April 2009.

USEPA (U.S. Environmental Protection Agency), 2011. *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard*. March 1, 2011.

USEPA (U.S. Environmental Protection Agency), 2012. *AIRS Air Quality Monitoring Data Reports*, http://www.epa.gov/airdata/. Accessed April 13, 2012.

Western Regional Climate Center, 2012. *Buttonwillow, CA, Period of Record Monthly Climate Summary*, http://www.wrcc.dri.edu/cgi-bin/cliMAIN.pl?ca1244. Accessed April 5, 2012.

Table 5.1-1
Temperature and Precipitation Data for Buttonwillow Station

Month	Average Temperatures (°F)[1]		Precipitation (inches)
	Low	High	
January	35.2	56.3	1.07
February	39.0	63.2	1.08
March	43.0	69.1	0.97
April	47.2	75.9	0.54
May	54.1	84.7	0.22
June	60.1	92.4	0.05
July	65.4	98.4	0.02
August	63.3	96.7	0.02
September	57.8	91.6	0.12
October	48.8	81.4	0.27
November	39.2	67.4	0.55
December	34.5	57.2	0.75
Annual Average	**48.9**	**77.9**	**5.66**

Source: Western Regional Climate Center, April 2012.

Note:

[1] Average temperature and precipitation data represent 1/1/1940–2/13/2012.

Table 5.1-2
Ambient Ozone Levels at Shafter–Walker Street Station, 2009–2011

	2009	2010	2011
Shafter–Walker Street Station, Kern County			
Maximum 1-hour average (ppm)	0.105	**0.106**	0.097
Number of days exceeding California 1-hour standard (0.09 ppm)	2	**8**	N/A
Number of days exceeding federal 1-hour standard (0.12 ppm)	0	0	0
Maximum 8-hour average (ppm)	0.084	**0.095**	0.086
Number of days exceeding California 8-hour standard (0.07 ppm)	31	**41**	N/A
Number of days exceeding federal 8-hour standard (0.075 ppm)[1]	11	**22**	18

Source: California Air Resources Board (CARB, 2012), www.arb.ca.gov; USEPA AIRS, 2012, http://www.epa.gov/airdata
Last update: April 5, 2012

Notes:
[1] Number of days with an 8-hour average exceeding federal standard concentration of 0.075 ppm. Regulatory standard is to maintain 0.075 ppm as a 3-year average of the fourth-highest daily maximum. Therefore, number of days exceeding standard concentration is not the number of violations of the standard for the year.
Maximum average values occurring during the most recent 3 years are indicated in bold.
The O_3 standard is attained when the expected number of days per calendar year with maximum hourly average concentrations above the standard is equal to or less than one.
New federal 8-hour O_3 standard was promulgated by USEPA on 18 July 1997. The federal 1-hour O_3 standard was revoked by USEPA on 15 June 2005.
N/A = not available
ppm = parts per million

Table 5.1-3
Ambient PM_{10} Levels at Bakersfield—5558 California Avenue, 2008–2010

	2008	2009	2010
Bakersfield—5558 California Avenue, Kern County			
State maximum 24-hour average (μg/m^3)	**263.6**	99.0	238.0
State annual average (μg/m^3)	**55.3**	41.2	32.6
Number of days exceeding California 24-hour standard (50 μg/m^3)	31	14	**67**
National maximum 24-hour average (μg/m^3)	**262.3**	94.5	86.0
Annual arithmetic mean (μg/m^3)	**53.6**	41.7	32.3
Number of days exceeding national 24-hour standard (150 μg/m^3)	**1**	0	0

Source: California Air Resources Board (CARB, 2012); www.arb.ca.gov.
Last update: April 5, 2012

Notes:
Maximum average values occurring during the most recent 3 years are indicated in bold.
μg/m^3 = micrograms per cubic meter

Table 5.1-4
Ambient $PM_{2.5}$ Levels at Bakersfield—5558 California Avenue, 2008–2010

	2008	2009	2010
Bakersfield—5558 California Avenue, Kern County			
Maximum 24-hour average (μg/m^3)	99.3	**195.5**	112
Number of days exceeding federal 24-hour Standard (35 μg/m^3)	**56**	41	26
1-year 98th percentile (μg/m^3)	64.5	**66.7**	53.3
3-year average, 98th percentile[1] (μg/m^3)	66	**68**	62
Annual arithmetic mean (μg/m^3)	**21.9**	19.0	14.1
3-year average, arithmetic mean[2] (μg/m^3)	20.9	**21.0**	18.4
State annual average (μg/m^3)	N/A	**21.2**	17.2

Source: California Air Resources Board (CARB, 2012), www.arb.ca.gov.
Last update: April 5, 2012

Notes:
[1] The 3-year average, 98th percentile is above the Federal AAQS of 35 μg/m^3.
[2] The 3-year average, arithmetic mean is above the CAAQS of 12 μg/m^3
Maximum average values occurring during the most recent 3 years are indicated in bold.
N/A = not available
mg/m^3 = micrograms per cubic meter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
μg/m^3 = micrograms per cubic meter

Table 5.1-5
Ambient CO Levels at Bakersfield—Golden State Highway, 2007–2009

	2007	2008	2009
Bakersfield—Golden State Highway Station, Kern County			
Maximum 1-hour average[1] (ppm)	3	**4**	2
Maximum 8-hour average[2] (ppm)	1.97	**2.17**	1.51

Source: California Air Resources Board (CARB, 2012), www.arb.ca.gov; USEPA AIRS, 2012, http://www.epa.gov/airdata
Last update: April 5, 2012

Notes:
Maximum average values occurring during the most recent 3 years are indicated in bold.
[1] All 1-hour concentrations are below the federal and California CO ambient air quality standards of 35 ppm and 20 ppm, respectively.
[2] All 8-hour concentrations are below the federal and California CO ambient air quality standard of 9 ppm.
ppm = parts per million

Table 5.1-6
Ambient NO_2 Levels at Shafter–Walker Street Station, 2009–2011

	2009	2010	2011
Shafter–Walker Street Station, Kern County			
Maximum 1-hour average[1] (ppm)	0.052	**0.074**	0.054
Annual average[2] (ppm)	0.014	0.012	0.012

Source: California Air Resources Board (CARB, 2012), www.arb.ca.gov; USEPA AIRS, 2012, http://www.epa.gov/airdata
Last update: April 5, 2012

Notes:
Maximum average values occurring during the most recent 3 years are indicated in bold.
[1] All 1-hour concentrations are below the California NO_2 ambient air quality standard of 0.25 ppm.
[2] All annual average concentrations are below the federal NO_2 ambient air quality standard of 0.053 ppm.
ppm = parts per million.

Table 5.1-7
Ambient SO_2 Levels at Fresno—First Street, 2009–2011

	2009	2010	2011
Monitoring Station	Fresno—First Street	Fresno—First Street	Fresno—First Street
Maximum 1-hour average[1] (ppm)	0.013	0.015	**0.016**
Maximum 24-hour average[2] (ppm)	**0.005**	0.004	0.004
Annual average[3] (ppm)	**0.001**	0.000	N/A

Source: California Air Resources Board (CARB, 2012), www.arb.ca.gov; USEPA AIRS, 2012, http://www.epa.gov/airdata.

Last update: April 5, 2012

Notes:

Maximum average values occurring during the most recent 3 years are indicated in bold.

[1] All 1-hour average concentrations are below the California SO_2 ambient air quality standard of 0.25 ppm (655 $\mu g/m^3$).

[2] All 24-hour average concentrations are below the California SO_2 ambient air quality standard of 0.04 ppm (105 $\mu g/m^3$) and the federal AAQS of 0.14 ppm (365 $\mu g/m^3$).

[3] All annual average concentrations are below the federal SO_2 AAQS of 0.03 ppm (80 $\mu g/m^3$).

N/A = not available

ppm = parts per million

Table 5.1-8
Estimated Daily Maximum Construction Emissions of Criteria Pollutants (lbs/day)

Activity	PM_{10}	$PM_{2.5}$	CO	ROG	NO_X	SO_2
Project Construction Emissions						
On-Site Combustion Emissions						
Construction equipment—on-road	7.84	7.06	61.80	22.69	127.81	0.13
Construction equipment—off-road	13.28	12.22	126.21	38.72	181.10	0.32
Worker vehicles	0.01	0.00	3.00	0.23	0.24	0.008
Delivery trucks	1.824	1.654	2.205	1.359	5.138	0.004
Linear Combustion Emissions	0.00	0.00	155.42	44.31	258.98	0.00
On-Site Fugitive Emissions						
Construction equipment—on-road	55.98	5.60				
Construction equipment—off-road	0.94	0.09				
Worker vehicles	4.42	0.44				
Delivery trucks	143.40	14.34				
Construction activity	36.28	11.55				
Linear Fugitive Emissions	0.00	0.00				
Subtotal of Project Emissions	**263.95**	**52.96**	**348.63**	**107.31**	**573.26**	**0.46**
Off-Site Construction Emissions						
Off-Site Combustion Emissions						
Worker vehicles	0.39	0.20	230.14	7.08	27.55	0.272
Delivery trucks	11.02	9.45	15.40	3.40	78.16	0.07
Off-Site Paved Road Fugitive Dust Emissions						
Worker vehicles	0.85	0.21				
Delivery trucks	13.87	3.40				
Subtotal of Off-Site Emissions	**26.13**	**13.26**	**245.54**	**10.48**	**105.71**	**0.35**
Total Maximum Daily Emissions (lbs/day)	**290**	**66**	**594**	**118**	**679**	**1**

Source: HECA, 2012.

Notes:

CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
ROG = reactive organic gases
SO_2 = sulfur dioxide

Table 5.1-9
Estimated Annual Maximum Construction Emissions of Criteria Pollutants (tons/year)

Activity	PM_{10}	$PM_{2.5}$	CO	ROG	NO_X	SO_2
Project Construction Emissions						
On-Site Combustion Emissions						
Construction equipment—on-road	0.78	0.70	7.68	2.77	15.84	0.02
Construction equipment—off-road	1.48	1.37	17.68	5.41	26.24	0.03
Worker vehicles	0.00	0.00	0.43	0.03	0.03	0.001
Delivery trucks	0.158	0.143	0.291	0.179	0.678	0.001
Linear Combustion Emissions	0.14	0.13	12.89	3.86	21.52	0.03
On-Site Fugitive Emissions						
Construction Equipment—on-road	6.04	0.60				
Construction equipment—off-road	0.15	0.01				
Worker vehicles	0.76	0.08				
Delivery trucks	12.24	1.22				
Construction activity	4.76	1.54				
Linear Fugitive Emissions	0.11	0.01				
Subtotal of Project Emissions	**29.2**	**5.8**	**39.0**	**12.3**	**64.3**	**0.1**
Off-Site Construction Emissions						
Off-Site Combustion Emissions						
Worker vehicles	0.07	0.03	33.08	1.02	3.96	0.039
Delivery trucks	1.00	0.86	2.03	0.45	10.32	0.01
Off-Site Paved Road Fugitive Dust Emissions						
Worker vehicles	0.14	0.04				
Delivery trucks	1.27	0.31				
Subtotal of Off-Site Emissions	**2.5**	**1.2**	**35.1**	**1.5**	**14.3**	**0.0**
Total Maximum Annual Emissions (tons/year)	**31.7**	**7.0**	**74.1**	**13.7**	**78.6**	**0.1**

Source: HECA, 2012.

Notes:

CO = carbon monoxide
NO_X = oxides of nitrogen
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
ROG = reactive organic gases
SO_2 = sulfur dioxide

Table 5.1-10
Estimated Emissions of GHG Pollutants, Entire Construction Period
(metric tonnes)

Activity	CO_2	CH_4	N_2O	CO_2e
Project Construction Emissions				
On-Site Combustion Emissions				
Construction equipment—on-road	5,215.7	0.1	0.1	5,244.7
Construction equipment—off-road	8,294.8	1.4	0.2	8,385.2
Worker vehicles	246.6	0.0	0.0	249.9
Delivery trucks	352.2	0.0	0.0	353.8
Linear Combustion Emissions	2,433.5	0.3	0.0	2,450.9
Subtotal of Project Emissions	**16,542.8**	**1.8**	**0.3**	**16,684.5**
Off-Site On-Road Emissions				
Off-Site Combustion Emissions				
Worker vehicles	13,953.4	3.3	1.7	14,536.2
Delivery trucks	5,299.6	0.2	0.2	5,355.8
Subtotal of Off-Site Emissions	**19,253.0**	**3.5**	**1.8**	**19,892.1**
Total Maximum Daily Emissions (tonnes)	**35,795.8**	**5.3**	**2.2**	**36,576.6**

Source: HECA, 2012.
Notes:
CO_2 = carbon dioxide
CH_4 = methane
N_2O = nitrous oxide
CO_2e = carbon dioxide equivalent

Table 5.1-11
Maximum Short-Term Emissions From CTG/HRSG And Coal Dryer Stack During On-Peak Operations

Pollutant	CTG/HRSG Emissions lb/hr	Coal Dryer Emissions lb/hr	Basis	CTG/HRSG Emissions Basis (ppmv)	CTG/HRSG Emissions lb/hr	CTG/HRSG Emissions Basis (ppmv)
	Hydrogen-Rich Fuel				Natural Gas	
NO_X	25.0	4.4	Case 1 (ON Peak, 97F Ambient)	2.5	34.1	4
CO	18.3	3.2	Case 1 (ON Peak, 97F Ambient)	3	26.0	5
VOC	3.5	0.6	Case 1 (ON Peak, 97F Ambient)	1	5.9	2
$PM_{10}/PM_{2.5}$	12.9	1.4	Case 3 (ON Peak, 39F Ambient)	15 lb/hr	15.0	15 lb/hr
SO_2	4.1	0.9	Case 2 (OFF Peak, 97F Ambient)	2 ppmv total sulfur in syngas, 10 ppmv sulfur in PSA Off-gas	4.7	12.65 ppm sulfur in natural gas
NH_3	18.5	3.2	Case 1 (ON Peak, 97F Ambient)	5	15.8	5

Source: HECA, 2012.
Notes:
Emissions include duct burner operations with syngas and PSA off-gas.
Coal dryer PM emissions control to 0.001 gr/dscf by baghouse

Table 5.1-12
CTG/HRSG and Coal Dryer Maximum Annual Operation Emissions

Pollutant	CTG/HRSG, ton/year				Coal Dryer, ton/year		
	Start-Up/ Shut-Down	Operations	Natural Gas Operations	Total	Start-Up/ Shut-Down	Operations	Total
NO_X	4.34	99.6	5.73	109.7	0.54	16.9	17.4
CO	15.7	72.8	4.36	92.9	0.91	12.4	13.3
VOC	0.49	13.9	1.00	15.3	0.04	2.4	2.4
$PM_{10}/PM_{2.5}$	0.82	51.3	2.52	54.6	0.05	5.6	5.6
SO_2	0.147	16.2	0.80	17.1	0.02	2.7	2.8
NH_3	0.00	73.6	2.65	76.3	0.00	12.5	12.5

Source: HECA, 2012.

Table 5.1-13
CTG/HRSG and Coal Drying Stack Emissions During Start-Up and Shut-Down

HRSG Start-Up							
Step	**Duration (hrs)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. CTG ignition and synchronization, 20 percent load on natural gas	0.5	lb/hr	2.1	67.1	2270	15.0	65
		lb	1.0	33.6	1135	7.5	32.4
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	2.4	107.2	1044	13.1	13
		lb	4.8	214	2088	26.3	26.8
3. CTG fuel change over, 40 percent load on syngas, start-up PSA/ammonia/urea units	50	lb/hr	2.4	66.6	81	13	4.6
		lb	120	3329	4052	657	232
Tons/Start-Up			**0.06**	**1.79**	**3.64**	**0.35**	**0.15**
Coal Drying Start-Up							
Step	**Duration (hrs)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
2. HRSG/STG warm-up, ramp CTG to 40 percent load on natural gas	2	lb/hr	0.3	15.1	147.4	0.9	1.9
		lb	0.7	30.3	294.7	1.9	3.8
3. CTG fuel change over, 40 percent load on syngas	50	lb/hr	0.3	9.4	11.5	0.9	0.7
		lb	16.9	470	573	47	33
Tons/Start-Up			**0.01**	**0.25**	**0.43**	**0.02**	**0.02**

Table 5.1-13
CTG/HRSG and Coal Drying Stack Emissions During Start-Up and Shut-Down

HRSG Shut-Down							
Step	**Duration (hrs)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea unit shut-down; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	2.4	66.6	81.0	13	4.6
		lb	9.6	266	324	52.6	18.5
2. CTG fuel change over 40 percent load on natural gas, gasifier depressurization	3	lb/hr	2.7	122	1191	15.0	15.3
		lb	8.2	367	3574	45.0	45.9
3. Minimum plant load, 20 percent load on natural gas	2	lb/hr	2.1	67.1	2270	15.0	64.8
		lb	4.2	134	4539	30.0	129.7
Tons/Shut-Down			**0.01**	**0.38**	**4.22**	**0.06**	**0.10**
Coal Drying Shut-Down							
Step	**Duration (hrs)**	**Units**	**SO_2**	**NO_X**	**CO**	**$PM_{10}/PM_{2.5}$**	**VOC**
1. PSA, ammonia, and urea plant shut-down; gasifier to 60 percent; CTG to 40 percent load on syngas	4	lb/hr	0.3	9.4	11.5	0.9	0.7
		lb	1.4	37.6	45.8	3.8	2.6
Tons/Start-Up			**0.00**	**0.02**	**0.02**	**0.00**	**0.00**

Source: HECA, 2012.
Notes:
Basis: Start-up/shut-down procedures provided by MHI.
Coal drying starts at Step 2, above.
$PM_{10}/PM_{2.5}$ emission rate based on 0.001 grain/dscf

Table 5.1-14
Total Combined Annual Criteria Pollutant Emissions[1]

Equipment \ Pollutant	NO_X	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$
	tons/yr					
HRSG/CTG	109.7	92.9	15.3	17.1	54.6	54.6
Coal Dryer	17.4	13.3	2.4	2.8	5.6	5.6
Auxiliary Boiler	1.4	8.6	0.9	0.5	1.2	1.2
Tail Gas Thermal Oxidizer	13.4	11.2	0.3	8.3	0.4	0.4
CO_2 Vent	N/A	124.1	2.8	N/A	N/A	N/A
Gasification Flare	3.2	18.5	0.01	0.02	0.03	0.03
Rectisol® Flare	1.2	0.8	0.01	0.3	0.03	0.03
SRU Flare	0.2	0.2	0.003	0.4	0.006	0.006
Cooling Towers[2]	N/A	N/A	N/A	N/A	25.5	15.3
Emergency Generators[3]	0.2	0.8	0.1	0.001	0.02	0.02
Fire Water Pump	0.09	0.2	0.01	0.0003	0.001	0.001
Nitric Acid Unit	17	N/A	N/A	N/A	N/A	N/A
Urea Pastillation Unit	N/A	N/A	N/A	N/A	0.2	0.2
Ammonium Nitrate Unit	N/A	N/A	N/A	N/A	0.8	0.8
Ammonia Start-Up Heater	0.04	0.1	0.02	0.01	0.02	0.02
Material Handling[4]	N/A	N/A	N/A	N/A	1.9	1.9
Fugitives	N/A	4.6	13.4	N/A	N/A	N/A
Total Annual	**163.7**	**275.2**	**35.4**	**29.4**	**90.3**	**80.2**

Source: HECA 2012
Notes:
1 Total annual emissions represent the maximum annual emissions during operations plus start-up and shut-down emissions
2 Includes contributions from all three cooling towers
3 Includes contributions from both emergency generators
4 Material handling emissions are shown as the contribution of all dust collection points.
HRSG = Heat Recovery Steam Generator
CTG = combustion turbine generator
CO = carbon monoxide
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter ($PM_{2.5}$ is assumed to equal PM_{10})
SO_2 = sulfur dioxide
VOC = volatile organic compound

Table 5.1-15
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
First fire	4	FSNL	Not operating	8.4	268.4	9,080	260	60
Rotor run-in	12	20%	Not operating	25.2	805	27,240	780	180
Steam blows	168	40%	Not operating	520.8	15,657	152,544	1,966	2,520
Restoration	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Initial steam turbine roll	24	40%	Not operating	74.4	2,237	21,792	281	360
NO_X tuning with water injection and initial STG loading	16	40%	Not operating	49.6	174	6057.6	112	240
NO_X tuning with water injection and initial STG loading	16	80%	Not operating	76.8	6,259	5,512	60.8	240
Finalize NO_X control constants	40	40%	Not operating	124	436	15,144	280	600
Finalize NO_X control constants	40	60%	Not operating	160	11,922	14,460	243.2	600
Finalize NO_X control constants	96	80%	Not operating	460.8	37,555	33,072	364.8	1,440
GTG water wash and contractual emission and simple cycle performance testing	16	80%	Not operating	76.8	6,259	5,512	60.8	240
Install SCR and oxidation catalyst	24	80%	Testing	112.8	818	624	142	360
CEMS drift and source testing	64	80%	Operating	300.8	2,182	1,664	377.6	960
Functional testing demonstration hours (six starts)	315	20% to 40%	Operating	859.95	24,466	48,857	1965.6	4,438
Functional testing demonstration hours (six shut-downs)	54	20% to 40%	Operating	139.32	4830.84	50,898	1180.98	810
Functional testing steady state hours	48	80%	Operating	225.6	1,637	1248	283.2	720

Table 5.1-15
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Natural Gas

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
GTG water wash and preparation for performance testing	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Continuous operation test	192	80%	Operating	902.4	6,547	4992	1132.8	2880
	1,129	**Total (lb)**		**4,118**	**122,055**	**398,696**	**9,490**	**16,648**
		Total (ton)		**2.1**	**61.0**	**199.3**	**4.7**	**8.3**

Source: HECA 2012.

Notes:
CEMS = continuous emissions monitoring system
CO = carbon monoxide
CTG = combustion turbine generator
HRSG = heat-recovery steam generator
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOCs = volatile organic compounds

Table 5.1-16
Duration and Criteria Pollutant Emissions for Commissioning of the Gasifier and Balance of Plant

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
Test Firewater Diesel Pump	6	100%	Operating	0	11	19	0	1
Test Diesel Generators (total both units)	20	100%	Operating	1	62	36	3	14
Auxiliary Boiler burner and FGR tuning	96	25% to 100%	Tuning	26	460	945	102	64
Auxiliary Boiler source testing	64	100%	Operating	28	78	483	52	65
Auxiliary Boiler operation to support commissioning	672	100%	Operating	292	823	5,072	548	685
ASU Cooling Tower	7,000	100% 2000 TDS	Operating	0	0	0	0	1,570
Process Cooling Tower	7,000	50% 4500 TDS	Operating	0	0	0	0	12,950
Power Block Cooling Tower	7,000	50% 4500 TDS	Operating	0	0	0	0	7,520
Functional testing flares on natural gas	72	Reduced	Operating	29	1,728	1,152	19	43
Flare operation on un-shifted syngas	168	50%	Operating	685	23,520	672,000	0	0
Flare operation on shifted (high-H_2) syngas	504	50%	Operating	2,056	70,560	372,960	0	0
Thermal oxidizer—SRU refractory cure and heating	576	Minimum	Operating	6	317	259	20	23
Thermal oxidizer to support commissioning	711	Min to 100%	Operating	7,844	1,669	1,408	68	68
Start-up/standby coal drying vent ops (CTG on natural gas)	120	40% to 80%	Operating	36	544	5,306	228	108

Table 5.1-16
Duration and Criteria Pollutant Emissions for Commissioning of the Gasifier and Balance of Plant

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
Normal coal drying vent ops (CTG on H_2-rich fuel)	1,200	100%	Operating	1,080	5,280	3,840	720	1,680
CO_2 vent	672	50%	Operating	0	0	165,312	3,696	0
		Total (lb)		**12,084**	**105,051**	**1,228,793**	**5,457**	**24,792**
		Total (ton)		**6.0**	**52.5**	**614.4**	**2.7**	**12.4**

Source: HECA 2012.

Notes:
CEMS = continuous emissions monitoring system
CO = carbon monoxide
CTG = combustion turbine generator
HRSG = heat-recovery steam generator
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOCs = volatile organic compounds

Table 5.1-17
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen-Rich Fuel

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
GTG starts on natural gas (for 20 starts)	50	20% to 40%	Not operating	116	4,952	64,460	1,184	676
GTG hold time allowance (40% load on H_2-rich fuel)	240	40%	Operating	576	4,795	5,832	1,104	3,120
GTG shut-down hold at 40% load on H_2-rich fuel (for 20 shut-downs)	80	40%	Operating	192	1,598	1,944	368	1,040
GTG fired shut-downs on natural gas (for 20 shut-downs)	100	20% to 40%	Operating	248	7,368	162,260	3,512	1,500
GTG/HRSG standby operation on natural gas	120	40%	Partially Operating	324	1,171	10,004	444	1,800
Gasifier fuel turnover tuning @ 40% H_2-rich fuel	20	40%	Partially Operating	48	1,332	1,620	92	300
CTG NO_X tuning on H_2-rich fuel	16	40%	Partially Operating	38	1,066	1,296	74	240
Gasifier feedstock dryer tuning	24	40%	Partially Operating	58	1,598	1,944	110	360
STG gasifier/SGC steam operation tuning	20	40%	Partially Operating	48	1,332	1,620	92	300
Zero flare tuning	48	40%	Operating	115	3,197	3,888	221	720
CTG NO_X tuning on H_2 rich-fuel	60	75%	Operating	246	1,308	960	186	900
CTG NO_X tuning on H_2 rich-fuel	60	100%	Operating	246	1,500	1,098	210	900
CTG load change testing	60	40% to 100%	Operating	198	2,748	2,982	246	900
CTG trip test	36	40% to 100%	Operating	119	1,649	1,789	148	540

Table 5.1-17
Duration and Criteria Pollutant Emissions for Commissioning of the CTG/HRSG on Hydrogen-Rich Fuel

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
GTG water wash and contractual emission and simple cycle performance testing on H_2-rich fuel	24	100%	Operating	72	689	226	89	360
Duct burner testing on H_2-rich syngas	48	100%	Operating	192	1,397	744	187	720
Duct burner testing on PSA off-gas	48	60%	Operating	240	893	653	125	720
Source testing @ 100% H_2-rich syngas (duct fired, H_2-rich + PSA)	16	100%	Operating	80	470	344	66	240
Source testing @ 70% H_2-rich syngas (duct fired, PSA only)	16	70%	Operating	64	298	218	42	240
IGCC performance and operating test	96	70% to 100%	Operating	432	2,304	1,690	326	1,440
	1,182	**Total (lb)**		**3,652**	**41,665**	**265,571**	**8,825**	**17,016**
		Total (ton)		**1.8**	**20.8**	**132.8**	**4.4**	**8.5**

Source: HECA 2012.

Notes:
CEMS = continuous emissions monitoring system
CO = carbon monoxide
CTG = combustion turbine generator
HRSG = heat-recovery steam generator
H_2 = hydrogen
lb = pound
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOC = volatile organic compound

Table 5.1-18
Duration and Criteria Pollutant Emissions for Commissioning of the Manufacturing Complex

Test Phase	Hours of Operation	CTG Load	SCR/CO Status	SO_X (lb)	NO_X (lb)	CO (lb)	VOC (lb)	PM_{10} (lb)
High-purity H_2 compressor testing to flare	48	100%	Operating	0.0	3,897.6	0.0	0.0	0.0
Operation of ammonia unit start-up heater	240	25% to 100%	Operating	20.1	108.2	364.1	39.4	49.2
Ammonia plant flaring during catalyst reduction	60	Minimum	Operating	0.0	210.0	0.0	0.0	0.0
Particulate emissions from urea pastillation	800	100%	Operating	0.0	0.0	0.0	0.0	40.0
Nitric acid plant tail gas NO_X abator tuning	60	25% to 100%	Tuning	0.0	1,260.0	0.0	0.0	0.0
Nitric acid plant tail gas with NO_X abator	600	100%	Operating	0.0	2,520.0	0.0	0.0	0.0
Ammonium nitrate vent scrubber emissions	660	100%	Operating	0.0	0.0	0.0	0.0	132.0
Urea storage and handling	800	100%	Operating	0.0	0.0	0.0	0.0	256.0
Venting high purity CO_2 for urea unit commissioning	120	25% to 100%	Operating	0.0	0.0	3.5	11.9	0.0
	3,388	**Total (lb)**		**20.1**	**7,995.8**	**367.5**	**51.3**	**477.2**
		Total (ton)		**0.01**	**4.00**	**0.18**	**0.03**	**0.24**

Source: HECA 2012.
Notes:
CEMS = continuous emissions monitoring system
CO = carbon monoxide
CO_2 = carbon dioxide
CTG = combustion turbine generator
HRSG = heat-recovery steam generator
H_2 = hydrogen
Lb = pound
N/A = not applicable
NO_X = nitrogen oxides
PM_{10} = particulate matter less than 10 microns in diameter
SCR = selective catalytic reduction
SO_X = sulfur oxides
VOCs = volatile organic compounds

Table 5.1-19
On-Site Maximum Trucks and Trains by Period

Period	Petcoke Trucks	Product Trucks	Miscellaneous Trucks	Coal Trains	Product Trains
1 hour	6	13	5	1	1
3 hours	17	39	5	1	1
8 hours	44	104	5	2	1
24 hours	55	130	5	2	1
Annual	15,200	20,880	1,818	109	153

Source: HECA, 2012.

Notes: The facility will also maintain 20 vehicles (10 gasoline and 10 diesel trucks) for onsite operations and maintenance (O&M).

This table presents the delivery trucks associated with Alternative 1 (rail transportation option).

Table 5.1-20
Operational Transportation Emissions Related to the Project

Area	Attainment Status	Emission Source	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
			Annual Emission Rates (tons/year)					
SJVAPCD (San Joaquin Valley)	Ozone non-attainment—extreme	Off-site train	25.39	93.08	1.69	1.64	1.53	5.35
	$PM_{2.5}$ non-attainment	Off-site truck	9.96	8.71	2.39	0.72	0.06	0.74
		Off-site workers commuting	4.17	0.48	1.05	0.28	0.01	0.13
		On-site train	1.09	2.65	0.05	0.05	0.06	0.28
		On-site truck	0.63	0.99	0.15	0.05	0.01	0.16
		Total Emission (ton/year)	**41.23**	**105.90**	**5.33**	**2.74**	**1.67**	**6.65**
		Conformity *de minimis* (ton/year)	**100**	**10**	**N/A**	**100**	**N/A**	**10**
		Less than *de minimis*?	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**
SCAQMD (South Coast)	Ozone non-attainment—extreme	Off-site train	0.00	0.00	0.00	0.00	0.00	0.00
	PM_{10} non-attainment—Serious	Off-site truck	7.80	6.82	1.87	0.56	0.05	0.58
	$PM_{2.5}$ non-attainment	**Total Emission (ton/year)**	**7.80**	**6.82**	**1.87**	**0.56**	**0.05**	**0.58**
	CO non-attainment—serious	**Conformity *de minimis* (ton/year)**	**100**	**10**	**70**	**100**	**N/A**	**10**
		Less than *de minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Table 5.1-20
Operational Transportation Emissions Related to the Project

Area	Attainment Status	Emission Source	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
			Annual Emission Rates (tons/year)					
EKAPCD (East Kern County)	Ozone non-attainment, former subpart 1 PM_{10} non-attainment—serious	Off-site train	12.16	44.57	0.81	0.79	0.73	2.56
		Off-site truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/year)	**12.16**	**44.57**	**0.81**	**0.79**	**0.73**	**2.56**
		Conformity *de minimis* (ton/year)	**N/A**	**100**	**70**	**N/A**	**N/A**	**100**
		Less than *de minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
MDAQMD (Mojave Desert)	Ozone non-attainment—moderate (San Bernardino County): approximately 75 percent of the total distance across of MDAQMD PM_{10} non-attainment—moderate (San Bernardino County)	Off-site train	24.94	70.01	1.66	1.61	1.50	4.02
		Off-site truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/year)	**24.94**	**70.01**	**1.66**	**1.61**	**1.50**	**4.02**
		Conformity *de minimis* (ton/year)	**N/A**	**100**	**100**	**N/A**	**N/A**	**100**
		Less than *de minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Table 5.1-20
Operational Transportation Emissions Related to the Project

Area	Attainment Status	Emission Source	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
			Annual Emission Rates (tons/year)					
Sacramento Metro	Ozone non-attainment — serious PM_{10} non-attainment— moderate (Sacramento County) $PM_{2.5}$ non-attainment	Off-site train	1.72	6.29	0.11	0.11	0.10	0.36
		Off-site truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/year)	**1.72**	**6.29**	**0.11**	**0.11**	**0.10**	**0.36**
		Conformity *de minimis* (ton/year)	**N/A**	**50**	**100**	**100**	**N/A**	**50**
		Less than *de minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Yuba City-Marysville	Ozone non-attainment, former subpart 1 (Sutter County) $PM_{2.5}$ non-attainment	Off-site train	1.07	3.93	0.07	0.07	0.06	0.23
		Off-site truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/year)	**1.07**	**3.93**	**0.07**	**0.07**	**0.06**	**0.23**
		Conformity *de minimis* (ton/year)	**N/A**	**100**	**N/A**	**100**	**N/A**	**100**
		Less than *de minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Chico	Ozone non-attainment— former subpart 1 (Sutter County) $PM_{2.5}$ Non-attainment	Off-site train	1.07	3.93	0.07	0.07	0.06	0.23
		Off-site truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/year)	**1.07**	**3.93**	**0.07**	**0.07**	**0.06**	**0.23**
		Conformity *de minimis* (ton/year)	**N/A**	**100**	**N/A**	**100**	**N/A**	**100**
		Less than *de minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Arizona	Ozone non-attainment, former subpart 1 (Maricopa and Pinal	Off-site train	31.16	57.13	3.78	0.20	1.88	3.28

Table 5.1-20
Operational Transportation Emissions Related to the Project

Area	Attainment Status	Emission Source	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
			Annual Emission Rates (tons/year)					
	counties)							
	PM_{10} non-attainment—moderate or serious (10 counties)	Off-site truck	0.00	0.00	0.00	0.00	0.00	0.00
	$PM_{2.5}$ Non-attainment (Santa Cruz and Pinal Counties)	**Total Emission (ton/year)**	**31.16**	**57.13**	**3.78**	**0.20**	**1.88**	**3.28**
	SO_2 non-attainment (Pinal County)	**Conformity *de minimis* (ton/year)**	**100**	**100**	**70**	**100**	**100**	**100**
	CO non-attainment (Phoenix and Tucson, AZ, Maricopa and Pima counties)	**Less than *de minimis*?**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
New Mexico	PM_{10} non-attainment—moderate (Dona Ana County)	Off-site train	24.15	88.56	1.61	1.56	1.46	5.09
	CO non-attainment—moderate (Bernalillo County)	Off-site truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/year)	**24.15**	**88.56**	**1.61**	**1.56**	**1.46**	**5.09**
		Conformity *de minimis* (ton/year)	**100**	**N/A**	**100**	**N/A**	**N/A**	**N/A**
		Less than *de minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Source: HECA, 2012.
Notes:
This table presents transportation emissions associated with Alternative 1 (rail transportation).
On-site worker travel and associated emissions are negligible
SJVAPCD – Carbon Monoxide – Not Classified (Bakersfield, CA, Kern County)
MDAQMD – $PM_{2.5}$ Unclassified/Attainment (federal), $PM_{2.5}$ Non-attainment (State)
MDAQMD – Approximately 75 percent of the train route (distance) within MDAQMD is ozone non-attainment area while all MDAQMD is PM_{10} non-attainment area. Therefore, for ozone precursor (NO_X and VOC), 75 percent of total travel mileage in MDAQMD was applied to estimate the emission rates of NO_X and VOC.
N/A = not applicable

Table 5.1-21
Carbon Dioxide Venting Scenarios

Scenario for Early Operation				
	Event	**Events (per yr)**	**Duration or Time to Repair (days per event)**	**Duration of CO_2 Vent Operation (days/year)[1]**
A	Cold Gasification Block start-up	2	3	6
B	CO_2 Compressor unplanned outage	4	2	8
C	CO_2 Pipeline unplanned outage	1	1	1
D	CO_2 off-taker unable to accept	2	3	6
Total Days				21
Scenario for Mature Operation				
	Event	**Events (per yr)**	**Duration or Time to Repair (days per event)**	**Duration of CO_2 Vent Operation (days/year)[1]**
A	Cold Gasification Block start-up	1	1	1
B	CO_2 Compressor unplanned outage	2 to 4	2	4 to 8
C	CO_2 Pipeline unplanned outage	0 to 1	1	0 to 1
D	CO_2 off-taker unable to accept	0	0	0
Total Days				5 to 10

Source: HECA, 2012.

Note:

[1] The flow rate of CO_2 during venting will vary depending on the operations at the Manufacturing Complex and Power Block. Venting is expected to occur at 50 to 85 percent of the maximum designed CO_2 venting rate.

Table 5.1-22
Maximum Annual CO_2e Emissions

Source	Permitted CO_2e Emissions (tonne/yr)
CTG/HRSG H_2-rich fuel and PSA off-gas	269,153
CTG/HRSG natural gas	44,772
CO_2 Vent	174,113
SF_6 circuit breakers	86
Flares	8,257
Thermal oxidizer	5,946
Emergency generators and fire pump	181
Auxiliary boiler	24,782
Ammonia synthesis plant start-up heater	409
Urea absorber vents	116
Nitric acid unit	7,426
Fugitives	35
Total CO_2e Annual Emissions	**535,278**

Source: HECA, 2012.
Notes:
Maximum permitted emissions include periods of start-up and shut-down.
CO_2e = carbon dioxide equivalent
CO_2 = carbon dioxide
CTG = combustion turbine generator/heat recovery steam generator
H_2 = hydrogen
SF_6 = sulfur hexafluoride

Table 5.1-23
Annual CO_2e Emissions for SB 1368 Emission Performance Standard

Operating Parameters	Early Operations (Maximum Permitted)	Mature Operations	Expected Mature Syngas Operations
Natural gas operation, hours per year	351	351	15
Hydrogen-rich fuel operation, hours per year	8,108	8,108	8,108
Intermittent CO_2 venting, hours per year	504	120	0
Electricity generated, MWh	2,699,860	2,699,860	2,599,060
Source	**CO_2e Emissions (metric ton/yr)**		
CTG/HRSG hydrogen-rich fuel and PSA off-gas	269,153	269,153	269,153
CTG/HRSG natural gas	44,772	44,772	1,913
CO_2 vent	174,113	41,456	0
SF_6 circuit breakers	86	86	86
Flares, thermal oxidizer, emergency engines, auxiliary boiler	0	0	0
Manufacturing Complex	0	0	0
Fugitives	35	35	35
Total CO_2e Annual Emissions	**488,160**	**355,502**	**271,187**
CO_2e lb/MWh	398.5	290.2	230.0

Source: HECA, 2012.

Notes:

- Early operations emissions include two periods of startup and shutdown, natural gas use in the CTG, and 504 hours of CO_2 venting.
- Mature operations emissions include two periods of startup and shutdown, natural gas use in the CTG and 120 hours of CO_2 venting.
- During expected mature operation, the CTG and duct burners will fire only hydrogen-rich fuel and PSA off-gas; it includes two start ups and shut down (which includes natural gas), but no natural gas backup use and no CO_2 venting.
- The fugitive CO_2 emissions are from all process areas; therefore, overestimate the emissions from the sequestration process.

Table 5.1-24
Greenhouse Gas Emissions Associated with the Mobile Sources During Project Operations

Source	Annual CO_2e Emissions (tonne/yr)
On-site trucks	413
On-site trains	291
Off-site workers commuting	824
Off-site trucks	10,866
Off-site trains	45,226
Total CO_2e Annual Emissions	**57,619**

Source: HECA, 2012.

Notes:

This table presents transportation emissions associated with Alternative 1 (rail transportation option).

On-site worker travel and associated emissions are negligible.

Table 5.1-25
Maximum Modeled Criteria Pollutant Impacts Due to Construction Emissions

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)	Background[1] ($\mu g/m^3$)	Maximum Total Predicted Concentration ($\mu g/m^3$)	Most Stringent AAQS ($\mu g/m^3$)	UTM Coordinates	
						East (m)	North (m)
Construction Impacts							
CO	1 hour	94.3	4,581	4,675	23,000	284,150.0	3,911,750.0
	8 hour	27.3	2,485	2,512	10,000	283,975.2	3,912,134.5
NO_2	1 hour[2, 3]	135.0	140	275	339	284,500.0	3,911,600.0
	Annual[2]	3.2	26	29	57	283,971.9	3,912,149.9
PM_{10}[4]	24 hour	42.1	263.6	306	50	283,966.7	3,911,925.0
	Annual	1.9	55.3	57	20	283971.9	3912149.9
$PM_{2.5}$[4]	24 hour	6.7	195.5	202	35	283,975.0	3,912,275.0
	Annual	0.4	21.9	22	12	283972.5	3912174.9
SO_2	1 hour[4]	0.2	41.9	42	655	284,150.0	3,911,750.0
	3 hour	0.1	26.0	26	1,300	284,050.2	3,912,034.5
	24 hour	0.03	13.1	13	105	283,975.2	3,911,934.5

Source: HECA 2012.

Notes:
1 Background Concentrations are maximum concentrations from the last 3 years of available EPA AirData and/or CARB data as presented in Section 5.1.1.2.
2 Results for NO_2 during construction used Plume Volume Molar Ratio Method (PVMRM) with ambient O_3 data.
3 Although there are NAAQS for SO_2 1-hour, NO_2 1-hour these are statistical standards therefore impacts from construction activities are only compared to the CAAQS due to the infrequent nature of the construction activities.
4 PM_{10} and $PM_{2.5}$ background levels exceed ambient standards.

$\mu g/m^3$ = micrograms per cubic meter
AAQS = Ambient Air Quality Standard
CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
SO_2 = sulfur dioxide

Table 5.1-26
Project Operations Modeling Impacts Compared with Significant Impact Levels and Monitoring Concentrations

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Class II Significant Impact Level (SIL) ($\mu g/m^3$)	Significant Monitoring Concentration (SMC) ($\mu g/m^3$)
Operational Impacts				
CO	1 hour	2,625	2,000	N/A
	8 hour	368	500	575
NO_2	1 hour[2]	24	7.55	NA
	Annual	0.6	1	14
PM_{10}	24 hour	4.8	5	10
	Annual	0.7	1	N/A

Source: HECA, 2012.
Notes:
[1] Model predicted concentrations are the maximum impact from HECA stationary sources.
[2] The NO_2 1-hour concentration is the maximum first high concentration averaged over 5 years. The NO_2 1-hour SIL is interim, and was established in June 29, 2010.
N/A = not applicable
SMC = Significant Monitoring Concentration

Table 5.1-27
AERMOD Modeling Results for Project Operations

Pollutant	Averaging Period	Modeled Impact ($\mu g/m^3$)	Background[1] ($\mu g/m^3$)	Monitoring Station Description[1, 2]	Total Predicted Concentration ($\mu g/m^3$)	CAAQS ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
Operational Impacts							
CO	1 hour[3]	2,663	4,581	[a]	7,244	23,000	40,000
	8 hour[3]	371	2,485	[a]	2,856	10,000	10,000
NO_2[8]	1 hour CAAQS[3]	185	140	[b]	325	339	--
	1 hour NAAQS[4]	126	[5]	[5]	126	--	188
	Annual CAAQS[6]	1.5	26	[b]	27	57	--
	Annual NAAQS[7]	0.6	26	[b]	27	--	100
PM_{10}	24 hour[3]	4.9	264	[c]	--	50	150
	Annual[6]	0.8	54	[c]	--	20	--
$PM_{2.5}$	24 hour[9]	3.1	196	[c]	--	--	35
	Annual[6]	0.6	22	[c]	--	12	15
SO_2	1 hour[3]	50	42	[d]	92	655	196
	3 hour[3]	29	26	[d]	55	--	1,300
	24 hour[3]	6	13	[d]	19	105	*revoked*
H_2S	1 hour[10]	23	N/A	N/A	23	42	--

Source: HECA, 2012.

Notes:

1 Background concentrations are maximum concentrations from the last 3 years of available EPA AirData and/or CARB data. See note 2.

2 Monitoring station/background concentration as described below:

- [a] Bakersfield—Golden State Highway Monitoring Station, Maximum Concentration, 2007–2009
- [b] Shafter–Walker Street Monitoring Station, Maximum Concentration, 2009–2011
- [c] Bakersfield—California Avenue Monitoring Station, Maximum Concentration, 2008–2010
- [d] Fresno—First Street Monitoring Station, Maximum Concentrations, 2007–2009 for 3-hour SO_2; 2009–2011 for 1-hour and 24-hour SO_2

3 Maximum modeled short term concentration, includes HECA mobile sources associated with Alternative 1 (rail transportation option) and stationary sources

4 Regional NO_2 analysis modeling results. Modeled impact is the maximum 5-year average of 98th percentile of 1-hour daily maximum concentration. Modeled impact includes contributions from HECA, nearby sources and background concentrations. Excludes HECA mobile sources. Includes HECA stationary sources modeled at maximum normal operating emissions or annualized maximum intermittent operating emissions, whichever resulted in higher 1-hour emission rates. See Section 5.1.2.5.9.1 and Appendix E-7, NO_2 1-Hour Regional Analysis, for details and USEPA Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 NAAQS, March 2011.

5 Hourly NO_2 background monitoring concentrations from the Shafter–Walker Street station were included in AERMOD analysis for the same years of meteorological data applied (2006–2010), data provided by SJVAPCD.

6 Maximum annual modeled concentration from any of the 5 years modeled, 2006–2010. Includes HECA mobile sources associated with Alternative 1 (rail transportation option) and stationary sources.

7 Maximum annual modeled concentration from any of the 5 years modeled: 2006–2010. Excludes mobile sources, includes HECA stationary sources

8 NO_2 modeling applied the PVMRM ozone limiting method with hourly ozone data from the Shafter–Walker Street monitoring station.

9 Maximum 5-year average first high daily concentration at any receptor. Excludes HECA mobile sources, includes HECA stationary sources.

10 Maximum modeled 1-hour concentration. Includes all HECA H_2S sources.

CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
SO_2 = sulfur dioxide
H_2S = hydrogen sulfide
NAAQS = National Ambient Air Quality Standards
CAAQS = California Ambient Air Quality Standards
$\mu g/m^3$ = micrograms per cubic meter
N/A = not available

Table 5.1-28
SCREEN3 Fumigation Modeling Results for Project Operations

Pollutant	Averaging Period	Maximum Modeled Impact (µg/m^3)	Background[1] (µg/m^3)	Monitoring Station Description[1,2]	Total Predicted Concentration (µg/m^3)	CAAQS (µg/m^3)	NAAQS (µg/m^3)
Fumigation Impacts							
CO	1 hour	282	4,581	[a]	4,863	23,000	40,000
NO_2	1 hour	43	140	[b]	183	339	N/A
SO_2	1 hour	2.7	42	[c]	45	655	N/A

Source: HECA, 2012.
Notes:
[1] Background concentrations are maximum concentrations from the last 3 years of available EPA AirData and/or CARB data
[2] Monitoring station/background concentration as described below:
[a] Bakersfield—Golden State Highway Monitoring Station, Maximum Concentration, 2007–2009
[b] Shafter–Walker Street Monitoring Station, Maximum Concentration 2009–2011
[c] Fresno—First Street Monitoring Station, Maximum Concentration, 2009–2011 for 1 hour SO_2
N/A = not applicable

Table 5.1-29
Commissioning Modeling Results

Modeling Scenario	Pollutant	Averaging Period	Maximum Estimated Impact ($\mu g/m^3$)	Background[1] ($\mu g/m^3$)	Monitoring Station Description[1]	Total Predicted Concentration ($\mu g/m^3$)	Most Stringent Standard ($\mu g/m^3$) [2]
Case A	CO	1-hour	1,975	4,581	[a]	6,556	23,000
		8-hour	801	2,485	[a]	3,286	10,000
Case B	NO_2[3]	1-hour	150	140	[b]	290	339
Case A2	PM_{10}	24-hour	3.4	264	[c]	NA	50
Case B2	SO_2	1-hour	97.4	42	[d]	139	655
		3-hour	37.5	26	[d]	64	1,300
		24-hour	7.5	13	[d]	20	105

Source: HECA 2012.

Notes:

[1] Background Concentrations are maximum concentrations from the last 3 years of available EPA AirData and/or CARB data at the following stations

[a] Bakersfield—Golden State Highway Monitoring Station, Maximum Concentration 2007–2009

[b] Shafter–Walker Street Monitoring Station, Maximum Concentration 2009–2011

[c] Bakersfield—California Avenue Monitoring Station, Maximum Concentration 2008–2010

[d] Fresno—First Street Monitoring Station Maximum Concentrations, 2007–2009 for 3-hour SO_2, 2009–2011 for 1-hour and 24-hour SO_2

[2] Although there are NAAQS for SO_2 1-hour, NO_2 1-hour, and $PM_{2.5}$ 24-hour, these are statistical standards therefore impacts from commissioning activities are only compared to the CAAQS due to the infrequent nature of the commissioning events.

[3] NO_2 modeling for commissioning was conducted with the PVMRM algorithm.

CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
SO_2 = sulfur dioxide
$\mu g/m^3$ = micrograms per cubic meter

Table 5.1-30
Alternative 2 (Truck Transportation) On-Site Maximum Trucks by Period

Period	Feedstock (Petcoke and Coal) Trucks	Product Trucks	Miscellaneous Trucks
1 hour	30	30	5
3 hours	90	89	5
8 hours	239	237	5
24 hours	299	296	5
Annual	76,200	48,960	1,818

Source: HECA, 2012.

Notes:

[1] The facility will also maintain 20 vehicles (10 gasoline and 10 diesel trucks) for onsite operations and maintenance (O&M).

[2] This table presents the delivery trucks associated with Alternative 2 (truck transportation option).

Table 5.1-31
Onsite and Offsite Transportation Emissions from Alternative 2 (Truck Transportation) by Air Basin

Area	Attainment Status	Emission Source	Annual Emission Rates (tons/yr)					
			CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
SJVAPCD (San Joaquin Valley)	Ozone Non-attainment – Extreme	Offsite Train	10.91	39.99	0.73	0.71	0.66	2.30
	$PM_{2.5}$ Non-attainment	Offsite Truck	22.37	19.56	5.37	1.62	0.14	1.65
		Offsite Workers Commuting	4.17	0.48	1.05	0.28	0.01	0.13
		Onsite Train	0.00	0.00	0.00	0.00	0.00	0.00
		Onsite Truck	1.42	2.76	0.28	0.09	0.01	0.41
		Total Emission (ton/yr)	**38.86**	**62.79**	**7.43**	**2.70**	**0.82**	**4.50**
		Conformity *De minimis* (ton/yr)	**100**	**10**	**NA**	**100**	**NA**	**10**
		Less than *De minimis*?	**Yes**	**No**	**Yes**	**Yes**	**Yes**	**Yes**
SCAQMD (South Coast)	Ozone Non-attainment – Extreme	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
	PM_{10} Non-attainment – Serious	Offsite Truck	7.96	6.96	1.91	0.58	0.05	0.59
	$PM_{2.5}$ Non-attainment	**Total Emission (ton/yr)**	**7.96**	**6.96**	**1.91**	**0.58**	**0.05**	**0.59**
	CO Non-attainment – Serious	**Conformity *De minimis* (ton/yr)**	**100**	**10**	**70**	**100**	**NA**	**10**
		Less than *De minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
EKAPCD (East Kern County)	Ozone Non-attainment (Former Subpart 1)	Offsite Train	9.66	35.42	0.64	0.62	0.58	2.03
	PM_{10} Non-attainment – Serious	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/yr)	**9.66**	**35.42**	**0.64**	**0.62**	**0.58**	**2.03**
		Conformity *De minimis* (ton/yr)	**NA**	**100**	**70**	**NA**	**NA**	**100**
		Less than *De minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Table 5.1-31
Onsite and Offsite Transportation Emissions from Alternative 2 (Truck Transportation) by Air Basin

Area	Attainment Status	Emission Source	Annual Emission Rates (tons/yr)					
			CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
MDAQMD (Mojave Desert)	Ozone Non-attainment – Moderate (San Bernardino County): approximately 75 percent of the total distance across of MDAQMD	Offsite Train	23.37	64.27	1.56	1.51	1.41	3.69
		Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
	PM_{10} Non-attainment – Moderate (San Bernardino County)	**Total Emission (ton/yr)**	**23.37**	**64.27**	**1.56**	**1.51**	**1.41**	**3.69**
		Conformity *De minimis* (ton/yr)	**NA**	**100**	**100**	**NA**	**NA**	**100**
		Less than *De minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Sacramento Metro	Ozone Non-attainment – Serious	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
	PM_{10} Non-attainment – Moderate (Sacramento County)	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
	$PM_{2.5}$ Non-attainment	**Total Emission (ton/yr)**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
		Conformity *De minimis* (ton/yr)	**NA**	**50**	**100**	**100**	**NA**	**50**
		Less than *De minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Yuba City-Marysville	Ozone Non-attainment - Former Subpart 1 (Sutter County)	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
	$PM_{2.5}$ Non-attainment	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/yr)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
		Conformity *De minimis* (ton/yr)	**NA**	**100**	**NA**	**100**	**NA**	**100**
		Less than *De minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Table 5.1-31
Onsite and Offsite Transportation Emissions from Alternative 2 (Truck Transportation) by Air Basin

Area	Attainment Status	Emission Source	Annual Emission Rates (tons/yr)					
			CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
Chico	Ozone non-attainment - Former Subpart 1 (Sutter County)	Offsite Train	0.00	0.00	0.00	0.00	0.00	0.00
	$PM_{2.5}$ non-attainment	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/yr)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
		Conformity *De minimis* (ton/yr)	**NA**	**100**	**NA**	**100**	**NA**	**100**
		Less than *De minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Arizona	Ozone Non-attainment (Former Subpart 1) (Maricopa Co, Pinal Co)	Offsite Train	31.16	57.13	3.78	0.20	1.88	3.28
	PM_{10} Non-attainment (Moderate or Serious) (10 counties)	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
	$PM_{2.5}$ Non-attainment (Santa Cruz and Pinal Counties)	**Total Emission (ton/yr)**	**31.16**	**57.13**	**3.78**	**0.20**	**1.88**	**3.28**
	SO_2 Non-attainment (Pinal county)	**Conformity *De minimis* (ton/yr)**	**100**	**100**	**70**	**100**	**100**	**100**
	CO Non-attainment (Phoenix and Tucson, AZ Maricopa and Pima Counties)	**Less than *De minimis*?**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Table 5.1-31
Onsite and Offsite Transportation Emissions from Alternative 2 (Truck Transportation) by Air Basin

Area	Attainment Status	Emission Source	Annual Emission Rates (tons/yr)					
			CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
New Mexico	PM_{10} Non-attainment – Moderate (Dona Ana County)	Offsite Train	24.15	88.56	1.61	1.56	1.46	5.09
	CO Non-attainment – Moderate (Bernalillo County)	Offsite Truck	0.00	0.00	0.00	0.00	0.00	0.00
		Total Emission (ton/yr)	**24.15**	**88.56**	**1.61**	**1.56**	**1.46**	**5.09**
		Conformity *De minimis* (ton/yr)	**100**	**NA**	**100**	**NA**	**NA**	**NA**
		Less than *De minimis*?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

Source: HECA, 2012.

Notes:

This table presents the transportation emissions associated with Alternative 2 (truck transportation option).
Onsite worker travel and associated emissions are negligible
SJVAPCD – Carbon Monoxide – Not Classified (Bakersfield, CA, Kern County)
MDAQMD – $PM_{2.5}$ Unclassified/Attainment (Federal), $PM_{2.5}$ Non-attainment (State)
MDAQMD – Approximately 75 percent of the train route (distance) within MDAQMD is ozone non-attainment area, while all MDAQMD is PM_{10} non-attainment area. Therefore, for ozone precursor (NO_X and VOC), 75 percent of total travel mileage in MDAQMD was applied to estimate the emission rates of NO_X and VOC.

Table 5.1-32
Difference in Annual Emissions Between
Transportation Alternatives 1 (Rail) and 2 (Truck)
Transportation

Area	Difference in Annual Emissions (tons/yr)[1]					
	CO	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
SJVAPCD (San Joaquin Valley)	-2.37	-43.11	2.10	-0.05	-0.85	-2.15
SCAQMD (South Coast)	0.16	0.14	0.04	0.01	0.00	0.01
EKAPCD (East Kern County)	-2.49	-9.15	-0.17	-0.16	-0.15	-0.53
MDAQMD (Mojave Desert)	-1.56	-5.73	-0.10	-0.10	-0.09	-0.33
Sacramento Metro	-1.72	-6.29	-0.11	-0.11	-0.10	-0.36
Yuba City-Marysville	-1.07	-3.93	-0.07	-0.07	-0.06	-0.23
Chico	-1.07	-3.93	-0.07	-0.07	-0.06	-0.23
Arizona	0.00	0.00	0.00	0.00	0.00	0.00
New Mexico	0.00	0.00	0.00	0.00	0.00	0.00

Source: HECA, 2012.

Notes:
1 Difference of Alternative 2 (truck transportation) total annual emissions for each Area minus Alternative 1 (rail transportation) total annual emissions.
2 Annual emissions include both trucks and trains for both alternatives.

Table 5.1-33
Greenhouse Gas Emissions Associated with the Mobile Sources During Project Operations for Alternative 2 (Truck Transportation)

Source	Annual CO_2e Emissions (tonne/yr)
On-site trucks	867
Off-site workers commuting	824
Off-site trucks	18,562
Off-site trains	37,464
Total CO_2e Annual Emissions	**57,717**

Source: HECA, 2012.

Notes:

[1] This table presents transportation emissions associated with Alternative 2 (truck transportation option).

[2] On-site worker travel and associated emissions are negligible.

Table 5.1-34
Laws, Ordinances, Regulations, and Standards—Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
Federal		
Clean Air Act 160-169A and implementing regulations, Title 42 United States Code (USC) 7470-7492 (42 USC 7470-7492; Title 40 Code of Federal Regulations (CFR) Parts 51 and 52 (40 CFR Parts 51 and 52) Prevention of Significant Deterioration Program)	Requires prevention of significant deterioration (PSD) review and facility permitting for construction of new or modified major stationary sources of air pollution. PSD review applies to pollutants for which ambient concentrations are lower than NAAQS.	USEPA Region IX
Title 40 CFR Parts 70 and 71	This rule tailors GHG emissions to PSD and Title V permitting applicability criteria.	USEPA Region IX
CAA 171-193, 42 USC 7501 et seq. (New Source Review)	Requires new source review (NSR) facility permitting for construction or modification of stationary sources. NSR applies to pollutants for which ambient concentrations are higher than NAAQS.	USEPA Region IX
40 CFR Part 98	This rule requires mandatory reporting of GHG emissions for facilities that emit more than 25,000 metric tons of CO_2 equivalent emissions per year.	USEPA Region IX
CAA 401 (Title IV), 42 USC 7651 (Acid Rain Program); SJVAPCD Regulation II, Rule 2540	Requires reductions in NO_X and SO_2 emissions. Applicable to all stationary sources subject to Part 72, Title 40, Code of Federal Regulations (CFR).	SJVAPCD, with USEPA Region IX oversight
CAA 501 (Title V), 42 USC 7661 (Federal Operating Permits Program)	Establishes comprehensive permit program for major stationary sources.	SJVAPCD, with USEPA Region IX oversight
CAA 111, 42 USC 7411, 40 CFR Part 60 (New Source Performance Standards, or NSPS)	Establishes national standards of performance for new stationary sources. This rule incorporates the New Source Performance Standards from Part 60, Chapter 1, Title 40, CFR.	SJVAPCD, with USEPA Region IX oversight

Table 5.1-34
Laws, Ordinances, Regulations, and Standards—Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
State		
H&SC 44300-44384; Title 17 of The California Code of Regulations (17 CCR 93300-93300.5) Toxic "Hot Spots" Act	Requires preparation and biennial updating of facility emission inventory of hazardous substances; health risk assessments.	CARB
California Code of Regulations, Title 17, Subchapter 10, Article 2, Sections 95100 et seq.	Requires mandatory GHG emissions reporting as part of the California Global Warming Solutions Act of 2006 (AB 32).	CARB
California Code of Regulations, Title 17, Subchapter 10, Article 5, Sections 95800-96023	Establishes a cap on GHG emissions and provides market-based compliance mechanisms (cap and trade program) for covered entities, including electrical generating units.	CARB
H&SC 41700	Provides that no person shall discharge from any source quantities of air contaminants or material which cause injury, detriment, nuisance, or annoyance to considerable number of persons or to the public which endanger the comfort, repose, health or safety or which can cause injury or damage to business or property.	CARB
California Public Resources Code 25523(a); 20 CCR 1752, 2300 2309 and Div. 2, Chap. 5, Art. 1, Appendix B, Park (k) (CEC and CARB Memorandum of Understanding)	Requires that CEC's decision on the AFC includes requirements to assure protection of environmental quality; AFC is required to address air quality protection.	CEC
The California Global Warming Solutions Act of 2006. AB 32 (Stats. 2006; Chapter 488; H&SC 38500 et seq.)	Requires the ARB to enact standards that will reduce GHG emission to 1990 levels by 2020. Requires new baseload generation power plants to not exceed the rate of GHG emissions from a combined-cycle gas turbine plant.	CARB
California Code of Regulation. Title 20, §2902, Greenhouse Gases Emission Performance Standard.	The GHGs emission performance standard (EPS) applicable to this chapter is 1,100 pounds of CO_2 per megawatt hour of electricity.	CARB
California Code of Regulation. Title 20, §2903, Compliance with the Emission Performance Standard	A power plant's compliance with the EPS shall be determined by dividing the power plant's annual average CO_2 emissions in pounds by the power plant's annual average net electricity production in MWh.	CARB

Table 5.1-34
Laws, Ordinances, Regulations, and Standards—Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
California Code of Regulation. Title 20, §2904, Annual Average CO_2 Emissions	(a) Except as provided in Subsections (b) and (c), a power plant's annual average CO_2 emissions are the amount of CO_2 produced on an annual average basis by each fuel used in any component directly involved in electricity production, including, but not limited to, the boiler, combustion turbine, reciprocating or other engine, and fuel cell. The fuels used in this calculation shall include, but are not limited to, primary and secondary fuels, backup fuels, and pilot fuels, and the calculation shall assume that all carbon in the fuels is converted to CO_2. Fuels used in ancillary equipment, including, but not limited to, fire pumps, emergency generators, and vehicles shall not be included. (b) [not presented in this report because it pertains to biomass fuels and does not affect the Project] (c) For covered procurements that employ geological formation injection for CO_2 sequestration, the annual average CO_2 emissions shall not include the CO_2 emissions that are projected to be successfully sequestered. The EPS for such power plants shall be determined based on projections of net emissions over the life of the power plant. CO_2 emissions shall be considered successfully sequestered if the sequestration project meets the following requirements: (1) Includes the capture, transportation, and geologic formation injection of CO_2 emissions; (2) Complies with all applicable laws and regulations; and (3) Has an economically and technically feasible plan that will result in the permanent sequestration of CO_2 once the sequestration project is operational.	CARB
Local		
SJVAPCD Regulation II, Rule 2201 (New and Modified Stationary Source Review Rule)	This rule shall apply to all new stationary sources and all modifications to existing stationary sources which are subject to the District permit requirements and after construction emit or may emit one or more affected pollutant. The requirements of this rule in effect on the date the application is determined to be complete by the Air Pollution Control Officer (APCO) shall apply to such application except as provided in Section 2.1.	SJVAPCD

Table 5.1-34
Laws, Ordinances, Regulations, and Standards—Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
SJVAPCD Regulation II, Rule 2520 (Federally Mandated Operating Permits)	2.0 Applicability The provisions of this rule shall apply to the following sources: 2.1 Major air toxics sources, 2.2 Any stationary source that emits or has the potential to emit 100 tons per year of any air contaminant, 2.3 Any major source, 2.4 Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA published after July 21, 1992 except as provided for in section 4.2 of this rule. 2.4.1 For stationary sources, which are subject to Rule 2520 solely as a result of Section 2.4, only the emissions units within the a stationary source that are subject to the section 111 or 112 standard or requirement shall be subject to the Part 70 permitting requirements; 2.5 A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV of the CAA; 2.6 Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act; 2.7 A solid waste incinerator subject to a performance standard promulgated pursuant to section 111 or 129 of the CAA; and 2.8 Any source in a source category designated, pursuant to 40 CFR Part 70.3, by rule of the EPA. 2.9 When calculating the potential to emit for the purpose of determining if the requirements of this rule are applicable, fugitive emissions must only be included for determining non-hazardous air pollutant emissions if the source is included in the list of source categories identified in the major source definition in 40 CFR part 70.2, or when determining if a stationary source is a major air toxics source.	SJVAPCD
SJVAPCD Regulation II, Rule 2540	All stationary sources subject to Part 72, Title 40, Code of Federal Regulations (CFR)	SJVAPCD

Table 5.1-34
Laws, Ordinances, Regulations, and Standards—Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
SJVAPCD Regulation II, Rule 2550 (Federally Mandated Preconstruction Review for Major Sources of Air Toxics)	The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after 28 June 1998. Requirements for other projects that result in increases in emissions of hazardous air pollutants are addressed in the District's Risk Management Policy for Permitting New and Modified Sources.	SJVAPCD
SJVAPCD Regulation III	Identifies fees that are applicable to permit modifications, new facilities, and permitted emissions	SJVAPCD
SJVAPCD Regulation IV, Rule 4001	All new sources of air pollution and modification of existing sources of air pollution shall comply with the standards, criteria, and requirements set forth therein.	SJVAPCD
SJVAPCD Regulation IV, Rule 4002 (National Emission Standards for Hazardous Air Pollutants)	This rule incorporates the National Emission Standards for Hazardous Air Pollutants from Part 61, Chapter I, Subchapter C, Title 40, Code of Federal Regulations (CFR) and the National Emission Standards for Hazardous Air Pollutants for Source Categories from Part 63, Chapter I, Subchapter C, Title 40, Code of Federal Regulations (CFR). All sources of hazardous air pollution shall comply with the standards, criteria, and requirements set forth therein.	SJVAPCD
SJVAPCD Regulation IV, Rule 4101 (Visible Emissions)	The provisions of this rule shall apply to any source operation which emits or may emit air contaminants.	SJVAPCD
SJVAPCD Regulation IV, Rule 4102 (Nuisance)	This rule shall apply to any source operation which emits or may emit air contaminants or other materials.	SJVAPCD
SJVAPCD Regulation IV, Rule 4201 (Particulate Matter Concentration)	This rule shall apply to any source operation which emits or may emit dust, fumes, or total suspended particulate matter.	SJVAPCD
SJVAPCD Regulation IV, Rule 4202 (Particulate Matter—Emission Rate)	This rule shall apply to any source operation which emits or may emit particulate matter emissions.	SJVAPCD
SJVAPCD Regulation IV, Rule 4301 (Fuel Burning Equipment)	The purpose of this rule is to limit the emission of air contaminants from fuel burning equipment. This rule limits the concentration of combustion contaminants and specifies maximum emission rates for sulfur dioxide, nitrogen oxides and combustion contaminant emissions.	SJVAPCD

Table 5.1-34
Laws, Ordinances, Regulations, and Standards—Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
SJVAPCD Regulation IV, Rule 4304 (Equipment Tuning Procedure)	The purpose of this rule is to provide an equipment tuning procedure for boilers, steam generators, and process heaters to control visible emissions and emissions of both nitrogen oxides (NO_X) and carbon monoxide (CO).	SJVAPCD
SJVAPCD Regulation IV, Rules 4305-4308 (Boilers, Steam Generators and Process Heaters)	The purpose of this rule is to limit emissions of nitrogen oxides (NO_X) and carbon monoxide (CO) from boilers, steam generators, and process heaters.	SJVAPCD
SJVAPCD Regulation IV, Rule 4311 (Flares)	The purpose of this regulation is to limit the emissions of volatile organic compounds (VOC), oxides of nitrogen (NO_X), and sulfur oxides (SO_X) from the operation of flares. This rule is applicable to operations involving the use of flares.	SJVAPCD
SJVAPCD Regulation IV, Rule 4320 (Boilers, Steam Generators and Process Heaters)	The purpose of this rule is to limit NO_X, CO, SO_2, and PM_{10} from boilers, steam generators, and process heaters.	SJVAPCD
SJVAPCD Regulation IV, Rule 4701 (Internal Combustion Engines)	Except as provided in Section 4.0, the provisions of this rule apply to any internal combustion engine rated greater than 50 brake horsepower (bhp) that requires a Permit to Operate (PTO).	SJVAPCD
SJVAPCD Regulation IV, Rule 4702 (Internal Combustion Engines)	This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.	SJVAPCD
SJVAPCD Regulation IV, Rule 4703 (Stationary Gas Turbines)	The provisions of this rule apply to all stationary gas turbine systems, which are subject to District permitting requirements, and with ratings equal to or greater than 0.3 megawatt (MW) or a maximum heat input rating of more than 3,000,000 Btu per hour, except as provided in Section 4.0.	SJVAPCD
SJVAPCD Regulation IV, Rule 4801 (Sulfur Compounds)	The provisions of this rule shall apply to any discharge to the atmosphere of sulfur compounds, which would exist as a liquid or a gas at standard conditions. A person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO_2), on a dry basis averaged over 15 consecutive minutes.	SJVAPCD
SJVAPCD Regulation VII, Rule 7012 (Hexavalent Chromium – Cooling Towers)	The requirements of this rule shall apply to any person who owns or operates or who plans to build, own, or operate a cooling tower in which the circulating water is exposed to the atmosphere.	SJVAPCD

Table 5.1-34
Laws, Ordinances, Regulations, and Standards—Air Quality

Laws, Ordinances, Regulations, and Standards	Applicability	Administering Agency
SJVAPCD Regulation VIII	The purpose of Regulation VIII (Fugitive PM_{10} Prohibitions) is to reduce ambient concentrations of fine particulate matter (PM_{10}) by requiring actions to prevent, reduce or mitigate anthropogenic fugitive dust emissions. The Rules contained in this Regulation have been developed pursuant to U.S. Environmental Protection Agency guidance for Serious PM_{10} Non-attainment Areas. The rules are applicable to specified anthropogenic fugitive dust sources. Fugitive dust contains PM_{10} and particles larger than PM_{10}. Controlling fugitive dust emissions when visible emissions are detected will not prevent all PM_{10} emissions, but will substantially reduce PM_{10} emissions.	SJVAPCD
SJVAPCD Regulation IX	This Rule specifies the criteria and procedures for determining the conformity of federal actions with the San Joaquin Valley Air Pollution Control District's air quality implementation plan.	SJVAPCD
Industry		
None Applicable	None Applicable	

Source: HECA, 2012.

Table 5.1-35
Relevant Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS[1]		CAAQS[2]
		Primary[3,4]	Secondary[3,5]	Concentration[3]
Ozone	1-hour	–	Same as primary standard	0.09 ppm (180 μg/m^3)
	8-hour	0.075 ppm (147 μg/m^3)		0.070 ppm (137 μg/m^3)
Carbon Monoxide	8-hour	9 ppm (10 mg/m^3)	None	9.0 ppm (10 mg/m^3)
	1-hour	35 ppm (40 mg/m^3)		20 ppm (23 mg/m^3)
Nitrogen Dioxide[6]	Annual average	0.053 ppm (100 μg/m^3)	Same as primary standard	0.030 ppm (57 μg/m^3)
	1-hour	0.100 ppm (188 μg/m^3)		0.18 ppm (339 μg/m^3)
Sulfur Dioxide[7]	Annual average	0.030 ppm (for certain areas)[7]	–	–
	24-hour	0.14 ppm (for certain areas)[7]	–	0.04 ppm (105 μg/m^3)
	3-hour	–	0.5 ppm (1,300 μg/m^3)	–
	1-hour	0.075 ppm (196 μg/m^3)	–	0.25 ppm (655 μg/m^3)
Respirable Particulate Matter (PM_{10})	24-hour	150 μg/m^3	Same as primary standard	50 μg/m^3
	Annual arithmetic mean	–		20 μg/m^3
Fine Particulate Matter ($PM_{2.5}$)	24-hour	35 μg/m^3	Same as primary standard	–
	Annual arithmetic mean	15 μg/m^3		12 μg/m^3
Lead[8,9]	30-day average	–	–	1.5 μg/m^3
	Calendar quarter	1.5 μg/m^3 (for certain areas)[9]	Same as primary standard	–
	Rolling 3-month average	0.15 μg/m^3		–

Table 5.1-35
Relevant Ambient Air Quality Standards

Pollutant	Averaging Time	NAAQS[1]		CAAQS[2]
		Primary[3,4]	Secondary[3,5]	Concentration[3]
Vinyl Chloride[8]	24-hour	No federal standards		0.01 ppm (26 μg/m^3)
Hydrogen Sulfide	1-hour			0.03 ppm (42 μg/m^3)
Sulfates	24-hour			25 μg/m^3
Visibility Reducing Particles[10]	8-hour (10 am to 6 pm, Pacific Standard Time)			See footnote 10

Source: USEPA-NAAQS, http://www.epa.gov/air/criteria.html; CARB-CAAQS, http://www.arb.ca.gov/aqs/aaqs2.pdf

Notes:

1 National standards (other than ozone, particulate matter, and those based on annual arithmetic mean) are not to be exceeded more than once a year. The ozone standard is attained when the fourth-highest 8-hour concentration measured at each site in a year, averaged over 3 years, is equal to or less than the standard. For PM_{10}, the 24-hour standard is attained when the expected number of days per calendar year with a 24-hour average concentration above 150 μg/m^3 is equal to or less than one. For $PM_{2.5}$, the 24-hour standard is attained when 98 percent of the daily concentrations, averaged over 3 years, are equal to or less than the standard.

2 California standards for ozone, carbon monoxide (except 8-hour Lake Tahoe), sulfur dioxide (1- and 24-hour), nitrogen dioxide, and particulate matter (PM_{10}, $PM_{2.5}$, and visibility-reducing particles) are values that are not to be exceeded. All others are not to be equaled or exceeded. California ambient air quality standards are listed in the Table of Standards in § 70200 of Title 17 of the California Code of Regulations.

3 Concentration expressed first in units in which it was promulgated. Equivalent units given in parentheses are based upon a reference temperature of 25°C and a reference pressure of 760 torr. Most measurements of air quality are to be corrected to a reference temperature of 25°C and a reference pressure of 760 torr; ppm in this table refers to ppm by volume, or micromoles of pollutant per mole of gas.

4 National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health.

5 National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant.

6 To attain the 1-hour national standard, the 3-year average of the annual 98th percentile of the 1-hour daily maximum concentrations at each site must not exceed 100 ppb.

7 On June 2, 2010, a new 1-hour SO_2 standard was established and the existing 24-hour and annual primary standards were revoked. To attain the 1-hour national standard, the 3-year average of the annual 99th percentile of the 1-hour daily maximum concentrations at each site must not exceed 75 ppb. The 1971 SO_2 national standards (24-hour and annual) remain in effect until 1 year after an area is designated for the 2010 standard, except that in areas designated non-attainment for the 1971 standards, the 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standards are approved.

8 The ARB has identified lead and vinyl chloride as "toxic air contaminants" with no threshold level of exposure for adverse health effects determined. These actions allow for the implementation of control measures at levels below the ambient concentrations specified for these pollutants.

9 The national standard for lead was revised on October 15, 2008 to a rolling 3-month average. The 1978 lead standard (1.5 μg/m^3 as a quarterly average) remains in effect until 1 year after an area is designated for the 2008 standard, except that in areas designated non-attainment for the 1978 standard, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.

10 In 1989, the ARB converted both the general statewide 10-mile visibility standard and the Lake Tahoe 30-mile visibility standard to instrumental equivalents, which are "extinction of 0.23 per kilometer" and "extinction of 0.07 per kilometer" for the statewide and Lake Tahoe Air Basin standards, respectively.

μg/m^3 = micrograms per cubic meter
CAAQS = California Ambient Air Quality Standards
mg/m^3 = milligram per cubic meter
NAAQS = National Ambient Air Quality Standards
ppm = parts per million [3]

Table 5.1-36
Attainment Status for Kern County with Respect to Federal and California Ambient Air Quality Standards

Pollutant	Federal Attainment Status	State Attainment Status
Ozone	Extreme non-attainment	Non-attainment
CO	Attainment	Attainment
NO_2	Attainment	Attainment
SO_2	Attainment	Attainment
PM_{10}	Attainment[1]	Non-attainment
$PM_{2.5}$	Non-attainment	Non-attainment
Lead	Unclassified	Attainment

Source: CARB (http://www.arb.ca.gov/desig/desig.htm); USEPA (http://www.epa.gov/air/oaqps/greenbk/index.html)

Notes:
[1] On 25 September 2008, USEPA redesignated the San Joaquin Valley to attainment for the PM_{10} National Ambient Air Quality Standard (NAAQS) and approved the PM_{10} Maintenance Plan.

CO = carbon monoxide
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
SO_2 = sulfur dioxide

Table 5.1-37
PSD Emission Threshold Triggers for New Stationary Sources

Pollutant	Applicability Thresholds (tpy)	Significant Emission Rate (tpy)	Project Emissions (tpy)	PSD Triggered by Project?
CO	100	100	275	Yes
SO_2	100	40	29	No
NO_X	100	40	164	Yes
PM_{10}	100	15	90	Yes
$PM_{2.5}$	100	10	80	No[1]
VOCs	100	40	35	No
CO_2	100,000	N/A	535,278	Yes
Lead (Pb)	N/A	0.6	0.007	No
Fluorides	N/A	3	0.001	No
Sulfuric acid mist	N/A	7	1.14	No
Hydrogen sulfide (H_2S)	N/A	10	2.64	No
Total reduced sulfur (TRS)	N/A	10	4.17	No
Reduced sulfur compounds	N/A	10	4.42	No

Source: 40 CFR § 52.21 and HECA 2012.
Notes:
[1] PSD is not triggered as the Project is in a non-attainment area for $PM_{2.5}$.
CO = carbon monoxide
CO_2e = carbon dioxide equivalent
NO_X = nitrogen dioxide
N/A = not applicable
Pb = lead
$PM_{2.5}$ = particulate matter less than 2.5 microns in diameter
PM_{10} = particulate matter less than 10 microns in diameter
SO_2 = sulfur dioxide
tpy = tons per year
VOCs = volatile organic compounds

Table 5.1-38
Prevention of Significant Deterioration Allowable Increments
($\mu g/m^3$)

Standard	Class I Area	Class II Area	Class III Area
PM_{10} Annual Arithmetic Mean	4	17	34
PM_{10} 24-Hour Maximum	8	30	60
CO 8-Hour Maximum	N/A	N/A	N/A
CO 1-Hour Maximum	N/A	N/A	N/A
NO_2 Annual Arithmetic Mean	2.5	25	50
NO_2 1-Hour Maximum	TBD	TBD	TBD

Source: 40 CFR § 52.21.
Notes:
$\mu g/m^3$ = micrograms per cubic meter
NO_2 = nitrogen dioxide
PM_{10} = particulate matter less than 10 microns in diameter
CO = carbon monoxide
N/A = not applicable
TBD = to be determined

Table 5.1-39
Proposed BACT for the Project

Pollutant	Technology	Emission Limit
CTG/HRSG Combustion Turbine (excluding Start-Up/Shut-Down conditions)		
NO_X	Diluent injection, Selective Catalytic Reduction (SCR), Limited operation on natural gas	2.5 ppm NO_X @ 15 percent O_2 on hydrogen-rich fuel, 3-hour average
		4 ppm NO_X @ 15 percent O_2 on natural gas fuel, 3-hour average
CO	GCP, CO catalyst), Limited operation on natural gas	3 ppm CO @ 15 percent O_2 on hydrogen-rich fuel, 3-hour average
		5 ppm CO @ 15 percent O_2 on natural gas fuel, 3-hour average
PM/PM_{10}	GCP, gas cleanup, gaseous fuels, pipeline-quality natural gas	15 lb/hr on hydrogen-rich fuel and natural gas fuel
SO_2	Hydrogen-rich gas cleanup, pipeline-quality natural gas	≤ 2 ppmv total sulfur in hydrogen-rich syngas, ≤ 10 ppmv total sulfur in PSA off-gas
		≤ 0.75 grain/100 SCF (12.65 ppm for natural gas)
VOC	CO catalyst), Limited operation on natural gas	1 ppm VOC @ 15 percent O_2 on hydrogen-rich fuel, 3-hour average
		2 ppm VOC @ 15 percent O_2 on natural gas fuel, 3-hour average
NH_3	SCR	5 ppm NH_3 slip on hydrogen-rich fuel and natural gas fuel
Coal Dryer		
PM/PM_{10}	Baghouse	0.001 grain/scf outlet dust loading
Cooling Towers		
PM/PM_{10}	High-efficiency drift eliminators, Total Dissolved Solids (TDS) limit in circulating water, and good operating practice	0.0005 percent drift as percent of the circulating water
Auxiliary Boiler, Natural Gas 213 MMBTU/hr		
NO_X	Low- NO_X burner and SCR	5 ppm NO_X @ 3 percent O_2
CO	GCP, annual tune-up	50 ppmvd @ 3 percent O_2
PM/PM_{10}	GCP, pipeline-grade natural gas fuel	0.005 lb/MMBtu heat input
SO_2		0.00285 lb/MMBtu (12.65 ppm for natural gas)
VOC		0.004 lb/MMBtu heat input
NH_3	SCR	5 ppm NH_3 slip natural gas fuel
Emergency Diesel Engines (2 Emergency Generators; 2,922 hp each)		
NO_X	Certified EPA Tier 4 diesel engine, combustion controls, restricted operating hours, low-sulfur diesel fuel	0.5 g/bhp/hr
CO		2.6 g/bhp/hr
PM/PM_{10}		0.07 g/bhp/hr
SO_2		Very-low-sulfur diesel fuel (15 ppmw or less)
VOC		0.3 g/bhp/hr

Table 5.1-39
Proposed BACT for the Project

Pollutant	Technology	Emission Limit
Emergency Diesel Engine (Fire Pump; 565 hp)		
NO_X	Certified EPA Tier 4 diesel engine, combustion controls, restricted operating hours, low-sulfur diesel fuel	1.5 g/bhp/hr
CO		2.60 g/bhp/hr
PM/PM_{10}		0.015 g/bhp/hr
SO_2		Very Low Sulfur Diesel fuel (15 ppmw or less)
VOC		0.14 g/bhp/hr
Gasification Flare		
NO_X, CO, PM/PM_{10}, SO_2	GCP, gaseous fuel only, Gas cleanup/limit on reduced sulfur in hydrogen-rich fuel	
VOC	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, VOC destruction of ≥ 98.5 percent	
Rectisol® Flare		
NO_X, CO, PM/PM_{10}, SO_2	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, gas cleanup/limit on reduced sulfur in syngas	
VOC	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, VOC destruction of ≥ 98.5 percent	
SRU Flare (Sulfur Recovery System)		
NO_X, CO, PM/PM_{10}	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases	
SO_2	Caustic Scrubber	
VOC	GCP, gaseous fuel only, flare gas recovery system for non-emergency releases, VOC destruction of ≥ 98.5 percent	
Thermal Oxidizer (Sulfur Recovery System) (excluding Start-Up/Shut-Down conditions)		
NO_X	GCP	0.24 lb/MMBtu
CO		0.20 lb/MMBtu
PM/PM_{10}		0.0076 lb/MMBtu
SO_2	GCP, gas cleanup to ≤ 10 ppmw H_2S	2 lb/hr process vent gas
VOC	GCP	0.0055 lb/MMBtu
CO_2 Vent		
CO	Gas cleanup, restricted operating hours	1,000 ppmv
VOC		40 ppmv
H_2S	Acid gas removal	10 ppmv
Feedstock		
PM/PM_{10}	Dust collector, adequate moisture to prevent visible emissions in excess of 5 percent opacity	0.005 grain/scf outlet dust loading

Table 5.1-39
Proposed BACT for the Project

Pollutant	Technology	Emission Limit
Ammonia Plant Heater, Natural Gas 55 MMBtu/hr		
NO_X	Low- NO_X burner, limited operation	9 ppm NO_X @ 3 percent O_2
CO	GCP, annual tune-up	50 ppmvd @ 3 percent O_2
PM/PM_{10}	GCP, pipeline-grade natural gas fuel	0.005 lb/MMBtu heat input
SO_2		0.00285 lb/MMBtu (12.65 ppm for natural gas)
VOC		0.004 lb/MMBtu heat input
Urea HP Absorber		
NH_3	Wet scrubber	11.1 lb/hr
Urea LP Absorber		
NH_3	Wet scrubber	2.0 lb/hr
Urea Pastillation		
PM/PM_{10}	Baghouse	0.001 grain/dscf
Nitric Acid Plant		
NO_X	SCR	0.2 lb/ton (15 ppmv in vent gas)
NH_3	SCR	5 ppm NH_3 slip
Ammonium Nitrate Plant		
PM/PM_{10}	Wet scrubber	0.2 lb/hr
Fugitives		
VOC	LDAR, leak detection for valves and connectors with VOC > 100 ppmv above background, and for pumps and compressor seals with VOC > 500 ppmv above background	Varies

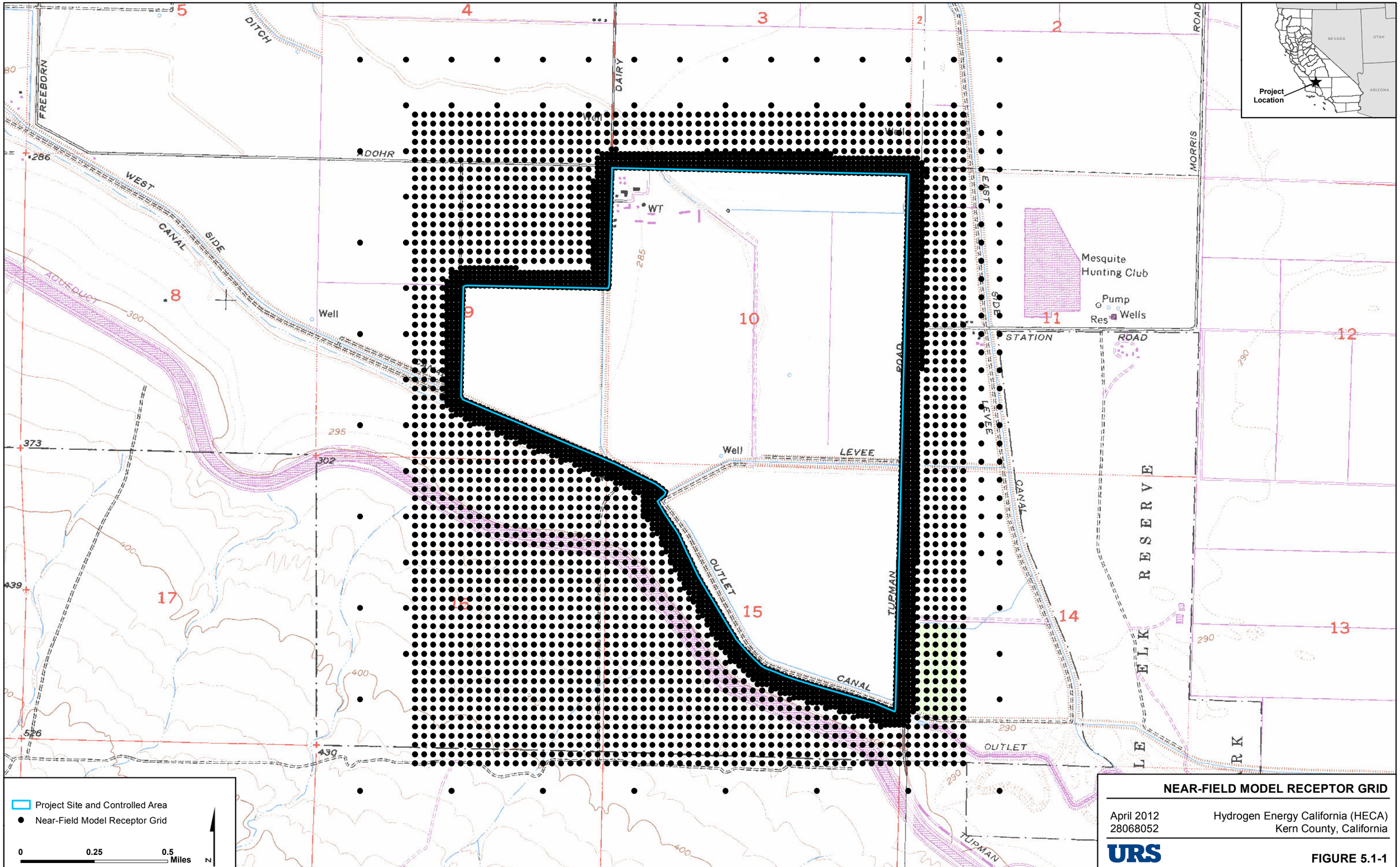
Source: HECA 2012.

Notes:
BACT = best available control technology
CO = carbon monoxide
CPUC = California Public Utility Commission
CTG = combustion turbine generator
FGR = flue gas recirculation
GCP = good combustion practice
LDAR = leak detection and repair
MMBtu = million British thermal units
NH_3 = ammonia
NO_X = nitrogen dioxide
O_2 = oxygen
PM/PM_{10} = particulate matter/particulate matter less than 10 microns
ppm = parts per million
ppmvd = parts per million volumetric dry
SCF = standard cubic feet
SCR = selective catalytic reduction
SO_2 = sulfur dioxide
VOC = volatile organic compound

Table 5.1-40
Involved Agencies and Agency Contacts

Agency	Contact/Title	Telephone
California Energy Commission	Gerry Bemis, Air Quality Specialist 1516 Ninth Street Sacramento, CA 95814	(916) 654-4960
California Air Resources Board	Mike Tollstrup, 1001 I Street Sacramento, CA 95814	(916) 322-6026
San Joaquin Valley Air Pollution Control District	Leonard Scandura, Supervising Air Quality Engineer 34946 Flyover Court Bakersfield, CA 93308	(661) 392-5601
U.S. Environmental Protection Agency	Gerardo Rios, Chief, Permits Office 75 Hawthorne Street San Francisco, CA 94105	(415) 972-3974

Source: HECA, 2012.



Sources: USGS (7.5' quads: Taft 1982, Delano 1982)

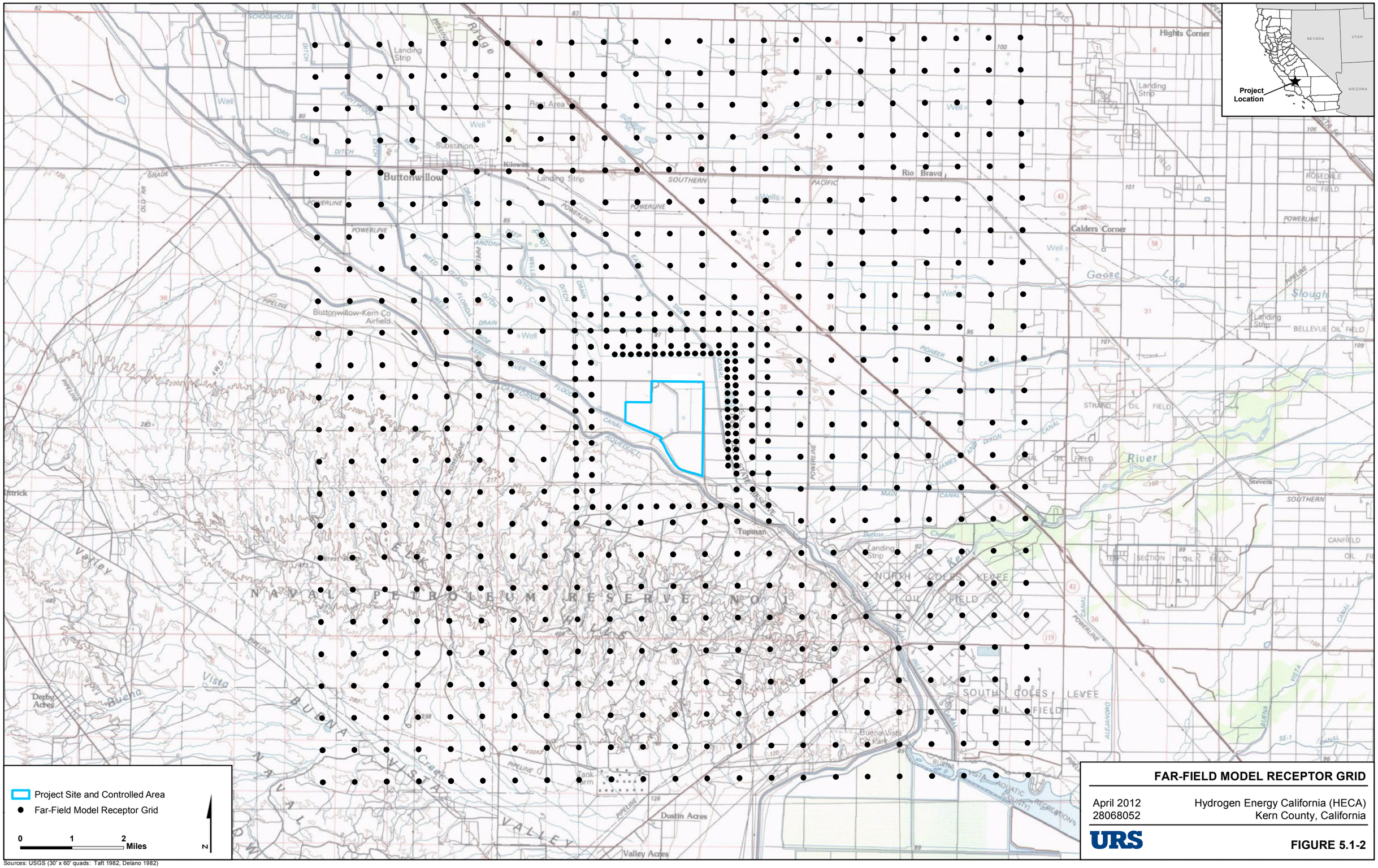
NEAR-FIELD MODEL RECEPTOR GRID

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 5.1-1



Sources: USGS (30' x 60' quads: Taft 1982, Delano 1982)

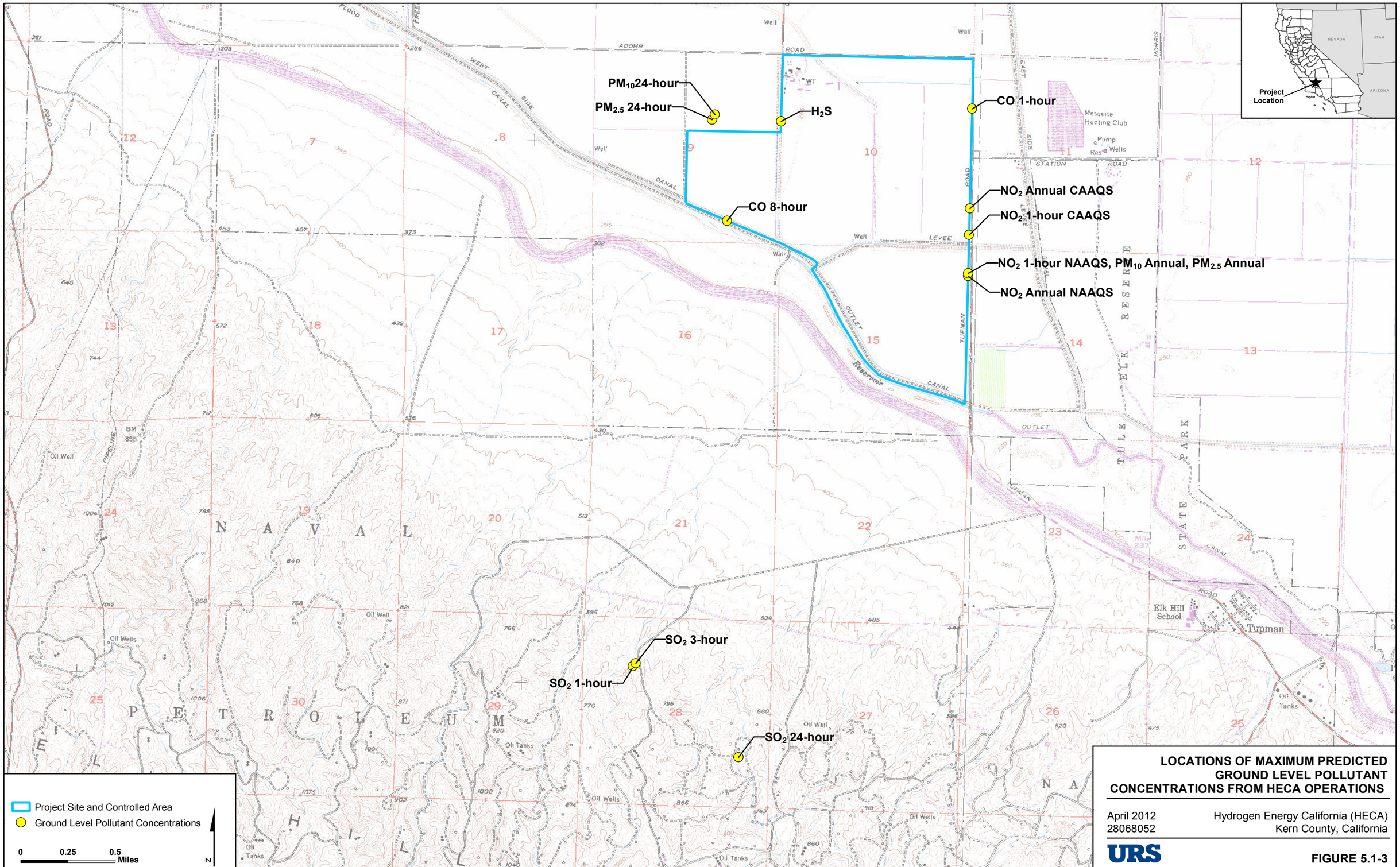
FAR-FIELD MODEL RECEPTOR GRID

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 5.1-2



LOCATIONS OF MAXIMUM PREDICTED GROUND LEVEL POLLUTANT CONCENTRATIONS FROM HECA OPERATIONS

April 2012
28068052

Hydrogen Energy California (HECA)
Kern County, California

URS

FIGURE 5.1-3