Long-Term Operation – Final Environmental Impact Statement

Appendix L – Air Quality Technical Appendix

November 2024

Contents

Tables

Figures

Acronyms and Abbreviations

ac-ft	acre-feet
AQMD	Air Quality Management District
ARB	California Air Resources Board
Bay Area	San Francisco Bay Area
BMP	best management practice
CAAQS	California Ambient Air Quality Standards
CO	carbon monoxide
CVP	Central Valley Project
hp-hr/ac-ft	horsepower-hours per acre-foot
hp-hr/yr	horsepower-hours per year
Kwh/ac-ft	kilowatt-hours per acre-foot
Kwh/yr	kilowatt-hours per year
NAAQS	National Ambient Air Quality Standards
NO_2	nitrogen dioxide
O_3	ozone
PM_{10}	particulate matter of 10 microns diameter and smaller
$PM_{2.5}$	particulate matter of 2.5 microns diameter and smaller
ROG	Reactive organic gases
SJVAPCD	San Joaquin Valley Air Pollution Control District
SO_2	sulfur dioxide
SWP	State Water Project
USEPA	U.S. Environmental Protection Agency

Appendix L Air Quality Technical Appendix

This appendix documents the technical analysis of air pollutant emissions to support the impact analysis in the environmental impact statement (EIS).

L.1 Background Information

This section describes the area of analysis and ambient air quality and conditions in the study area. The discussion in this appendix is organized by the action areas and air basins. The counties, air basins and air quality management districts in California, including those in the action area, do not specifically align with the action areas, as noted below and in the description of each air basin (California Air Resources Board 2023a, 2023b). The action areas include the following air basins and counties.

- Trinity River region: Trinity Reservoir and Trinity River downstream of Lewiston Reservoir
    - This region is located within the North Coast Air Basin.
    - This region is located within Humboldt and Trinity Counties.
- Sacramento River region: Sacramento River from Shasta Lake downstream to and including the Sacramento-San Joaquin Delta
    - This region is located within the Sacramento Valley Air Basin.
    - This region is located within Shasta, Tehama, Glenn, Colusa, Sutter, Yolo, and Sacramento Counties.
- Clear Creek region: Clear Creek from Whiskeytown Reservoir to its confluence with the Sacramento River
    - This region is located within the Sacramento Valley Air Basin.
    - This region is located within Shasta County.
- American River region: American River from Folsom Reservoir downstream to its confluence with the Sacramento River
    - This region is located within the Sacramento Valley Air Basin.
    - This region is located within Placer, Sacramento, and Yolo Counties.
- Stanislaus River region: Stanislaus River from New Melones Reservoir to its confluence with the San Joaquin River
    - This region is located within portions of the San Joaquin Valley and Mountain Counties Air Basins.

- This region is located within Calaveras, Tuolumne, Stanislaus, San Joaquin, and Merced Counties.

- San Joaquin River region: San Joaquin River from Friant Dam downstream to and including the Sacramento-San Joaquin Delta
    - This region is located within the San Joaquin Valley Air Basin.
    - This region is located within Fresno, Madera, Merced, Stanislaus, and San Joaquin counties.
- Bay-Delta region: San Francisco Bay, Suisun Marsh, and Delta
    - This region is located within portions of the Sacramento Valley, San Joaquin Valley, and San Francisco Bay Air basins.
    - This region is located within Solano, Sacramento, San Joaquin, Contra Costa, San Francisco, and Alameda counties.
- Central Valley Project (CVP) and State Water Project (SWP) Service Areas region: CVP and SWP service areas (south to Diamond Valley)
    - This region is located within portions of the San Francisco Bay, North Central Coast, San Joaquin Valley, Mojave Desert, South Coast, San Diego, and Salt on Sea Air Basins.
    - This region is located within Santa Clara, San Benito, Kings, Kern, Ventura, Los Angeles, San Bernardino, Orange, Riverside, San Diego, and Imperial Counties.
- Nearshore Pacific Ocean region: nearshore Pacific Ocean on the coast from Point Conception to Cape Falcon in Oregon
    - This region is located within portions of the South Central Coast, North Central Coast, San Francisco Bay, and North Coast Air basins.
    - This region borders Santa Barbara, San Luis Obispo, Monterey, Santa Cruz, San Mateo, San Francisco, Marin, Sonoma, Mendocino, Humboldt, and Del Norte counties.

L.1.1 Ambient Air Quality

Air quality conditions and potential impacts in the action area are evaluated and discussed qualitatively. The following subsections briefly describe the existing air quality environmental setting by air basin for the action area. The counties within each air basin in the action area are presented in Table L-1, along with nonattainment designations to characterize existing ambient air quality. Nonattainment designations indicate that concentrations of pollutants measured in ambient air exceed the applicable Federal and State Ambient Air Quality Standards. As shown in Table L-1, many of the counties included in the action area are designated as nonattainment for the federal and/or state ozone and particulate matter standards. Particulate matter issues may be exacerbated under dry conditions because when irrigation water supplies are decreased, there is increased potential for the formation and transport of fugitive dust.

Table L-1. Areas and Pollutants Designated as Nonattainment for Federal and State Ambient Air Quality Standards

County	Air Basin	Air Quality Management District	Federal Nonattainment Designations[1]	State Nonattainment Designations[2]
Trinity River Region				
Humboldt	North Coast	North Coast Unified	–[3]	PM_{10}
Trinity	North Coast	North Coast Unified	–	–
Sacramento River Region				
Shasta	Sacramento Valley	Shasta	–	Ozone
Tehama	Sacramento Valley	Tehama	Ozone (Tuscan Buttes)	Ozone, PM_{10}
Glenn	Sacramento Valley	Glenn	–	PM_{10}
Colusa	Sacramento Valley	Colusa	–	PM_{10}
Sutter	Sacramento Valley	Feather River	Ozone	Ozone, PM_{10}
Yolo	Sacramento Valley	Yolo-Solano	Ozone, $PM_{2.5}$	Ozone, PM_{10}
Sacramento	Sacramento Valley	Sacramento Metro	Ozone, $PM_{2.5}$	Ozone, PM_{10}
Clear Creek Region				
Shasta	Sacramento Valley	Shasta	–	Ozone
American River Region				
El Dorado	Mountain Counties	El Dorado County	Ozone, $PM_{2.5}$ (Sacramento Metro AQMD portion)	Ozone, PM_{10}
Placer	Sacramento Valley, Mountain Counties, Lake Tahoe	Placer	Ozone (Sacramento Metro AQMD portion), $PM_{2.5}$ (Sacramento Metro AQMD portion)	Ozone, PM_{10}
Sacramento	Sacramento Valley	Sacramento Metro	Ozone, $PM_{2.5}$	Ozone, PM_{10}
Yolo	Sacramento Valley	Yolo-Solano	Ozone, $PM_{2.5}$	Ozone, PM_{10}
Stanislaus River Region				
Amador	Mountain Counties	Amador County	Ozone	Ozone
Calaveras	Mountain Counties	Calaveras	Ozone	Ozone, PM_{10}
Tuolumne	Mountain Counties	Tuolumne	Ozone	Ozone
Stanislaus	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
San Joaquin	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Merced	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}

County	Air Basin	Air Quality Management District	Federal Nonattainment Designations[1]	State Nonattainment Designations[2]
San Joaquin River Region				
Fresno	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Madera	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Merced	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Stanislaus	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
San Joaquin	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Bay-Delta Region				
Solano	Sacramento Valley, San Francisco Bay	Yolo-Solano, Bay Area	Ozone (Bay Area AQMD portion)	Ozone, PM_{10}
Sacramento	Sacramento Valley	Sacramento Metro	Ozone, $PM_{2.5}$	Ozone, PM_{10}
San Joaquin	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Contra Costa	San Francisco Bay	Bay Area	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
San Francisco	San Francisco Bay	Bay Area	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Alameda	San Francisco Bay	Bay Area	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
CVP and SWP Service Areas Region				
Santa Clara	San Francisco Bay	Bay Area	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
San Benito	North Central Coast	Monterey Bay Unified	–	Ozone, PM_{10}
Kings	San Joaquin Valley	San Joaquin Valley Unified	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Kern	San Joaquin Valley, Mojave Desert	San Joaquin Valley Unified, Kern	Ozone (Eastern Kern), $PM_{2.5}$, PM_{10} (Eastern Kern)	Ozone, $PM_{2.5}$ (Eastern Kern), PM_{10}
Ventura	South Central Coast	Ventura	Ozone	Ozone, PM_{10}
Los Angeles	South Coast, Mojave Desert	South Coast, Antelope Valley	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$ (Eastern Los Angeles), PM_{10}
San Bernardino	South Coast, Mojave Desert	South Coast, Mojave Desert	Ozone, $PM_{2.5}$, PM_{10}	Ozone, $PM_{2.5}$ (South-Eastern San Bernardino), PM_{10}

County	Air Basin	Air Quality Management District	Federal Nonattainment Designations[1]	State Nonattainment Designations[2]
Orange	South Coast	South Coast	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Riverside	South Coast, Salton Sea, Mojave Desert	South Coast, Mojave Desert	Ozone, $PM_{2.5}$, PM_{10}	Ozone, $PM_{2.5}$ (Eastern Riverside), PM_{10}
San Diego	San Diego	San Diego	Ozone	Ozone, $PM_{2.5}$, PM_{10}
Imperial	Salton Sea	Imperial	Ozone, $PM_{2.5}$	Ozone, PM_{10}
Nearshore Pacific Ocean Region				
Santa Barbara	South Central Coast	Santa Barbara	–	Ozone, PM_{10}
San Luis Obispo	South Central Coast	San Luis Obispo	Ozone (eastern portion)	Ozone, PM_{10}
Monterey	North Central Coast	Monterey Bay Unified	–	PM_{10}
Santa Cruz	North Central Coast	Monterey Bay Unified	–	PM_{10}
San Mateo	San Francisco Bay	Bay Area	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
San Francisco	San Francisco Bay	Bay Area	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Marin	San Francisco Bay	Bay Area	Ozone, $PM_{2.5}$	Ozone, $PM_{2.5}$, PM_{10}
Sonoma	North Coast, San Francisco Bay	Northern Sonoma, Bay Area	Ozone (Bay Area AQMD portion), $PM_{2.5}$ (Bay Area AQMD portion)	Ozone (Bay Area AQMD portion), $PM_{2.5}$ (Bay Area AQMD portion), PM_{10} (Bay Area AQMD portion)
Mendocino	North Coast	Mendocino	–	–
Humboldt	North Coast	North Coast Unified	–	PM_{10}
Del Norte	North Coast	North Coast Unified	–	–

Sources: U.S. Environmental Protection Agency 2023; California Air Resources Board 2023a.
Notes: AQMD = Air Quality Management District; Bay Area = San Francisco Bay Area; $PM_{2.5}$ = particulate matter of 2.5 microns diameter and smaller; PM_{10} = particulate matter of 10 microns diameter and smaller
[1] Areas designated as nonattainment by U.S. Environmental Protection Agency related to National Ambient Air Quality Standards as of March 31, 2023.
[2] Areas designated as nonattainment by California Air Resources Board related to California Ambient Air Quality Standards as of March 2023.
[3] Dash indicates that the county has no nonattainment areas.

L.1.1.1 North Coast Air Basin

The North Coast Air Basin includes Humboldt, Del Norte, Trinity, and Mendocino Counties, and northern Sonoma County (California Air Resources Board 2023a). This air basin contains the Trinity River region and portions of the nearshore Pacific Ocean region of the action area. The basin is sparsely populated and stretches along the northern coastline through forested mountains. Prevailing winds blow clean air inland from the Pacific Ocean, and air quality is typically good (California Air Resources Board 2013a). Del Norte, Mendocino, Trinity, and north Sonoma Counties are designated attainment for the federal and state air quality standards while Humboldt County is designated nonattainment for PM_{10} (U.S. Environmental Protection Agency 2023; California Air Resources Board 2023a).

L.1.1.2 Sacramento Valley Air Basin

The Sacramento Valley Air Basin encompasses nine air districts and 11 counties, including all of Shasta, Tehama, Glenn, Colusa, Butte, Sutter, Yuba, Sacramento, and Yolo counties; the westernmost portion of Placer County; and the northeastern half of Solano County. The air basin is bounded by tall mountains: the Coast Ranges to the west, the Cascade Range to the north, and the Sierra Nevada to the east. This air basin contains the Sacramento River, Clear Creek, and American River regions, and portions of the Bay-Delta region of the action area.

Winters are wet and cool, and summers are hot and dry. When air stagnates or is trapped by an inversion layer in the valley, ambient pollutant concentrations can reach or exceed ambient air quality standards. On-road vehicles are the largest source of smog-forming pollutants, and particulate matter emissions are primarily from area sources, such as fugitive dust from paved and unpaved roads and vehicle travel (California Air Resources Board 2013a).

To characterize the existing ambient air quality in the Sacramento Valley Air Basin, analysts reviewed data from area monitoring stations (California Air Resources Board 2023c). For the three years of 2019–2021, which are the most recent years for which complete data are available, monitoring data indicated the following:

- Concentrations of 8-hour ozone (O_3) , 1-hour O_3, 24-hour $PM_{2.5}$, and 24-hour PM_{10} have exceeded the National Ambient Air Quality Standards (NAAQS) and California Ambient Air Quality Standards (CAAQS).
- Measured concentrations of nitrogen dioxide (NO_2) have complied with the NAAQS and CAAQS.
- Monitored sulfur dioxide (SO_2) and lead concentrations are very low.

L.1.1.3 Mountain Counties Air Basin

The Mountain Counties Air Basin includes the mountainous areas of the central and northern Sierra Nevada range, from Plumas County south to Mariposa County, including Plumas, Sierra, Nevada, Central Placer, El Dorado, Amador, Calaveras, Tuolumne, and Mariposa counties. This air basin includes portions of the Stanislaus River region of the action area.

The area is sparsely populated, and motor vehicles are the primary source of emissions in the air basin. Air quality issues often result when eastward surface winds transport pollution from more populated air basins to the west and south. Wood smoke from stoves and fireplaces contributes to elevated ambient PM_{10} concentrations during winter (California Air Resources Board 2013a). Amador, Calaveras, El Dorado, Nevada, Mariposa, Placer, and Tuolumne Counties are designated as nonattainment for the state ozone standards (California Air Resources Board 2023a). El Dorado, Nevada, Placer, Plumas, and Sierra Counties are designated as nonattainment for the state PM_{10} standards (California Air Resources Board 2023a).

L.1.1.4 San Francisco Bay Area Air Basin

The San Francisco Bay Area Air Basin consists of a single air district and nine counties, including all of Napa, Marin, San Francisco, Contra Costa, Alameda, San Mateo, and Santa Clara counties; the southern portion of Sonoma County; and the southwestern portion of Solano County. The hills of the Coast Ranges bound the San Francisco and San Pablo Bays and the inland valleys of the air basin. This air basin includes portions of the Bay-Delta and nearshore Pacific Ocean regions of the action area.

The San Francisco Bay Area Air Basin includes the second largest urban area in California, hosting industry, airports, international ports, freeways, and surface streets. On-road vehicles are the largest source of smog-forming pollutants, and PM_{10} emissions are primarily from area sources, such as fugitive dust from paved and unpaved roads and vehicle travel (California Air Resources Board 2013a). Air quality in the San Francisco Bay Area (Bay Area) is often good, as sea breezes blow clean air from the Pacific Ocean into the air basin, but transport of pollutants from the San Francisco Bay Area can exacerbate air quality problems in the downwind portions of the San Francisco Bay Area Air Basin, as well as in the Sacramento Valley and San Joaquin Valley air basins.

To characterize the existing ambient air quality for the San Francisco Bay Area Air Basin, analysts reviewed data from area monitoring stations (California Air Resources Board 2023c). For the three years of 2019–2021, which are the most recent years for which complete data are available, monitoring data indicated the following:

- Concentrations of 8-hour O_3, 1-hour O_3, 24-hour $PM_{2.5}$, and 24-hour PM_{10} have exceeded the NAAQS and CAAQS.
- Measured concentrations of NO_2 have complied with the NAAQS and CAAQS.
- Monitored SO_2 and lead concentrations are very low.

L.1.1.5 San Joaquin Valley Air Basin

The San Joaquin Valley Air Basin encompasses eight counties, including all of San Joaquin, Stanislaus, Madera, Merced, Fresno, Kings, and Tulare counties; and western Kern County. It is bounded on the west by the Coast Range, on the east by the Sierra Nevada, and in the south by the Tehachapi Mountains. This air basin contains the San Joaquin River Region and portions of the Stanislaus River and Bay-Delta regions of the action area.

Winters are cool and wet and summers are dry and very hot. The area is heavily agricultural, and hosts other localized industries such as forest products, oil and gas production, and oil refining. On-road vehicles are the largest source of smog-forming pollutants, and PM_{10} emissions are primarily from sources such as agricultural operations and fugitive dust from paved and unpaved roads and vehicle travel (California Air Resources Board 2013a). Air quality issues may be exacerbated under dry conditions. When water supplies and irrigation levels are decreased in urban, rural, and agricultural areas, there is increased potential for the formation and transport of fugitive dust.

To characterize the existing ambient air quality for the San Joaquin Valley Air Basin, analysts reviewed data from area monitoring stations (California Air Resources Board 2023c). For the three years of 2019–2021, which are the most recent years for which complete data are available, monitoring data indicated the following:

- Concentrations of 8-hour O_3, 1-hour O_3, 24-hour $PM_{2.5}$, and 24-hour PM_{10} have exceeded the NAAQS and CAAQS.
- Measured concentrations of NO_2 have complied with the NAAQS and CAAQS.
- Monitored SO_2 and lead concentrations are very low.

Concentrations of PM_{10} and $PM_{2.5}$ have been a continuing concern in the San Joaquin Valley Air Basin. The San Joaquin Valley Air Pollution Control District (SJVAPCD) is the local regulatory agency with jurisdiction over air quality issues in the San Joaquin Valley area. In response to the area's historical air quality problems with dust and particulate matter, the SJVAPCD was the first agency in the state to regulate emissions from on-field agricultural operations. In 2004, the agency adopted Rule 4550, the Conservation Management Practices rule, and Rule 3190, the Conservation Management Practices Fee rule. To comply with these rules, farmers with 100 acres or more of contiguous land must prepare and implement biennial Conservation Management Plans to reduce dust and particulate matter emissions from on-farm sources, such as unpaved roads and equipment yards, land preparation, harvest activities, and other farming activities. The SJVAPCD published a handbook titled *Agricultural Air Quality Conservation Management Practices for San Joaquin Valley Farms* and a list of conservation management practices in 2004 to provide guidance to farmers (San Joaquin Valley Air Pollution Control District 2004a, 2004b). Examples of conservation management practices include activities that reduce or eliminate the need for soil disturbance, activities that protect soil from wind, use of dust suppressants, alternatives to burning agricultural wastes, and reduced travel speeds on unpaved roads and equipment yards. Lands not currently under cultivation or used for pasture are exempt from Rule 4550, other than recordkeeping to document the exemption. Fees vary depending on the size of the farm, and include an initial application fee, and a biennial renewal fee.

In addition to requirements for on-field agricultural practices, the SJVAPCD rules and regulations address avoidance of nuisance conditions (Rule 4102), prohibitions on open burning (Rule 4103), and fugitive-dust control (Regulation VIII). Specifically, the SJVAPCD dust-control rules include Rule 8021 for control of PM_{10} from construction, demolition, excavation, extraction, and other earthmoving activities; Rule 8031 for control of PM_{10} from handling and storage of bulk materials; Rule 8051 for control of PM_{10} from disturbed open areas; Rule 8061 for control of PM_{10} from travel on paved and unpaved roads; Rule 8071 for control of PM_{10} from unpaved vehicle and equipment traffic areas; and Rule 8081 for off-field agricultural sources, such as bulk materials handling and transport and travel on unpaved roads. Each of these rules requires fugitive dust control, often through application of water, gravel, or chemical dust stabilizers.

L.1.1.6 South Coast Air Basin

The South Coast Air Basin is California's largest metropolitan region. The area includes the southern two-thirds of Los Angeles County, all of Orange County, and the western urbanized portions of Riverside and San Bernardino counties. The South Coast Air Basin generally forms a lowland plain, bounded by the Pacific Ocean on the west and by mountains on the other three sides. The potential for air pollution in the basin is high. The warm sunny weather associated with a persistent high-pressure system is conducive to the formation of ozone. The problem is aggravated by the surrounding mountains, frequent low inversion heights, and stagnant air conditions. All of these factors act together to trap pollutants in the Basin. Pollutant concentrations in parts of the Basin are among the highest in the nation (California Air Resources Board 2013a). On-road vehicles and certain industrial sectors are the largest source of smog-forming pollutants and PM_{10} emissions.

To characterize the existing ambient air quality in the South Coast Air Basin, analysts reviewed data from area monitoring stations (California Air Resources Board 2023c). For the three years of 2019–2021, which are the most recent years for which complete data are available, monitoring data indicated the following:

- Concentrations of 8-hour O_3, 1-hour O_3, 24-hour $PM_{2.5}$, and 24-hour PM_{10} have exceeded the NAAQS and CAAQS.
- Measured concentrations of NO_2 have complied with the NAAQS and CAAQS.
- Monitored SO_2 and lead concentrations are very low.

L.1.1.7 South Central Coast Air Basin

The South Central Coast Air Basin includes San Luis Obispo, Santa Barbara and Ventura Counties. It is bordered by the Pacific Ocean on the south and west and lies just north of the highly populated South Coast Air Basin. This air basin includes portions of the nearshore Pacific Ocean region of the action area.

Sources of pollutants in the air basin include powerplants, oil production and refining, vehicle travel, and agricultural operations. San Luis Obispo, Santa Barbara, and Ventura Counties are designated as nonattainment for the state PM_{10} standards. San Luis Obispo and Ventura Counties are designated as nonattainment for the state ozone standards while Santa Barbara County is designated as nonattainment-transitional for the state ozone standard. Eastern San Luis Obispo and Ventura Counties are designated as nonattainment for the federal ozone standard (U.S. Environmental Protection Agency 2023). Wind patterns link Ventura and Santa Barbara Counties, resulting in pollutant transport between the South Central Coast Air Basin and South Coast Air Basin. San Luis Obispo County is separated from these counties by mountains, and the air quality in San Luis Obispo County is linked more with conditions in the San Francisco Bay Area Air Basin and San Joaquin Valley Air Basin. Additionally, air emissions from the South Coast Air Basin can be blown offshore, and then carried to the coastal cities of the South Central Coast Air Basin. Under some conditions, the reverse air flow can carry pollutants from the South

Central Coast Air Basin to the South Coast Air Basin and contribute to ozone violations there (California Air Resources Board 2013a).

L.1.1.8 North Central Coast Air Basin

The North Central Coast Air Basin includes Santa Cruz, San Benito and Monterey counties (California Air Resources Board 2023a). This air basin includes portions of the nearshore Pacific Ocean region of the action area.

The North Central Coast Air Basin is in attainment for all NAAQS and is designated as nonattainment for the state ozone and PM_{10} standards (California Air Resources Board 2023a). Although the air basin is separated from the Bay Area by the Santa Cruz Mountains and Coast Ranges to the north, wind can transport air pollution from the San Francisco Bay Area Air Basin and contribute to elevated ozone concentrations in the North Central Coast Air Basin (California Air Resources Board 2013a).

L.2 Evaluation of Alternatives

This section describes the technical background for the evaluation of environmental consequences associated with the action alternatives and the No Action Alternative.

L.2.1 Methods and Tools

The impact assessment considers changes in air pollutant emissions related to changes in CVP and SWP operations under the alternatives as compared to the No Action Alternative. This section details methods and tools used to evaluate those effects. It should be noted that Alternative 2 consists of four phases that could be utilized under its implementation. All four phases are considered in the assessment of Alternative 2 to bracket the range of potential impacts.

Potential air quality impacts were assessed for each component of each alternative. Where possible, the direction (positive or negative effect on air quality) and magnitude of change were identified for emissions of criteria pollutants, which are seven common pollutants for which the U.S. Environmental Protection Agency (USEPA) has set National Ambient Air Quality Standards (NAAQS) according to health-based criteria. The criteria pollutants are carbon monoxide (CO), lead, nitrogen dioxide (NO_2), ozone, particulate matter of 10 microns diameter and smaller (PM_{10},), particulate matter of 2.5 microns diameter and smaller ($PM_{2.5}$), and sulfur dioxide (SO_2). Lead is not a component of the fuels used in power plants and consequently is not assessed. Reactive organic gases (ROG), though not a criteria pollutant, are evaluated because they contribute to ozone formation. Ozone is not emitted directly from sources but is formed in the atmosphere from chemical reactions of the ozone precursor chemicals nitrogen oxides (NO_x) and ROG. Therefore, potential ozone impacts are assessed based on emissions of NO_x and ROG. The California Air Resources Board (CARB) has set state ambient air quality standards that are similar to or stricter than the NAAQS. The primary actions that could affect emissions are described as follows.

Air quality impacts from potential changes in emissions from fossil-fueled powerplants (hydropower generation)

Under the No Action Alternative, the climate conditions and trends described in Section L.1 would continue. Under the No Action Alternative, Reclamation would continue with current operation of the CVP, as described in the 2020 Record of Decision and subject to the 2019 Biological Opinions. The 2020 Record of Decision for the CVP and the 2020 Incidental Take Permit for the SWP represent current management direction or intensity pursuant to 43 CFR § 46.30. The No Action Alternative and air quality emissions are discussed further in Section L.2.2.

The action alternatives would change operations of the CVP and SWP, which could change river flows and reservoir levels. These changes could affect the amount of power the hydroelectric facilities in the system could generate. Where flows increase on rivers that have hydroelectric facilities then hydropower generation could increase. The additional hydroelectric power is expected to displace power that must be purchased from suppliers connected to the regional electric system (grid). To the extent that the displaced power would have been generated by fossil-fueled powerplants, emissions of criteria pollutants from these plants would decrease. (In 2022, approximately 48% of grid electricity in California was generated by fossil-fueled plants [U.S. Environmental Protection Agency 2024].) Conversely, if hydropower generation decreases, the decrease must be offset by purchased power from the grid to meet demand for power. To the extent that the additional purchased power would have been generated by fossil-fueled powerplants, emissions from these plants would increase.

Operations of the CVP and SWP also entail transfers of water. Many, but not all, transfers require water to be pumped. Appendix F, *Modeling*, provides further information on quantities of water transferred. For those transfers that require pumping, changes in the quantities of water transferred could affect emissions by changing the amount of electricity required. If the amount of water transferred increases, the electrical energy required for pumping also would increase. To the extent that the increased electricity would be purchased from the grid and would be generated by fossil-fueled powerplants, emissions from these plants would increase. Conversely, if the amount of water transferred decreases, the electrical energy required for pumping also would decrease. To the extent that the amount of purchased electricity that is generated by fossil-fueled powerplants decreases, emissions from these plants would decrease.

Air quality effects resulting from changes in hydropower generation (including power required for water transfers), and consequently in the demand for grid power, were evaluated on a project-wide basis in terms of air pollutant emissions from fossil-fueled powerplants. For the details of the power modeling on which the air quality analysis was based, see Appendix U, *Power Technical Appendix*. The power modeling estimated energy usage in terms of *net generation*, defined as the difference between the amount of electricity generated by CVP/SWP hydropower facilities and the amount of electricity used by CVP/SWP for water transfers and facility operations. A positive value for net generation means that CVP/SWP generated more power than it used, and the excess was sold to the grid. A negative value for net generation means that CVP/SWP used more power than it generated and offset the deficit by purchasing the additional power from the grid. Table L-2 summarizes the results of the power modeling and shows the estimated net generation for each alternative for a long-term average year. The emissions calculations reflect net generation for the entire CVP/SWP system, as shown in the last line in the table.

Table L-2. Summary of Power Modeling Results

Facilities	Energy Component	Energy (Gigawatt-hours per average year)							
		No Action	Alt 1	Alt 2 with TUCP without VA	Alt 2 without TUCP without VA	Alt 2 without TUCP with Delta VA	Alt 2 without TUCP with All VA	Alt 3	Alt 4
CVP	Energy Generation[1]	4,478	4,553	4,508	4,494	4,491	4,493	4,500	4,499
	Energy Use[2]	1,535	1,725	1,552	1,551	1,503	1,501	933	1,579
	Net Generation[3]	2,943	2,828	2,956	2,943	2,988	2,992	3,567	2,920
SWP	Energy Generation[1]	3,744	4,131	3,778	3,754	3,747	3,752	3,035	3,822
	Energy Use[2]	6,415	8,068	6,638	6,581	6,568	6,590	3,399	6,794
	Net Generation[3]	-2,671	-3,937	-2,860	-2,827	-2,821	-2,838	-364	-2,972
Total	Energy Generation[1]	8,222	8,684	8,286	8,248	8,238	8,245	7,535	8,321
	Energy Use[2]	7,950	9,793	8,190	8,132	8,071	8,091	4,332	8,373
	Net Generation[3]	272	-1,109	96	116	167	154	3,203	-52

Source: Appendix U, *Power Technical Appendix*.

Notes: Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements; CVP = Central Valley Project; SWP = State Water Project; 1 gigawatt-hour = 1,000 megawatt-hours = 1,000,000 kilowatt-hours

[1] Hydropower generated

[2] Energy used for facility operation and water transfers

[3] Net generation equals hydropower generation minus energy use. Net generation of zero would indicate that hydropower generation exactly equals energy use. Negative net generation values indicate that energy use exceeds energy generation and the additional energy needed is purchased from the grid. Positive net generation values indicate that energy generation exceeds energy use and the additional energy generated is sold to the grid.

The changes in annual net generation estimated by the power modeling were multiplied by emission factors (mass of pollutant emitted per unit of energy generated) to derive annual emissions. Emission factors for NO_x and SO_2 were obtained from the U.S. Environmental Protection Agency eGRID model and represent averages for the California statewide mix of powerplants in 2022, which is the most recent year of data available (U.S. Environmental Protection Agency 2024). eGRID does not provide emission factors for CO, PM_{10}, $PM_{2.5}$, and ROG, so emission factors for these pollutants were derived from data for the electric utility sector in the California Air Resources Board emission inventory for 2012, which is the most recent year of data available for the electric utility sector (California Air Resources Board 2013b). Table L-3 lists the emission factors that were used in the air quality analysis.

Table L-3. Emission Factors Used in the Air Quality Analysis.

Pollutant	Electric Generation (lb/Mwh)	Diesel Pump Engines (g/hp-hr)
CO	0.385	3.974
NO_x	0.403	3.63
PM_{10}	0.122	0.115
$PM_{2.5}$	0.116	0.105
ROG	0.044	0.433
SO_2	0.015	0.007

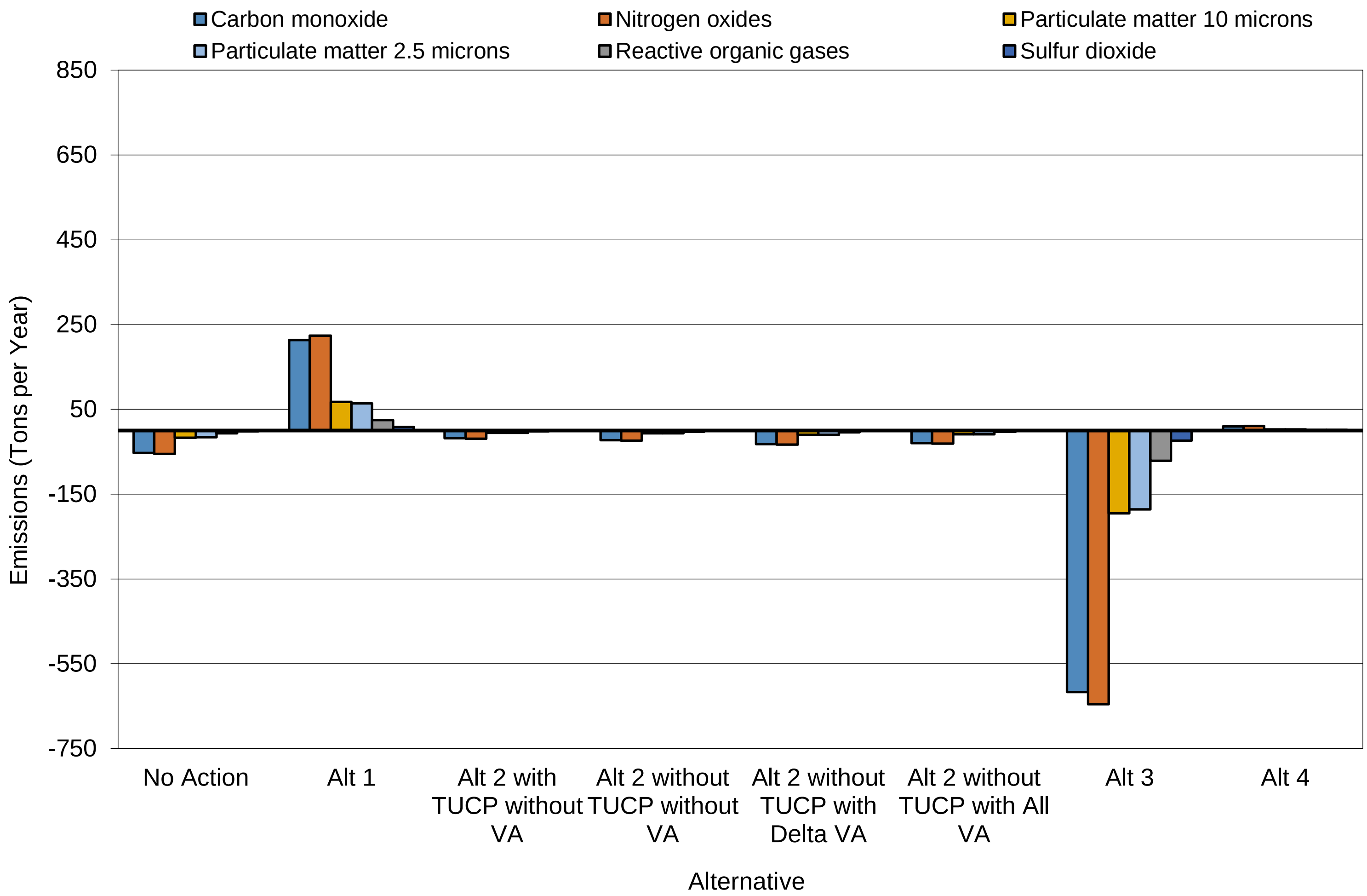
Sources: electric generation – California Air Resources Board 2013b, U.S. Environmental Protection Agency 2024; diesel pump engines – California Air Pollution Control Officers Association 2022.
Notes: g/hp-hr = grams per horsepower-hour; lb/Mwh = pounds per megawatt-hour; CO = carbon monoxide; NO_x = nitrogen oxides; PM_{10} = particulate matter of 10 microns diameter and smaller; $PM_{2.5}$ = particulate matter of 2.5 microns diameter and smaller; ROG = reactive organic gases; SO_2 = sulfur dioxide

Table L-4 shows the estimated emissions from fossil-fueled grid powerplants associated with net generation, based on the net generation values given in Table L-2. Figure L-1 and Figure L-2 show the emissions of each pollutant for grid power generation and the changes compared to the No Action Alternative, respectively.

Table L-4. Emissions from Net Generation

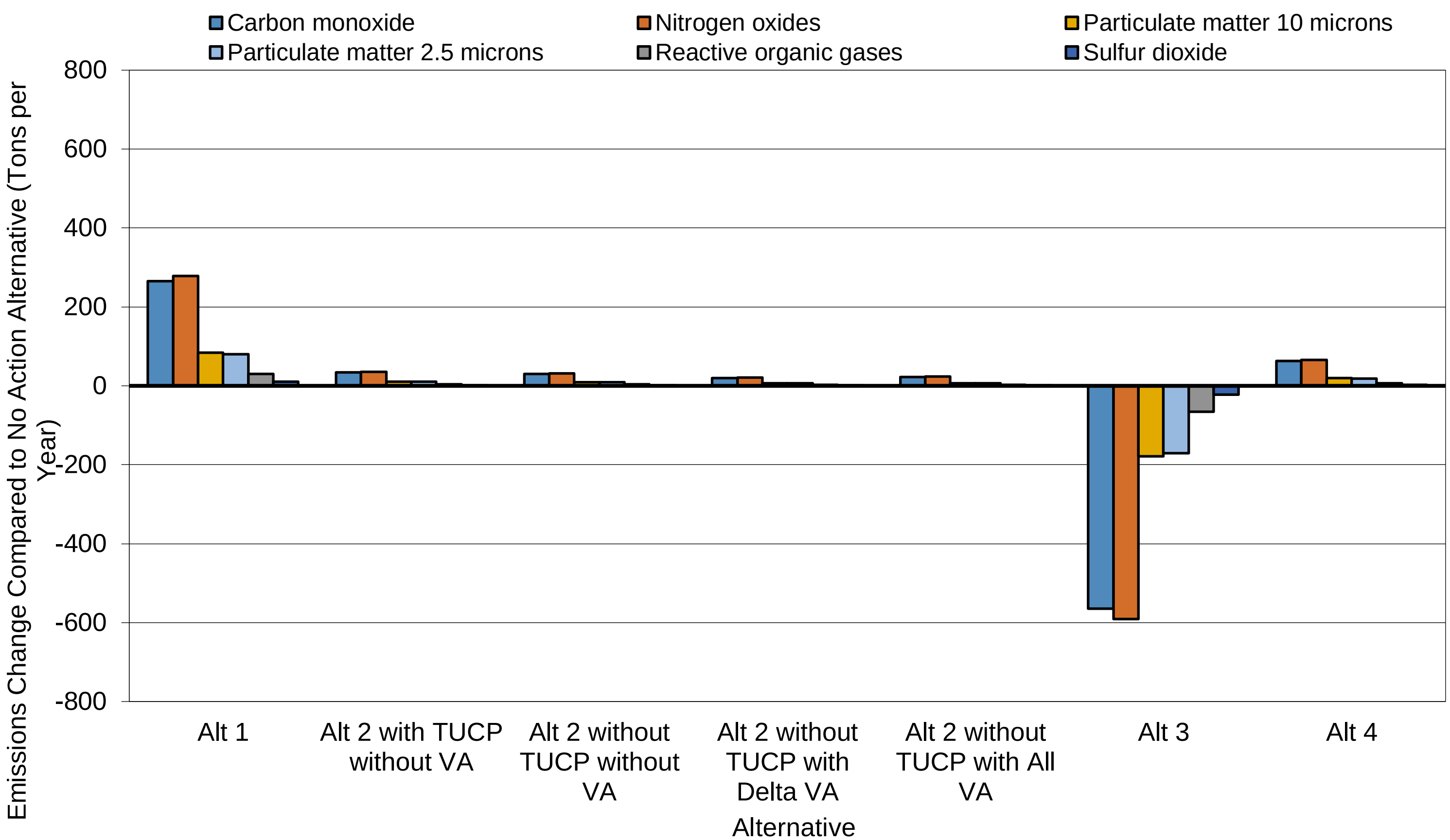
Pollutant	Emissions (U.S. tons per average year)							
	No Action	Alt 1	Alt 2 with TUCP without VA	Alt 2 without TUCP without VA	Alt 2 without TUCP with Delta VA	Alt 2 without TUCP with All VA	Alt 3	Alt 4
CO	-52	214	-18	-22	-32	-30	-617	10
NO_x	-55	223	-19	-23	-34	-31	-645	10
PM_{10}	-17	68	-6	-7	-10	-9	-195	3
$PM_{2.5}$	-16	64	-6	-7	-10	-9	-186	3
ROG	-6	25	-2	-3	-4	-3	-71	1
SO_2	-2	8	-1	-1	-1	-1	-24	0

Notes:
Values represent the emissions effects of net generation, i.e., CVP/SWP hydropower generation minus CVP/SVP energy use. Emissions of zero would indicate that CVP/SWP hydropower generation exactly equals CVP/SWP energy use. Negative emission values indicate decreases in emissions because net generation is positive and displaces grid power; positive emission values indicate increases in emissions because net generation is negative and CVP/SWP purchases the needed power from the grid.
CO = carbon monoxide; NOx = nitrogen oxides; PM_{10} = particulate matter of 10 microns diameter and smaller; $PM_{2.5}$ = particulate matter of 2.5 microns diameter and smaller; ROG = reactive organic gases; SO_2 = sulfur dioxide; Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements



Notes: Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements

Figure L-1. Emissions from Grid Power Generation



Notes: Emissions for the No Action Alternative are not shown because they are the baseline to which changes under the action alternatives are compared. These baseline emissions are indicated by the No Action bar in Figure L-1.

Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements

Figure L-2. Changes in Emissions from Grid Power Generation Compared to the No Action Alternative

Potential changes in emissions from fossil-fueled powerplants (groundwater pumping)

Under the No Action Alternative, the climate conditions and trends described in Section L.1 would continue. Under the No Action Alternative, Reclamation would continue with current operation of the CVP, as described in the 2020 Record of Decision and subject to the 2019 Biological Opinions. The 2020 Record of Decision for the CVP and the 2020 Incidental Take Permit for the SWP represent current management direction or intensity pursuant to 43 CFR § 46.30. The No Action Alternative and associated air pollutant emissions are discussed further in Section L.2.2.

The action alternatives would change operation of the CVP and SWP, which could change river flows and reservoir levels. These changes could affect the amount of water available for agricultural irrigation. If surface water availability decreases, farmers could make up the difference in water supply by increasing groundwater pumping. Approximately 90% of groundwater pumps are powered by grid electricity (U.S. Department of Agriculture 2019), so increased pumping would increase the demand for grid power. To the extent that the additional purchased power would be generated by fossil-fueled powerplants, emissions from these plants would increase. Although the specific power purchases that water users may make in the future are not known, approximately 50% of the grid electricity in California was generated by fossil-fueled plants in 2021, as noted above. Approximately 10% of groundwater pumps are powered by engines (U.S. Department of Agriculture 2019), so increased use of these pumps would increase engine exhaust emissions. Conversely, if surface water availability increases, farmers could decrease the amount of groundwater they pump, which would lead to a decrease in emissions.

Air quality effects resulting from changes in groundwater pumping were evaluated on a project-wide basis in terms of air pollutant emissions from the fossil-fueled powerplants (for electrically powered pumps) and from engines (for engine-powered pumps). For the details of the groundwater modeling on which the air quality analysis was based and the project-wide quantities of water pumped, see Appendix I, *Groundwater Technical Appendix*. The groundwater modeling estimated that for a long-term average year, the quantities of water pumped would be 13,465 thousand acre-feet (TAF) for the No Action Alternative, 13,337 TAF for Alternative 1, 13,487 for Alternative 2 With TUCP Without VA, 13,484 for Alternative 2 Without TUCP Without VA, 13,524 for Alternative 2 Without TUCP With Delta VA, 13,505 for Alternative 2 Without TUCP With All VA, 14,091 for Alternative 3, and 13,450 for Alternative 4.

The quantities of water pumped estimated by the groundwater modeling were converted to the amounts of energy required and the result was multiplied by emission factors to derive annual emissions. The amount of energy required to pump water varies widely due to several factors, among them the depth to groundwater (the amount of lift) that the pump has to overcome, which varies greatly spatially; the design of the well; the efficiency of the pump engine or motor; and the efficiency of the pump itself. A reasonable range for the average amount of energy required in California is 400 to 1,200 kilowatt-hours per acre-foot (Kwh/ac-ft) (California Energy Commission 2015). For this analysis the midpoint of the range (800 Kwh/ac-ft) was assumed.

For an electric pump, the energy requirement of 800 Kwh/ac-ft represents the electricity usage at the pump motor. There are energy losses in the electrical distribution system from the powerplant to the motor, so that in order to deliver a particular amount of energy to the pump, the powerplant must generate slightly more energy. The average loss rate for the western United States regional grid is approximately 5.1% (U.S. Environmental Protection Agency 2024). The energy requirements for electric pumps were adjusted by this percentage for this analysis. The resulting emissions from fossil-fueled powerplants were calculated in the same way as explained above, using the number of acre-feet of water pumped, the adjusted energy requirement, the fraction of pumps that are electric (90%), and the emission factors listed in Table L-3.

For an engine-powered pump, the energy requirement of 800 Kwh/ac-ft represents the energy supplied to the pump by the engine, and is expressed in horsepower-hours per acre-foot (hp-hr/ac-ft). As noted above, approximately 10% of groundwater pumps are powered by engines: 8% diesel-fueled and 2% fueled by natural gas, gasoline, LP gas, propane, and butane (U.S. Department of Agriculture 2019). Of these fuels, diesel generally has the highest emissions, so to produce a conservative (high) estimate of emissions all engine-powered pumps were assumed to be diesel-fueled.

Table L-5 shows the estimated energy usage for groundwater pumping. For engines, Table L-6 displays the energy requirements in both kilowatt-hours per year (Kwh/yr) consistent with the unit for electric pumps, and horsepower-hours per year (hp-hr/yr) consistent with the emission factor unit in Table L-3 for engines.

Table L-5. Estimated Energy Usage for Groundwater Pumping

Energy Source	Unit	No Action	Alt 1	Alt 2 with TUCP without VA	Alt 2 without TUCP without VA	Alt 2 without TUCP with Delta VA	Alt 2 without TUCP with All VA	Alt 3	Alt 4
Electric pumps (energy at powerplant)	Kwh/yr	9,623,166,200	9,531,687,160	9,638,889,160	9,636,745,120	9,665,332,320	9,651,753,400	10,070,555,880	9,612,446,000
Pump engines (energy at pump)	Kwh/yr	1,615,800,000	1,600,440,000	1,618,440,000	1,618,080,000	1,622,880,000	1,620,600,000	1,690,920,000	1,614,000,000
	hp-hr/yr	2,166,787,800	2,146,190,040	2,170,328,040	2,169,845,280	2,176,282,080	2,173,224,600	2,267,523,720	2,164,374,000
Sum	Kwh/yr	11,238,966,200	11,132,127,160	11,257,329,160	11,254,825,120	11,288,212,320	11,272,353,400	11,761,475,880	11,226,446,000

Source: Appendix I, *Groundwater Technical Appendix*.
Notes: Water quantities were converted to energy usage using an average rate of 800 Kwh/ac-ft (California Energy Commission 2015).
Kwh/ac-ft = kilowatt-hours per acre-foot; Kwh/yr = kilowatt-hours per year; hp-hr/yr = horsepower-hours per year; Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements

The energy usage for groundwater pumping shown in Table L-5 was multiplied by the emission factors shown in Table L-3 to derive annual emissions. Emission factors given in Table L-3 for engines were obtained from the California Air Resources Board-approved CalEEMod model (California Air Pollution Control Officers Association 2022). CalEEMod provides emission factors specific to calendar year and horsepower range, and the values corresponding to 2024 and an average pump rating of 121 horsepower (U.S. Department of Agriculture 2019) were used in this analysis. Table L-6 shows the estimated emissions from groundwater pumping. Figure L-3 and Figure L-4 show the emissions of each pollutant and the changes compared to the No Action Alternative for groundwater pumping, respectively.

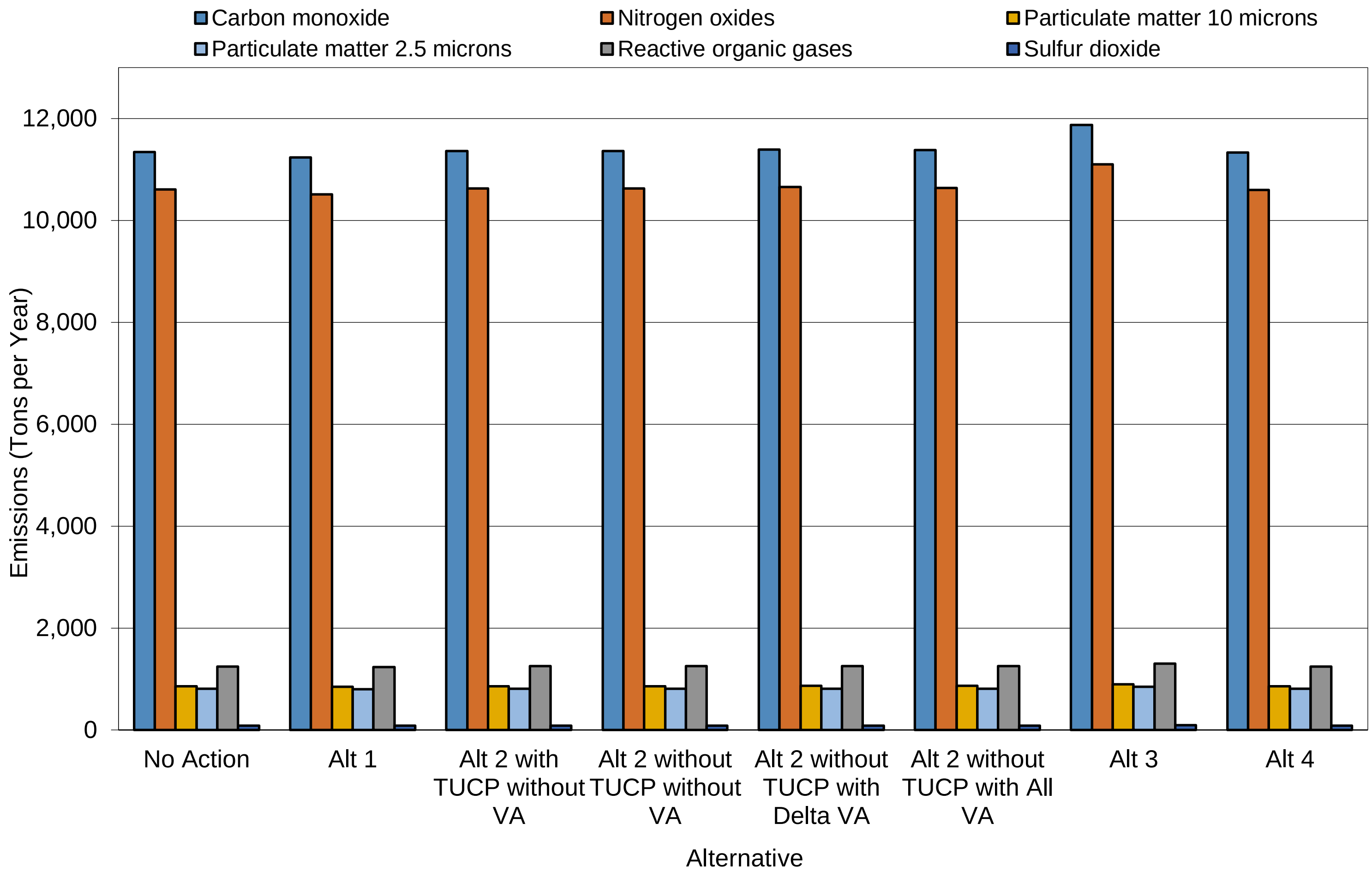
The emission factors given in Table L-3 are annual averages. Due to methodological limitations, they do not account for the timing of groundwater pumping. However, timing of groundwater pumping for agricultural use is expected to be flexible through a given day. PG&E provides Time-Of-Use rates for energy for agricultural users. Time-Of-Use rates encourage groundwater pumping when solar energy is abundant which is also when grid emissions are low due to the availability of solar power. Time-Of-Use rates discourage groundwater pumping when the cost of energy is high which is also when grid emissions are high. Therefore, Reclamation expects that electricity used for pumping groundwater produces less emissions than the average daily long-term grid emissions rate because there is much less pumping during peak energy demand times with higher emissions, and there is more pumping during off-peak energy demand times with lower emissions when solar and other renewables are generating. As a result, the emissions estimated for groundwater pumping may be overestimated.

Table L-6. Emissions from Groundwater Pumping

Pollutant	Emissions (U.S. tons per average year)							
	No Action	Alt 1	Alt 2 with TUCP without VA	Alt 2 without TUCP without VA	Alt 2 without TUCP with Delta VA	Alt 2 without TUCP with All VA	Alt 3	Alt 4
Electric Pumps								
CO	1,853	1,835	1,856	1,856	1,861	1,859	1,939	1,851
NO_x	1,939	1,921	1,942	1,942	1,948	1,945	2,029	1,937
PM_{10}	586	581	587	587	589	588	613	585
$PM_{2.5}$	559	554	560	560	562	561	585	558
ROG	214	212	214	214	215	214	224	214
SO_2	72	71	72	72	72	72	76	72
Diesel Pumps								
CO	9,492	9,402	9,507	9,505	9,533	9,520	9,933	9,481
NO_x	8,670	8,588	8,684	8,682	8,708	8,696	9,073	8,661
PM_{10}	275	272	275	275	276	275	287	274
$PM_{2.5}$	251	248	251	251	252	252	262	251
ROG	1,034	1,024	1,036	1,036	1,039	1,037	1,082	1,033
SO_2	17	17	17	17	17	17	17	17
Total Pumping Emissions[1]								
CO	11,345	11,237	11,363	11,361	11,395	11,379	11,872	11,332
NO_x	10,609	10,508	10,627	10,624	10,656	10,641	11,103	10,597
PM_{10}	861	853	862	862	865	863	901	860

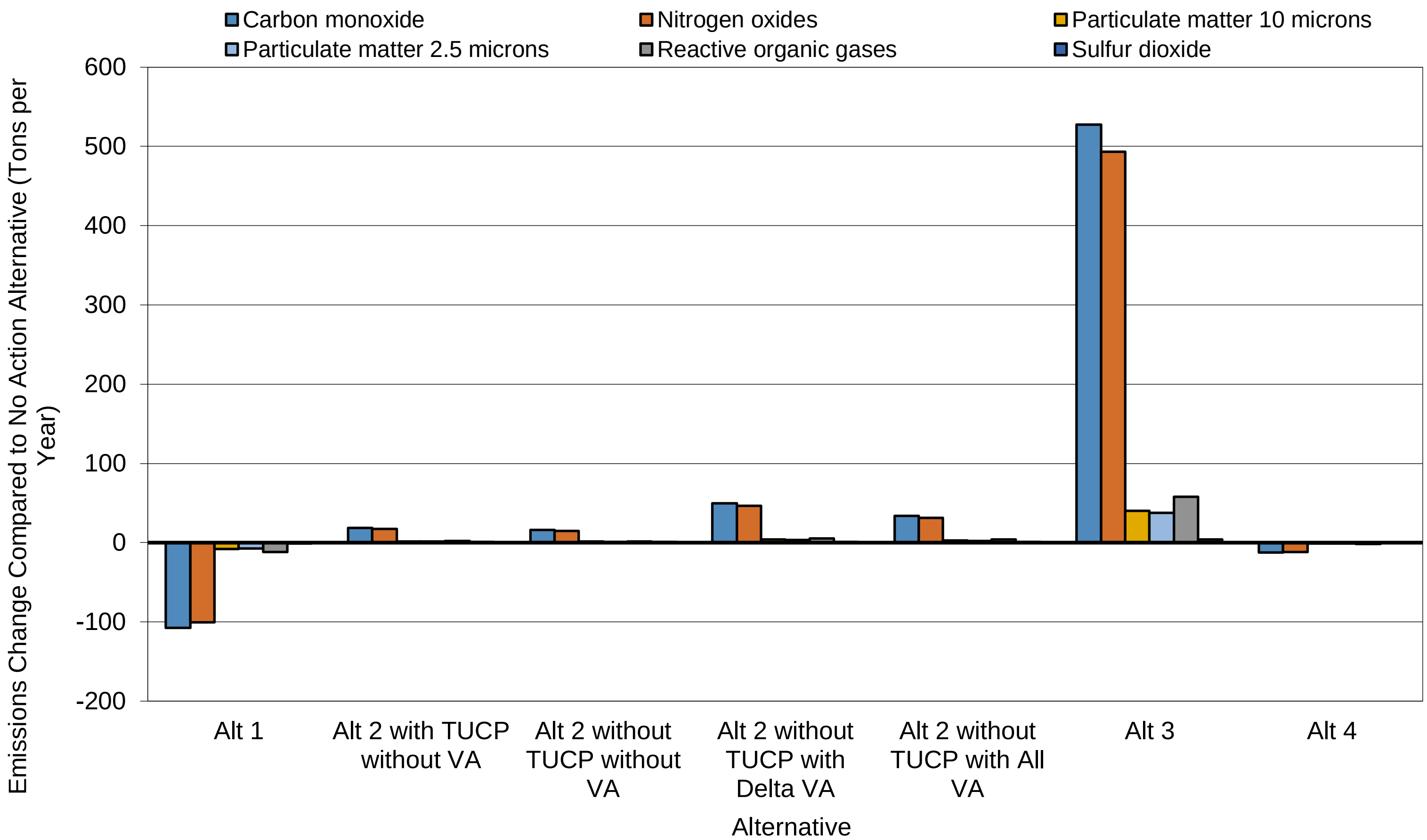
Pollutant	Emissions (U.S. tons per average year)							
	No Action	Alt 1	Alt 2 with TUCP without VA	Alt 2 without TUCP without VA	Alt 2 without TUCP with Delta VA	Alt 2 without TUCP with All VA	Alt 3	Alt 4
$PM_{2.5}$	810	802	811	811	813	812	848	809
ROG	1,248	1,236	1,250	1,250	1,253	1,252	1,306	1,247
SO_2	89	88	89	89	89	89	93	89

Notes: Alt = Alternative; CO = carbon monoxide; NO_x = nitrogen oxides; PM_{10} = particulate matter of 10 microns diameter and smaller; $PM_{2.5}$ = particulate matter of 2.5 microns diameter and smaller; ROG = reactive organic gases; SO_2 = sulfur dioxide; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements
[1] Sum of individual values may not equal total due to rounding.



Notes: Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements

Figure L-3. Emissions from Groundwater Pumping



Notes: Emissions for the No Action Alternative are not shown because they are the baseline to which changes under the action alternatives are compared. These baseline emissions are indicated by the No Action bar in Figure L-3.

Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements

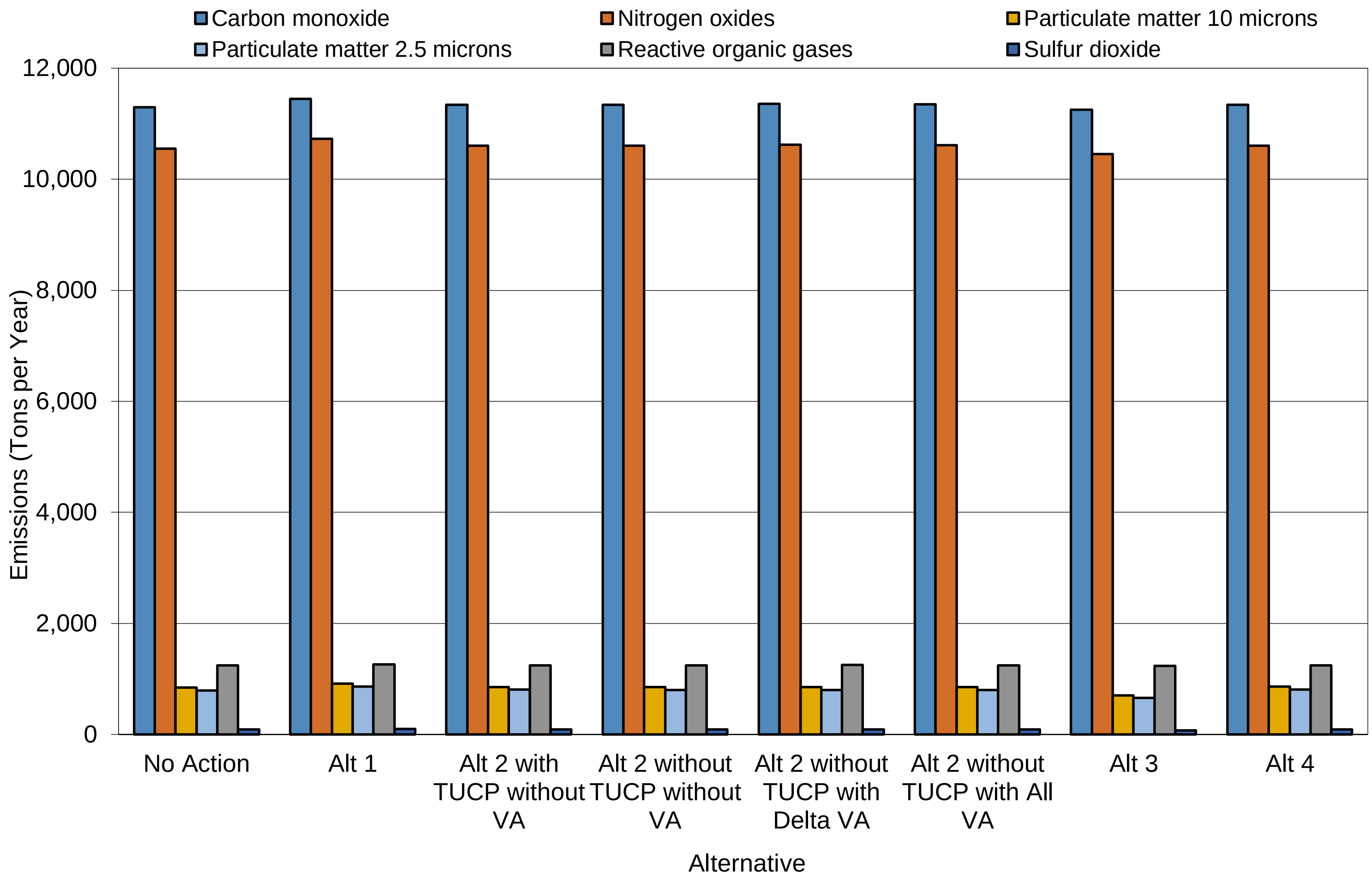
Figure L-4. Changes in Emissions from Groundwater Pumping Compared to the No Action Alternative

The total emissions associated with the project are the sum of the emissions from net generation (Table L-4) and groundwater pumping (Table L-6). Table L-7 shows the estimated total project emissions for a long-term average year. Figure L-5 and Figure L- show the overall emissions of each pollutant for all emission sources, and the changes in emissions compared to the No Action Alternative, respectively.

Table L-7. Total Project Emissions

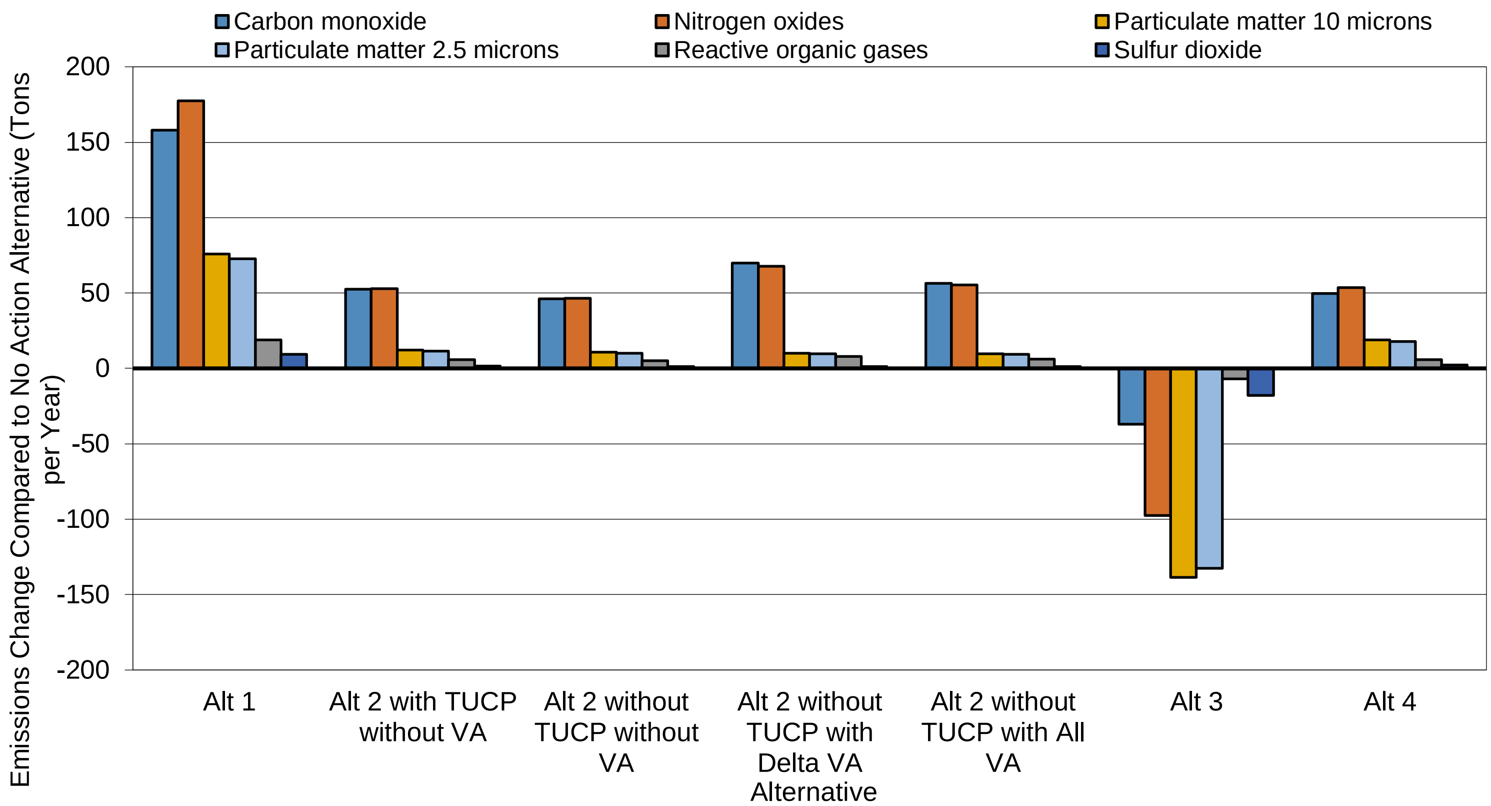
Pollutant	Emissions (U.S. tons per average year)							
	No Action	Alt 1	Alt 2 with TUCP without VA	Alt 2 without TUCP without VA	Alt 2 without TUCP with Delta VA	Alt 2 without TUCP with All VA	Alt 3	Alt 4
CO	11,293	11,451	11,345	11,339	11,362	11,349	11,256	11,342
NO_x	10,554	10,732	10,607	10,601	10,622	10,610	10,457	10,608
PM_{10}	844	920	856	855	854	854	706	863
$PM_{2.5}$	794	867	806	804	804	803	661	812
ROG	1,242	1,261	1,248	1,247	1,250	1,248	1,235	1,248
SO_2	87	96	88	88	88	88	69	89

Notes: Values represent the sum of emissions from fossil-fueled powerplants (for CVP/SWP purchases of grid power and for electrically-powered groundwater pumps) and emissions from diesel engines (for engine-powered groundwater pumps).
CO = carbon monoxide; NO_x = nitrogen oxides; PM_{10} = particulate matter of 10 microns diameter and smaller; $PM_{2.5}$ = particulate matter of 2.5 microns diameter and smaller; ROG = reactive organic gases; SO_2 = sulfur dioxide; Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements



Notes: Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements

Figure L-5. Emissions from All Sources



Notes: Emissions for the No Action Alternative are not shown because they are the baseline to which changes under the action alternatives are compared. These baseline emissions are indicated by the No Action bar in Figure L-5.

Alt = Alternative; TUCP = Temporary Urgency Change Petition; VA = Voluntary Agreements

Figure L-6. Changes in Emissions from All Sources Compared to the No Action Alternative

Under Alternative 1 in an average year, overall emissions would increase compared to the No Action Alternative, as shown in Table L-7. Under the four phases of Alternative 2, in an average year, emissions would increase compared to the No Action Alternative, but emissions would increase less than under Alternative 1. Under Alternative 3 in an average year, emissions would decrease compared to the No Action Alternative and would result in the least emissions of all alternatives. Under Alternative 4, emissions would increase compared to the No Action Alternative. Emissions under Alternative 4 would increase less than under Alternative 1 but more than under all four phases of Alternative 2.

L.2.2 No Action Alternative

Under the No Action Alternative, Reclamation would continue with current operation of the CVP, as described in the 2020 Record of Decision and subject to the 2019 Biological Opinions. The 2020 Record of Decision for the CVP and the 2020 Incidental Take Permit for the SWP represent current management direction or intensity pursuant to 43 CFR § 46.30. The emissions levels shown for an average year with the No Action Alternative in Table L-4, Table L-6, Table L-7, Figure L-1, Figure L-3, and Figure L-5 would continue to occur.

The No Action Alternative is based on 2040 conditions. Changes that would occur over that time frame without implementation of the action alternatives are not analyzed in this technical appendix. However, the changes in air pollutant emissions that are assumed to occur by 2040 under the No Action Alternative are summarized in this section.

Conditions in 2040 would be different from existing conditions because of the following factors:

- Climate change and sea-level rise
- General plan development throughout California, including increased water demands in portions of the Sacramento Valley

By the end of September, the surface water elevations at CVP reservoirs generally decline, and there is potential for exposure of land surfaces as inundated areas drain. Exposed soil surfaces can emit PM_{10} and $PM_{2.5}$ during dry and windy conditions. It is anticipated that climate change would result in more short-duration high-rainfall events and less snowpack in the winter and early spring months. The reservoirs would be full more frequently by the end of April or May by 2040 than in recent historical conditions, potentially resulting in less exposure of previously inundated areas around reservoirs and fewer PM_{10} and $PM_{2.5}$ emissions. However, as the water is released in the spring, there would be less snowpack to refill the reservoirs. This condition would reduce reservoir surface levels, again increasing exposure of previously inundated areas around reservoirs and potentially resulting in PM_{10} and $PM_{2.5}$ emissions.

Irrespective of CVP and SVP operations, development in the region to accommodate population growth, including residential, commercial, industrial, transportation, and other projects, would continue under the No Action Alternative and result in associated effects on emissions. Land uses in 2040 would occur in accordance with adopted general plans. Development under the general plans could affect emissions, depending on the type and location of development. Infill projects where areas are already developed could increase density but would be done in compliance with applicable zoning and general plan policies around air quality. Development in non-urbanized areas could convert natural or rural areas to developed areas, resulting in impacts on emissions.

Air quality plans and emission control programs administered by the State and the respective air quality management districts would remain in place to address emissions in the region and statewide.

The No Action Alternative would also rely upon increased use of Livingston-Stone National Fish Hatchery during droughts to increase production of winter-run Chinook salmon. However, this component requires no physical changes to the facility and would have no adverse effect on emissions.

L.2.3 Alternative 1

L.2.3.1 *Potential Air Quality Effects from Changes in Emissions from Fossil-fueled Powerplants (Hydropower Generation)*

Under Alternative 1, actions in the upper Sacramento Trinity/Clear Creek, American River, Stanislaus River, San Joaquin River, and Bay-Delta regions, and actions associated with operations, could increase or decrease releases and flows, depending on conditions in a particular region, year, and season. Hydropower generation could change accordingly, leading to either increases or decreases in emissions. Reductions in hydropower generation, leading to increases in grid power generation and the associated emissions, could result in air quality effects. Under Alternative 1 in an average year, net generation for the CVP and SWP combined would decrease compared to the No Action Alternative. As a result, emissions from fossil-fueled powerplants on the grid would increase by 508%[1] for each pollutant compared to the No Action Alternative, as shown in Table L-4, which could lead to adverse air quality effects. The relatively low magnitudes of the emissions changes indicated in Table L-4, and the fact that the emissions would be dispersed regionally among the power plants contributing energy to the grid, suggest that potential adverse air quality impacts compared to the No Action Alternative would be small, and would not lead to violation of the NAAQS or CAAQS.

L.2.3.2 *Potential Air Quality Effects from Changes in Emissions from Fossil-fueled Powerplants and Pump Engines (Groundwater Pumping)*

Under Alternative 1, actions in the upper Sacramento Trinity/Clear Creek, American River, Stanislaus River, San Joaquin River, and Bay-Delta regions, and actions associated with operations, could increase or decrease releases and flows, depending on conditions in a particular region, year, and season. The amount of groundwater pumping could change accordingly, leading to either increases or decreases in emissions. Reductions in hydropower generation, leading to increases in grid power generation and the associated emissions, could result in air quality effects. Under Alternative 1 in an average year, groundwater pumping would decrease compared to the No Action Alternative. As a result, the associated emissions would decrease by 1.0% for each pollutant compared to the No Action Alternative, as shown in Table L-6. Because the

[1] Percentage greater than 100% accounts for change in emissions from a decrease under the No Action Alternative to an increase under Alternative 1.

emissions would decrease compared to the No Action Alternative, they would not lead to violation of the NAAQS or CAAQS.

L.2.4 Alternative 2

Under all phases of Alternative 2, actions in the upper Sacramento Trinity/Clear Creek, American River, Stanislaus River, San Joaquin River, and Bay-Delta regions, and actions associated with operations, could increase or decrease releases and flows, depending on conditions in a particular region, year, and season. Hydropower generation could change accordingly, leading to either increases or decreases in emissions. Reductions in hydropower generation, leading to increases in grid power generation and the associated emissions, could result in air quality effects. Similarly, under all phases of Alternative 2 the amount of groundwater pumping could change, leading to either increases or decreases in emissions.

Potential air quality effects from changes in emissions from fossil-fueled powerplants (hydropower generation)

Under Alternative 2 With TUCP Without VA in an average year, net generation for the CVP and SWP combined would decrease compared to the No Action Alternative. As a result, emissions from fossil-fueled powerplants on the grid would increase by 64.7% for each pollutant compared to the No Action Alternative, as shown in Table L-4, which could lead to adverse air quality effects. The relatively low magnitudes of the emissions changes indicated in Table L-4, and the fact that the emissions would be dispersed regionally among the power plants contributing energy to the grid, suggest that any potential adverse air quality impacts compared to the No Action Alternative would be small and would not lead to violation of the NAAQS or CAAQS.

Under Alternative 2 Without TUCP Without VA in an average year, net generation for the CVP and SWP combined would decrease compared to the No Action Alternative. As a result, emissions from fossil-fueled powerplants on the grid would increase by 57.4% for each pollutant compared to the No Action Alternative, as shown in Table L-4, which could lead to adverse air quality effects. The relatively low magnitudes of the emissions changes indicated in Table L-4 and the fact that the emissions would be dispersed regionally among the power plants contributing energy to the grid, suggest that any potential adverse air quality impacts compared to the No Action Alternative would be small and would not lead to violation of the NAAQS or CAAQS.

Under Alternative 2 Without TUCP With Delta VA in an average year, net generation for the CVP and SWP combined would decrease compared to the No Action Alternative. As a result, emissions from fossil-fueled powerplants on the grid would increase by 38.6% for each pollutant compared to the No Action Alternative, as shown in Table L-4, which could lead to adverse air quality effects. The relatively low magnitudes of the emissions changes indicated in Table L-4, and the fact that the emissions would be dispersed regionally among the power plants contributing energy to the grid, suggest that potential adverse air quality impacts compared to the No Action Alternative would be small and would not lead to violation of the NAAQS or CAAQS.

Under Alternative 2 Without TUCP With All VA in an average year, net generation for the CVP and SWP combined would decrease compared to the No Action Alternative. As a result, emissions from fossil-fueled powerplants on the grid would increase by 43.4% for each pollutant compared to the No Action Alternative, as shown in Table L-4, which could lead to adverse air quality effects. The relatively low magnitudes of the emissions changes indicated in Table L-4, and the fact that the emissions would be dispersed regionally among the power plants contributing energy to the grid, suggest that potential adverse air quality impacts compared to the No Action Alternative would be small, and would not lead to violation of the NAAQS or CAAQS.

Potential air quality effects from changes in emissions from fossil-fueled powerplants and pump engines (groundwater pumping)

Under Alternative 2 With TUCP Without VA in an average year, groundwater pumping would increase compared to the No Action Alternative. As a result, the associated emissions would increase by 0.2% for each pollutant compared to the No Action Alternative, as shown in Table L-6. The relatively low magnitudes of the emissions changes indicated in Table L-6, and the fact that the emissions would be dispersed regionally among the power plants (for electric pumps) and engines (for diesel pumps) in the region, suggest that potential adverse air quality impacts compared to the No Action Alternative would be small, and would not lead to violation of the NAAQS or CAAQS.

Under Alternative 2 Without TUCP Without VA in an average year, groundwater pumping would increase compared to the No Action Alternative. As a result, the associated emissions would increase by 0.1% for each pollutant compared to the No Action Alternative, as shown in Table L-6. The relatively low magnitudes of the emissions changes indicated in Table L-6, and the fact that the emissions would be dispersed regionally among the power plants (for electric pumps) and engines (for diesel pumps) in the region, suggest that potential adverse air quality impacts compared to the No Action Alternative would be small, and would not lead to violation of the NAAQS or CAAQS.

Under Alternative 2 Without TUCP With Delta VA in an average year, groundwater pumping would increase compared to the No Action Alternative. As a result, the associated emissions would increase by 0.4% for each pollutant compared to the No Action Alternative, as shown in Table L-6. The relatively low magnitudes of the emissions changes indicated in Table L-6, and the fact that the emissions would be dispersed among the power plants (for electric pumps) and engines (for diesel pumps) in the region, suggest that any potential adverse air quality impacts compared to the No Action Alternative would be small, and would not lead to violation of the NAAQS or CAAQS.

Under Alternative 2 Without TUCP With All VA in an average year, groundwater pumping would increase compared to the No Action Alternative. As a result, the associated emissions would increase by 0.3% for each pollutant compared to the No Action Alternative, as shown in Table L-6. The relatively low magnitudes of the emissions changes indicated in Table L-6, and the fact that the emissions would be dispersed among the power plants (for electric pumps) and engines (for diesel pumps) in the region, suggest that potential adverse air quality impacts compared to the No Action Alternative would be small, and would not lead to violation of the NAAQS or CAAQS.

L.2.5 Alternative 3

L.2.5.1 *Potential Air Quality Effects from Changes in Emissions from Fossil-fueled Powerplants (Hydropower Generation)*

Under Alternative 3 relative to the No Action Alternative, actions in the upper Sacramento Trinity/Clear Creek, American River, Stanislaus River, San Joaquin River, and Bay-Delta regions, and actions associated with operations, could increase or decrease releases and flows, depending on conditions in a particular region, year, and season. Hydropower generation could change accordingly, leading to either increases or decreases in emissions. Reductions in hydropower generation, leading to increases in grid power generation and the associated emissions, could result in air quality effects. Under Alternative 3 in an average year, net generation for the CVP and SWP combined would increase compared to the No Action Alternative. As a result, emissions from fossil-fueled powerplants on the grid would decrease by 1,078%[2] for each pollutant compared to the No Action Alternative, as shown in Table L-4, which could lead to beneficial air quality effects. Because the emissions would decrease compared to the No Action Alternative, Alternative 3 would not lead to violation of the NAAQS or CAAQS.

L.2.5.2 *Potential Air Quality Effects from Changes in Emissions from Fossil-fueled Powerplants and Pump Engines (Groundwater Pumping)*

Under Alternative 3 relative to the No Action Alternative, actions in the upper Sacramento Trinity/Clear Creek, American River, Stanislaus River, San Joaquin River, and Bay-Delta regions, and actions associated with operations, could increase or decrease releases and flows, depending on conditions in a particular region, year, and season. The amount of groundwater pumping could change accordingly, leading to either increases or decreases in emissions. Reductions in hydropower generation, leading to increases in grid power generation and associated emissions could result in air quality effects. Under Alternative 3 in an average year, groundwater pumping would increase compared to the No Action Alternative. As a result, the associated emissions would increase by 4.6% for each pollutant compared to the No Action Alternative, as shown in Table L-6. The relatively low magnitudes of the emissions changes indicated in Table L-6 and the fact that the emissions would be dispersed among the power plants (for electric pumps) and engines (for diesel pumps) in the region, suggest that potential adverse air quality impacts compared to the No Action Alternative would be small, and would not lead to violation of the NAAQS or CAAQS.

[2] Percentage less than -100% accounts for change in emissions from a decrease under the No Action Alternative to a greater decrease under Alternative 3.

L.2.6 Alternative 4

L.2.6.1 *Potential Air Quality Effects from Changes in Emissions from Fossil-fueled Powerplants (Hydropower Generation)*

Under Alternative 4 relative to the No Action alternative, actions in the upper Sacramento Trinity/Clear Creek, American River, Stanislaus River, San Joaquin River, and Bay-Delta regions, and actions associated with operations, could increase or decrease releases and flows, depending on conditions in a particular region, year, and season. Hydropower generation could change accordingly, leading to either increases or decreases in emissions. Reductions in hydropower generation, leading to increases in grid power generation and associated emissions could result in air quality effects. Under Alternative 4 in an average year, net generation for the CVP and SWP combined would decrease compared to the No Action Alternative. As a result, emissions from fossil-fueled powerplants on the grid would increase by 120% for each pollutant compared to the No Action Alternative, as shown in Table L-4, which could lead to adverse air quality effects. The relatively low magnitudes of the emissions changes indicated in Table L-4, and the fact that the emissions would be dispersed regionally among the power plants contributing energy to the grid, suggest that any potential adverse air quality impacts compared to the No Action Alternative would be small and would not lead to violation of the NAAQS or CAAQS.

L.2.6.2 *Potential Air Quality Effects from Changes in Emissions from Fossil-fueled Powerplants and Pump Engines (Groundwater Pumping)*

Under Alternative 4 relative to the No Action Alternative, actions in the upper Sacramento Trinity/Clear Creek, American River, Stanislaus River, San Joaquin River, and Bay-Delta regions, and actions associated with operations, could increase or decrease releases and flows, depending on conditions in a particular region, year, and season. The amount of groundwater pumping could change accordingly, leading to either increases or decreases in emissions. Reductions in hydropower generation, leading to increases in grid power generation and associated emissions could result in air quality effects. Under Alternative 4 in an average year, groundwater pumping would decrease compared to the No Action Alternative. As a result, the associated emissions would decrease by 0.1% for each pollutant compared to the No Action Alternative, as shown in Table L-6. The relatively low magnitudes of the emissions changes indicated in Table L-6, and the fact that the emissions would be dispersed among the power plants (for electric pumps) and engines (for diesel pumps) in the region, suggest that potential adverse air quality impacts compared to the No Action Alternative would be small, and would not lead to violation of the NAAQS or CAAQS.

L.2.7 Mitigation Measures

Following is a description of mitigation measures identified for air quality resources per alternative. These mitigation measures include avoidance and minimization measures that are part of each alternative and, where appropriate, additional mitigation to lessen impacts of the alternatives.

L.2.7.1 Avoidance and Minimization Measures

Alternatives 1-4

Grid-generated electric power comprises the output of numerous powerplants across California and in other states, and no specific powerplant can be associated with power purchased by CVP/SVP. Fossil-fueled powerplants are subject to the air quality permitting requirements of the air quality management district in which they are located. To obtain a permit, the plant must demonstrate to the satisfaction of the district that its maximum air quality impacts will not exceed the CAAQS or NAAQS. The plant also may be required to comply with USEPA requirements for Best Available Control Technology or Lowest Achievable Emissions Rate. Therefore, no additional mitigation is proposed for energy-related air quality impacts.

Groundwater pump engines produce exhaust emissions that potentially can affect air quality in the local area around the pump. Pump engines are subject to USEPA and CARB emissions standards for criteria pollutants. Most pump engines are relatively small (less powerful than a typical automobile engine) and usually are located in agricultural areas without dense development in the immediate vicinity. Therefore, human exposure to pump engine exhaust is expected to be low, and no mitigation is identified.

L.2.7.2 Additional Mitigation

No additional mitigation has been identified.

L.2.8 Summary of Impacts

Table L-8 shows a summary of impacts and potential mitigation measures for consideration.

Table L-8. Impact Summary

Impact	Alternative	Magnitude and Direction of Impacts	Potential Mitigation Measures
Potential changes in hydropower generation could affect emissions from fossil-fueled powerplants	No Action Alternative	Continuation of existing hydropower conditions and associated air pollutant emissions	-
	Alternative 1	Increase in emissions compared to No Action Alternative. Under Alternative 1, emissions from fossil-fueled powerplants would increase by 508%[1] compared to the No Action Alternative.	-
	Alternative 2	Increase in emissions compared to No Action Alternative. Under Alternative 2, emissions from fossil-fueled powerplants would increase at varying levels for each phase of Alternative 2, as follows: 64.7% increase with TUCP without VA; 57.4% increase without TUCP without VA; 38.6% increase without TUCP with Delta VA; and 43.4% increase without TUCP with All VA.	-

Impact	Alternative	Magnitude and Direction of Impacts	Potential Mitigation Measures
	Alternative 3	Decrease in emissions compared to No Action Alternative. Under Alternative 3, emissions from fossil-fueled powerplants would decrease by 1,078%[2] compared to the No Action Alternative.	-
	Alternative 4	Increase in emissions compared to No Action Alternative. Under Alternative 4, emissions from fossil-fueled powerplants would increase by 120% compared to the No Action Alternative.	-
Potential changes in the amount of groundwater pumping and pumping for water transfers could affect emissions from fossil-fueled powerplants	No Action Alternative	Continuation of existing pumping conditions and associated air pollutant emissions	-
	Alternative 1	Decrease in emissions compared to No Action Alternative. Under Alternative 1, emissions from fossil-fueled powerplants would decrease by 1.0% compared to the No Action Alternative.	-
	Alternative 2	Increase in emissions compared to No Action Alternative. Under Alternative 2, emissions from fossil-fueled powerplants would increase at varying levels for each phase of Alternative 2, as follows: 0.2% increase with TUCP without VA; 0.1% increase without TUCP without VA; 0.4% increase without TUCP with Delta VA; and 0.3% increase without TUCP with All VA.	-
	Alternative 3	Increase in emissions compared to No Action Alternative. Under Alternative 3, emissions from fossil-fueled powerplants would increase by 4.6% compared to the No Action Alternative.	-
	Alternative 4	Increase in emissions compared to No Action Alternative. Under Alternative 4, emissions from fossil-fueled powerplants would decrease by 0.1% compared to the No Action Alternative.	-
Potential changes in the combined impact of hydropower generation, grid emissions, groundwater pumping, and water transfers	No Action Alternative	Continuation of existing hydropower and pumping conditions and associated air pollutant emissions	-
	Alternative 1	Increase in emissions compared to No Action Alternative. Under Alternative 1, combined emissions from fossil-fueled powerplants would increase compared to the No Action Alternative by varying levels	-

Impact	Alternative	Magnitude and Direction of Impacts	Potential Mitigation Measures
		for each pollutant, as follows: 1.4% CO, 1.7% NO_X, 9.0% PM_{10}, 9.1% $PM_{2.5}$, 1.5% ROG, and 11.0% SO_2.	
	Alternative 2	Increase in emissions compared to No Action Alternative. Under Alternative 2, combined emissions from fossil-fueled powerplants would increase at varying levels for each phase of Alternative 2. Under Alternative 2 with TUCP without VA, emissions would increase as follows: 0.5% CO, 0.5% NO_X, 1.4% PM_{10}, 1.5% $PM_{2.5}$, 0.5% ROG, and 1.7% SO_2. Under Alternative 2 without TUCP without VA, emissions would increase as follows: 0.4% CO, 0.4% NO_X, 1.3% PM_{10}, 1.3% $PM_{2.5}$, 0.4% ROG, and 1.5% SO_2. Under Alternative 2 without TUCP with Delta VA, emissions would increase as follows: 0.6% CO, 0.6% NO_X, 1.2% PM_{10}, 1.2% $PM_{2.5}$, 0.6% ROG, and 1.4% SO_2. Under Alternative 2 without TUCP with All VA, emissions would increase as follows: 0.5% CO, 0.5% NO_X, 1.2% PM_{10}, 1.2% $PM_{2.5}$, 0.5% ROG, and 1.3% SO_2.	-
	Alternative 3	Decrease in emissions compared to No Action Alternative. Under Alternative 3, combined emissions from fossil-fueled powerplants would decrease compared to the No Action Alternative by varying levels for each pollutant, as follows: 0.3% CO, 0.9% NO_X, 16.4% PM_{10}, 16.7% $PM_{2.5}$, 0.6% ROG, and 20.6% SO_2.	-
	Alternative 4	Increase in emissions compared to No Action Alternative. Under Alternative 4, combined emissions from fossil-fueled powerplants would increase compared to the No Action Alternative by varying levels for each pollutant, as follows: 0.4% CO, 0.5% NO_X, 2.2% PM_{10}, 2.3% $PM_{2.5}$, 0.5% ROG, and 2.7% SO_2.	-

[1] Percentage greater than 100% accounts for change in emissions from a decrease under the No Action Alternative to an increase under Alternative 1.

[2] Percentage less than -100% accounts for change in emissions from a decrease under the No Action Alternative to a greater decrease under Alternative 3.

L.2.9 Cumulative Impacts

Past, present, and reasonably foreseeable projects, described in Appendix Y, *Cumulative Impacts Technical Appendix,* may have cumulative effects on air quality, to the extent that they could affect fossil-fueled powerplant emissions from hydropower generation and groundwater pumping.

Past and present actions contribute to the existing condition of the affected environment in the project area while reasonably foreseeable actions are those that are likely to occur in the future that are not speculative. Past, present, and reasonably foreseeable projects include actions to develop water storage capacity, water conveyance infrastructure, water recycling capacity, the reoperation of existing water supply infrastructure, including surface water reservoirs and conveyance infrastructure, and habitat restoration actions. The projects identified in Appendix Y that have the most potential to contribute to cumulative impact on air quality are:

- B.F. Sisk Dam Raise and Reservoir Expansion Project
- Sites Reservoir

The No Action Alternative would continue with current operations of the CVP and may result in changes to air quality emissions from fossil-fueled powerplant emissions from hydropower generation and groundwater pumping. These changes may contribute to the cumulative impacts and were described and considered in the 2020 Record of Decision.

Alternative 1 would lead to increases in regional emissions of CO, NO_x, PM_{10}, $PM_{2.5}$, ROG, and SO_2 compared to the No Action Alternative, as described above. The emissions increases from Alternative 1 are expected to be relatively small compared to the emissions from past, present, and reasonably foreseeable projects. Consequently, the emissions from Alternative 1, when combined with emissions from past, present, and reasonably foreseeable projects, are not expected to result in pollutant concentrations that would lead to new exceedances of the CAAQS or NAAQS or to worsen existing exceedances.

Alternative 2, including all four phases would have cumulative impacts similar to those of the Alternative 1 but with less intensity. As with the emissions from the phases of Alternative 2 are expected to be relatively small compared to the emissions from past, present, and reasonably foreseeable projects. Consequently, the cumulative air quality impacts of the phases of Alternative 2 along with past, present, and reasonably foreseeable projects are not expected to lead to new exceedances of the CAAQS or NAAQS or to worsen existing exceedances.

Alternative 3 would lead to decreases in regional emissions of CO, NO_x, PM_{10}, $PM_{2.5}$, ROG, and SO_2, compared to the No Action Alternative. Because emissions would decrease under Alternative 3, the cumulative air quality impacts of Alternative 3 along with past, present, and reasonably foreseeable projects are not expected to lead to new exceedances of the CAAQS or NAAQS or to worsen existing exceedances.

Alternative 4 would have cumulative impacts similar to those of the Alternative 1 but with less intensity. Compared to the No Action Alternative, Alternative 4 would lead to increases in emissions of CO, NO_x, PM_{10}, $PM_{2.5}$, ROG, and SO_2. The emissions from Alternative 4 are expected to be relatively small compared to the emissions from past, present, and reasonably foreseeable projects. Consequently, the cumulative air quality impacts of Alternative 4 along with past, present, and reasonably foreseeable projects are not expected to lead to new exceedances of the CAAQS or NAAQS or to worsen existing exceedances.

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