BAY AREA AIR QUALITY MANAGEMENT DISTRICT

FINAL STAFF REPORT
Proposed New Regulation 13: Climate Pollutants, Rule 5: Industrial Hydrogen Plants and Proposed Amendments to Regulation 8, Organic Compounds, Rule 2: Miscellaneous Operations

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STAFF REPORT

Proposed Regulation 13: Climate Pollutants, Rule 5: Industrial Hydrogen Plants

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I. EXECUTIVE SUMMARY

Overview

In support of the State of California's mandates to reduce greenhouse gas (GHG) emissions, including short-lived climate pollutants, the Bay Area Air Quality Management District (BAAQMD or Air District) adopted a policy goal of reducing Bay Area GHG emissions to 40 percent below 1990 levels by 2030, and 80 percent below 1990 levels by 2050. Methane is a potent and short-lived climate pollutant; its global warming potential is 34 times greater than that of carbon dioxide on a 100-year time horizon and 86 times greater than that of carbon dioxide, when compared on a 20-year time horizon.[1,2] Methane represents the second largest emissions of GHGs in the Region, after carbon dioxide. In 2015, all methane sources located within the Air District emitted an estimated 10 million carbon dioxide equivalent metric tons, which is about 10 percent of the Bay Area's GHG inventory. The sources of methane emissions include stationary sources such as landfills, wastewater treatment facilities, refineries, natural gas production and distribution systems; mobile sources such as cars and trucks; and natural sources such as wetlands. Reducing emissions of short-lived climate pollutants, including methane, can have a dramatic effect on climate change in the near term as their atmospheric lifetime is much less than longer-lived GHGs, such as carbon dioxide. These climate pollutants are estimated to be responsible for roughly 40 percent of the current net climate forcing effect.[3i] Given the importance of controlling methane, the Air District developed a comprehensive Basin-wide Methane Strategy as part of its 2017 Clean Air Plan to better quantify and reduce the Region's methane emissions.

Summary of the Proposal

This staff report provides the technical support for the adoption of Proposed Regulation 13: Climate Pollutants, Rule 5: Industrial Hydrogen Plants (Rule 13-5), the first rule proposed as part of this Basin-wide Methane Strategy. Rule 13-5 is designed to reduce methane and other organic compounds—referred to as "total organic compounds"—from industrial hydrogen plant operations. The Proposal will require that, within six years from adoption, each atmospheric vent at an industrial hydrogen plant meet a combined emission standard for total organic compounds of 15 pounds per day <u>and</u> 300 parts per million by volume (ppmv), except for deaerator and carbon dioxide vents.

Proposed Rule 13-5 also provides an alternative compliance option. In lieu of complying with the atmospheric vent emission standard, an affected facility could opt to reduce the overall emissions of methane and other GHGs by 90 percent via an approach approved by the Air District. The measures undertaken to achieve these emissions reductions would be contained in an Alternative Compliance Plan prepared by the owner or operator of an industrial hydrogen plant opting to comply with Proposed Rule 13-5 through this option. It should be noted that only the hydrogen plants at PBF Energy (PBF) and Valero refineries are anticipated to require modifications to comply with the emission standards of the proposal and that the three other Bay Area refineries

[1] Based on the 20-year global warming potential reported for methane in the Intergovernmental Panel on Climate Change Fifth Assessment Report.

[2] Unless otherwise stated, this report uses the 20-year global warming potential (GWP) of 86 when calculating the carbon dioxide equivalent of methane emissions since the emission reduction actions being considered are within that time frame.

[3] Forster P., et al. (2007) Changes in Atmospheric Constituents and in Radiative Forcing, in Solomon S. et al. (2007) Climate Change 2007: Physical Science Basis, Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, Figure 2.21.

would not be impacted by the emission standards. Other requirements of Proposed Rule 13-5 may affect operations at industrial hydrogen plants at the other Bay Area refineries.

Staff is proposing to exempt sources that are subject to the atmospheric vent emission standard of Rule 13-5 (Section 13-5-301) from the requirements of Regulation 8 Rule 2: Miscellaneous Operations (Rule 8-2). This is because the vent emissions standard contained in Proposed Rule 13-5 is more stringent than the general emission standard contained in Rule 8-2, which only addresses organic compounds excluding methane. Facilities complying with Rule 13-5 through the alternative compliance option would remain subject to Rule 8-2 because this option applies to only methane.

Staff is also proposing amendments to Rule 8-2 to allow for alternative test methods to ensure that facilities that process non-petroleum products utilize the appropriate test methods for the materials that are being processed. This additional amendment to Rule 8-2 is being made at this time to be consistent with other recently amended rules and is unrelated to Proposed Rule 13-5.

Proposed Rule 13-5 includes reporting requirements for owners or operators to notify the Air District of hydrogen plant atmospheric venting occurrences when total organic compound emissions exceed 15 pounds per day and the concentrations exceed 300 ppmv measured as methane on a dry basis.

The operator of an industrial hydrogen plant subject to the Proposed Rule 13-5 would have to monitor and record all parameters necessary to demonstrate compliance with the provisions contained in the standards section of the rule. Hydrogen plant atmospheric vents would be required to have flowrate meters installed. Operators of hydrogen plant deaerator vents and carbon dioxide scrubbing vents would have to install flowrate meters, recorders, and sampling ports, and must monitor total organic compound emissions. Because atmospheric venting from a pressure swing absorption unit that is properly maintained and operated should never exceed the total organic compound atmospheric vent emission standards of Proposed Rule 13-5, the owner or operator of a hydrogen plant with a pressure swing absorption vent would not be required to maintain emission records from the pressure swing absorption vent unless the unit malfunctions, which would likely lead to an exceedance of the vent emissions standards.

Emissions and Emissions Reductions

Air District staff developed a methane emissions inventory for Proposed Rule 13-5 based on a survey of industrial hydrogen plant operators that provided information spanning six years of operations. A methane emissions inventory of approximately 2,555 metric tons per year (based on a three-year average for years 2016, 2017, and 2018) is used as the basis for emission reductions and cost effectiveness for the purposes of this rule. If approved and fully implemented, staff estimates that Proposed Rule 13-5 would reduce methane emissions from hydrogen plants by 2,281 metric tons in a typical year; this will result in at least a 90 percent reduction in GHG emissions from hydrogen production facilities. The anticipated emission reductions resulting from the adoption of this rule will make progress toward the achievement of the goals of the Air District's Methane Strategy.

Economic Impacts

Costs and Incremental Cost Effectiveness: Staff estimated the annualized cost of compliance for the two facilities that would most likely have to install control equipment: the industrial hydrogen plants associated with the PBF and Valero refineries. Staff determined the total annualized cost to reduce total organic compound emissions from hydrogen plant operations with flares at each of the hydrogen plants associated with PBF and Valero will be $15.5 million dollars. For the purposes of the economic and environmental analysis, staff assumed that emissions would be controlled with flares. Flares are less costly than some other methods, but there are several other control methods that would comply with the proposed rule. Table ES-1 summarizes the estimated annualized costs, emissions reductions, and cost effectiveness for Proposed Rule 13-5. Staff determined that it would be cost effective for affected sources to comply with the emission requirements of Rule 13-5.

Table ES-1
Annualized Costs, Emissions Reductions and Cost Effectiveness for Methane

Facility	**Annualized Costs** ($ millions)	**Methane Emissions Reductions** (metric tons/year)	**CO_2e Emission Reductions 20-yr Time Horizon** (metric tons/year)	**Cost Effectiveness 20-yr Time Horizon** ($/$CO_2e$ metric ton)	**CO_2e Emission Reductions 100-yr Time Horizon** (metric tons/year)	**Cost Effectiveness 100-yr Time Horizon** ($/$CO_2e$ metric ton)
PBF	$8.6	909	78,174	$111	30,906	$280
Valero	$6.8	1,372	117,965	$58	46,637	$147
TOTALS	**$15.5**	**2,281**	**196,139**	**$79**	**77,543**	**$200**

* CO_2e: Carbon Dioxide Equivalent

In conducting the incremental cost-effectiveness analysis, staff compared the costs of compliance between that of installation of a flaring system and the use of a pressure-swing adsorption system that would achieve hydrogen purities in excess of 99.99 percent. This method is commonly used in hydrogen plants in the Bay Area. For the incremental cost effectiveness analysis, it was assumed that 100 percent of the methane contained in the hydrogen vent gas would be controlled. This would amount to a reduction of 2,523 metric tons/year of total organic compound emissions in a typical year. Staff estimated that the total capital cost to install a pressure swing adsorption system at both Valero and PBF were $307 million. The total annualized costs for the two pressure swing adsorption systems ranged from $59 to $61 million per year.

The incremental cost between two options is calculated as follows:

$$\frac{\$60.7\text{ million} - \$15.5\text{ million}}{(2{,}523 - 2{,}281)\text{ metric tons}} = \frac{\$45.2\text{ million}}{242\text{ metric tons}} = \mathbf{\$186{,}518\text{ per metric ton}}$$

Socioeconomic Impacts: Applied Development Economics of Walnut Creek, California prepared a socioeconomic analysis of Proposed Rule 13-5. This analysis is based on the costs of compliance with the rule, and is attached to this report as Appendix D. It would cost the industrial hydrogen production industry between $15.3 and $17.7 million per year to comply with the total organic compound emission limits, with costs for individual facilities ranging from $0.2 to 8.6 million per year. The cost for facilities that require emissions control and monitoring equipment ranged from $6.1 to $8.6 million per year. The cost for facilities that already comply with the Rule and only require monitoring equipment ranged from $0.2 million to 1.1 million per year. The upper range of costs expressed as a percent of annual income for individual facilities range between 0.2 to 11.3 percent.

For the Air Liquide hydrogen plant, which is a smaller facility, the annualized monitoring costs represent 7.6 to 11.3 percent of estimated net income. The upper end of the cost estimate range exceeds the 10 percent threshold of significance for the Air Liquide plant. While the high-end estimate should be considered as a worst-case scenario, the costs may be substantially lower than this estimated value. Nevertheless, the potential impacts associated with costs above the threshold of significance were estimated based on this high-end estimate. Of particular concern under the Health and Safety Code would be the potential for lost jobs at the plant to compensate for the impact to net income. At $270,000 per year, the upper end impact is about $30,000 above the 10 percent impact threshold. The average salary and benefits for workers in the gas production industry in California is $92,300. The maximum cost impact exceeding the threshold, therefore, represents less than a third of the cost for one employee at Air Liquide. We conclude that it is unlikely the company would choose to reduce employment to mitigate this impact.

Potential Cost Mitigation: One potential cost mitigation is that the GHG emissions reductions realized as a result of the implementation of Rule 13-5 may be eligible to be traded as carbon credits on the national and international markets. The market value of carbon credits fluctuates, but the most recent data from the California Air Resources Board indicates that the median price for a carbon credit ranged from $15.32 (offset) to $24.62 (allowance).[ii] [4] If applied to the anticipated reduction of 2,281 metric tons of methane (equivalent of 77,558 metric tons of carbon dioxide based on a 34 GWP for methane), a carbon credit value ranging from $1.3 million (offset) to $2.1 million (allowance) could be realized. Depending on the allowable cap for each facility, the affected companies may be able to monetize a portion of their carbon reductions under this program.

Social Cost of Greenhouse Gases: Failure to reduce emissions of GHGs imposes ongoing costs on society in terms of contributing to climate change and the long-term effects it will have on a wide range of human activities and the built and natural environment. The social cost of carbon attempts to measure the economic harm caused by climate change based on the dollar value per ton of carbon dioxide emissions.[iii] When implemented at Bay Area refineries, Proposed Rule 13-5 will eliminate about 2,281 metric tons per year of methane emissions. Using the alternate discount rate assumptions cited in the most current Interagency Working Group (IWG)[5] report, the annual social cost of carbon reduction would range from $1.7 million to $9.8 million.[iv] The anticipated costs of compliance for Rule 13-5 range from $15.3 million to $17.7 million per year.

Environmental Impacts

[4] An offset carbon credit means that the GHG emission will be offset by a mitigating project, such as reforestation or agricultural projects. An allowance carbon credit functions more like a permit to emit.

[5] The legal rationale for including SCC in socioeconomic impact studies of new regulations dates back to a 2007 court decision in which the US Court of Appeals, Ninth Circuit ruled that federal agencies needed to account for the cumulative effects of GHG emissions in cost-benefit analyses. The Interagency Working Group (IWG) was formed as a result of a 2007 court decision and has issued and updated social cost of carbon estimates since 2010. Agencies are required, to the extent permitted by law and where applicable, “to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs.”

As required by the California Environmental Quality Act, the Air District prepared an Initial Study and Draft Environmental Impact Report (EIR) to analyze potential environmental impacts from the Proposed Rule 13-5. The Draft EIR was published on January 21, 2022, for review and comment. GHG impacts were found to be beneficial and aesthetic impacts during the construction of additional pollution control equipment were found to be less than significant. Hydrogen plants at two refineries are expected to need additional control technology to comply with Proposed Rule 13-5: the Valero Refinery in Benicia and the hydrogen plants that provide hydrogen to the PBF Refinery in Martinez. Compliance options could include installing flare technology to control total organic compound emissions; installing a gas recovery system; or implementing an Alternative Compliance Plan. The impacts associated with an Alternative Compliance Plan may vary but would be expected to include the addition of piping, valves, and flanges and similar equipment to reroute gas streams within the facility. Worst case emissions of pollutants associated with operation of control equipment were found to be less than significant except for emissions of oxides of nitrogen (NOx) which may be significant should a flare be utilized as a control option by both affected facilities. Thus, construction, operational and cumulative air quality impacts would be potentially significant. NOx emissions would be significantly less if the alternative compliance option were utilized.

Air District Impacts and Cost Recovery

Staff estimated the additional Air District resources necessary to implement Proposed Rule 13-5. The Engineering Division would need two additional full-time equivalents (FTEs); the Compliance and Enforcement Division would need one additional FTE; and the Meteorology and Measurements Division would need one FTE for a total of four FTEs. The Air District will evaluate whether Regulation 3: Fees will need to be updated to ensure consistency and cost recovery when incorporating the increased administrative time that will be necessary to process applications to comply with the provisions of the Proposed Rule 13-5.

Statutory Findings and Recommendation

Air District staff determined that the Proposed Rule 13-5 and rule amendments meet the required statutory findings of necessity, authority, clarity, consistency, non-duplication, and reference. Considering these findings, staff recommends that the Board of Directors:

1) Certify the Final Environmental Impact Report and adopt an accompanying Statement of Overriding Considerations; and

Adopt Proposed Rule 13-5: Industrial Hydrogen Plants and proposed amendments to Regulation 8, Rule 2: Miscellaneous Operations.

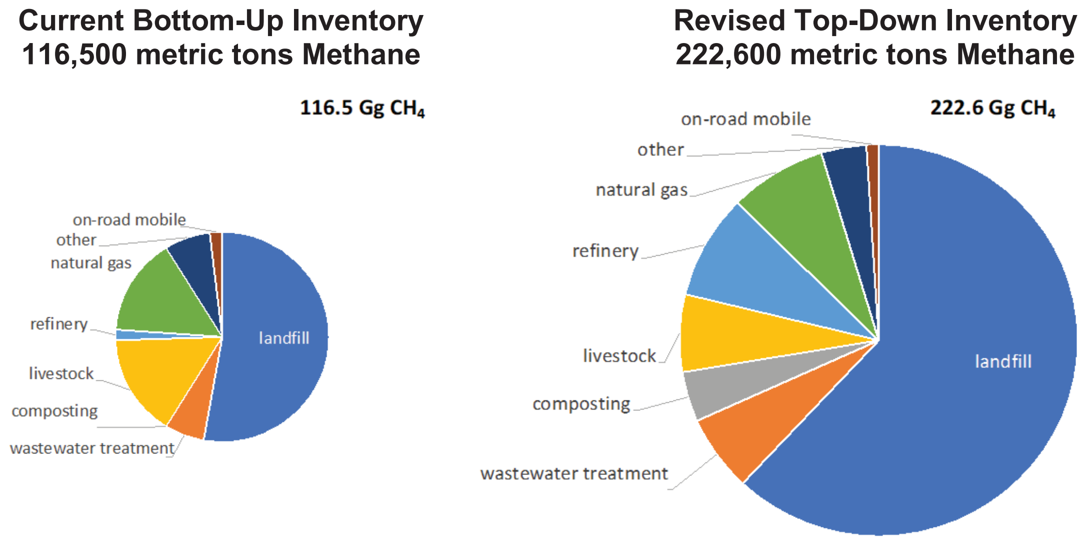
II. BACKGROUND

A. Methane

Methane is an odorless, colorless gas under normal conditions. It is a chemical compound of four hydrogen atoms attached to a single carbon atom with the chemical formula CH_4. It is the simplest alkane, and the main constituent of natural gas. Methane is also a powerful super-greenhouse gas (GHG). It is 86 times more potent than carbon dioxide (CO_2) when compared on a 20-year time horizon (or 34 times on a 100-year basis) and it has a much shorter atmospheric lifespan of 12 years (vs. 20 – 200 years). Due to these factors, actions to reduce methane emissions can provide significant and immediate climate benefits while CO_2 emissions are steadily reduced to achieve long-term climate stability. Curbing methane emissions would also reduce emissions of its co-pollutants, which can include key climate, criteria, and toxic pollutants, resulting in public health and (further) climate benefits.

Methane is the second leading GHG in the Bay Area Air District. In 2015, sources in the Air District emitted an estimated 10 million metric tons of CO_2 equivalent (MMT CO_2e), about 10 percent of the GHG inventory when calculated on a 20-year basis. According to a recent study commissioned by the Air District to evaluate its methane inventory,[v] three source categories represent approximately 84 percent of these emissions. These categories are mainly related to human activities; landfills are the largest source, accounting for 53 percent of these emissions, followed by livestock (16 percent) and natural gas production and distribution (15 percent). These emissions estimates carry a large uncertainty (50 percent or more), consistent with a recent study that suggests that methane emissions in the Air District's "bottom-up" inventory are 1.5 to 2 times lower than expected from top-down measurements.[vi, vii] This "methane gap" has been repeatedly observed for the United States and California regions, where top-down observations that account for ambient methane concentrations suggest that there are large, unaccounted methane emissions in bottom-up inventories. Figure 1 provides a comparison of the two inventories and the major contributors.

Figure 1:
Draft 2020 Top-Down and Bottom-Up Bay Area Methane Emissions Inventory [vii]



Updates to the methane inventory from the top-down indicate that methane emission may be over twice as much as indicated from the bottom-up approach. Air District staff are continually evaluating the methane emissions inventory to better understand this difference.

Based on a top-down approach, methane emissions from refineries are estimated to be at least two thousand metric tons per year.[6] Although methane emissions from refineries are estimated to constitute less than two percent of the anthropogenic methane emitted in the Bay Area, preliminary study findings indicate that fugitive methane emissions from refineries may be significantly higher than bottom-up inventory estimates.

B. Industry Description

1. Hydrogen Properties

Hydrogen is both the most abundant substance in the universe and the simplest element there is, consisting of just one proton and one electron. However, it doesn't typically exist on earth by itself, and must be produced from compounds that contain it such as water and methane. Hydrogen is a colorless, odorless, and non-toxic gas at standard temperature and pressure (normal conditions). Hydrogen gas is highly flammable, can serve as an energy carrier, not an energy source, and is used in an extensive range of industrial applications.[viii]

2. Hydrogen Production Processes

As noted previously, hydrogen is non-toxic, has no global warming potential, and is generally not considered an air pollutant, but the primary methods of industrial hydrogen production may result

[6] Hydrogen plant owners and operators reported to the Air District average total yearly methane emissions of 2,555 metric tons per year (based on a three-year average for years 2016, 2017, and 2018).

in emissions of methane and other hydrocarbons. Biological and electrolytic processes generally do not result in significant emissions, whereas thermochemical processes utilizing methane or other hydrocarbons have greater potential for emissions of methane and other organic compounds. Electrolytic processes convert water to hydrogen and oxygen, while thermochemical processes harvest hydrogen from hydrocarbons resulting in residual amounts of hydrocarbons and methane in the hydrogen product. Hydrogen is currently produced by a number of different well-established electrolytic and thermochemical processes, and many others are under development given the potential for hydrogen as a clean energy carrier.

a. Biological and Electrolytic Processes

Biological processes of hydrogen production include microbial biomass conversion and solar photobiological methods. Microbial biomass conversion utilizes microorganisms, such as bacteria to breakdown organic matter to produce hydrogen through a fermentation process, and microbial electrolysis cells use microbes combined with a small amount of electric current to produce hydrogen. Solar photobiological systems use microorganisms – such as green microalgae of cyanobacteria – along with sunlight to turn water and sometimes organic matter into hydrogen. Research into these technologies is in the early stage but they have long-term potential for sustainable hydrogen production with low environmental impact.

Hydrogen production by means of electrolysis promises a carbon-free means of hydrogen production from renewable sources by using electricity to split water into hydrogen and oxygen. This process occurs in an electrolyzer which functions like a fuel cell and consists of an anode and a cathode separated by an electrolyte. Hydrogen production by means of electrolysis requires electricity and today's grid electricity is often generated using technology that results in GHG emissions and is energy intensive. The US Department of Energy and others are working to bring down the cost of renewable electricity production and to develop solar electrolysis processes that all have potential but are far away from commercial availability.

b. Thermochemical Processes

Some thermal processes use heat in combination with closed chemical cycles to produce hydrogen from feedstocks such as water and others use the energy from natural gas, coal, or biomass to release hydrogen from their molecular structure. Thermochemical water splitting is a long-term technology pathway that uses high temperatures from concentrated solar power and chemical reactions to produce hydrogen with potentially no GHG emissions. Biomass gasification converts organic material at high temperatures with a controlled amount of oxygen or steam without combustion to form carbon monoxide, hydrogen, and CO_2. The carbon monoxide then reacts with water to form CO_2 and more hydrogen. Gasification plants for biofuels are being built and operated in the United States but none are currently on the horizon in the Bay Area. Reforming processes convert organic fuels (either natural gas, petroleum based, or biomass derived liquids) into hydrogen by reactions with high temperature steam at high pressures sometimes in the presence of a catalyst. These processes use either a steam reforming reaction or partial oxidation to produce carbon monoxide and hydrogen followed by a water-gas shift reaction to convert the carbon monoxide to CO_2 and additional hydrogen. In general, biomass derived fuels are composed of larger molecules than petroleum or methane, making them more difficult to reform. Research is needed to identify better catalysts and to reduce the cost of biomass derived liquids as well as capital, operation, and maintenance costs associated with biomass reforming processes.

c. Hydrogen Production in Petroleum Refining Processes

i. Steam-methane Reforming

As the demand for hydrogen increases, it is economically advantageous for refineries to produce their own hydrogen, instead of purchasing it. In some instances, refineries pay an independent third party to produce hydrogen in a facility either contiguous to or located within the refinery property. The production and distribution of hydrogen within refineries is all part of an integrated system that is referred to as a hydrogen plant for the purposes of this report and the development of Proposed Rule 13-5. A refinery may incorporate one or more hydrogen plants into its hydrogen distribution network that delivers hydrogen to processes (or "consumers" covered in the previous section of this report) that use hydrogen.

The majority of hydrogen produced at a refinery comes from the hydrogen plant steam-methane reforming processes (see Figure 2 for a depiction of a typical steam methane reformer). The primary process of the plant consists of a steam-methane reformer and additional hydrogen purification steps that are integrated with all the processes in need of hydrogen throughout the refinery.

Hydrogen production via steam-methane reforming generally includes four steps:

1) Purification of the feed gas (usually natural gas or refinery fuel gas, although other sources of hydrocarbon gases may be used depending on economic conditions) prior to reforming;

2) Steam and methane are reformed in the furnace box to convert most of the methane gas to hydrogen via the following chemical reaction:

$$CH_4 + H_2O \rightarrow CO + 3\ H_2$$

3) Temperature shift reaction (also called the water shift reaction) that converts some of the remaining carbon monoxide to hydrogen; and

$$CO + H_2O \rightarrow CO_2 + H_2$$

4) Final product purification step.[7]

Hydrogen gas containing total organic compounds may be generated at a refinery process unit by other means than steam methane-reforming process outside of the industrial hydrogen plant. Depending on the configuration of the petroleum refinery, the hydrogen gas generated from a refinery process unit can be routed to an industrial hydrogen plant for compression and distribution. For the purposes of Rule 13-5, an industrial hydrogen plant is defined as a comprehensive operation that includes all equipment used for hydrogen production by use of steam-methane reformation, hydrogen compression operations, hydrogen delivery and hydrogen distribution systems.

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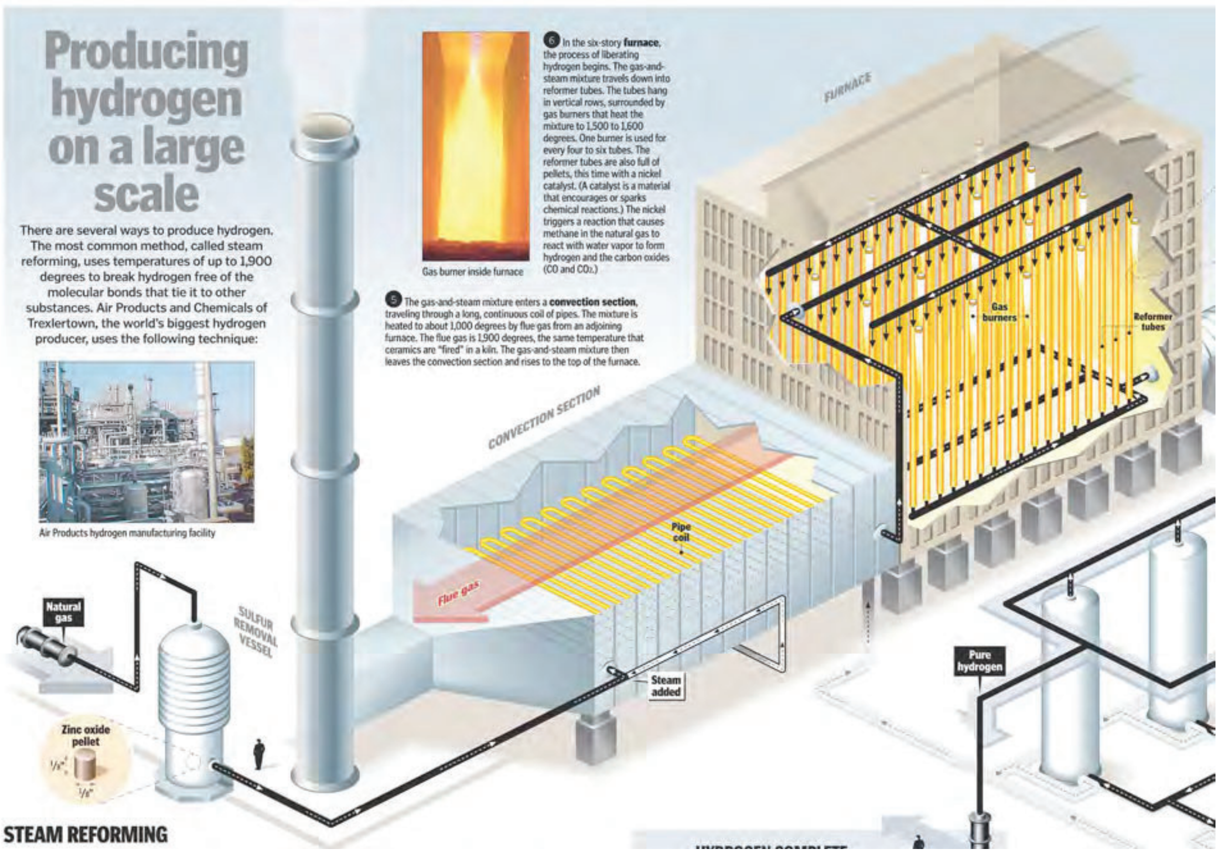
[7] While the chemical reaction equations above imply the full conversion of methane and carbon monoxide to carbon dioxide and water, in reality, these reactions never fully convert all of the reactant to the products; under these circumstances, this reaction can result in up to four to six percent methane in the product hydrogen.

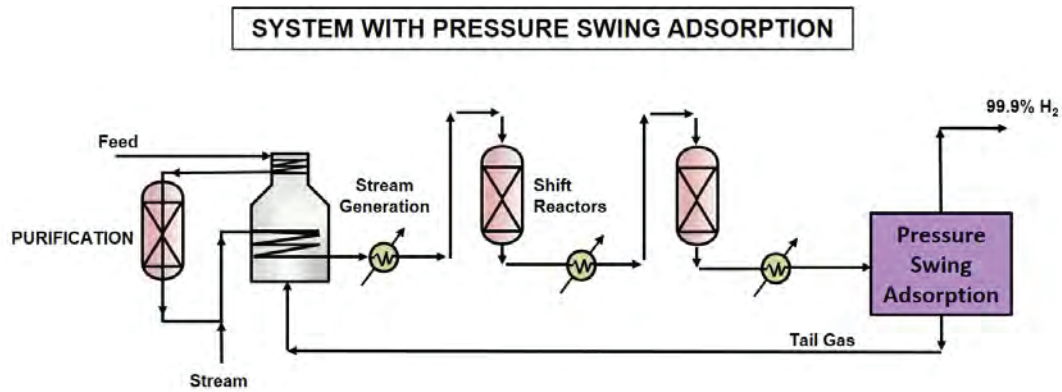
Figure 2: Depiction of the interior of a typical steam-methane reformer



Source: Air Products

Many refinery hydrogen plants utilize pressure swing adsorption to remove methane and other contaminants from the hydrogen production stream. The pressure swing absorption process produces a higher purity of hydrogen required by certain refinery applications. Prior to distributing hydrogen into the refinery hydrogen network, most hydrogen plants use a pressure swing adsorption process for the final purification step at the end of the steam-methane reforming operation to produce an ultra-pure hydrogen with a minimum purity of 99.99 percent concentration in the gas stream from what was previously a concentration ranging between 95 percent to 97 percent. A byproduct of the pressure swing adsorption process, referred to as “tail gas” is impure hydrogen gas that does not meet specifications for refinery hydrogen consumers and is routed back to the steam-methane reformer as fuel and can contain methane concentrations ranging between 15 percent and 20 percent.

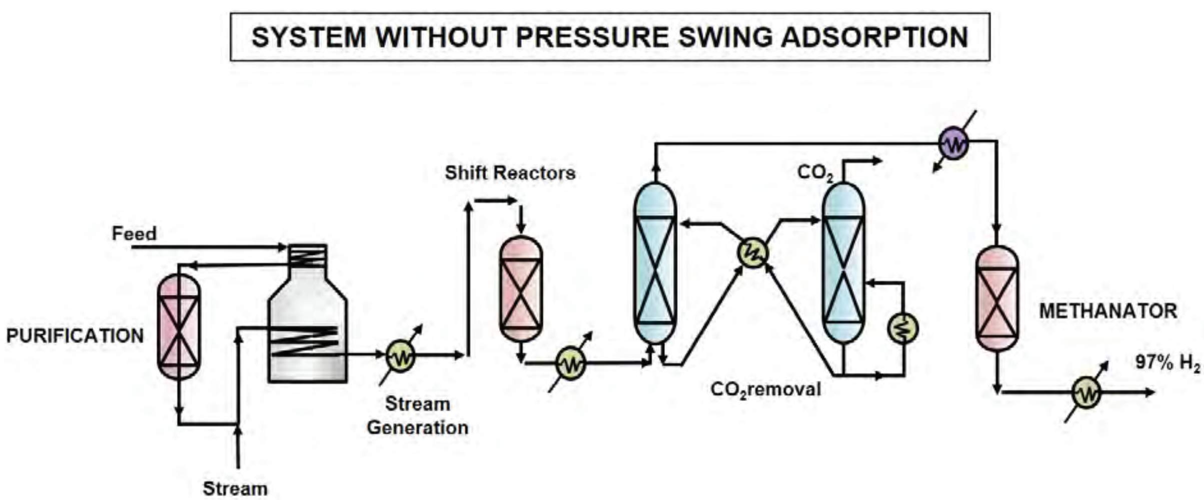
Figure 3: Flow diagram of a hydrogen plant with pressure swing adsorption purification



Source: Air District Staff

By contrast, a hydrogen plant that does not use a pressure swing adsorption process produces a less pure hydrogen stream that contains a higher amount of total organic compounds, including methane—generally between four and six percent.

Figure 4: Diagram of a Hydrogen Plant Without Pressure Swing Absorption Purification



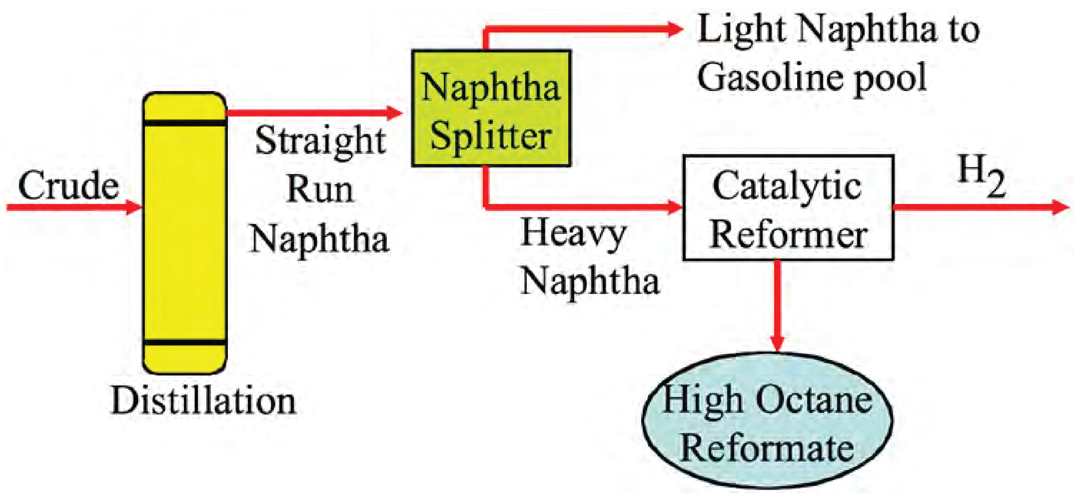
Source: Air District Staff

Methane emissions occur when impure hydrogen gases containing total organic compounds are purposely vented from atmospheric vents (sometimes referred to as process vents) located at various junctures throughout the hydrogen plant. Most atmospheric venting of impure hydrogen gas in Bay Area refineries occurs within the hydrogen plant steam-methane reforming processes described in Figure 3 and Figure 4 above. For most facilities, hydrogen gas is only vented when necessary for safety-related reasons such as refinery startups, shutdowns, emergencies, malfunctions, trips, or process upsets.[ix] A total of nine operational hydrogen plants are associated with Bay Area refineries; two of the hydrogen plants—one at the Valero refinery and the other at the PBF Energy (PBF) refinery—regularly vent hydrogen gas from various atmospheric vents during normal operations. Most hydrogen plants typically have three to four atmospheric vents located in the steam-methane reforming process unit and each vent is used to release impure hydrogen gas under specific operational conditions.

ii. Catalytic Reforming Units

Catalytic reforming units, sometimes referred to as naphtha reforming units, function as part of a petroleum refinery's secondary method of producing hydrogen (see flow diagram in Figure 5 below). The primary purpose of the catalytic reforming process is to convert heavy naphthas distilled from crude oil into lighter components. During this chemical process, heavy naphthas that typically have low octane ratings are reformed into lighter naphthas with higher octane ratings. Often referred to as reformates, light naphthas are used as blending stocks for high-octane gasoline. As a byproduct of the naphtha reforming process, hydrogen is produced and used in nearby hydrogen consumers.

Figure 5: Flow Diagram Schematic of a Refinery Catalytic Reforming Process



Source: Dr. Semih Eser via https://www.e-education.psu.edu/fsc432/content/catalytic-reforming.

Although the hydrogen gas from catalytic reforming unit contains a greater concentration of total organic compounds than that of hydrogen gas from steam-methane reforming operations, the relative amount of total organic compound mass emissions from catalytic reforming units is less than the amount emitted from hydrogen plants due to the difference in volumes and flowrates. The total organic compound emissions from a hydrogen plant can range between 2,000 pounds per day to 40,000 pounds per day, whereas total organic compound emission contribution from a catalytic reforming unit can range from 600 pounds per day to 700 pounds per day.

Hydrogen gas generated from catalytic reforming unit can either be routed to the hydrogen plant which is then combined with hydrogen gas from steam-methane reformation operation or be routed directly to the hydrogen consumers. If the hydrogen gas from catalytic reforming unit is routed to the hydrogen plant for further processing, any venting that occurs from the combined hydrogen gas stream will be subject to Proposed Rule 13-5 since the venting will likely occur within the confines of an Industrial Hydrogen Plant as defined in the rule.

3. Hydrogen Consumers

Currently, approximately 10 million metric tons of hydrogen is produced per year in the United States, primarily for use in petroleum refining and ammonia production.[x] In the San Francisco Bay Area, hydrogen production is primarily limited to use in petroleum refining. There is also great potential for hydrogen use across multiple sectors for near-zero emissions in other chemical and industrial process applications, and integrated clean energy systems to power data centers, ports, manufacturing, and transportation.

In the petroleum refining industry, hydrogen is used extensively in the processing of crude oil into refined fuels such as gasoline and diesel. Hydrogen is consumed in desulfurization units to remove contaminants from fuels and feedstocks, and hydrogen is used in the refinery fuel system. As petroleum refinery product specifications become more stringent to meet environmental requirements, refinery demand for hydrogen has continually increased to supply the refinery hydrogen consumers (process units). The two primary hydrogen consumers in Bay Area petroleum refineries are processes known as hydrotreating and hydrocracking.

a. Hydrotreating

Hydrotreating is a process in which hydrogen is added to a hydrocarbon gas stream (often referred to as a feedstock) over a bed of catalysts typically containing molybdenum with nickel or cobalt, at an intermediate temperature and pressure, as well as other process-specific operating conditions. The purpose of hydrotreating is to remove sulfur and other undesirable compounds, such as unsaturated hydrocarbons and nitrogen, from the hydrocarbon stream.[xi] Sulfur will "poison" (shorten the lifespan of) catalysts used in hydrocarbon processing applications so refineries take measures to protect catalysts to extend their operating longevity as long as possible. During hydrotreating, sulfur compounds react with hydrogen to form hydrogen sulfide, while nitrogen compounds react to form ammonia. Unsaturated hydrocarbons, such as aromatics and olefins, are saturated by the hydrogen and lighter products are created. The final result of the hydrotreating process is the substantial reduction of sulfur and other contaminants from the original feedstock.

b. Hydrocracking

Hydrocracking produces lighter hydrocarbon molecules with higher value for diesel, aviation fuel and petrol fuel from long-chain hydrocarbons. In this process, heavy gas oils, heavy residues or similar boiling-range heavy distillates are reacted with hydrogen in the presence of a catalyst at high temperature and pressure. The heavy feedstocks molecules are broken (or "cracked") into light or middle distillate products—for example, naphtha, kerosene, and diesel—or base stocks for lubricants. For some refineries, the hydrocracker unit is the top hydrogen consumer. Hydrogen is the key component that enables the hydrocracking process to reduce the product boiling range appreciably by converting the majority of the feedstock to lower-boiling, more desirable products.[xii]

4. Pollutants and Emissions Sources

Proposed Rule 13-5 would address total organic compound emissions from hydrogen plant atmospheric vents. A noncomprehensive list of hydrogen plant atmospheric vents includes deaerator vents (which remove dissolved gasses from liquids), CO_2 scrubbing vents (which remove CO_2 from gas streams), catalytic reforming unit vents, and vents used to purge gases during startup, shutdown, and malfunction conditions. Most hydrogen plants are designed with multiple atmospheric vents—usually a total of three to four vents located in strategically engineered points starting near the front-end of the plant where the steam-methane reforming process occurs, to the back end of the plant where final treatment of hydrogen gas occurs prior to being routed to the hydrogen distribution network.

Typically, after hydrogen gas is produced in the hydrogen plant, it is routed from the plant to refinery hydrogen consumers such as hydrocrackers and hydrotreaters. For safety reasons, operational events such as hydrogen plant and/or refinery shutdowns, malfunctions, trips, upsets, and power outages may require immediate evacuation of pressurized hydrogen gas that may contain total organic compounds. Such events usually occur a couple of times per year at most; however, when they do, emissions of methane and other organic compounds can be quite substantial. Total organic compound emissions can also occur during the hydrogen plant startup and shutdown processes. In the case of one facility, a single exhaust stack located outside of the hydrogen plant vents, emitted almost continuously, a mixture of hydrogen plant gas and naptha reforming unit gas containing a mixture of hydrogen gas and organic compounds. Another Bay Area refinery vents total organic compounds from their hydrogen plants to atmosphere on a frequent basis. In both cases, such emissions are a result of system design as opposed to malfunctions or emergencies.

C. Regulatory History

Hydrogen plant organic compound emissions were historically subject to federal permitting requirements, Air District permitting requirements and Air District organic rules as listed below. Methane emissions from hydrogen plants are not currently regulated other than as equipment leaks, and methane emissions from equipment leaks are insignificant in comparison to mass emissions vented from hydrogen plants. There is no history of control for vented methane emissions from hydrogen plants.

1. Air District Rules / Regulations

Currently, the Air District does not have a rule specifically addressing “vented” methane emissions from hydrogen production operations and associated distribution systems. However, the following four Air District regulations control organic emissions from various hydrogen plant operations:

- Regulation 8: Organic Compounds, Rule 2: Miscellaneous Operations (Rule 8-2) is a backstop rule that limits precursor organic compound emissions (excluding methane) from various operations not addressed in other Air District rules. Rule 8-2 currently addresses hydrogen plant production operations, with a concentration emission limit of 300 ppm and a mass emission limit of 15 pounds per day for total carbon (organic compounds excluding methane) on a dry basis.
- Regulation 8: Organic Compounds, Rule 10: Process Vessel Depressurization limits emissions of organic compounds from the depressurizing and opening of process vessels at petroleum refineries and chemical plants.
- Regulation 8: Organic Compounds, Rule 18: Equipment Leaks limits the emissions of total organic compound “leaks” from a wide variety of equipment such as valves, connectors, pumps, compressors, and other equipment located at petroleum refineries (including hydrogen plants), chemical plants, bulk plants, and bulk terminals. As defined

in the rule, total organic compounds include methane, so this rule addresses hydrogen plant methane emissions to some extent.

- Regulation 8: Organic Compounds, Rule 28: Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants limits episodic emissions of organic compounds, excluding methane, from pressure relief devices on equipment handling gaseous organic compounds at petroleum refineries, including hydrogen plants.

Recently, the Air District revised the definition of Petroleum Refinery to address the conversion of some facilities from crude oil to renewable feedstocks for manufacturing eventual products.

2. State Regulations

At the State level, the Mandatory Reporting of Greenhouse Gas Emissions program requires petroleum refineries to report annual GHG emissions generated by various refining operations to the California Air Resources Board.[xiii] Although California regulates GHG emissions from petroleum refineries and other large sources via California's Cap-and-Trade program, methane-specific emission reductions are not required.[xiv]

3. Federal Regulations

There are no substantive federal air quality regulations that address methane emissions from petroleum refining hydrogen plants. Refineries report annual GHG emissions to the United States Environmental Protection Agency as required by the Greenhouse Gas Reporting Program.[xv]

D. Technical Review of Control Technologies

Vented methane emissions from industrial refinery hydrogen plants are not currently subject to emission limits, so they are usually uncontrolled unless a hydrogen gas stream contains toxic or volatile organic compounds which are then subject to emission limit requirements of an Air District regulation. Not all volatile organic compound abatement technology will capture or control methane emissions. Activated carbon is commonly used to extract volatile organic compounds from gaseous streams via an adsorption process that traps volatile organic compound molecules onto the surface of carbon molecules while the remainder of the gaseous stream including methane continues to flow through the carbon bed.

1. Flares

One example of control technology that reduces methane as a co-benefit of reducing other air contaminants is a flare. Refinery flares are primarily used as a safety device, not as control equipment, to reduce gases that often may include a mixture of gases including volatile organic compounds, toxic air contaminants, oxides of nitrogen, sulfur oxides and methane. Nevertheless, two Bay Area refinery and one third-party operator use flare systems dedicated to control hydrogen gas emissions, and thus, any associated methane or other organic compound emissions. If operated correctly, refinery flares destroy total organic compound emissions at a minimum 98 percent control efficiency.

2. Thermal Oxidizers

Thermal oxidizers are another example of control technology used to thermally destroy industrial vapor streams. They are commonly used in refineries and chemical plants to control hydrocarbon-based vapors. Typically, thermal oxidizers are available in four different types depending on a variety of operational factors. They include direct-fired, recuperative, catalytic, and regenerative thermal oxidizers. Thermal oxidizers can be used for planned atmospheric venting occurrences such as startups and some shutdowns; however, they generally cannot be used for unplanned events such as malfunctions, upsets, trips, and emergencies. Thermal oxidizers, when operated correctly, can achieve at a minimum 98 percent control efficiency.

3. Closed Loop Systems

A third method of controlling total organic compound emissions currently employed at two local refineries is a closed loop system. This system functions via flare headers, which capture hydrogen system gas streams, and reintroduces the recovered gas into the refinery's fuel gas system. When necessary, for safety-related reasons such as emergencies, malfunctions, unplanned shutdowns, upsets and trips in the refinery system, the flare header system sends recovered hydrogen gas, as part of a gas recovery mixture, to the flare for combustion, thus emitting two percent or less of the uncombusted methane component to atmosphere. The balance of recovered gas is used in the refinery fuel system. Less than two percent of flare header gas is emitted to the atmosphere post combustion. Flare headers, a collection system for refinery waste vapor streams, contains a mixture of refinery gases, including hydrogen gas. However, under normal operating conditions, this approach can achieve up to 100 percent control efficiency.

4. Pressure Swing Adsorption Technology

Although not technically considered a control technology, pressure swing adsorption technology can significantly reduce methane and other organic compound emissions. Pressure swing adsorption purification is a method of separating one or more gas species from a gaseous stream containing additional (desirable) gas species. Pressure swing adsorption is used in hydrogen production as a final purification step to separate hydrogen gas molecules from other (impure) gas molecules, such as methane, carbon monoxide and CO_2. Under continuous pressure, an adsorbent material targets gas with dissimilar adsorption properties as an effective way of extracting very pure hydrogen.[xvi] As depicted in Figure 6 of this report, tail-gas, a byproduct of the pressure swing adsorption process containing the removed impurities, can then be sent back to the steam-methane reformer as fuel for the steam-methane reforming process. Normally, pressure swing adsorption purification removes methane molecules from the hydrogen gas stream only at the back end of the steam-methane reforming process unit. Atmospheric venting prior to the pressure swing adsorption step contains methane and other air contaminants. Pressure swing adsorption technology results in virtually no total organic compound emissions during normal operations.

Figure 6: Image of several tanks containing the adsorbent material that comprise part of a pressure swing adsorption process

Source: https://www.petrosadid.com/fixed_equipment/process_package/pressure_swing_adsorption.php

III. PROPOSED NEW RULE AND AMENDMENTS

A. Description and Applicability

Section 13-5-101 – Description: The purpose of Proposed Rule 13-5 is to limit methane and other organic compound, defined as "total organic compound," emissions from industrial hydrogen plants using the steam-methane reformation process. All refinery facilities operating in the Air District utilize hydrogen produced through steam-methane reformation that they provide themselves or through a third party.

Section 13-5-102 – Applicability: Proposed Rule 13-5 applies to all industrial hydrogen plants utilizing steam-methane reformation and is not limited to those affiliated with refinery operations but applies to industrial hydrogen plants operating on their own or as part of refinery operations and third parties producing hydrogen servicing refinery consumers.

B. Exemptions

Section 13-5-103 – Exemption, Specific Operations: Proposed Rule 13-5 includes an exemption for specific hydrogen plant operations already subject to methane and/or organic compound emission requirements of existing Air District hydrocarbon rules, specifically Rules 8-5, 8-10, 8-18, and 8-28.

Section 13-5-104 – Limited Exemption, Deaerator Vents and Carbon Dioxide Scrubbing Vents: Proposed Rule 13-5 includes a limited exemption from the standards section of the rule for deaerator vents and CO_2 scrubbing vents. These vents are exempt from control requirements but are still subject to monitoring and recordkeeping requirements. Data from this monitoring and recordkeeping will aid the Air District in further development of a methane inventory from industrial hydrogen plants from which to evaluate and determine if emissions from these sources are significant. The Air District may determine at a future time that these emissions require controls through amendment of the rule.

Section 13-5-105 – Limited Exemption, Small Scale Industrial Hydrogen Plants: Small scale industrial hydrogen plants that are designed to produce less than 20 tons of hydrogen per day (7.6 million standard cubic feet per day) are exempt from Proposed Rule 13-5. However, this is provided that the owner and/or operator maintains records of annual hydrogen production and basis of this determination as required by Section 13-5-506.3. In the event that these records show the industrial hydrogen plant produces more than 20 tons per day on an annual average, then the facility is no longer exempt from the rule. This production level is roughly one quarter the capacity of the smallest hydrogen plant currently permitted to operate in the Air District.

C. Major Definitions

Proposed Rule 13-5 includes a few definitions that reference existing definitions in existing Air District Rules and several new definitions that are specific to industrial hydrogen plants. Major definitions include the following:

Section 13-5-201 – Alternative Compliance Plan: A document that identifies, among other things, sources, quantities, emissions, and emissions reduction measures that would be implemented to comply with the alternative methane and GHG emissions standard.

Section 13-5-202 – Atmospheric Vent: An opening where a hydrogen gas stream is discharged during hydrogen plant operations. Atmospheric vents include openings where gas streams are discharged directly to the atmosphere and excludes openings where gas streams are discharged to the atmosphere after being routed to a control device or a gas recovery device. Abated vents would require an Air District permit and so long as the abatement device operates within permitted parameters, it would not be subject to the emissions standards or monitoring requirements of Proposed Rule 13-5. For the purposes of this rule, an atmospheric vent may be physically located in any portion of an Industrial Hydrogen Plant. For the purposes of Proposed Rule 13-5, pressure relief devices, as defined in and subject to Regulation 8: Organic Compounds; Rule 28: Episodic Releases from Pressure Relief Devices at Petroleum Refineries and Chemical Plants, Section 8-28-210 are not considered atmospheric vents when operated as designed and properly maintained.

Section 13-5-203 – Carbon Dioxide Scrubbing Vent: The atmospheric vent from a device or process unit that adsorbs carbon dioxide from a gas stream.

Section 13-5-204 – Deaerator Vent: The atmospheric vent from a device that removes oxygen and other dissolved gases from liquids.

Section 13-5-205 – Effective Date: This definition is included to ensure that monitoring and recordkeeping begins upon adoption of Proposed Rule 13-5, but emission limits will go into effect no later than three years after Air District permits are issued as required by Section 13-5-401 and 13-5-405. This timeline allows facilities to undertake all necessary construction and permitting actions necessary to control emissions as required by the Rule.

Section 13-5-206 – Global Warming Potential: Proposed Rule 13-5 provides a means of comparison of potential climate change effects associated with different GHGs. The comparison utilizes a 100-year timeframe consistent with Schedule T of Air District Regulation 3: Fees.

Section 13-5-207 – Greenhouse Gas: This definition lists the gases included in the category of climate forcing compounds consistent with AB 32, California Health, and Safety Code Section 38505(g).

Section 13-5-208 – Industrial Hydrogen Plant: The comprehensive hydrogen operation, including but not limited to, all operations that produce hydrogen using the steam-methane reformation process, and the hydrogen distribution system, including all compression operations.

Section 13-5-211 – Steam-Methane Reformation Process: An industrial chemical process in which steam is used to produce hydrogen from a hydrocarbon source such as methane or any other hydrocarbon source. The definition provides example chemical formulae for steam-methane reforming and water-gas shift reactions.

Section 13-5-212 – Total Organic Compound (TOC): Any organic compound or mixture of organic compounds, including methane.

D. Standards

Section 13-5-301 – Emission Limits for Industrial Hydrogen Plants: The proposed emission limits for Proposed Rule 13-5 are 15 pounds (6.8 kilograms) per day of total organic compound and 300 parts per million by volume total organic compound, as methane on a dry basis for industrial hydrogen plants.

Section 13-5-302 – Prohibition of Comingling and Dilution: Circumvention of the emissions standard through comingling or dilution of hydrocarbon streams to atmospheric vents as a means to comply with the standard is expressly prohibited by this section. The emission limits of Proposed Rule 13-5 apply to atmospheric vents that emit gases directly to the atmosphere and not those routed to a control device. Any streams that are comingled prior to abatement would not be subject to the emissions standards in Section 13-5-301 and therefore would not result in a violation of Section 13-5-302.

Section 13-5-303 – Alternative Methane and Other Greenhouse Gas Emissions Standard Option: Proposed Rule 13-5 includes an alternative methane and other GHG emissions standard option that allows a facility to comply with the rule by reducing emissions by 90 percent from an established baseline. The 90 percent GHG emissions reduction requirement was derived based on overall control efficiency based on a flaring calculated as shown below. The detailed calculations for the emissions rates presented in Table 1 are provided in Appendix B of EIR. The owner or operator of a hydrogen plant must notify the Air District that they intend to pursue this option within six months of adoption of the rule and within one year, provide an estimate of the methane emissions baseline to be validated by the Air District. Within one year of that validation, the owner or operator shall submit a plan that details how these emissions reductions will be accomplished for review and approval by the Air District. Up to 20 percent of the total emission reductions may be substituted for methane by reductions of other climate pollutant reductions from the hydrogen plant on a GHG equivalent basis. These limits will go into effect no later than three years after Air District permits are issued in accordance with Section 13-5-401 and 405. For the facilities that chose this option, the hydrogen plant vents would remain subject to the requirements of Rule 8-2: Miscellaneous Operations.

In the event that the Air District denies approval of the submitted Alternative Compliance Plan, the owner and/or operator of the hydrogen production facility must comply with Sections 13-5-301 and 401. This does not preclude an owner/operator with an approved ACP from complying with Sections 13-5-301 and 401, should they choose. The timelines for the two compliance options in Section 13-5-301 and 303 are aligned and allow for this possibility.

It should be noted that only the hydrogen plants at PBF and Valero refineries are anticipated to require modifications to comply with the emission standards of the proposal and that the three other Bay Area refineries would not be impacted by the emission standards. Other requirements of Proposed Rule 13-5 may affect operations at industrial hydrogen plants at the other Bay Area refineries.

Table 1
Overall Flare Control Efficiency Calculation [8]

Description	**Emissions** (MT CO_2e/year)	Note
Average Baseline GHG Emissions	**85,783[9]**	-
Net GHG Reduction from Flare Use	**77,543**	GHG Reduction - GHG Emissions Increase
GHG Reduction due to control of methane using a flare	84,067	98% of Average Baseline Emissions
GHG Emissions Increase from Purge and Pilot Gas	148	(CO_2+N_2O*GWP $_{N_2O}$+CH_4*GWP $_{CH_4}$)
GHG Emissions Increase from Combustion of Methane	6,349	(CO_2+N_2O*GWP $_{N_2O}$)
GHG Emissions Increase from Combustion of Hydrogen	27	(CO_2+N_2O*GWP $_{N_2O}$)
Overall Flare Control Efficiency	**90.4%**	(Net GHG Reduction from Flare Use/Average Baseline Emissions)

Note: GHG reduction due to control of methane = (average baseline emissions) (98%) = (85,783 metric ton of CO_2e) (98%) = 84,067 metric ton (MT) of Carbon Dioxide Equivalent (CO_2e)

Net GHG reduction from flare use = (GHG reduction due to control of methane) - (GHG emissions increase from purge and pilot gas + GHG emissions increase from combustion of methane + GHG emissions increase from combustion of hydrogen) = (84,067) MT of CO_2e – (148 + 6,349 + 27) MT of CO_2e = 77,543 MT of CO_2e

Overall flare control efficiency = (Net GHG reduction from flare use / average baseline emissions)(100%) = (77,543 / 85,783) (100%) = 90.4% MT of CO_2e

The detailed calculations for the emissions rates presented in Table 1 are provided in Appendix B of the EIR. The net GHG emissions were calculated by subtracting the GHG emissions increase

[8] Methane GWP value of 34 and nitrous oxide GWP of 298 from Schedule T of Regulation 3 was used to convert the mass emissions to CO_2e mass emissions.

[9] Average baseline emission was reported by hydrogen plant owners and operators in response to Air District hydrogen plant emissions questionnaire. This number was calculated by summing the average emissions for Valero and PBF for 2016 to 2018 period.

due to operation of flare, which includes carbon dioxide, nitrous oxide, and methane emissions that results from purge and pilot gas, methane, and hydrogen combustion, from the GHG reduction resulting from operation a flare assuming control efficiency of 98 percent. For the emission standard in Section 13-5-303, the emission standard was rounded from 90.4 percent to 90 percent based on the overall flare control efficiency calculation presented in Table 1.

Example Calculation of Section 13-5-303 Alternative Methane and Other Greenhouse Gas Emissions Standard Option

S-1 Hydrogen Plant

Baseline Emissions:

- Total Hydrogen Plant Methane Emissions = 10,000 lbs /year
- Carbon Dioxide Scrubbing Vent = 100,000 lbs/year of carbon dioxide
- Methane GWP value of 34 from Schedule T of Regulation 3 was used to convert the mass emissions of methene to CO_2e mass emissions.

Baseline Methane CO_2e Emissions
= (10,000 lbs of methane)(34) = 340,000 CO_2e lbs/year

Methane Emissions Reductions Required with 20% Substitution with Other GHG

Annual Plant-wide Methane Emissions Reduction Required
= (340,000 CO_2e lbs/year)(90%)
= 306,000 CO_2e lbs/year

20% of Carbon Dioxide Emissions Reductions Allowance
= (306,000 CO_2e lbs/year)(20%)
= 61,200 CO_2e lbs/year

Annual Carbon Dioxide Scrubbing Vent Emissions Allowance
= (100,000-61,200) lbs/year of carbon dioxide
= 38,800 lbs/year of carbon dioxide

Annual Plant-wide Methane Emissions Reduction Required with the 20% Substitution
= (306,000-61,0,200) CO_2e lbs/year
= 244,800 CO_2e lbs/year

Annual Plant-wide Methane Emissions Limit
= (340,000-244,8000) CO_2e lbs/year
= (95,2000 CO_2e lbs/year)(1/34) = 2,800 lbs/year of methane

Summary of Hydrogen Plant-wide Emissions Allowances:
Annual methane emissions: 2,800 lbs/year of methane
Annual carbon dioxide emissions allowance:38,800 lbs/year of carbon dioxide

E. Administrative Requirements

Section 13-5-401 – Control Device Requirements for Industrial Hydrogen Plants: This section provides a schedule for application of permits for control technology, construction, commencement of operation, and eventual compliance with control requirements in the previous standards section of the rule. If an owner or operator of an industrial hydrogen plant does not already comply with the emissions standards of Section 13-5-301, within three years of rule adoption, they must submit an application for an Authority to Construct and/or Permit to Operate a control device to bring their facility in to compliance. Operation of the control device is required within three years of receipt of the Authority to Construct. This section does not apply to an owner and/or operator who will comply with Section 13-5-303 by implementing an Alternative Compliance Plan.

Section 13-5-402 – Reporting Requirements for Total Organic Compounds Vented from Industrial Hydrogen Plants: This section details the notification and reporting requirements for total organic compounds vented from hydrogen plants exceeding rule limits and is consistent with the notification and reporting requirements for equipment breakdown provided in Air District Regulation 1: General Provisions and Definitions. When such venting occurs, the owner or operator must notify the Air District immediately upon discovery and within 30 days report the cause of the venting occurrence; the date, time, and duration of the occurrence; the make, model, and type of control device; the operating parameters of the control device including temperature, pressure, flow rate, and concentrations of each constituent in the gaseous stream; and the mass emissions for each constituent in the gaseous stream including total organic compound.

Section 13-5-403 – Baseline Methane and Other Greenhouse Gas Emissions Calculation Procedures: This section establishes the calculation procedures for determining baseline methane and other GHG emissions. Annual baseline emissions must be determined from verifiable records of operations during the three-year period from January 1, 2016, to December 31, 2018.

Section 13-5-404 – Plan Submission for the Alternative Methane and Other Greenhouse Gas Emissions Standard Option: This section provides the elements required to be submitted and submittal deadline for owners or operators of industrial hydrogen plants seeking to comply with the alternative methane and GHG emissions standard option. This section also specifies that the global warming potentials provided in Regulation 3, Schedule T be used when determining GHG equivalency.

Section 13-5-405 – Implementation of the Alternative Methane and Other Greenhouse Gas Emissions Standard Option: This section provides a schedule for application of permits necessary for implementation of the Alternative Compliance Plan including control technology, construction, commencement of operation, and eventual compliance with control requirements in section 13-5-303 of the rule. The owner or operator of an industrial hydrogen plant seeking this compliance option is required to submit an application for an Authority to Construct and/or Permit to Operate to comply with the Alternative Compliance plan within one year of Air District approval and commence operation of equipment to implement the plan within three years of receipt of the Authority to Construct.

F. Monitoring and Records

Section 13-5-501 – Monitoring Requirements, General: Proposed Rule 13-5 includes a monitoring requirement for total organic compound emissions from atmospheric vents. Effective two years after the adoption of the Rule, by the next turnaround and no later than five years from the adoption of this Rule, the owner or operator of any industrial hydrogen plant shall monitor total organic compound emissions on a daily basis, in total pounds per day and parts per million by volume (ppmv) total organic compound, as methane, on a dry basis from hydrogen plant atmospheric vents. The monitoring must include the continuous recording of data of gas composition, temperature, pressure, flow rate and volume in million standard cubic feet per day. All emissions data must be converted into mass emissions, in pounds per day, for both methane and organic compound emissions. Within the same time limits described above, the owner or operator of any industrial hydrogen plant must install, operate, and maintain in good working order, a sampling port for the purpose of testing emissions from the atmospheric vents, and provide a piping and instrumentation diagram. All records must be retained for all vents and any information deemed necessary by the Air District to approve the sampling port.

Section 13-5-502 – Monitoring Requirements, Alternative Methane and Other Greenhouse Gas Emissions Standard Option: For the owners or operators of industrial hydrogen plants that opt to comply by the alternative methane and other GHG emissions standard, Proposed Rule 13-5 provides monitoring requirements to verify compliance with this alternative standard. Effective two years after adoption, by the next turnaround and no later than five years from adoption, the Rule specifies daily monitoring of methane emissions from atmospheric vents, and daily monitoring of methane and GHG emissions reductions from all atmospheric vents, CO_2 deaerator vents, and deaerator vents. Owners or operators will be required to continuously record temperature, pressure, flow rate and volume from all vents as part of this option and will need to convert this data into mass emissions in pounds per day for both methane and other GHG emissions. This information will be used to determine compliance with the alternative methane and other GHG emissions standard addressed in Section 13-5-303 of the rule.

Section 13-5-503 – Reporting Requirements, Alternative Methane and Other Greenhouse Gas Emissions Standard Option: This section requires that information gathered as per the previous section be summarized and reported to the Air District annually.

Section 13-5-504 – Monitoring Requirements, Deaerator Vents and Carbon Dioxide Scrubbing Vents: Proposed Rule 13-5 also includes a quarterly monitoring requirement for deaerator vents and CO_2 scrubbing vents that is effective two years after adoption of this Rule, and must be implemented by the next turnaround and no later than five years from adoption. The owner or operator of any industrial hydrogen plant that operates deaerators or CO_2 scrubbing equipment must monitor total organic compound emissions on a quarterly basis, in total pounds per day and ppmv total organic compound, as methane, on a dry basis from hydrogen plant atmospheric deaerator vents and CO_2 scrubbing vents. All emissions data must be converted into mass emissions, in pounds per day, for both methane and organic compound emissions. The owner or operator of any industrial hydrogen plant that operates deaerators or CO_2 scrubbing equipment must install, operate, and maintain in good working order, a sampling port for the purpose of testing emissions from the atmospheric vents, and provide a piping and instrumentation diagram. All records are required to be retained for all vents and any information deemed necessary by the Air District to approve the sampling port.

Section 13-5-505 – Monitoring Requirements, Pressure Swing Adsorption Vents: Proposed Rule 13-5 includes monitoring requirements of pressure swing adsorption vents to demonstrate hydrogen gas percent purity of pressure swing adsorption vents via a hydrogen gas analyzer. The owner or operator of the facility may present the engineering means of verifying the purity of these streams as an alternative method which may be approved by the APCO as sufficient. Purity verifications are required to be recorded quarterly, and all records must be retained for a minimum of five years and made available to the APCO upon request.

Section 13-5-506 – Recordkeeping Requirements: The owner or operator of any industrial hydrogen plant is required to keep records of all industrial hydrogen plant atmospheric venting during normal operating conditions and venting due to startups, shutdowns, malfunctions, and emergencies. Records must include temperature; mass emissions of both methane and organic compounds, in pounds per day; parts per million emissions by volume, as methane, on a dry basis; venting duration; gas composition; volume vented in million standard cubic feet per day; and for any startup, shutdown, malfunction or emergency, the reason for such startup, shutdown, malfunction or emergency. The owner or operator of a small-scale industrial hydrogen plant is required to maintain records and basis for meeting the exemption limits found in Section 13-5-105.

G. Manual of Procedures

Section 13-5-601 – Determination of Compliance and Monitoring of TOC Emissions: This section includes test methods for determining compliance and monitoring of total organic compound emissions. SCAQMD Method 25.3 (modified as approved by APCO) or any other method approved by the APCO are provided for the total organic compound emissions

Section 13-5-504 – Monitoring Requirements, Deaerator Vents and Carbon Dioxide Scrubbing Vents: This section includes test methods for determining compliance and monitoring of methane, and GHG emissions. The section references EPA method 18 or any other method approved by the APCO.

H. Exclusion from Regulation 8, Organic Compounds, Rule 2: Miscellaneous Operations (Rule 8-2)

Because Rule 8-2 currently regulates non-methane organic compound emissions from miscellaneous sources, to avoid potential regulatory overlap with Proposed Rule 13-5, staff proposes the following amendment to language in Rule 8-2-201:

8-2-201 Miscellaneous Operations: Any operation other than those limited by the other Rules of this Regulation 8, the Rules of Regulation 10, ~~or~~ Rule 12 of Regulation 12, or limited by compliance with Section 301 of Rule 5 of Regulation 13.

Hydrogen plant operations that are currently subject to Rule 8-2 emission limits for non-methane emissions will continue to be subject until the total organic compound emission requirements of Proposed Rule 13-5 become applicable. Those owners or operators of industrial hydrogen plants that opt to comply with Section 13-5-303 through the alternative methane and other GHG emissions standard option will remain subject to the organic compound emission requirements of Rule 8-2.

Staff is also proposing amendments to the Section 600 Manual of Procedures section to allow for alternative test methods to ensure that facilities that process non-petroleum products utilize the appropriate test methods for the material they are handling. This additional amendment to Rule

8-2 is being made at this time to ensure consistency with other recently amended rules and is unrelated to Proposed Rule 13-5. Staff proposes the following amendment to language in Rule 8-2, Section 8-2-601:

8-2-601 **Determination of Compliance**: Emissions of organic compounds as specified in Section 8-2-301 shall be measured as prescribed by any of the following methods 1) BAAQMD Manual of Procedures, Volume IV, ST-7, 2) EPA Method 25 or 25A, or 3) any other method approved by the APCO. A source shall be considered in violation if the VOC emissions measured by any of the referenced test methods exceed the standards of this rule.

I. Comparative Analysis

There are no rules or regulations, federal or state, that limit GHG emissions from industrial hydrogen plant operations. Although California regulates GHG emissions from petroleum refineries and other large sources via California's Cap-and-Trade program, methane-specific emission reductions are not required. The South Coast Air Quality Management District has a hydrogen plant rule—Rule 1189—that limits volatile organic compound emissions (mainly methanol) from hydrogen plant process vents during normal operations. Because South Coast Rule 1189 does not control methane emissions from hydrogen plant process vents, it cannot be compared to Proposed Rule 13-5. Rule 13-5 will be the most stringent and only GHG regulation in the United States for industrial hydrogen plant operations.

IV. EMISSIONS AND EMISSIONS REDUCTIONS

The Air District established a baseline emissions inventory for estimating emissions reductions from industrial hydrogen plants by reviewing emissions data submitted by hydrogen plant owners and operators. These data include methane emissions from the venting of hydrogen gas produced, distributed, and used in industrial hydrogen plants. According to these data, the average total yearly methane emissions for each of the past three calendar years (2016 through 2018) from all industrial hydrogen plants is approximately 2,555 metric tons per year; this is equivalent to about 86,878 metric tons of CO_2 on a 100-year time horizon and 219,751 metric tons of CO_2 based on 20-year time horizon. However, this value does not include methane emissions from deaerator vents or from CO_2 scrubbing vents because most hydrogen plant operators do not know the extent of methane emissions from these particular types of atmospheric vents. In past years, occasional source tests performed on deaerator vents and CO_2 scrubbing vents did not focus on methane emissions because, at the time, these source types were not suspected of emitting methane. While the total amount of total organic compound emissions from all hydrogen plant operations is, therefore, not fully known, deaerator vent and carbon monoxide vent monitoring requirements in Proposed Rule 13-5 will ultimately provide the Air District the data necessary to determine these emissions.

Table 2
Hydrogen Plant Methane Emissions from Bay Area Petroleum Refineries

Facility	2016 Methane Emissions (metric tons per year)	2017 Methane Emissions (metric tons per year)	2018 Methane Emissions (metric tons[a] per year)	Average Annual Emissions for 2016–2018 (metric tons[a] per year)
Air Liquide [P66] [a]	0	0	0	**0**
Air Products [Marathon] [a]	0	0	0	**0**
Air Products [PBF] [a]	15	4	76	**32**
Chevron Refinery [a]	0	0	0	**0**
Marathon Refinery [a]	0	0	0	**0**
P66 Refinery [a]	0	0	0	**0**
PBF Refinery	907	1,520	589	**1,005**
Valero Refinery	988	2,752	814	**1,518**
TOTALS	**1,911**	**4,276**	**1,479**	**2,555**

Source: Emissions reported in metric tons per year by hydrogen plant owners/operators in response to Air District hydrogen plant emissions questionnaire.

a. Hydrogen plants reporting zero emissions already control methane and other hydrocarbon emissions by either operating a pressure swing adsorption system to remove methane and hydrocarbons prior to venting, recovering potential emissions and routing them to the refinery fuel gas system, or they route hydrogen vent gas to a flare where the gases are combusted.

In addition, Air District staff reviewed emissions data measured from aerial flights conducted by NASA Jet Propulsion Laboratory to ensure consistency with the emissions data submitted by hydrogen plant owners and operators.[xvii] To further ensure the baseline emissions inventory is accurate, staff reviewed emissions data collected by the Air District during compliance and testing activities.

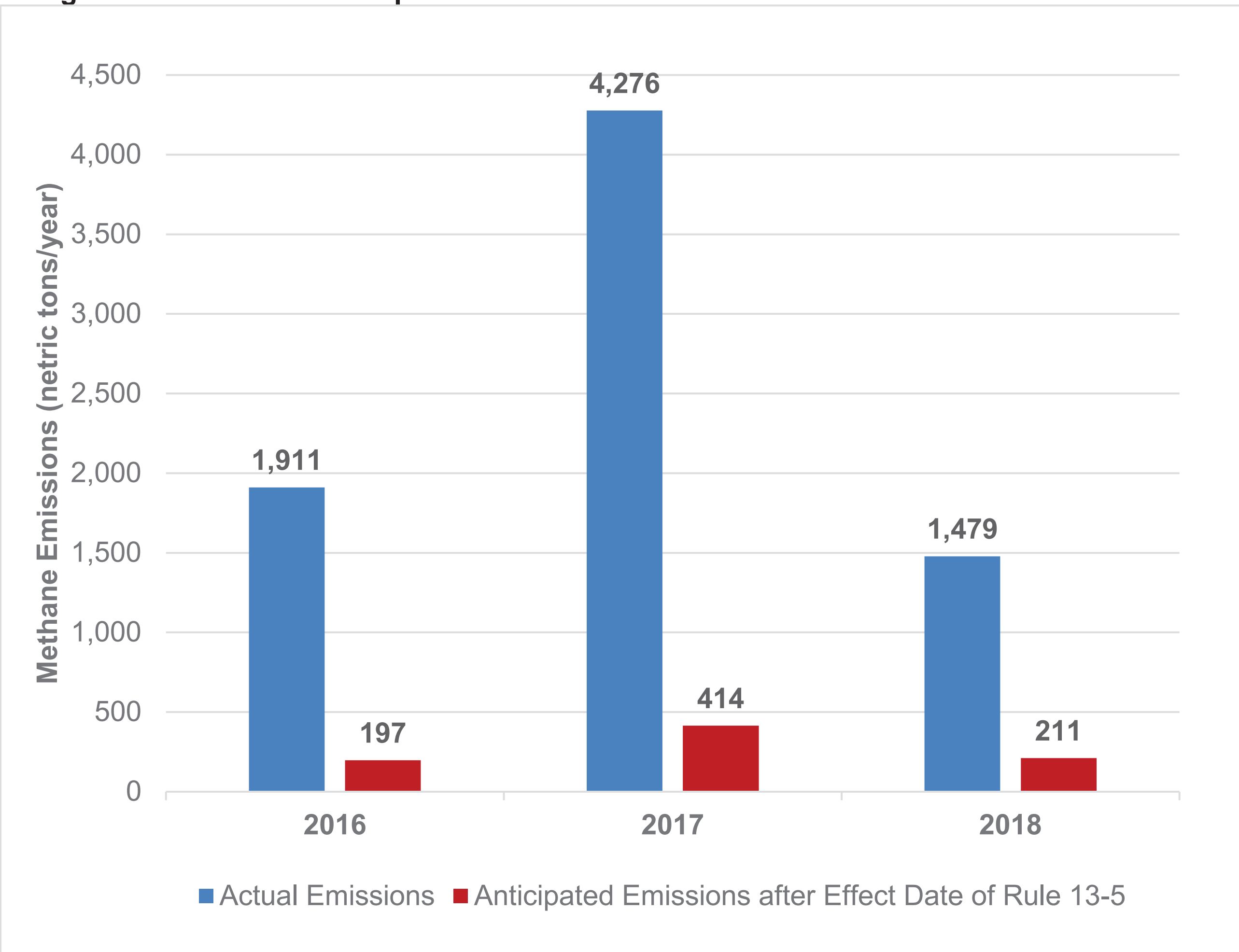
The extent of non-methane organic compounds vented from industrial hydrogen plants is unknown because hydrogen plant operators do not monitor atmospheric vents for non-methane organic compound emissions. Non-methane organic compounds can be present in hydrogen gas depending on the separation method and operational scheme utilized at a hydrogen plant.

Hydrogen gas from a hydrogen plant which combines hydrogen generated from a steam-methane reformation process and that from a catalytic reforming unit may contain trace amount of non-methane organic compounds, whereas hydrogen vent gas from a hydrogen plant that operates a pressure swing adsorption system will contain a negligible amount of non-methane hydrocarbons. Thus, non-methane hydrocarbon emissions from petroleum hydrogen plants will vary.

The graph below provides actual methane emissions and anticipated methane emissions that would have been achieved with the standards of Proposed Rule 13-5 in place assuming at least 90 percent reduction in methane for the years 2016 to 2018. Note that if flares are used to control methane, the actual methane reductions would be approximately 98 percent. However, since the flare is converting the methane to CO_2, the net GHG reduction would roughly 90 percent as shown in Table 1.

Actual emission reductions will vary from year-to-year depending on production rates at each facility. On average, the emission reductions will be approximately 2,514 tons per year or 2,281 metric tons.

Figure 7: Actual and Anticipated Methane Emissions after Effective date of Rule 13-5



V. ECONOMIC IMPACTS

The Air District conducted two different types of economic analyses for rule development activities. The two analyses conducted were (1) a socioeconomic analysis under the California Health and Safety Code (H&SC) section 40728.5, and (2) an incremental cost analysis under H&SC section 40920.6. "In developing regulations to achieve air quality objectives, air districts shall consider the cost effectiveness of their air quality programs, rules, regulations, and enforcement practices in addition to other relevant factors, and shall strive to achieve the most efficient methods of air pollution control. However, priority shall be placed upon expeditious progress toward the goal of healthful air."

The requirements in Proposed Rule 13-5 will have economic impacts on industrial hydrogen plant operators in two different ways: the cost to comply with Proposed Rule 13-5 emission limit requirements, and a separate cost to comply with emissions monitoring requirements. Based on multiple conversations with representatives from each refinery and independent third-party hydrogen plant operators, and, based on six years of hydrogen plant emissions data submitted to Air District staff, operators of industrial hydrogen plants servicing two of the refineries—Valero and PBF PBF—will have to design, purchase, install and maintain control technology to comply with the Proposed Rule 13-5 emission requirements. Recently, the Air Products Company, an independent third-party operator of hydrogen plants that produces hydrogen for the PBF refinery, purchased two hydrogen plants previously owned and operated by PBF. PBF staff has confirmed with Air District staff that even though they no longer own any of the hydrogen plants, PBF will cover the entire cost to comply with the requirements of Proposed Rule 13-5. Two of the refineries will incur costs to install total organic compound emission monitoring equipment on deaerator vents and CO_2 scrubbing vents. All refineries will incur costs to monitor total organic compound emissions from CO_2 scrubbing and deaerator vents. The base cost information presented in the following sections were provided to the Air District by Valero and PBF. The details regarding the cost information used to calculate the total control cost and cost effectiveness values are available in Appendix C.

A. Control Cost and Cost Effectiveness

P66 refinery and the Marathon refinery recently announced they will be shutting down their crude oil refining operations at their respective facilities. However, staff assumed that both refineries will be operating their hydrogen plants when Proposed Rule 13-5 goes into effect for the purposes of this discussion on cost and cost effectiveness. In addition, as noted above, PBF informed staff they will cover the costs for Air Products' hydrogen plats to comply with Proposed Rule 13-5-301. Air Products recently purchased both of PBF's hydrogen plants so they now own and operate a total of three hydrogen plants for PBF.

Staff determined the total capital cost to reduce total organic compound emissions from hydrogen plant operations with flares at each of the hydrogen plants associated with PBF and Valero will be $70 million dollars. For the purpose of the cost effectiveness analysis, it was assumed methane emissions are equivalent to total organic compound emissions since hydrogen gas vented from atmospheric vents consist mostly of methane. In addition, the cost and emissions reductions for a flare was used for the cost-effectiveness analysis since this was one of the most cost-effective scenarios that will lead to compliance with this rule. The total cost for a flare includes total capital investment, direct installation, indirect installation, direct annual, and indirect annual costs. Total capital investment costs include but are not limited to the hydrogen system flare, piping, piping insulation, piping support structures, monitoring equipment, utility costs, instrumentation, sales tax, and freight. Direct installation costs include site preparation, foundation and supports, handling and erection, electrical, piping insulation and painting. Indirect installation costs include engineering and design, construction and field expenses, contractors' fees, start-up, performance testing and contingency costs. Table 3 summarizes the total annualized cost associated with compliance with Rule 13-5 using a flare.

Table 3
Total Annualized Costs Associated with Compliance with the Emissions Standards of Proposed Rule 13-5: Hydrogen Plants

Facility	Total Compliance Cost - Flare
PBF	$7.8 – 8.6 million
Valero	$6.1 – 6.8 million

Staff estimated the annualized cost for all hydrogen plants to comply with requirement to install flowrate meters to range between $637,200 to $700,920, the annualized cost to perform quarterly emissions monitoring to range between $504,000 to $1,440,000, the annualized cost to install sampling ports in deaerator vents and carbon monoxide scrubbing vents to range between $25,488 to $38,232 and the annualized cost to install emissions monitoring equipment in atmospheric vents to range between $4,855,887 to $6,169,887. The annualized total cost to the refinery industry to comply with Rule 13-5 monitoring-related requirements would range from approximately $15,327,522 to $17,653,986. The reason a range of annualized costs is provided for each monitoring requirement category is because it is not known if scaffolding equipment will be required when monitoring equipment is installed or when source testing for emissions is conducted.[10] Thus, the cost for scaffolding is built in as an added cost. In some cases, operators may have some of the required monitoring equipment already installed. As noted in Appendix C, estimated costs stated above represent the upper end of potential costs for each facility to comply with monitoring requirements. Most facilities currently collect hydrogen gas composition, temperature, pressure, and flow rate data using parametric monitoring equipment or other methods such as modeling techniques. The cost to install atmospheric monitoring equipment for primary hydrogen plant atmospheric vents can be avoided if a facility can demonstrate that atmospheric vents have the capability to vent to atmosphere after vent control technology is installed and operational. Therefore, staff anticipates the annualized cost to comply with the monitoring requirements to be considerably less than stated above for all industrial hydrogen operators to comply with all requirements in Section 13-5-500.

Cost effectiveness is defined as the ratio between the annualized cost and the amount of annual emission reductions in dollars per ton. The cost effectiveness to comply with proposed Rule 13-5 emission limit requirements is presented in Table 4.

[10] See Costs in Appendix C

Table 4
Annualized Costs, Emissions Reductions and Cost Effectiveness for Methane

Facility	Annualized Costs ($ millions)	Methane Emissions Reductions[11] (tons/year)	Cost Effectiveness ($/ton)	Methane Emissions Reductions (metric tons/year)	Cost Effectiveness ($/metric ton)
PBF	$8.6	1,002	$8,627	909	$9,510
Valero	$6.8	1,513	$4,519	1,372	$4,981
TOTALS	**$15.5**	**2,514**	**$6,156**	**2,281**	**$6,786**

Furthermore, staff has determined the CO_2 equivalent cost effectiveness as follows:

Total Methane Reduced (MT)
= (2,523 MT)(90.4%)
= 2,281 MT

2,281 metric tons converted to CO_2e
= (2,281) metric tons x 34 (GWP)
= 77,543 MT of CO_2e

Total annualized cost to reduce emissions for PBF and Valero = $15.5 million

Total CO_2e Cost Effectiveness
= $15.5 million annualized costs / 77,543 MT of CO_2e
= $200 / MT of CO_2e reduced

A CO_2e cost effectiveness compares at roughly 6 times the current California market value for carbon emission credits of $29.15 per metric ton of CO_2 equivalent reduction.[xviii]

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[11] The net methane control efficiency of a flare was assumed to be 90% for the cost effectiveness analysis. Though flare has an abatement efficiency of 98 percent for total organic compounds, staff determined that this is equivalent to net control efficiency of 90 percent respective to GHG benefits due to usage of purge gas, and pilot gas required and conversion of methane to carbon dioxide with the operation of a flare.

Table 5
Annualized Costs, Emissions Reductions and Cost Effectiveness for CO_2e

Facility	**Annualized Costs** ($ millions)	**Methane Emissions Reductions** (metric tons/year)	**CO_2e Emission Reductions 20-yr Time Horizon** (metric tons/year)	**Cost Effectiveness 20-yr Time Horizon** ($/$CO_2e$ metric ton)	**CO_2e Emission Reductions 100-yr Time Horizon** (metric tons/year)	**Cost Effectiveness 100-yr Time Horizon** ($/$CO_2e$ metric ton)
PBF	$8.6	909	77,174	$111	30,906	$280
Valero	$6.8	1,372	117,965	$58	46,637	$147
TOTALS	**$15.5**	**2,281**	**196,139**	**$79**	**77,543**	**$200**

In addition to evaluating a flare as a control measure, staff reviewed the alternative control measures proposed by Valero and PBF.

Valero proposed the following alternative emissions reduction measures and is expected to reduce methane emissions from the hydrogen plant by at least 30 percent with the measures below:

- Installing control valves at the existing atmospheric vents to reduce flow and allow for improved pressure control.
- Improving the existing process control system to improve the response time to change in demand to hydrogen gas production.
- Installing flowmeter to the existing atmospheric vents to increase certainty and performing feasibility analysis to determine if the existing flare and gas recovery system can utilize the excess hydrogen gas.
- Installing letdown station with valves and manifold to allow excess hydrogen gas to be routed to the existing LPFG system.

PBF proposed to implement the following alternative emissions reduction measures and is expected to reduce methane emissions from the hydrogen plant from 65 to 85 percent with the measures below:

- Combusting the excess hydrogen gas with lower hydrogen purity using existing control device.
- Routing the excess hydrogen gas with lower hydrogen purity to the existing fuel recovery system.
- Prioritizing the use of hydrogen gas with lower purity by the hydrogen consumers while preferentially venting hydrogen gas with higher purity.

The total capital cost to implement the alternative reduction measures proposed by Valero and PBF ranged from $5,000,000 to $10,000,000. Additional details related to cost of the alternative reduction measure is available in Appendix C. Since the proposed alternative reduction measures would not meet the required emission reduction to comply with this Rule, the proposed alternative reduction measures were not used as the bases for the cost-effectiveness analysis.

B. Incremental Cost Effectiveness

The Air District also assessed the incremental cost-effectiveness for this regulation, since more than one control option could be used to meet the same emission reduction objectives. The H&SC 40920.6 defines incremental cost-effectiveness as the difference in costs divided by the difference in emission reductions between one level of control and the next. As discussed above, the cost-effectiveness for the requirement to use flare control technology to comply with a total organic compound emission limit of 15 pounds per day and 300 ppm total carbon by volume on a dry basis is estimated to be $6,786 per metric ton of total organic compound emissions reduced.

Another option hydrogen plant operators have to reduce total organic compounds is to utilize pressure swing adsorption system to remove contaminants including methane and non-methane hydrocarbons from the hydrogen gas stream. This separation process would produce hydrogen gas, which had hydrogen purity previously ranging between 95 percent to 97 percent, with minimum hydrogen purity of 99.99 percent concentration with the removal of majority of methane and non-methane hydrocarbons. Thus, the total organic compound emissions occurring from a hydrogen plant utilizing a pressure swing adsorption system will be negligible given the high hydrogen purity.

For the incremental cost effectiveness analysis, it was assumed that 100 percent of the methane contained in the hydrogen vent gas would be controlled. This would amount to a reduction of 2,523 metric tons/year of total organic compound emissions in a typical year.

Staff estimated that the total capital cost to install a pressure swing adsorption system at both Valero and PBF were $307 million. The total annualized costs for the two pressure swing adsorption systems ranged from $59 to $63 million per year.

The incremental cost between two options is calculated as follows:

Total Annualized Cost for Valero and PBF
= ($60.7 million – $15.5 million) / (2,523– 2,281) metric tons
= $45.2 million / 242 metric tons/year
= $186,518 / metric ton or $169,206 / ton

C. Socioeconomic Impacts

Section 40728.5 of the California Health and Safety Code requires an air district to assess the socioeconomic impacts of the adoption, amendment, or repeal of a rule if the rule is one that “will significantly affect air quality or emissions limitations.” Applied Development Economics of Walnut Creek, California has prepared a socioeconomic analysis Proposed Rule 13-5. This analysis is based on the costs of compliance with the Proposed New Rule, and is attached to this report as Appendix D. It would cost the industrial hydrogen production industry between $15.3 and 17.7 million per year to comply with total organic compound emission limits, with costs for individual facilities ranging from $0.2 to 8.6 million per year. The upper range of costs expressed as a percent of annual income for individual facilities range between 0.2 to 11.3.

For the Air Liquide hydrogen plant, which is a smaller facility, the annualized monitoring costs represent 7.6 to 11.3 percent of estimated net income. The upper end of the cost estimate range exceeds the 10 percent threshold of significance for the Air Liquide plant. While the high-end estimate should be considered as a worst-case scenario, the costs may be substantially lower than this estimated value. Nevertheless, the potential impacts associated with costs above the threshold of significance were estimated based on this high-end estimate. Of particular concern under the Health and Safety Code would be the potential for lost jobs at the plant to compensate for the impact to net income. At $270,000 per year, the upper end impact is about $30,000 above the 10 percent impact threshold. The average salary and benefits for workers in the gas production industry in California is $92,300. The maximum cost impact exceeding the threshold, therefore, represents less than a third of the cost for one employee at Air Liquide. We conclude that it is unlikely the company would choose to reduce employment to mitigate this impact.

D. Potential Cost Mitigation

While staff economic analyses indicate that Proposed Rule 13-5 will be cost effective and will not impose significant socioeconomic impacts on the affected facilities; these analyses do not reflect cost mitigations options potentially available to the affected facilities. One such potential cost mitigation is that the GHG emissions reductions realized as a result of the implementation of Proposed Rule 13-5 may be eligible to be traded as carbon credits on the national and international markets. Carbon credits allow for business operations that generate carbon emissions to offset those impacts by trading credits with other business operations that reduce, remove, or avoid GHG emissions. The carbon credits market consists of both a voluntary market and a compliance market. The compliance market, which is represented as a cap-and-trade market, currently operates in California.

Under the California Air Resources Board regulations, major sources that generate large amounts of carbon emissions can purchase carbon credits to meet emissions goals. Refineries are subject to cap-and-trade requirements. The California cap-and-trade program has 450 participants.[xix] The market value of carbon credits fluctuates, but the most recent data from the Air Resources Board (ARB) indicates that the median price for a carbon credit ranged from $15.32 (offset) to $24.62 (allowance).[xx] [12] Applied to the proposed reduction of 2,281 metric tons of methane (equivalent of 77,543 tons of CO_2 based on a 34 GWP for methane), this would imply a carbon credit value ranging from $1.30 million (offset) to $2.10 million (allowance). Depending on the allowable cap for each facility, the affected companies may be able to monetize a portion of their carbon reductions under this program.

E. Social Costs of Greenhouse Gases (GHG)

Compliance with Proposed Rule 13-5 will impose costs on the affected refineries and hydrogen producers in the Bay Area. However, failure to reduce emissions of GHG imposes ongoing costs on society in terms of contributing to climate change and the long-term effects it will have on a wide range of human activities and the built and natural environment. The social cost of carbon takes a holistic view of how carbon emissions create societal impacts and uses various data measures to put a cost on it. At a simplistic level, social cost of carbon attempts to measure the economic harm caused by climate change based on the dollar value per ton of CO_2 emissions.[xxi]

The legal rationale for including social cost of carbon in socioeconomic impact studies of new regulations dates back to a 2007 court decision in which the US Court of Appeals for the Ninth

[12] An offset carbon credit means that the GHG emission will be offset by a mitigating project, such as reforestation or agricultural projects. An allowance carbon credit functions more like a permit to emit.

Circuit ruled that federal agencies needed to account for the cumulative effects of GHG emissions in a cost-benefit analyses.[xxii]

The methodologies for quantifying social cost of carbon are highly varied. The monetary values assigned to social cost of carbon depend on several assumptions about socioeconomic forecasts (population and economic growth, and the resulting carbon emissions), climate projections (rising temperatures and sea levels compared to CO_2 levels, etc.), benefits and costs; and the discount rate (indication of rate at which society trades off present for future benefits).[xxiii]

At the federal level, the Interagency Working Group (IWG) was formed as a result of the 2007 court decision discussed above and has issued and updated social cost of carbon estimates since 2010. While the estimates have covered a wide range, depending on the measures used, the Biden administration announced an initial estimated social cost of carbon of about $51 per metric ton of CO_2. This figure is the one most frequently cited in media reports; and is based on work previously completed during the Obama administration (adjusted for inflation). The social cost of carbon estimate assumes a discount rate of 3.0 percent, which moderately trades off present costs into the future.[xxiv] It should be noted that the current social cost of carbon estimates from the IWG range from $14 to $152 per metric ton, depending on the discount rate assumption.[13]

In addition, the IWG separately assigned interim social cost values to methane and nitrous oxide (N_2O) of $1,500 and $18,000 per ton of emissions, respectively, using a 3.0 percent discount rate assumption.[14]

When applied to Bay Area refineries, the Proposed Rule 13-5 will eliminate about 2,281 metric tons of methane emissions. Using the alternate discount rate assumptions cited in the most current IWG report, the social cost reduction would range from $1.7 million to $9.8 million. The anticipated costs of compliance for Rule 13-5 fall within the range of $15.3 to $17.7 million per year. The IWG began the peer review process of a revised report in January 2022 that will account for more up-to-date climate change analysis and feedback.

F. Air District Impacts

Staff has determined that Proposed Rule 13-5 will require additional staff time and resources in a number of areas. Implementation of Proposed Rule 13-5 would affect three staffing demands on Air District Divisions with estimates of additional staffing needs: 1) Engineering, two additional full-time equivalents (FTEs); 2) Compliance and Enforcement, one additional FTE; and 3) Meteorology and Measurements, one additional FTE. Rule 13-5 is structured so that the effective dates of requirements in the standards section are far enough into the future that additional staffing needs can be fully evaluated and changes to Regulation 3: Fees may be implemented to assure Air District recovery of increased staffing costs associated with implementing and enforcing the requirements of Rule 13-5.

The administrative procedures in Proposed Rule 13-5 represent a moderate workload increase for the Air District's Engineering Division during the permitting process for emissions control systems because the owners or operators of industrial hydrogen plants must comply with control

[13] The IWG's SCC estimates are based on averages of model runs using multiple different inputs. The scenarios include 5.0, 3.0, and 2.5 percent discount rates, with an additional scenario that uses a 3.0 percent discount rate at the 95th percentile of the modeling results.

[14] The cost factor assumes 2020 dollar values, using the previous estimates dating back to 2016 and adjusted for inflation using the US Bureau of Economic Analysis' GDP price deflator values.

equipment permitting timelines delineated in Section 13-5-401. The owners or operators may need to permit modifications of existing equipment as part of the permitting process for control equipment or as part of implementing necessary equipment to meet the alternative compliance option of Section 13-5-303. As a result of the two- to three-year timeline for permitting, evaluation of total organic compound control technology will be a high priority for Engineering staff assigned to those specific hydrogen plant operations. If the owners or operators opt for the alternative compliance plan provisions of Section 13-5-303, additional staff time will be necessary for evaluation of methane and other GHG emissions baselines, and review and approval of emissions reductions plans. Staff estimate that two additional FTEs will be necessary to accommodate the increased demand on staff time from the Engineering Division for processing of permits and evaluation of emissions inventories, reductions, and alternative compliance plans.

Field staff from the Compliance and Enforcement Division normally investigate occasional hydrogen plant events such as malfunctions, upsets and power outages that require hydrogen plant operations to shut down and eventually start up again. To verify compliance with the emissions standard in Section 13-5-301, field staff will need to verify hydrogen gas emissions from hydrogen plants are adequately controlled and will have to verify that effected hydrogen plant owners or operators comply with the control technology implementation schedule, along with reporting requirements for hydrogen plant owners or operators in the event of venting of organic compound emissions after Proposed Rule 13-5 becomes effective. Compliance and Enforcement staff may be required to consult with Engineering staff on review and approval of emissions reduction plans as a result of facilities opting to comply with Section 13-5-303. Field staff will also have to verify hydrogen plants compliance with monitoring requirements for deaerator vents, and CO_2 scrubbing vents, review compliance records addressed in Section 13-5-506, and verify installation of flowrate meters and total organic compound analyzers. Staff estimate that one additional FTE will be necessary to accommodate the increased demand on staff time from the Compliance and Enforcement Division for additional compliance verification, review of records and incident reports, and consultation with Engineering staff for review of emissions reductions plans.

Source test staff from the Meteorology and Measurements Division will be required to evaluate total organic compound emissions monitoring methodologies and emissions monitoring data. Source Test staff must approve installation locations on vents for emissions monitoring technologies as required by Sections 13-5-501 and 502, and Source Test staff will also need to review quarterly emissions monitoring data from deaerator vents and CO_2 scrubbing vents. Staff estimate that one additional FTE will be necessary to accommodate the increased demand on staff time from Meteorology and Measurements Division for evaluation and approval of emissions testing and monitoring requirements contained in Proposed Rule 13-5.

As part of Air District cost recovery efforts, staff will propose updated fee requirements in Regulation 3: Fees (Reg 3) for the Air District Board of Directors' consideration for adoption in 2022, which will likely take effect on July 1, 2022. Staff has determined that Reg 3 will need to include a new fee to address the requirements for hydrogen plant operations consistent with additional staffing and resource requirements to implement the provisions of Proposed Rule 13-5. Many of the required actions of the rule will not take effect until after this date and staff may continue to evaluate the need for fee updates as these provisions come into effect.

G. Air District Cost Recovery

The Air District has the authority to assess fees to regulated entities for the purpose of recovering the reasonable costs of implementing and enforcing applicable regulatory requirements. In 2012, the Air District's Board of Directors adopted a Cost Recovery Policy which specifies that newly adopted regulatory measures should include fees that are designed to recover increased regulatory program activity costs associated with the measure, unless the Board of Directors determines that a portion of those costs should be covered by tax revenue.

In accordance with the adopted Cost Recovery Policy, the Air District staff has determined that Regulation 3: Fees will need to be amended to include a new fee to address the increased administrative time that will be necessary to process applications to comply with the provisions of the Proposed Rule 13-5. Regulation 3: Fees to ensure consistency and cost recovery.

VI. REGULATORY IMPACTS

Section 40727.2 of the California Health and Safety Code requires an air district, in adopting, amending, or repealing an air district regulation, to identify existing federal and air district air pollution control requirements for the equipment or source type affected by a proposed change in air district rules. The air district must then note any differences between these existing requirements and the requirements imposed by the proposed changes.

There are currently no federal or state regulations addressing methane emissions resulting from the production of hydrogen. The California Air Resources Board adopted a regulation to control emissions of methane from oil and gas production in 2017, but this regulation is limited to oil and natural gas production, processing and storage and does not extend to refining operations or steam-methane reformation operations. In November of 2021, the United States Environmental Protection Agency proposed New Source Performance Standard updates and emissions guidelines to reduce methane emissions from existing sources in the oil and natural gas industry. These proposals do not currently address emissions of methane from hydrogen production.

As stated previously in Section III of this report, Air District Rule 8-2 currently regulates non-methane organic compound emissions from miscellaneous operations, which includes industrial hydrogen plants. Proposed Rule 13-5 applies the same numerical standard as that found in Rule 8-2, but to total organic compounds including methane, whereas the standard in Rule 8-2 excludes methane. In respects to emissions of non-methane hydrocarbons, applying this standard to total organic compounds including methane is at least as stringent as applying it to organic compounds excluding methane. To prevent regulatory overlap, Rule 8-2 will also be amended as part of this rulemaking effort to exclude from that rule facilities complying with Section 13-5-301. Regulation 8-2 will still apply to facilities that opt to comply with Section 13-5-303 since that standard does not address emissions of organic compounds other than GHGs.

Proposed Rule 13-5 does not violate the provisions of the California Global Warming Solutions Act of 2006 (H&SC Section 38594). Section 13-5-303 includes an allowance for methane emissions to be offset up to 20 percent by other GHG emission reductions on a CO_2e basis. This option is not specifically limited to carbon dioxide, and is a voluntary option, not a requirement of the Rule. Rule 13-5 does not directly regulate carbon dioxide but rather provides additional regulatory flexibility to comply with its required methane reductions. Section 38594(c)(1) of the California Health and Safety Code provides that the Air District retains authority to adopt a rule for purposes other than to reduce carbon dioxide from sources subject to a market-based compliance mechanism adopted by the state board. Thus, Section 13-5-303 does not violate Section 38594(b) of the California Health & Safety Code.

VII. ENVIRONMENTAL IMPACTS

The California Environmental Quality Act (CEQA), Public Resources Code Section 21000 et seq., requires that the potential environmental impacts of proposed projects be evaluated and that feasible methods to reduce or avoid identified significant adverse environmental impacts of these projects be identified. The Air District contracts with an independent consultant to conduct a CEQA analysis of potential environmental impacts from any rule making projects.

A. Notice of Preparation / Initial Study

The Air District prepared a Notice of Preparation and an Initial Study (NOP/IS) in anticipation of a Draft EIR for Proposed Rule 13-5 and this NOP/IS was distributed to responsible agencies and interested parties for a 30-day review on June 30, 2021. A notice of availability of this document was distributed and was published on the Air District's website and newspapers throughout the area of the Air District's jurisdiction and a CEQA scoping meeting was conducted on July 27, 2021, to solicit public comment regarding the scope and content of the environmental information to be included in the Draft Environmental Impact Report.

The NOP/IS initially identified the following environmental resources as being potentially significant, requiring further analysis in the Draft EIR:

- Aesthetics,
- Air Quality, and
- Greenhouse Gas Emissions.

Public comments received on the NOP/IS raised additional concerns related to potential impacts on biological resources, those associated with the use of supplemental natural gas, those associated with project alternatives, and a recommendation to consult with Native American Tribes. Evaluation of these additional potential impacts were included in the Draft EIR as part of the evaluation of the impacts identified in the NOP/IS. With respect to consultation with Native American Tribes, impacts to cultural or tribal cultural resources are not expected. No Native American Tribes have requested consultation under Assembly Bill 52; but individual projects may be examined when the precise location compliance methods are known so that consultation with Tribes may prove more constructive.

Impacts to the following environmental resources were considered to be less than significant in the NOP/IS:

- Agriculture & Forestry Resources,
- Cultural Resources,
- Energy,
- Geology & Soils,
- Hazards & Hazardous Materials,
- Hydrology & Water Quality,
- Land Use & Planning,
- Mineral Resources,
- Noise,

- Population & Housing,
- Public Services,
- Recreation,
- Transportation,
- Tribal Cultural Resources,
- Utilities & Services Systems, and
- Wildfire.

B. Draft Environmental Impact Report

Pursuant to CEQA, the Air District prepared a Draft EIR to address the potential environmental impacts associated with the Rule 13-5. The Draft EIR was published on January 24, 2022 for review and comment. Aesthetic and GHG impacts were found to be less than significant. With respect to air quality impacts, hydrogen plants at two refineries are expected to need additional control technology to comply with Proposed Rule 13-5, the Valero Refinery in Benicia and the hydrogen plants that provide hydrogen to the PBF Refinery in Martinez. Compliance options could include installing flare technology to control total organic compound emissions; installing a gas recovery system; or implementing an Alternative Compliance Plan. The impacts associated with an Alternative Compliance Plan may vary but would be expected to include the addition of piping, valves, and flanges and similar equipment to reroute gas streams within the facility. Worst case emissions of pollutants associated with construction and operation of control equipment were found to be less than significant with the exception of emissions of NOx which may be significant should a flare be utilized for control. Operational emissions of NOx were estimated to be approximately 30 tons per year if the affected facilities opted to use flaring as the method of control. Because of potential NOx emissions, cumulative air quality impacts were also found to be potentially significant. Implementation of the alternative control option in Proposed Rule 13-5 would be expected to result in much lower NOx emissions. Table 6 summarizes these air quality impacts, mitigation measures, and residual impacts, as well as other potential impacts evaluated in the DEIR.

Table 6
Summary of Air Quality Impacts, Mitigation Measures, and Residual Impacts

Impact	Mitigation Measures	Residual Impacts
Aesthetics		
The addition of flares at the facilities may add visible structures to the skyline, which are not expected to change the visual character of either the PBF Martinez or Valero Benicia Refinery, respectively. Multiple structures at the refineries are similar in height and width as potential new flares. Aesthetic impacts would be less than significant.	None required.	Aesthetic impacts associated with implementation of Rule 13-5 would be less than significant.
Air Quality		
The construction activities may include construction of two flare systems. The construction emissions may exceed the CEQA significance thresholds for NOx and are potentially significant.	The Air District's Basic Construction Mitigation Measures are expected to be implemented.	Construction emissions of NOx, may remain significant.
Worst-case operational activities associated with the implementation of Proposed Rule 13-5 may include the operation of two flares. The emissions calculations determined that NOx emissions from flares could exceed the CEQA thresholds and are potentially significant. The emissions of other criteria pollutants would be less than significant.	Any new equipment may be required to comply with BACT. Compliance with the BACT requirements would minimize emissions from the source to the maximum degree feasible	Operational emissions of ROG, CO, SOx, PM_{10}, and $PM_{2.5}$ would be less than significant. The operational emissions of NOx may be significant.
Implementation of Proposed Rule 13-5 would likely result in a reduction in TAC emissions from the control of the non-methane hydrocarbons that are potentially in the vent stream, or at worst result in no increase in TAC emissions. Therefore, TAC emissions and the related health risks associated with implementation of Rule 13-5 are expected to be less than significant.	None Required	Potential TAC emissions would be less than significant.
Greenhouse Gases		
Implementation of Proposed Rule 13-5 by the Air District may result in a minor increase in GHG emissions associated with the pilot gas for the flares (6,524 MT/year). Implementation of Rule 13-5 is expected to result in an overall emission reduction of over 77,477 CO_2e MT/year (see Table 3.3-9). Therefore, the GHG emissions associated with the project would be less than the significant thresholds and less than significant.	None Required	Implementation of Rule 13-5 is expected to result in a reduction in GHG emissions providing a beneficial impact.
Cumulative Air Quality		
Air quality impacts associated with the implementation of Proposed Rule 13-5 are potentially significant for NOx if both affected facilities install a new flare. Given that the Bay Area is not in attainment with the federal and state ozone standard, and that implementation of Proposed Rule 13-5 could result in significant air quality impacts, cumulative air quality impacts are also potentially significant.	Any new equipment may be required to comply with Air District BACT requirements. Compliance with the BACT requirements would minimize emissions from the source to the maximum degree feasible	The use of a flare would be expected to reduce VOCs by about 98 percent, leading to a beneficial impact of reducing TAC emissions. The cumulative operational emissions of NOx may be potentially significant.

C. Final Environmental Impact Report

Two comment letters were received during the comment period that address issues raised in the DEIR, and responses to those comments are included in the proposed Final EIR. Minor clarifications and revisions to the DEIR have been incorporated in the proposed Final EIR, none of which affect the environmental impacts of the project or otherwise represent "significant new information" requiring recirculation within the meaning of CEQA Guidelines Section 15088.

Prior to making a decision on the adoption of the Proposed Rule 13-5 and the proposed Amendments to Rule 8-2, the Air District's Board of Directors must review and certify the Final EIR as providing adequate information on the potential adverse environmental impacts of these actions. The proposed Final EIR concludes that NOx impacts during the construction and operation of flares, which may occur in order to comply with the Rule, were found to remain potentially significant after mitigation and cumulatively considerable. The EIR estimates that potentially significant air quality impacts associated with construction of air pollution control equipment to comply with the Proposed Project would be expected to be, in the worst-case, 55.31 pounds per day of NOx (in light of Bay Area emissions of approximately 298 tons of NOx per day). The EIR estimates that potentially significant air quality impacts associated with operation of air pollution control equipment to comply with the Proposed Project would be expected to be, in the worst-case, 35.2 tons per year of NOx (in light of Bay Area emissions of approximately 298 tons of NOx per day).

Because NOx impacts remain potentially significant, the Board of Directors must also adopt a Statement of Overriding Considerations in order to move forward with the adoption of the Proposed Rule 13-5 and the proposed Amendments to Rule 8-2. Air District staff recommends that the Board adopt a Statement of Overriding Considerations as the Proposed Project benefits in reducing methane emissions outweigh the Proposed Project's adverse NOx impacts, as detailed throughout this Staff Report and in the Final EIR for the Proposed Project.

VII. RULE DEVELOPMENT / PUBLIC PARTICIPATION PROCESS

As part of the Proposed Rule 13-5 rule development process, staff reached out to petroleum refinery industry experts and environmental advocacy and community groups. Staff conducted a briefing with the Refinery Rules Technical Working Group community members on June 27, 2019, to familiarize them on the basic operations and primary processes of hydrogen plants, and thus, to better enable them to participate in Refinery Rules Technical Working Group discussions for the Proposed Rule 13-5 rule development project. Staff conducted a Refinery Technical Working Group meeting on July 17, 2019, to discuss the availability and feasibility of all potential vented methane emission controls for hydrogen production equipment/processes. Staff submitted a comprehensive questionnaire to all hydrogen plant operators requesting pertinent parametric and emissions data relating to all hydrogen venting occurrences during the past six years. The questionnaire was divided into two phases with a due date of November 18, 2019, for Phase I and a due date of January 10, 2020, for Phase II. In July and August of 2019, Air District staff visited all of the ten hydrogen plants at least once for a total of 15 visits spread among the five refineries within the Air District's jurisdiction. Staff typically had pre-meetings with refinery staff, including hydrogen plant operators, conducted tours of the hydrogen plants and, when necessary, held post-tour meetings to ask more questions and clarify information. A second round of tours were concluded in January 2020 to help staff identify possible controls for each hydrogen plant as each refinery is designed differently, and thus, may not be capable of using the same types of controls or install gas recovery systems in the same locations or with similar configurations as other refineries.

A workshop for Proposed Draft Rule 13-5 was held in January 2020, at Air District headquarters. Staff met with Western States Petroleum Association (WSPA) and industrial hydrogen plant operators in March of 2020 to discuss the Draft New Rule. As initially drafted, Proposed Rule 13-5 was based on the concept of controlling methane and organic compound emissions by requiring a minimum hydrogen gas purity when vented from hydrogen plant operations. Any control method currently used, including hydrogen gas recovery or hydrogen gas flaring would have resulted in the reduction of methane emissions and organic compound emissions based on control efficiency requirements. After the preliminary staff report was published on September 4, 2020, Air District staff met with WSPA, refinery representatives and third-party operators on October 6, 2020, to discuss outstanding Proposed Rule 13-5 issues and comments.

Comments from industry included requests to change the emphasis in Proposed Rule 13-5 from controlling hydrogen gas purity to instead focus on addressing methane gas emissions. Furthermore, it was stressed that the four-year timeline to design, permit, purchase, and install controls for methane gas was not enough time, especially for the initial steps of designing and permitting controls. Other comments included concerns with potential duplication with existing Organic Rules; requests for exemptions for low-level methane emissions; and switching from percent weight standards to percent volume standards. The above concerns were addressed in the subsequent revision of Proposed Draft Rule 13-5 published on the Air District website in June 2021 along with the NOP/IS for the DEIR to be prepared for the rule. Proposed Draft Rule 13-5 was revised to address methane emissions in the form of "Total Organic Compounds," which include both methane and other organic compounds. The draft emissions standard in Section 13-5- 301 was modeled after the requirements in Regulation 8, Rule 2: Miscellaneous Operations, with an emission limit of 15 pounds per day and 300 parts per million for total organic compounds.

Staff held a scoping meeting on July 27, 2021, to solicit public comment regarding the scope and content of the environmental information to be included in the Draft EIR, with a deadline of July 30, 2021, for comments on both the environmental analysis discussed in the NOP/IS as well as any comments on the draft rule language. Staff also updated the Stationary Source and Climate Impacts Committee on rule development activities for Proposed Rule 13-5 on July 19, 2021. At that committee meeting, concerns were raised about the potential use of flares to control emissions from these sources.

Air District staff received industry comments from WSPA and individual refinery representatives regarding monitoring requirements contained in Draft Rule 13-5 along with proposals from representatives of two facilities to control emissions of methane and other GHGs through means other than the draft standard in Section 13-5-301. Air District staff met with industry staff on two separate occasions in September 2021 to discuss these alternatives and subsequently requested more information to better understand these proposals. Air District staff also met with WSPA and other industry representatives in October 2021 to discuss the monitoring requirements contained in the Rule.

Review of the alternative methods to reduce emissions as presented in these October meetings found them to be insufficient to meet the air quality goals of this rule development effort, but continued development of the emissions reductions methods described could potentially result in sufficient reductions to be deemed equivalent. Air District staff revised Proposed Rule 13-5 to include an Alternative Compliance Plan option (Section 13-5-303) as an alternative to the total organic compound emissions standard of Section 13-5-301. The Alternative Compliance Plan provisions contained in all subsequent versions of Proposed Rule 13-5 allow for sufficient review by Air District Staff to determine equivalency.

On January 24, 2022, Air District Staff posted a revised Draft Rule 13-5, DEIR, Draft Staff Report, and other supporting documents to solicit public comment, with the 45-day comment period ending March 10, 2022. Air District Staff met with Industry representatives on three occasions to discuss the revised proposal and industry comments. Staff considered all comments received and made further revisions to Draft Rule 13-5 to clarify monitoring requirements and resolve impediments to meeting compliance deadlines. On March 25, 2022, the revised rule was posted along with a Rescheduling of Public Hearing Notice to allow for public comment on the revisions to be submitted by April 15, 2022, with the Board Hearing rescheduled from April 6 to May 4, 2022. Air District Staff considered all comments received and a Response to Comments Summary is included as Appendix F of this report.

VIII. CONCLUSION / RECOMMENDATIONS

Pursuant to the California Health and Safety Code Section 40727, before adopting, amending, or repealing a rule the Board of Directors must make findings of necessity, authority, clarity, consistency, non-duplication, and reference. This section addresses each of these findings.

A. Necessity

"Necessity" is defined in Section 40727(b) to mean that "a need exists for the regulation, or for its amendment or repeal, as demonstrated by the record of the rulemaking authority." The meaning of "necessity" in Section 40727(a) is further illuminated by Health & Safety Code Section 40001(c) which provides that "prior to adopting any rule or regulation to reduce criteria pollutants, a district shall determine that there is a problem that the proposed rule or regulation will alleviate and that the rule or regulation will promote attainment or maintenance of state or federal ambient air quality standards."

The adoption of Proposed Rule 13-5 is necessary because industrial hydrogen plant operations are a major source of methane emissions. It is imperative to reduce GHG emissions that are within the Air District's authority to ensure the Region meets its climate protection goals and further expedite the reduction of methane. At the recent climate summit in Glasgow, over 100 countries (including the United States) signed the Climate Change Conference Global Methane Pledge to commit to collectively reduce global methane emissions by 30 percent by 2030.[xxv]

As previously discussed, the Air District adopted a policy goal of reducing Bay Area GHG emissions to 40 percent below 1990 levels by 2030, and 80 percent below 1990 levels by 2050. Recognizing the importance of reducing methane emissions in the Bay Area, the Air District developed a comprehensive Basin-wide Methane Strategy as part of its 2017 Clean Air Plan to better quantify and reduce the Region's methane emissions. This rule would be one of the Air District's first GHG regulations that will serve to reduce emissions of methane, a potent GHG, in the form of total organic compounds.

B. Authority

"'Authority' means that a provision of law or of a state or federal regulation permits or requires the regional agency to adopt, amend, or repeal the regulation." H&SC Section 40727(b)(2)

The Air District has the authority to adopt this rule under Sections 40000, 40001, 40702, and 40725 through 40728.5 of the California Health and Safety Code.

C. Clarity

"'Clarity' means that the regulation is written or displayed so that its meaning can be easily understood by the persons directly affected by it." H&SC Section 40727(b)(3)

Proposed Rule 13-5 is clear, in that the rule specifically delineates the affected industry, compliance options, and administrative requirements for industry subject to this rule, so that its meaning can be easily understood by the persons directly affected by it.

D. Consistency

"'Consistency' means that the regulation is in harmony with, and not in conflict with or contradictory to, existing statutes, court decisions, or state or federal regulations." H&SC Section 40727(b)(4)

Proposed Rule 13-5 is consistent with other Air District rules, and not in conflict with state or federal law.

E. Non-Duplication

"'Nonduplication' means that a regulation does not impose the same requirements as an existing state or federal regulation unless a district finds that the requirements are necessary or proper to execute the powers and duties granted to, and imposed upon, a district." H&SC Section 40727(b)(5)

As the regulatory analysis indicated, Proposed Rule 13-5 is non-duplicative of other statutes, rules, or regulations.

F. Reference

"'Reference' means the statute, court decision, or other provision of law that the district implements, interprets, or makes specific by adopting, amending, or repealing a regulation." H&SC Section 40727(b)(6)

By adopting the Proposed Rule and Proposed Amendments, the Air District Board of Directors will implement, interpret and/or make specific the provisions of Sections 38594, 40000, 40001 and 40702 of the California Health & Safety Code.

Proposed Rule 13-5 met all legal noticing requirements, was discussed with the regulated community and other interested parties, and reflects consideration of the input and comments of many affected and interested stakeholders.

G. Recommendations

Air District staff recommends adoption of proposed Regulation 13, Climate Pollutants, Rule 5: Industrial Hydrogen Plants and adoption of amendments to Regulation 8: Organic Compounds, Rule 2: Miscellaneous Operations and certification of the CEQA Final EIR and adoption of a Statement of Overriding Considerations.

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