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Re: Technical Report on behalf of CBE, on Oxy USA Draft Environmental Impact Report for the Dominguez Oil Field Development Project, SCH No. 2012031019

I am writing on behalf of Communities for a Better Environment ("CBE"), regarding the Oxy USA Draft Environmental Impact Report ("DEIR") for the Dominguez Oil Field Development Project (hereafter "The Project"). I am a senior scientist at CBE and responsible for engineering evaluations of pollution sources and solutions for CBE. A true and current copy of my CV is attached, at Exhibit 1, to this document. Although the oil drilling Project has changed in the last year so that it is currently described by Oxy representative as no longer include fracking (hydraulic fracturing), there are nonetheless major environmental impacts due to the Project that are missing from the DEIR analysis. This technical report does not evaluate whether or not the Project includes fracking; it looks at other serious environmental impacts that are independently implicated by Project, as described in the DEIR. .

As also noted in the Legal Comment Letter to the Project, neighbors of the project have expressed serious concerns about potential Project impacts. there are . Oil drilling operations in general have caused many public complaints about disruptive odors and noises, extreme vibrations, foundation damage, asthma impacts, dust, oily residue distributed by air onto homes, intense diesel truck traffic, water runoff, subsidence of properties, and more. While all of these are valid concerns, I have specifically evaluated only a few areas of impacts as follows:

- **Radiation contamination due to the Project was not discussed in the DEIR despite it's being a known hazard in Oil and Gas drilling, as documented by EPA.** This constitutes a significant impact that must be evaluated, monitored, and mitigated for this Project, and for Cumulative Impacts from all oil and gas drilling in the region. Alternatives to the Project should also be considered that eliminate radiation exposure risk.
- **Methane leaks from Oil and Gas drilling have been shown at far higher levels in recent studies, as compared to levels assumed in the DEIR, using generalized emissions factors**. The DEIR estimated 0.51 MT/yr (metric tonnes/year[1]) due to the Project, but EPA and other estimates showed far higher leak rates from 4 to 17%, which translates to up to 78,500 MT/year. This major disparity compared to the DEIR estimate must be evaluated and corrected.
- **Flare VOC emissions were greatly underestimated –** The DEIR includes a hidden assumption that the Emergency Flare would never be turned on for the life of the Project,

[1] Metric tonnes per year, CO2 equivalent

so that only pilot light emissions were calculated. The Process Flare emissions calculations also grossly underestimatemissions, apparently through use of an inappropriately high flare combustion efficiency despite evidence that oil field flare destruction of hydrocarbons goes far lower, although the calculations that were provided are somewhat vague, or imprecise, and need to be completed the public to have access to a full Project Description.

- **The Project failed to adequately consider the extreme risk of oil fires that could occur after a major earthquake in the region (expected imminently), which would greatly endanger public safety.** Instead the Project treated earthquakes and fires as separate issues, as if unrelated. This provides an unrealistic estimate of the probability that oil fires would occur. Such fires are very difficult to extinguish, and after a major earthquake could more easily spread. They also can cause large clouds of hazardous smoke. Siting an intensive oil drilling operation within an urban area that is extremely vulnerable to earthquakes must be considered in light of these major potential dangers, and alternatives the Project must be seriously considered.
- **The categorization of this Project as "Light Industrial" despite its size and Heavy Industrial implications is troubling** (since many proposed operations are very similar to those at an oil refinery, which would certainly be considered heavy industry, and since there are a large number of wells, with processing of flammable and acutely hazardous materials proposed).

I. Evaluation of known radiation dangers from drilling operations are entirely missing from the DEIR

According to the U.S. Environmental Protection Agency (EPA), radioactive waste and radon gas can be brought to the surface by oil and gas drilling operations, as shown in the excerpt from an EPA 2006 publication:

> **Radioactive Waste from Oil and Gas Drilling**[2]
>
> There are two categories of radioactive material that workers and the public need to be concerned about:
>
> • Naturally-occurring radioactive material (NORM) that are **released into the atmosphere and deposited on the ground through the drilling process**, and
>
> • Technologically-enhanced naturally-occurring radioactive material (TENORM), which is radionuclides that have been concentrated by the extraction and production process, such as mineral scales and sludge waste buildup in oil and gas extraction equipment. The radiation comes from naturally-occurring radioactive material (NORM) in the underground rock and sediment.
>
> . . . The radon gas may be released to the atmosphere, while the produced water and mud containing radium are placed in ponds or pits for evaporation, re-use, or recovery. The radium brought up during drilling can also decay to radon gas, which a worker can inhale and can raise the risk of lung cancer. Radium-226 emits gamma radiation and the lead emits low-level energy

[2] See, Radioactive Waste from Oil and Gas Drilling information, US EPA, available at: http://www.epa.gov/radtown/docs/drilling-waste.pdf.

> gamma radiation and beta particles. Gamma radiation can also penetrate the skin and raise the risk of cancer. Following worker safety guidance will reduce total on-site radiation exposure.
> *[emphasis added]*

No mention of this problem was made in the DEIR (the DEIR does discuss "thermal radiation," but this just means heat from burning fuels, and has nothing to do with radioactivity). Clearly, the Project activities which cause any radioactive contamination at the surface or in water and soil, has the potential to cause a significant impact. No mitigation to limit public exposure, or monitoring equipment are identified as part of the Project; this needs to be corrected.

EPA identifies the risk of lung cancer for workers as part of the risk. Worker exposure and public exposure needs to be evaluated in detail for the direct impacts of the Project, and for the Cumulative Impacts of all Oxy-owned, and other drilling operations. In addition to neighbors in the area of the facility, sensitive receptors including schools and other facilities should be evaluated for potential exposure.

EPA has noted that the public "needs to be concerned about" the buildup of radioactivity in oil drilling equipment and sludge. This needs evaluation and requires mitigation including monitoring and prevention of radioactive contamination and health risk. Because EPA identified the radioactivity as cumulative, increases over time must also be considered.

EPA also evaluated the relative risk of radiation in different states. Some states had higher risk, some lower. In general, California was found to have lower radioactivity present, but EPA also found that radioactivity becomes more concentrated in drilling muds, produced water, and equipment used in drilling. These are activities that are included in the proposed Project by Oxy, and must be evaluated for radiation buildup.

> **Produced Waters**
>
> The radioactivity levels in produced waters are generally low, but the volumes are large. . . .
>
> **Scale**
>
> . . . Scales are normally found on the inside of piping and tubing. The API found that the highest concentrations of radioactivity are in the scale in wellhead piping and in production piping near the wellhead. Concentrations were as high as tens of thousands of picocuries per gram. However, the largest volumes of scale occur in three areas:
>
> - water lines associated with separators, (separate gas from the oil and water)
> - heater treaters (divide the oil and water phases)
> - gas dehydrators, where scale deposits as thick as four inches may accumulate . . . .
>
> The average radium concentration in scale has been estimated to be 480 pCi/g. It can be much higher (as high as 400,000 pCi/g) or lower depending on regional geology.
>
> **Sludge**
>
> Sludge is composed of dissolved solids which precipitate from produced water as its temperature and pressure change. Sludge generally consists of oily, loose material often containing silica compounds, but may also contain large amounts of barium. Dried sludge, with a low oil content, looks and feels similar to soil. . . .

> API has determined that most sludge settles out of the production stream and remains in the oil stock and water storage tanks.
>
> . . . The average concentration of radium in sludges is estimated to be 75 pCi/g. This may vary considerably from site to site. Although the concentration of radiation is lower in sludges than in scales, sludges are more soluble and therefore more readily released to the environment. **As a result they pose a higher risk of exposure.**
>
> The concentration of lead-210 (Pb-210) is usually relatively low in hard scales but **may be more than 27,000 pCi/g in lead deposits and sludge.**
>
> **Contaminated Equipment**
>
> Gas plant processing equipment is generally contaminated on the surface by lead-210 (Pb-210)**. However, TENORM may also accumulate in gas plant equipment** from radon (Rn-222) gas decay. **Radon gas is highly mobile.** It originates in underground formations and dissolves in the organic petroleum areas of the gas plant. **It concentrates mainly in the more volatile propane and ethane fractions of the gas.**

Risks to the nearby population is also described by EPA:

> **Nearby Residents/Office Workers**
>
> **Risks evaluated for members of the public working or residing within 100 meters of a disposal site are similar to those of disposal workers.** They include: direct gamma radiation, inhalation of contaminated dust, inhalation of downwind radon, ingestion of contaminated well water, ingestion of food contaminated by well water, and ingestion of food contaminated by dust deposition.
>
> **Risks analyzed for the general population within a 50 mile radius of the disposal site include exposures from the downwind transport of re-suspended particulates and radon,** and exposures arising from ingestion of river water contaminated via the groundwater pathway and surface runoff. Downwind exposures include inhalation of re-suspended particulates, ingestion of food contaminated by deposition of re-suspended particulates, and inhalation of radon gas.
>
> **Individuals working inside an office building inadvertently constructed on an abandoned NORM waste pile also face the threat of radiation exposure.** Potential risks assessed for the onsite individual include exposures from direct gamma radiation, dust inhalation, and indoor radon inhalation. *[Emphasis Added]*

These impacts must be considered significant, since radioactivity concentrates over time even if levels start out low. Especially when no measures are taken for monitoring, this constitutes a hidden danger.

II. Oxy underestimated flare emissions

<u>The DEIR flare calculations</u>

In oil drilling operations, flares are used to burn "waste" gas that is brought out of the ground along with the crude oil (when the gas is not put to other uses, such as cleaning it up to sell as natural gas). Unfortunately, the DEIR emission estimates for VOCs (Volatile Organic

Compounds, or hydrocarbons) and many other pollutants[3] only included a fraction of the Process Flare and Emergency Flare potential emissions. If corrected, the flaring emissions would cause significant emissions of VOCs and other pollutants, which need to be mitigated.

There are at least two big problems with the flare calculations:

1) The Emergency Flare was calculated only with Pilot light emissions, as if it would never be used for the entire lifetime of the Project, rather than calculating the potential emissions using the Emergency Flare.
2) The Process Flare emissions were greatly underestimated, apparently by using inappropriately high assumed combustion efficiency.

Here are the small daily maximum and average flare emissions that were estimated in the DEIR, excerpted from two tables in Appendix B:[4]

Table 10. Projected Maximum Daily Emission Rates During Operations						
Category	Daily Emissions (lb/day)					
	VOC	CO	NOX	SOX	PM10	PM2.5
Emergency Flare	0.05	0.25	0.94	0.004	0.05	0.05
Process Flare	3.25	10.51	26.86	0.28	3.48	3.48
Table 11. Projected Average Daily Emission Rates During Operations						
Category	Daily Emissions (lb/day)					
	VOC	CO	NOX	SOX	PM10	PM2.5
Emergency Flare	0.05	0.25	0.94	0.004	0.05	0.05
Process Flare	2.79	9.04	23.09	0.24	2.99	2.99

Before gases are routed to the flare as waste gases, some of these VOC/hydrocarbons are instead put to use. The separation and treatment of these VOCs (including methane, ethane, butane and propane and others) is described in the DEIR as follows, but substantial leftover gas is sent to the flares:[5]

[3] The criteria pollutants NOx, CO, PM10. and PM2.5, and toxics benzene formaldehyde, total PAHs, naphthalene, acetaldehyde, acrolein, ethyl benzene, hexane, toluene, and xylene were also calculated only from the flare pilot `light, rather than from the total gas burned in the flare.

[4] Oxy Volume 2-DEIR Appendix B-AirQualityTechReport, Environ [DEIR Appendix B], Tables 10 and 11 at pp. B-38 and B39, available at: http://ci.carson.ca.us/content/files/pdfs/planning/oxyproject/Volume%202Appendix%20B-AirQualityTechReport.pdf

[5] DEIR, at p. 2-17 *"The final step before gas transfer of [sic] into the sales pipeline will be to remove any heavy hydrocarbons and water by using a combined refrigeration/dehydration system. Ethylene glycol will be injected to prevent freezing at low temperatures before the gas is chilled to sub-zero temperatures in the Low Temperature Separator. At sub-zero temperatures, the heavy hydrocarbons (i.e., propane, butane, etc. (referred to as C3+ for the number of carbon atoms in the compounds)) will condense to liquids and be removed in a threephase Low Temperature Separator. The gas, which now meets the specifications for natural gas, will then be transferred into the sales pipeline." . . .*

- Some portion is removed for sale as natural gas,
- Some of these hydrocarbons are blended into crude oil for sale,
- Some are used to fuel equipment onsite,
- Some gases are used as a vapor blanket inside storage tanks,
- The remainder of these gases are burned in the flares.

Because there is substantial flare capacity, and there are two of them, this clearly indicates that substantial amounts of VOC gases remain after the other removal processes, to be sent to the flares. Standard protocols for estimating these emissions needs to be carried out. The volumes of gases sent to the Process Flare is large - 464,000 scfd (Standard Cubic Feet per Day), and the flare operates continuously all year. According to Appendix B (p. B-96), they operate 24 hours a day, seven days a week, 365 days per year.

<u>Emergency Flare</u>

These DEIR calculations included only the *pilot flame* emissions, leaving out the much higher emissions that would occur due to actual flare usage. Just like a gas stove in the kitchen has a pilot light, a flare must also have a pilot light on continuously, so that when the flare is "turned on" (meaning that gases are sent to the flare to be combusted), it is ready to ignite these gases, which are a much larger volume compared to the small pilot. This is the whole purpose of the flare (to burn waste gases, not to sit forever unused, with a pilot light). The flare burns most of the VOCs into CO2 emissions (which are not toxic, but are greenhouse gases). However, because combustion is never perfectly efficient, substantial VOC emissions as well as other pollutants are emitted to the atmosphere.[6]

Including only the pilot flame emissions in the DEIR is the same as only calculating emissions when the flare is "off." The DEIR clearly must include the emissions from actual usage.

The specific calculations provided by the DEIR in Appendix B for the emergency flare[7] confirm that only the emissions from the pilot flame were calculated, as shown by the excerpt from Table A-4, which is labeled as emissions for the Emergency Flare Pilot. It also has a descriptive paragraph below it, describing only calculations for the pilot light:

"The heavy hydrocarbons (also called natural gas liquids (NGLs)), which were separated in the three-phase Low Temperature Separator, will be sent to the NGL System to remove entrained methane, ethane, and propane, so as to meet the specification for NGLs to be allowed to be included in the crude oil for sale. The methane, ethane, and propane will be used on-site as fuel gas to produce process heat with any excess blended into the sales gas stream as specification allows. If no additional gas can be blended into the sales gas stream, the gas will be consumed using an existing dedicated process flare. The existing process flare was installed as part of the test well drilling activities and will be incorporated into the Oil and Gas Processing Facilities to serve the same function."

[6] In addition to those listed in the previous footnote, flares also burn sulfur compounds such as hydrogen sulfide gas (H2S), which turns into sulfur dioxide - also toxic, but not as deadly as H2S. The Project has methods to strip H2S gas before the flare.

[7] DEIR Appendix B, at pp. B-57

Table A-4. Project Criteria Pollutant and TACs Emissions - Emergency Flare (Pilot)

Pollutant [1]	CAS	Emission Factor[1,2]	Maximum Daily Controlled	Average Annual
		lb/MMscf	lbs/day	lbs/yr
VOC	-	7.00	5.04E-02	1.84E+01
CO	-	35.00	2.52E-01	9.20E+01
NO_x	-	130.00	9.36E-01	3.42E+02
SO_x	-	0.60	4.32E-03	1.58E+00
PM_{10}	-	7.50	5.40E-02	1.97E+01
$PM_{2.5}$	--	--	5.40E-02	1.97E+01

1. ***Criteria pollutant emissions from natural gas combustion in the <u>flare pilots</u> are estimated using the natural gas default factors for VOC, SOx, and PM10*** *from SCAQMD's Annual Emissions Reporting Program online help document (available online at http://www.aqmd.gov/webappl/Help/AER/index.html): Default Emission Factors for External Combustion Equipment for Forms B1 and B1U (for all sizes); Natural Gas, Other Equipment. PM2.5 is calculated using PM profiles in the California Emission Inventory Data and Reporting System (CEIDARS) developed by the CARB, assuming Incinerator, afterburner, flare - Gaseous fuel (SCAQMD. 2006. Final - Methodology to calculate PM2.5 and PM2.5 Significance Thresholds. Appendix A)."* [Emphasis added]

The Maximum Daily Controlled VOC emission result listed above for the flare pilot is a Maximum Daily Controlled level of 5.04E-2 lbs/day, which means 5.04×10^{-2} or 0.05 lbs/day, which is the same as the daily emissions listed for the Project totals, for the Emergency Flare (Tables 10 and 11 above). This shows clearly that only pilot light emissions are included in project totals for the Emergency Flare. (Average Annual emissions are also reported, by multiplying daily emissions by 365 days per year.)

The maximum and average capacity of the Emergency Flare is not provided, and nor the potential percent usage of the flare. The Emergency Flare may be sized similarly to the Process Gas Flare, or may be larger or smaller. If it is the same size and would be run at the same time as the Process Gas Flare during emergencies, then daily emissions would double as compared to the estimates below for the Process Gas Flare. The Project Description is thus incomplete, and needs to provide the full capacity of the Emergency Flare and maximum potential volume of gases sent to the flare hourly, daily, and annually, and the full potential to emit. Permit conditions will be needed which identify all the details of these flares for the expanded Project operations.

<u>Process Flare</u>

For the Process Flare, the problem is different. While gases routed to the flare when it is in use were calculated in the DEIR, the calculations appeared to use a very high combustion efficiency assumption. It is not normal for field gas flares to have extremely high combustion efficiency, and studies have demonstrated far lower levels. Combustion efficiency is a measure of how much hydrocarbon would be destroyed by the flare.

The DEIR does not explicitly identify many characteristics of the Process Flare (such as what is its age, what is the manufacturer's rating on flare gas capacity, does the flare include any flare gas flow or content monitoring, what is the mix of specific gases expected into the flare, and the percentage of each (propane? methane? etc.), or expected combustion efficiency.

Appendix B shows substantial flare gas volumes routed to the flare 24 hours a day, seven days a week, 365 days per year. The DEIR states that the maximum permitted flow rate of gases burned in the Process Flare is 464,000 scfd (Standard Cubic Feet per Day). (Appendix B, p. B-96). The Process Flare emissions are calculated and shown as follows:

Table A-13. Project Criteria Pollutant and TACs Emissions - Process Flare

Pollutant[1]	CAS	Emission Factor[1,2]	AHU	AHC	MHU	MHC	MDU	Maximum Daily Controlled	Average Annual
		lb/MMscf	lbs/hr	lbs/hr	lbs/hr	lbs/hr	lbs/day	lbs/day	lbs/yr
VOC	-	7.00	0.12	0.12	0.14	0.14	3.25	3.25	1,019
NO_x	-	-	0.96	0.96	0.96	0.96	26.86	26.86	8,429
SO_x	-	0.60	0.01	0.01	0.01	0.01	0.28	0.28	87
CO	-	-	0.38	0.38	0.38	0.38	10.51	10.51	3,298
PM_{10}	-	7.50	0.13	0.13	0.15	0.15	3.48	3.48	1,092
$PM_{2.5}$	--	--						3.48	1,092

(Although the DEIR does not explain the terms above, AHU is Average Hourly Uncontrolled, AHC is Average Hourly Controlled, MHU is Maximum Hourly Uncontrolled, MHC is Maximum Hourly Controlled, and MDU is Maximum Daily Uncontrolled emissions. The Project description is not complete without a showing of the lbs/hr and lbs day into the flare (not just out of the flare), and an explicit identification of the combustion efficiency.)

The DEIR appears to have used a generalized emission factor, and did not seek to calculate more specific protocols for field gas flares. The Clean Air Act requires that when more accurate and specific information is available for equipment, it must be used rather than using a generalized emission factor meant for a broad range of equipment when more specific information is not available.

Further, the DEIR calculations only refer generally to an AQMD website that is available calculating a large number of different types of equipment. This website is available for industries, but when we attempted to register to use this website to replicate the calculations identified by Oxy as being generated at this website, we were not able to do so, because it requires a Facility ID. (This apparently means that you have to be an emitter of air pollution to use the site.) At any rate, all the assumptions used and calculations performed should be provided in the DEIR.

A standard calculation of Process Flare VOC emissions when applied to OXY would be as follows, for maximum lbs/day. While the DEIR did not identify the mix of hydrocarbon gases and their percentages sent to the flare, the DEIR did propose using 2,517 MMBTU/MMSCF[8] (or

[8] Appendix B at p. 96 states: *"While the flare rating and capacity is expected to be as shown, the emissions shown here are conservatively based on the average expected flow rate from SPEC Service and a higher heating value of 2,517 MMBtu/MMcf."* Propane has a heating value of about 2517 (2516 is also commonly cited, as in this propane industry publication: http://www.propane101.com/aboutpropane.htm)

2,517 BTU/SCF, which is a measure of heat content of the gases in British Thermal Units sent to the flare per standard cubic foot of gas volume). The DEIR states that the Process Flare operates continuously, all year long. This is the value of the hydrocarbon propane, so the emissions calculations below accordingly based on those propane values. .

We can directly calculate the lbs/day of hydrocarbon going into the flare using the information previously cited from the DEIR, and from standard conversion factors:

464,000 Standard Cubic Feet per Day **X** **0.116 lbs/scf[9] of hydrocarbon/VOC gas into the flare**
(Volume of gas burned in the flare/day) (Mass of the gas per cubic foot of volume)

= 53,830 lbs/day of hydrocarbon (VOC) going *into* the flare (not yet combusted)

To get the amount of hydrocarbon coming *out* of the flare, the amount into the flare is multiplied by the combustion efficiency of the flare (the VOC destruction efficiency). Combustion efficiency can vary. Using potential ranges below would result in significant VOC emissions under varying conditions:

At **90%** Efficiency:
53,830 lbs/day going *into* the flare X 10% VOC remains = **5,383 lbs VOC emitted by the flare**

At **98%** Efficiency:
53,830 lbs/day going *into* the flare X 2% VOC remains = **1,077 lbs VOC emitted by the flare**

At **99%** Efficiency:
53,830 lbs/day going *into* the flare X 1% VOC remains = **538 lbs VOC emitted by the flare**

At **99.5%** Efficiency:
53,830 lbs/day going *into* the flare X 0.5% VOC remains = **269 lbs VOC emitted by the flare**

A standard assumption by air quality agencies is often to assume that flare efficiency is 98% for oil refinery flares. Even applying this high efficiency of 98% would result in 392 lbs of hydrocarbons emitted by the flares (VOCs). But the Oxy DEIR appears to be using a far higher combustion efficiency, or else applies some other hidden assumption, for instance, that only a tiny fraction of the flare gas is hydrocarbon. The DEIR needs to provide a clear description of the conditions and assumptions used for the Project.

In fact, combustion efficiency for oil drilling operation flares are well-documented to range to very low efficiency (and can even go down to 62% or even lower). At 62% efficiency, the VOC emissions would be 20,500 lbs of VOC emitted by the flare! It is unlikely that flare

[9] Propane is C3H8, with a molecular weight of 44, or 44 lbs/lb-mole. Using a standard engineering conversion factor at standard temperature and pressure: 44lbs/lb-mole /379 scf /lb-mole = .116 lbs/SCF for propane

combustion efficiency would always be this low, but, it is extremely unlikely that the combustion efficiency would ever be, and certainly not always be, 99.98% or higher, which may have been assumed in the Oxy DEIR.

The emissions calculations above were at the maximum flow rate per day. Calculations can also be done at average flow, resulting in average emissions, using the average flow rate of 400,000 SCF/day of flare gas flow instead of 464,000 SCF/day. Average emissions results would be 86% of maximum emissions (400,000/464,000 = 86%).

Since these flares are *existing* flares, the details of flare manufacture and design missing from the DEIR should be available, and provided in the EIR process, and the combustion efficiency assumptions be corrected.

Documentation of low hydrocarbon destruction efficiency in Oil Field and Other Flares

As stated above, many studies demonstrate that combustion efficiency of flares frequently go far lower than 98% (which is often assumed by regulators), although the Oxy DEIR apparently assumed an even higher efficiency.

Wind is one factor that reduces flare efficiency (in addition to variations in the heat content of gas sent to the flare, flare design, and other factors). Even at low wind speeds (below 3.5 m/s), flare efficiency can be as low as 70%, with even more significant decreases in efficiency at higher wind speeds.[10] This is especially so in oil field flares, which are less sophisticated than oil refinery flares. VOC destruction efficiency drops significantly when crosswinds are greater than 5 mph.[11] In sum, the wind speeds in the region and at the flare height can be expected to substantially reduce efficiency well below the applicant's assumed 98% efficiency.

A well known flare manufacturer, John Zink, has highlighted problems that can lower flare efficiency (resulting in higher VOC emissions). John Zink is listed as a co-author on an article published in Hydrocarbon Processing on flares at the Flint Hills (MI) refinery which states:

> . . . ***There is growing concern that emissions of VOCs from flares may be much higher than previously thought.*** *One possible reason is that wind effects can reduce flare destruction efficiency. The estimated emissions from flares are often based on measurements made with little or no wind. Accordingly, the emissions may be much higher under windy conditions.*
>
> . . . *Another very challenging problem is that weather conditions, the waste-gas flowrate, and composition are highly variable and not generally controllable.*[12]

[10] Douglas M. Leahey, Katherine Preston and Mel Strosher, "Theoretical and Observational Assessment of Flare Efficiency," 51 *J. Air & Waste Mgmt.* 1610, 1616 (2001).
[11] U.S. EPA, VOC Fugitive Losses: New Monitors, Emissions Losses, and Potential Policy Gaps, 2006 International Workshop, October 25-27, 2006, at 24
[12] *Minimize facility flaring, Flares are safety devices that prevent the release of unburned gases to atmosphere,* J. Peterson, Flint Hills Resources, Corpus Christi, Texas, N. Tuttle, H. Cooper and C. Baukal, John Zink Co., LLC, Tulsa, Oklahoma, June 2007 Hydrocarbon Processing, pp. 111–15 (emphasis added) (citations omitted).

A Canadian study, "Performance of Flare Flames in a Crosswind, With Nitrogen Dilution,"[13] is cited in the Hydrocarbon Processing article coauthored by the John Zink Company. The study identifies windspeed as a major impact on flare efficiency, cites wind tunnel flare efficiencies under 90 percent under certain wind conditions, and references an earlier Canadian study that found average flare efficiency of only 70 percent as a result of crosswind effects.[14] This drastically increases emissions compared to an assumption of 98% or higher destruction efficiency.

A major study for the Canadian government about flares found:[15]

> Emissions from flaring operations are complex and their composition influenced by a variety of factors including flare design, operating conditions, and composition of waste gases. Gas streams with low heating values are unable to maintain a stable flame, thereby reducing overall efficiencies of combustion (McCrillis, 1988). Flared gases with varying amounts of liquid hydrocarbons, carbon dioxide, nitrogen, and/or sulfur gases may not only have reduced combustion efficiencies, the combustion process may also produce undesirable components in the emission (Pohl and Soelberg, 1985; 1986; and 1986a). Strong cross-winds can produce a significant reduction in the combustion efficiency of a flare by shedding and/or tearing some of the eddies from the flame that contain incomplete or partially combusted gases from the flare (Gallant et al.; 1984; Grouset and Pilon, 1987).
>
> In light of the many variables that can affect combustion efficiency in flaring, the potential for emissions that may affect air quality, and the widespread use of flares in Alberta, a Government/Industry Consultative Committee on Flaring (GICCOF) was established to examine the whole practice of flaring. They noted that some of the main problems encountered in examining flares were in sampling methodology, knock-out drum effects, and effects of high winds.

This report also found that toxic emissions could be formed by the flare, including benzene and PAHs (Executive Summary).

I. The DEIR did not evaluate the potential for large methane emissions due to leaks shown by multiple studies

The DEIR vastly underestimated the Project potential to emit greenhouse gases from fugitive sources (leaks) from drilling operations. The Project has identified fugitive emissions of only 0.51 MT/year (metric tonnes of CO2 equivalent per year), as shown in Table 3 from Appendix C, (at p. C-27):

[13] P.E.G. Gogolek, A.C.S. Hayden, *Performance of Flare Flames in a Crosswind With Nitrogen Dilution*, Journal of Canadian Petroleum Technology, August 2004, Volume 43, No. 8.
[14] Gogolek and Hayden, Performance of flare flames in a crosswind with nitrogen dilution, Journal of Canadian Petroleum Technology, 2004 vol. 43, no. 8, pp. 43-47
[15] Investigation of Flare Gas Emissions in Alberta, Final Report to Environment Canada Conservation and Protection, 1996, http://www.ags.gov.ab.ca/publications/SPE/PDF/SPE_005.PDF at pp. 3-4

Table 3: Oxy Project Operation Direct and Indirect GHG Emissions				
Project Emission Source	Potential to Emit (MT/year)			
	CO_2	CH_4	N_2O	CO_2e [8]
Stationary Source				
Emergency Flare	147	0.00	0.00	148
Carbon Adsorber Unit for Surry System	0	0.00	0.00	<1
Process Heater Unit	4,681	0.08	0.01	4,685
Truck Loading Unit	0	0.00	0.00	<1
Emergency Generator Unit	15	0.00	0.00	15
Carbon Adsorber Unit for Sump Water	0	0.00	0.00	<1
Fugitives	0	0.51	0.00	11
Workover Rig	220	0.11	0.00	223
Process Flare	12,638	0.21	0.02	12,650
Backhoe	8	0.00	0.00	8
Mobile Sources				
Workers & Contractors [1]	87	0.00	0.00	87
Mud/Hauling Trucks [2]	130	0.00	0.00	130
NGL Trucks [3]	489	0.02	0.00	489
Solid Trucks [4]	7	0.00	0.00	7
Workover Rig [5]	2	0.00	0.00	2
Indirect Sources				
Electricity Consumption (total) [6]	28,029	1.27	0.48	28,204
Waste Disposal [7]	2	0.11	0.00	4
Total Operation Emissions	**46,455**	**2.33**	**0.51**	**46,666**

Unfortunately, recent studies found extremely high levels of methane gas leakage from oil and gas drilling operations For example, the Science Journal *Nature* reported as follows:[16]

> **Methane leaks erode green credentials of natural gas,**
> **Losses of up to 9% show need for broader data on US gas industry's environmental impact**
>
> Scientists are once again reporting alarmingly high methane emissions from an oil and gas field, underscoring questions about the environmental benefits of the boom in natural gas production that is transforming the US energy system. The researchers, who hold joint appointments with the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado in Boulder, first sparked concern in February 2012 with a study suggesting that up to 4% of the methane produced at a field near Denver was escaping into the atmosphere. If methane — a potent greenhouse gas — is leaking from fields across the country at similar rates, it could be offsetting much of the climate benefit of the ongoing shift from coal- to gas-fired plants for electricity generation.

[16] Nature News, 02 January 2013, available at: http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123

> Industry officials and some scientists contested the claim, but at an American Geophysical Union (AGU) meeting in San Francisco, California, last month, the research team reported new Colorado data that support the earlier work, as well as preliminary results from a field study in the Uinta Basin of Utah suggesting even higher rates of methane leakage — an eye-popping 9% of the total production. That figure is nearly double the cumulative loss rates estimated from industry data — which are already higher in Utah than in Colorado.
>
> "We were expecting to see high methane levels, but I don't think anybody really comprehended the true magnitude of what we would see," says Colm Sweeney, who led the aerial component of the study as head of the aircraft programme at NOAA's Earth System Research Laboratory in Boulder.

The figure above reported by Nature in the NOAA study topped 9% losses of gas, even higher than the 4% figure found in the 2012 study.

The DEIR states that the project will produce 3 million cubic feet of gas per day.[17] Four to nine percent leakage of 3 million cubic feet of gas per day is equal to 120,000-270,000 cubic feet per day of methane leakage, or 44-99 million cubic feet per year. This is equivalent to 18,500 to 42,000 MT (metric tonnes) per year of CO2 equivalent greenhouse gases, if 4 to 9% of the product leaks;[18] (a far cry from the 0.51 tons per year found in the DEIR).

Studies also looked at many different states, including Colorado, Utah, Texas, Oklahoma, and California.[19] In fact, a 2013 study specific to Los Angeles solved the mystery, regarding why methane levels measured over the region were much higher than expected. The study found that the increased emissions could be traced to a few sources – the La Brea tar pits, landfill methane gas, natural gas pipeline leaks, and oil and gas drilling operations.

This report found that oil and gas operations alone in the Los Angeles region leaked about 17%—even higher than the unexpectedly high numbers found in the other Western states.[20] This report also identifies a report by the California Air Resources Board which verified a similar leak rate.

Seventeen percent is 4.25 times higher than the 4% figure discussed above, resulting in 4.25 x 18,500 metric tonnes per year, or **78,500 metric tonnes per year of CO2 equivalent emission**s. Again, this is a far cry from the 0.51MT per year estimated in the DEIR, and this only includes the oil and gas

[17] DEIR at p. 1-1

[18] Methane gas has a density of 0.0422 lbs/cubic foot x 44 million cubic feet/year x 1 ton/2000 lbs x 22 tons CO2 Equivalent per 1 ton methane = 20,330 tons CO2 equivalent /year, and at 99 million cubic feet/year, this calculation yields about 46,000 US tons per year CO2 equivalent, or to 18,500 to 42,000 metric tonnes (MT) (A metric tonne is 2200 lbs or 1000 kg compared to a U.S. ton of 2000 lbs.). (CO2 equivalent is found by multiplying the pounds or tonnes of methane by 22, since methane is far more potent as a greenhouse gas than CO2. Greenhouse gases are generally described in CO2 equivalent tons, so they can be easily compared.)

[19] *Air sampling reveals high emissions from gas field, Methane leaks during production may offset climate benefits of natural gas*, Nature News, 07 February 2012, http://www.nature.com/news/air-sampling-reveals-high-emissions-from-gas-field-1.9982; *Study finds U.S. methane emissions higher than past estimates, points to oil and gas drilling,* Stephanie Paige Ogburn, E&E Publishing (Environment and Energy), ClimateWire: Tuesday, November 26, 2013 http://www.eenews.net/stories/1059991023;

[20] *Mystery Solved: Previously Unexplained Higher Levels of Greenhouse Gas in L.A. from Fossil-Fuel Sources,* CIRES, Cooperative Institute for Research in Environmental Sciences, May 14, 2013, available at: http://cires.colorado.edu/news/press/2013/greenhousegases.html

drilling operations, not the natural gas pipeline leaks in the region, after the gas from the Project is sold by Oxy, and transported by pipeline. Such pipeline leaks also need to be re-assessed in the DEIR because of this LA-specific leakage investigation's findings.

Methane leakage by itself can be far higher than the greenhouse gas emissions that the DEIR estimated for the rest of the Project. CEQA requires an estimation of the full potential to emit, requires mitigation including continuous monitoring of methane and other gas leaks, and requires special measures to stop these enormous leaks. The DEIR may not ignore the substantial evidence found by these studies, and simply apply generalized emissions factors for which there is substantial and specific evidence to the contrary.

II. The Project failed to adequately consider the extreme risk of oil and gas fires after a major earthquake (expected imminently), with a high potential to endanger public safety

The Project treated earthquakes and fires as separate issues. This provides an unrealistic probability that oil and gas fires would occur. The Project instead should be considered to cause a significant increase in the probability of oil and gas fires due to the imminent earthquake hazard. This also causes a significant risk of Cumulative Impacts, due to the large number of drilling operations in the region, and the major draw on public resources that would be called on if multiple major oil and gas fires occurred after an earthquake.

Oil and gas fires are very difficult to extinguish, and could easily spread. Such fires can emit large clouds of hazardous black smoke over the region. Siting an intensive oil drilling operation within an urban area that is very vulnerable to earthquakes, must be evaluated for these dangers, and alternatives the Project must be seriously considered.

A major earthquake is not just a theoretical possibility. The risk of a major earthquake in the region is imminent and severe. A September 2005 Los Angeles Times article,[21] *Katrina's Aftermath, California Earthquake Could Be the Next Katrina*, reported:

> "A state study published last year on hazard reduction paints a sobering picture of California's earthquake danger. About 62% of the population lives in a zone of high earthquake danger, including 100% of the population of Ventura County, **99% of Los Angeles County** and 92% of Riverside County. . . .
>
> **"Researchers at the Southern California Earthquake Center said there is an 80% to 90% chance that a temblor of 7.0 or greater magnitude will strike Southern California before 2024**."

The Southern California Earthquake Center (at the University of Southern California)[22] (SCEC) earlier found:[23]

[21] September 10, 2005, Los Angeles Times, KATRINA'S AFTERMATH, California Earthquake Could Be the Next Katrina, by Jia-Rui Chong and Hector Becerra, Times Staff Writers, http://www.latimes.com/news/local/la-earthquake08sep08,1,2126004.story?coll=la-util-news-local

[22] SCEC (at the University of Southern California) gathers and combines new information about earthquakes in Southern California, is supported by the National Science Foundation and the U.S. Geological Survey, and coordinates efforts of over 50 institutions

[23] *Seismic Hazards in Southern California: Probable Earthquakes, 1994-2024*, Presentation and Panel

"The last official estimate of earthquake potential in southern California was the 1988 report of the Working Group on California Earthquake Probabilities. The report estimated the probabilities of large "characteristic" earthquakes on major faults, like the San Andreas and San Jacinto faults. The report concluded that there is a 60% chance of at least one large earthquake (M=>7) on the San Andreas fault before the year 2018.

The report concluded that the probability is even higher, 80-90%, when other faults are included." Such an earthquake could occur today. Severe ground shaking will occur during the inevitable major earthquake in Los Angeles area. Los Angeles' soil types cause increased ground shaking:[24]

The Uniform Building Code does not prevent significant and even severe earthquake damage
In an Environmental Impact Report performed for Industrial Service Oil Company, Inc. (ISOCI) of Los Angeles, the potential for damage to structures (including oil treatment and storage structures) was identified, despite the fact that the facility stated it would comply with the Uniform Building Code:[25]

> ***Based on the historical record, it is highly probable that the Los Angeles region will be affected by future earthquakes.*** *Research shows that damaging earthquakes will be likely to occur on or near recognized faults showing evidence of recent geologic activity.*
>
> *The impacts of an earthquake on the site are considered to be greater than the current conditions since additional structures will be constructed including new treatment and storage facilities.* ***Impacts of an earthquake could include tank and other structural failure.***
>
> *Additional structures at the site must be designed to comply with the Uniform Building Code . . . The goal of the code is to provide structures that will:*
>
> > *(1) Resist minor earthquakes without damage;*
> > *(2) resist moderate earthquakes without structural but with some non-structural damage; and*
> > *(3) resist major earthquakes without collapse but with some structural and non-structural damage. . . .*

Thus, the ISOCI EIR found that an earthquake in the region could cause tank and other structural failure, and also found that the Uniform Building code does not preclude all damage from earthquakes. It found that the Code is only meant to cause *resistance* to earthquake

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Discussion Held at the OES Conference, "Northridge Earthquake--One Year Later," January 20, 1995, Southern California Earthquake Center, http://www.scec.org/news/newsletter/issue11.pdf

[24] *"Another project in progress will update this map by showing a higher level of shaking for soft-soil sites. This will lead to a higher rate of damaging shaking because the more common smaller earthquakes will produce greater shaking in soft soil. The result will be to increase slightly the rates for the sedimentary basins such as the Los Angeles basin and the San Gabriel, Ventura and San Bernardino Valleys."* Seismic Hazards Map for Southern California, Southern California Earthquake Data Center, http://www.data.scec.org/general/PhaseII.html

[25] Draft Environmental Impact Report for the Industrial Services Oil Company, Inc. (ISOCI) Hazardous Waste Facility Application, November 2005, page 3-58

damage and collapse. These same risks exist at the proposed Oxy site.

A discussion of remaining risks which exist after compliance with the Uniform Building Code was provided in a publication by Dr. Robert J. Kuntz, President of the California Engineering Foundation, and Daniel L. Tanner, the California Engineering Foundation's Economic Consultant. This document found:[26]

> **The California Building Code offers only minimal protection from seismic damage,** i.e., a structure should not be damaged in a minor earthquake, damaged beyond repair in a moderate earthquake, nor collapse in a major earthquake. However new technologies, such as seismic isolation, can mitigate both structural and building contents damage and are becoming available to government and industry. There is a need for design professionals, building officials, planners, and building owners to become aware of these new technologies, the criteria for their use, and how to incorporate them into practice.
>
> **The Uniform Building Code provides minimal seismic protection determined acceptable by local governments, but Code specifications do not prevent structural damage nor ensure the use of a building after an earthquake.**
>
> Such limited protection is not consistent with the needs of commerce or emergency facilities, which must remain operational after an earthquake, nor does it protect the contents of a building. Two earthquakes which struck near the Lawrence Livermore National Laboratory in California, within two days of each other in January of 1980, caused a total of $10 million in damage. Nearly half of the damage was to laboratory equipment, testing systems, and other building contents.

As an illustration of the potential damage that can occur in an industrial area during a major earthquake, the 1999 earthquake in Turkey was evaluated by the Pacific Earthquake Engineering Research Center. An excerpt of a report on this study is provided below. The report found *"The earthquake struck the industrial heartland of Turkey."* It found that complete structural failures due to earthquake were few in number, but severe damage short of complete structural failure did occur. One example was the failure of floating roofs in crude oil tanks.

Such fracturing and crumpling of support structures and other earthquake damage to industrial equipment not only cause leaks and spills, but could easily cause fires. Even in residences, fires during earthquakes are a known common hazard due to leaking natural gas, broken structures and electrical systems, ignition sources, etc. When damage occurs during major earthquakes to heavy industrial facilities that store, transfer, and process combustible materials, there is even more potential for dangerous fires. The Turkish example included a fire during the 1999 earthquake when a refinery cooling tower failed, and also when eight naphtha- storing fuel tanks burned.

A publication funded by the Earthquake Engineering Research Institute and the Washington Emergency Management Division (2005)[27] found severe damage due to earthquakes, including long term environmental impacts of hazardous material releases. The Report found:

[26] Disaster Recovery Journal, 1999, http://www.drj.com/drworld/content/w2_066.htm

> Fire following the earthquake caused severe damage to the Tüpras refinery. Other observed structural failures in the refinery were to a 115-m-tall smokestack, floating roofs in crude oil tanks, and piles supporting a jetty. Substations and one power generation facility suffered damage ranging from overturned transformers to fractured porcelain switches."

Another publication described the Kocaeli fire, the tank structural damage, fire and collapse, and oil spilled into the sea, and major equipment including a large boiler knocked off its foundation:[28]

Fig. 5. Fire damage to naphtha tanks at Tüpras refinery.

In addition to the risk of fires associated with earthquakes well known to California regulators (as well as those documented after the Turkish earthquake), a publication of the University of Patras, Greece -- *Safeguarding Hydrocarbons Inside Local Earthquake Defense Systems*[29] -- found major fire risks from earthquakes associated with burning hydrocarbons to be a general problem around the world:

> ***"Hydrocarbons, particularly gas, also create a much increased risk of fire as a major secondary consequence following earthquake damage.*** *There is a growing danger that*

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[27] *Scenario for a Magnitude 6.7 Earthquake on the Seattle Fault, A Project Funded by the Earthquake Engineering Research Institute and the Washington Emergency Management Division, February 2005, Excerpts from a publication of the same title to be released March 2005* , page 20, http://seattlescenario.eeri.org/documents/EQ%202-28%20Booklet.pdf

[28] *PEER Center News*, Vol. 2 No. 4 October 1999, http://peer.berkeley.edu/news/1999october/turkey.html , excerpt. *PEER Center News* is a quarterly publication of Pacific Earthquake Engineering Research Center, highlighting research and information of interest to earthquake engineering researchers and professionals. http://peer.berkeley.edu/news/1999october/turkey.html

[29] *Safeguarding Hydrocarbons Inside Local Earthquake Defense Systems,* Project participants: UPS: Seismology Centre, University of Patras, Greece, UEA: School of Environmental Sciences, University of East Anglia, Norwich, England, DEPA: The Public Gas Company of Greece, GSCP: The General Secretariat of Civil Protection, AGISCO, Aspinal & Associates, and ECS: Euroconsultants, http://seismo.geology.upatras.gr/shields/SHIELDS2003.htm

major Greek cities may experience fire damage after a strong earthquake, enhanced by the increased supply of gas into urban areas. Fires following the earthquake at Kobe in Japan 1995 and Turkey 1999 (Fig.1,2) provided a salutary example of impact even in a well-regulated, modern and earthquake conscious country. Longer memories recall the conflagration in Tokyo that followed the 1923 Kwanto earthquake."

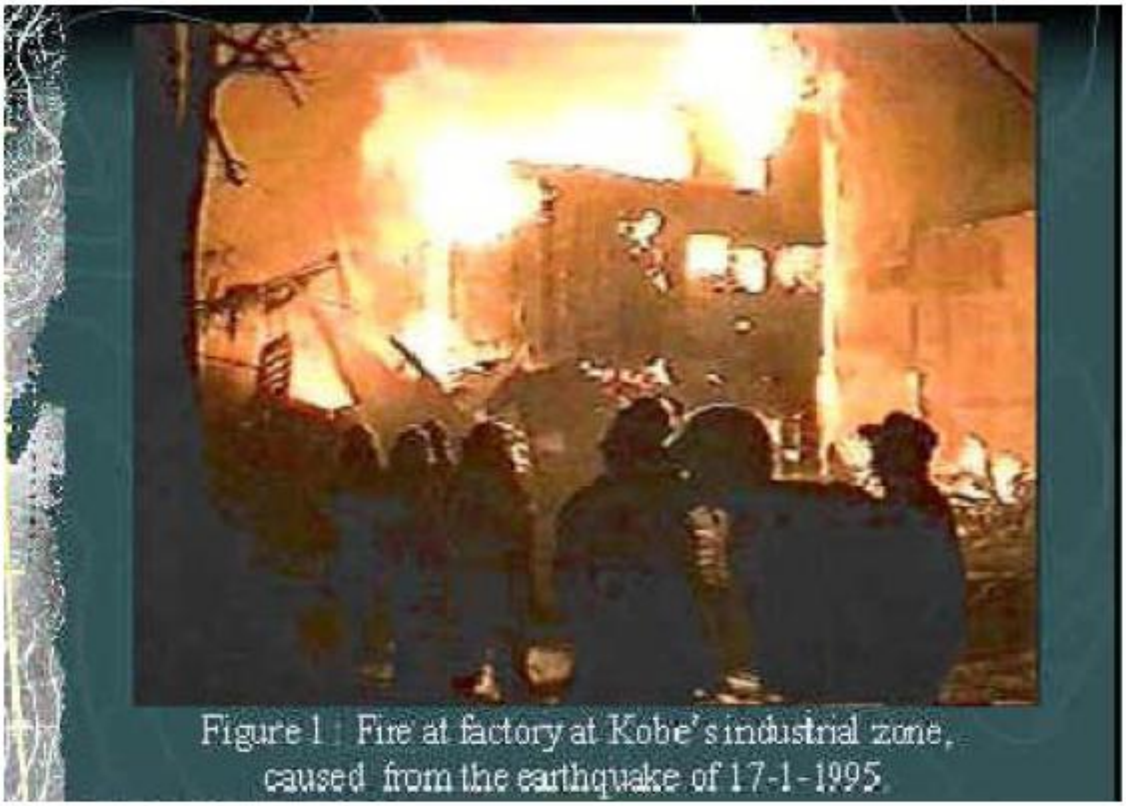

Figure 1 : Fire at factory at Kobe's industrial zone, caused from the earthquake of 17-1-1995.

Oxy's processing, storage, and piping of hydrocarbons and other hazardous materials increases the risk of fire during earthquake damage dramatically compared to non-industrial areas. In addition, it is widely known that there is significant potential for fires due to natural gas line ruptures during a major earthquake. For example, a publication of Michigan Tech (*What Are Earthquake Hazards?*[30]) found:

> *"**The fourth main earthquake hazard is fire. These fires can be started by broken gas lines and power lines,** or tipped over wood or coal stoves. They can be a serious problem, especially if the water lines that feed the fire hydrants are broken, too."*

Fires at a facility processing hydrocarbons and oils can be extremely severe. Examples of severe industrial fires at oil processing facilities include a major fire at an automotive fluids blending plant (called Third Coast Industries) south of Houston Texas. The U.S. Chemical Safety and

[30] Michigan Tech, Geological and Mining Engineering and Sciences Division, http://www.geo.mtu.edu/UPSeis/hazards.html , Exhibit 28
Communities for a Better Environment, Warren Negative Declaration, May 26, 2009 Page 22

Hazard Investigation Board came to the conclusion that higher flash point ("non-ignitable") materials such as heavy oils can represent major fire hazards.[31] This agency concluded after evaluation of the huge 2002 automotive fluid blending plant fire in Texas, that oils with flash points greater than 200°F classified as "Combustible IIIB" (including motor oils) should be treated with more care regarding fire safety. The Texas fire under investigation could not be put out, and completely destroyed the facility.

In the Texas case, the Chemical Safety Board found that while most of the material onsite at this facility had higher flash points (meaning they wre heavier, less volatile materials), the presence of small amounts of some liquids which were more easily combustible with lower flashpoints, could have caused the fire to start, and then combusted the bulk of the higher flashpoint materials. The Chemical Safety Board found that such higher flash point oils burn "fiercely" once a fire is started.

The Board concluded that fire codes and workplace safety regulations should apply more controls to combustible liquid storage and handling. In the aftermath of the Third Coast fire, the Board communicated its concerns in correspondence to the U.S. Occupational Safety and Health Administration (OSHA). The Chemical Safety Board also found:

> . . . the facility was not designed to contain the contaminated runoff that could result from fighting the fire with water. Fire officials therefore decided they had no choice but to let the plant burn, and they focused on protecting nearby homes from destruction.

Fires and explosions at oil and gas wells have been documented in many states in the U.S. The following excerpt from a non-profit organization (Earthworks) that collects data on impacts of oil and gas production found:

> **Fires and explosions**[32]
>
> Fires and explosions at oil and gas wells not only cause immediate safety issues for workers and nearby residents, but they also present longer-term health risks from breathing in toxic fumes associated with these events.
>
> - Methane seepage associated with past and present drilling has caused explosions. In February 2005, a Durango, Colorado trailer exploded and a man was sent to the hospital when methane from an abandoned well seeped into his home and exploded when he lit his stove. The 70-year-old man in the home was severely burned -- his hair was singed off and his clothes were burned to his body.
> - In November 2005, a hydraulic fracturing pit caught fire at natural gas well site near Rifle, Colorado.
> - In December 2005, residents living near Silt, Colorado raised concerns about chemicals being released from the intentional burning of condensate pits at gas

[31] *Third Coast Industries Fire,* Brazoria County, Texas May 1, 2002, U.S. Chemical Safety and Hazard Investigation Board, CSB Investigation Digest, http://www.csb.gov/third-coast-industries-petroleum-products-facility-fire/

[32] http://www.nodirtyenergy.org/index.php?Itemid=164&id=115&option=com_content&task=view

well sites in their neighborhood. • In February 2006, a gas well fire injured six people in Fayette County, Pennsylvania. Other incidents in Pennsylvania that year included a hydraulic fracturing fluid fire, truck explosions at well sites, and other gas well explosions.

- In February 2006, as many as 50 people were evacuated from their homes in Weld County, Colorado when thick, black smoke from a burning natural-gas tank spread through their community.
- In November 2007, An explosion at a natural-gas processing plant west of the Durango Colorado airport shook homes and woke residents. The plant was purged of all petroleum products , but because of the hazardous materials on site firefighters had to allowed a certain amount of the fire to burn itself down before they could attempt to put out the fire.

A string of explosions have been documented in Texas recently, as drilling of the Barnett Shale has intensified. These explosions have resulted in deaths, noxious fumes, evacuations and property damage. Some example include:

- April 2005: Tab Dotson, a worker on a crew drilling a natural gas well in Wise County, Texas, was killed when the forklift he was driving knocked open a closed gas well causing it to explode. The ensuing explosion and fire killed Dotson instantly. Another worker was injured.
- December 2005: A natural gas well and pipeline explosion injured a worker at a nearby rig and ignited secondary fires for a mile around. The sound from the blast shook residents for miles around the area, and the flash was visible for 100 miles.
- April 2006: Robert Gayan was killed when a natural gas well he was working on in Forest Hill exploded. Nearby residents complained of breathing problems. The gas well exploded in the Fort Worth suburb of Forest Hill, Texas, forcing the mandatory evacuation of 500 homes.

March 2007: plumes of black smoke were created from a pipeline explosion and fire that occurred after a backhoe digging a trench for a new Barnett Shale pipeline hit existing propane and gas lines. A number of vehicles were destroyed, and the fire melted a high-voltage power line that left 5,000 people without electricity for several hours.

An oil well in Pennsylvania was filmed during a fire (Gas Well Fire Doused In Fayette County (Pennsylvania) Feb. 14, 2006[33]), with a news report that flames shot 30 feet and injured six people. The report stated that firefighters were attempting to put the flames out with water, next would try dirt, and then would try nitrogen as a last resort, indicating the difficulty of controlling a fire of this sort.

[33] http://kdka.com/local/gas.well.fire.2.381516.html

A 2005 oil depot fire in the Hertfordshire in the United Kingdom also illustrates how severe offsite impacts from smoky oil fires can be. The inefficient burning of petroleum products at this site caused huge smoking plumes similar to smoking which could occur at the Warren facility if a fire were to break out, due to earthquake or other reasons.[34]

The Hertfordshire Oil Terminal fire showed that such fires cause huge smoky plumes due to poor combustion of hydrocarbon materials. Smoke from an oil fire and/or hazardous materials burning could cause major emissions of particulate matter, PAHs (Polycyclic Aromatic Hydrocarbons), sulfur oxides, heavy metals including lead, mercury, and chromium, chlorinated compounds including deadly dioxins, and many other hazardous compounds.

Smoky fires and gas plumes from such an event could reach nearby residential areas and impact workers offsite and onsite, and could billow for miles. Even a moderate fire could heavily impact neighbors and schoolchildren, especially people with respiratory problems, asthma, or heart conditions, but could also significantly impact healthy adults. The impact would depend on fire size, availability of the fire department (which may not be the case in an earthquake), and how long it takes to put out the fire. In the event of an earthquake, the public has been repeatedly informed that emergency services may not be available for some time, due to obstructions on roadways, and broken water supplies.

The potential of such hazards due to a major earthquake must be evaluated in the DEIR.

V. The categorization of this Project as "Light Industrial" despite its size and Heavy Industrial implications is troubling

The Project involves a large number of wells, drilling, flaring, and processing of flammable and acutely toxic gases such as hydrogen sulfide. If carried out in other industries (such as an oil refinery), they would undoubtedly be considered heavy industry. While the City of Carson may

[34] http://en.wikipedia.org/wiki/2005_Hertfordshire_Oil_Storage_Terminal_fire#Causes

define other drilling operations as light industrial, this extensive Project is consistent with other Heavy Industrial zoning designations. Interestingly, other states such as North Dakota and Texas, often assumed to have lower environmental standards than California, typically define oil drilling as "Heavy Industrial."[35] For example, according to an article in the Texas Bar Journal:[36]

> *"Since most local zoning ordinances prohibit oil and gas drilling or production in a city except for narrowly defined zoning districts (**usually those zoned for heavy industry**), a party wanting to drill a well within a city is often required to obtain a specific use permit or similar type of zoning authorization before developing a well site. Such zoning regulations will often contain conditions in which the applicant must comply in development and operation of the drill site."*

This publication goes on to describe special problems with noise, the need for buffer zones, insurance, water issues, issues with abandoned wells, and cleanup of the site after the Project is closed. While some of these issues are evaluated in the DEIR, adding a new Project that would normally be considered Heavy Industry to an area considered Light Industrial should raise red flags regarding the appropriateness of the site, and also indicate a much higher level of scrutiny and mitigation needed.

The City of Carson may distinguish between different oil drilling operations that do not use intensive or "enhanced" drilling technologies compared to one such as the proposed Oxy Project. This Project however, should be reevaluated in the DEIR process due to its intensive industrial nature.

A more detailed discussion of the zoning designation should be included in the DEIR order to provide a reasonable description of the Project. CEQA requirements go beyond compliance only with local requirement; if not, there would be no need for CEQA. CEQA requires a clear description of the Project. The implications and impacts described should include a discussion about additional conditions and alternatives which would be evaluated if the Project was instead designed as Heavy Industrial in a Light Industrial area.

Thank you for your consideration of these comments.

Julia May,
Senior Scientist
Communities for a Better Environment

See Enclosure: CV, at Exhibit 1.

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[35] Zoning Ordinance of the City of Williston, North Dakota, http://www.cityofwilliston.com/usrfiles/AUD/Docs/ZoningOrdinance.pdf, at p. 115

[36] April 2013, *Oil and Gas in the City, Keeping an eye on the issues associated with drilling in an urban space,* Kevin B. Laughlin, https://www.texasbar.com/AM/Template.cfm?Section=Texas_Bar_Journal&Template=/CM/ContentDisplay.cfm&ContentID=21992 , at p. 317

EXHIBIT 1

To Julia May Technical Report on behalf of CBE, on Oxy USA Draft Environmental Impact Report for the Dominguez Oil Field Development Project, SCH No. 2012031019

CV of Julia May, Senior Scientist
Communities for a Better Environment

Julia E. May

Senior Scientist / Environmental Consultant

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Experience

1989-present **Energy and Industrial Air Pollution Engineering Evaluation**

- Evaluation of energy issues including electricity planning, natural gas and coal-fired power plant permitting and impacts, transmission and reliability issues, alternative energy and policy options.
- Industrial air pollution source evaluation including criteria pollutants, toxics, greenhouse gases, pollution prevention methods and engineering solutions.
- Research on best and worst industrial practices, chemical and fossil fuel phaseout methods, policy, and technologies.
- Analyzing permitting, emissions and air monitoring data; compiling available health and environmental impacts data. Evaluation of technical basis of regulatory compliance with environmental laws. Working through practical technical issues of regulation, negotiating with industry and government agencies to craft most health-protective policy and regulatory language.
- Translating inaccessible technical information into lay language and educational materials. Providing technical assistance and cumulative impacts analyses to communities of color that face severe pollution burdens. Assisting communities and workers in developing proposals for environmental health protection regulation, permitting, and policy.
- Managed science department for statewide environmental organization. Hired by regulatory agency as technical advisor to identify feasible air pollution control methods not previously adopted, and to assist communities submitting comments during regulatory proceedings.

Education

1981 **B.S. Electrical Engineering**, University of Michigan, Ann Arbor

Engineering principles, circuit design, mathematics, thermodynamics, physics, materials science, chemistry, and others

Project examples:

- Evaluation of California Long Term Procurement Plan (electricity planning) and California power plant permits, reliability, transmission alternatives, environmental impacts (e.g. Potrero, Hunters' Point, Oakley), and coal gasification proposals outside California (1990s to present).

- Evaluation of proposed refinery expansions, oil drilling and pipeline permitting: Emissions and solutions relating to feedstock switches to Canadian tar sands crude oil at ConocoPhilips Wood River, BP Whiting, Detroit Marathon, and proposed new MHA Nation, North Dakota, refineries, as well as dozens of refinery expansions in Northern and Southern California. Oil drilling operations, air impacts, in residential Los Angeles neighborhood. Pipeline transport impacts of crude oil, hydrogen, and other oil industry feedstocks in California and Midwest. Evaluation of coal gasification plant emissions. (1990s to present)
- Development of model California oil industry criteria pollutant regulation, and proposed greenhouse gas regulation and alternatives analysis: Oil refinery regulations for flares, pressure relief devices, tanks, leakless fugitives standards, petroleum product marine loading, and others. (1990s to present)

Positions

2004- present

Independent Environmental Consultant (2004 - ongoing) and Senior Scientist, Communities for Better Environment (2006 – present) – Energy Use / Industrial pollution quantification / Alternatives analysis, including engineering analysis of proposed and existing industrial permits, analysis of statewide goals and energy planning, as well as policy analysis. Analysis of impacts and solutions to environmental problems including trends in energy use, oil industry feedstocks, associated equipment changes, emissions of criteria pollutants, toxic emissions, and greenhouse gases. Technical consultant and strategist in community campaigns on industrial regulation. Geographic areas include Southern California, Northern California, and multiple U.S. states.

2001-2003

Statewide CBE Lead Scientist, CBE, Oakland, CA

Responsible for accuracy and strategic value of CBE's technical evaluations within community and environmental law enforcement campaigns, also led statewide technical staffing. Identified underestimations in electrical power plant expansion air emissions in a community of color which had very high asthma rates; identified alternatives option including sufficient conservation, clean energy generation, and transmission available to prevent need for fossil fuel expansion, documented facts in California Energy Commission proceedings. Analysis of and recommendations on adding regulation to Bay Area Ozone Attainment Plan (concerning flares, pressure relief devices, wastewater ponds, storage tanks, and others) which were ultimately adopted. Evaluated Environmental Impact Reports and Title V permits for refineries and chemical plants; identified emissions, potential community impacts and alternatives. Successfully assisted negotiating Good Neighbor Agreements by identifying technical solutions to environmental violations to bring facilities into compliance.

1990-2001 **Clean Air Program Director, Northern California Region, CBE**

Analysis of permits, regulation, air pollution inventories and other emissions information for oil refinery, power plant, cement kiln, smelter, dry cleaner, consumer product, lawn mower, mobile source, and other air pollution sources, neighbor and worker health impacts, with pollution prevention policy development. Successfully advocated for national models of oil refinery regulation. Evaluated and documented root causes of industrial chemical accidents as part of community campaigns for industrial safety. Technical assistance to community members negotiating Good Neighbor Agreements with refineries. Successful advocacy for adoption of policies eliminating ozone depletors in favor of benign alternatives.

1987-1990 **Research Associate, CBE**

Led successful campaign working closely with maritime workers and refinery neighbors for adoption of strict oil refinery marine loading vapor recovery regulation, which became statewide and national model. Member of technical working group at BAAQMD evaluating emissions, controls, safety, and costs. Also analyzed school pesticide use and won policy for integrated pest management on school grounds.

1986 **Assistant Editor of appropriate technology publication, Rain Magazine**, Portland, OR

Production of publication on innovative energy and environmental success models around the U.S. and the world. Compiled, co-edited, wrote, and provided production for non-profit publication.

1981-1985 **Electrical Engineer, National Semiconductor Corp., Santa Clara, CA**

Electronics engineering design team member for analog-to-digital automotive engine controls for reducing air emissions. Troubleshooting hardware and evaluating fault-analysis software efficacy.

A few special activities

2002 & 2006 **Roundtable on Bay Area Ozone Attainment Progress and South Coast AQMD community technical advisor** Invited member of problem-solving group of decision makers including BAAQMD board members, industrial representatives, and government officials for reviewing progress and proposing action to control San Francisco Bay Area regional smog.

Hired as Technical Advisor of SCAQMD to community organizations evaluating availability of alternative options in regional ozone attainment plan

1995-2003 **Air pollution monitoring projects including Optical Sensing Air Pollution Monitoring Equipment community "Bucket Brigade" low-tech monitoring projects**

Provided technical analysis for community negotiators, resulting in permanent installation of a state-of-the art air pollution monitoring system on the refinery fenceline, using optical sensing to continuously measure air pollution and broadcast data to a community computer screen. Researched and reviewed manufacturer specifications, developed Land Use Permit language, and worked with refinery and manufacturer for better Quality Assurance/Quality Control. Worked with US EPA, Contra Costa County, and community groups evaluating the system and publishing report evaluating monitoring of emissions. Administered EPA-funded "Bucket Brigade" low-tech air pollution monitoring project for community groups of Contra Costa County Bucket Brigade project, who carried out training events in several communities surrounding major Bay Area refineries and chemical plants.

1997 **Installation of Photovoltaic Panels,** Solar Energy International, Colorado. Practical training on solar energy system design and installation for general electrical energy uses including water pumping, house cooling, etc, and applying energy conservation principles.

1993 **Chemistry of Hazardous Materials** course, U.C. Berkeley Extension, for environmental professionals