

Expert Report of Greg Karras
Communities for a Better Environment (CBE)
Submitted August 26, 2009
Regarding the

Contra Costa Pipeline Project
Draft Environmental Impact Report released in May 2009 by the
Contra Costa County Department of Conservation and Development
SCH #2007062007; County File #LP072009

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I, Greg Karras, declare and say:

1. I reside in San Francisco and am employed as a Senior Scientist for Communities for a Better Environment (CBE). My duties for CBE include technical research, analysis, and review of information regarding industrial investigation, pollution prevention engineering, pollutant releases into the environment, and potential effects of environmental pollutant accumulation and exposure.

Qualifications

2. My qualifications for this opinion include extensive experience, knowledge, and expertise gained from two decades of industrial and environmental health investigation in the energy manufacturing sector, including petroleum refining, and in particular, refineries in the San Francisco Bay Area.

3. Among other assignments, I served as an expert for CBE and other non-profit groups in efforts to prevent pollution from refineries, to assess pipeline impacts at refineries, to investigate alternatives to fossil fuel energy, and to improve environmental monitoring of dioxins and mercury. I serve as an expert for CBE in collaboration with the City and County of San Francisco and local groups in efforts to replace electric power plant technology with reliable, least-impact alternatives. I serve as an expert for CBE and other groups in a project involving comprehensive investigation of environmental impacts of and alternatives to refining heavier, more contaminated oil.

4. I authored a technical paper on the first publicly verified pollution prevention audit of a California petroleum refinery in 1989 and the first comprehensive analysis of refinery selenium discharge trends in 1994. I authored an alternative energy blueprint, published in 2001, that served as a basis for the Electricity Resource Plan adopted by the City and County of San Francisco in 2002. From 1992 through 1994 I authored a series of technical analyses and reports that supported the successful achievement of cost-effective pollution prevention measures at 110 industrial facilities in Santa Clara County. I authored the first comprehensive, peer-reviewed dioxin pollution prevention inventory for the San Francisco Bay, which was published by the American Chemical Society and Oxford University Press in 2001. In 2005 and 2007 I co-authored two technical reports that documented air quality impacts from flaring by San Francisco Bay Area refineries, and identified feasible measures to prevent these impacts. I authored or coauthored two recent research reports on impacts of processing lower quality oil on greenhouse gas emissions from refineries in California and the U.S. My curriculum vitae and list of publications are appended hereto as Attachment 1.

Scope of review

5. In my role at CBE I have reviewed the proposed hydrogen pipeline between oil refineries called the Contra Costa Pipeline Project (Pipeline) and the May 29, 2009 Draft Environmental Impact Report (DEIR) released by Contra Costa County for the proposed Pipeline. My review of the DEIR and Pipeline reported herein is focused on potential impacts resulting from the production and use of hydrogen to be supplied. My opinions on these matters and the basis for these opinions are stated in this report.

Background

6. Hydrogen is a major oil refinery feedstock. The U.S. Energy Information Administration (EIA) reports that the oil refining and petrochemical industries account for more than 90 percent of current hydrogen use.¹ In 2008, Bay Area refiners reported a total hydrogen production capacity of 598.5 million standard cubic feet (scf) per day.²

7. Refiners use hydrogen to make higher-value products from lower-quality oil inputs. In one such usage, refiners bond hydrogen to contaminants in the oil to remove the contaminants from the oil. This is done to protect downstream processing as well as environmental health. In addition to causing pollutant releases from refineries and from the use of refined products, contaminants in the oil deactivate the catalysts used in some key refining processes.

8. Refiners also bond hydrogen to the hydrocarbon compounds in the oil to boost their hydrogen-carbon ratios. This is done to improve the combustion properties of refined fuels. Heavier oils have an abundance of larger, denser hydrocarbons that have relatively low hydrogen-carbon ratios, and must be broken (cracked) into smaller fuel-size compounds to make motor fuels from such oils efficiently, which can further reduce their hydrogen-carbon ratios. So refiners add hydrogen to those oil streams to improve the combustion properties and thus the value of their refined products.

9. Refiners also use hydrogen to quench and control the high temperature, high pressure process reactions that crack the larger, denser hydrocarbons in their oil streams and remove contaminants embedded in these larger compounds.³ Some of these process reactions can occur at temperatures and pressures as high as 780 °F and 3,000 pounds-per-square-inch. (See Attachment 3.) The process units that perform such cracking, contaminant removal and/or hydrogenation reactions are collectively called “hydroprocessing” units. Total hydroprocessing capacity is equal to 112% of total crude input capacity in the California refining industry overall. (Attachment 2.) This reflects the fact that some oil streams in refineries are hydroprocessed more than once.

¹ EIA report SR/OIAF-CNEAF/2008-04, August 2008, at page ix.

² Oil & Gas Journal Worldwide Refining surveys, appended hereto as Attachment 2.

³ See Robinson and Dolbear (2007), appended hereto as Attachment 3.

10. California refineries use hydrogen *primarily* to process lower-quality oil streams. Process catalyst poisons tend to concentrate in the larger, denser hydrocarbons in heavier oil streams.⁴ These larger hydrocarbons must be cracked into engine fuel-size compounds, and then re-shaped (reformed) to make vehicle fuels efficiently. The processes that do that, such as catalytic cracking and naphtha reforming, are vulnerable to catalyst deactivation by sulfur, metals and/or other contaminants in the oil. (See Attachment 3.) Hydrogen is used to decontaminate heavier oil streams before sending them to these downstream cracking and reforming processes. This hydroprocessing of heavier, more contaminated streams (such as gas oil and residua) consumes several times more hydrogen per barrel of oil processed than does hydroprocessing of lighter gasoline-size streams such as naphtha. (Id.) Of the total hydrogen demand for hydroprocessing in California refineries, only about 12% is used in treating gasoline-size streams (naphtha), while approximately 73% of this hydrogen is for hydroprocessing the heaviest streams from whole crude—gas oil and residua.⁵ Nearly all of the increased hydrogen demand in California refineries since 1995 was for processing these heavier gas oil and residua streams. (Attachment 5.)

11. The development and expansion of hydrogen-intensive processing for the purpose of refining heavier, more contaminated oil has been reported in petroleum industry literature for decades. Hydroprocessing and hydrogen production to feed it were developed long before reformulated fuel standards were established to help control emissions from gasoline and diesel combustion. For example, the Chevron Richmond refinery is operating a hydrocracker and hydrogen plant that were built in the 1960s.

12. Many years ago the hydrogen created as a by-product of naphtha reforming supplied all of most refineries' hydrogen, but increasing demand for feeding expanding hydroprocessing of lower-quality oil has led to additional hydrogen production using add-on hydrogen plants. Today 53% of U.S. refineries and all five major Bay Area refineries report using additional hydrogen production capacity. (Attachment 2.)

⁴ See CBE (2009), appended hereto as Attachment 4.

⁵ See CBE (2008), appended hereto as Attachment 5. See also Attachment 25: Accounting for 9% ethanol addition to reformulated gasoline, in-state “clean gasoline” production exceeds in-state gasoline sales, which are declining even before the new Low Carbon Fuel Standard takes effect.

13. The expanding refining of lower-quality oil enabled by more hydrogen-intensive processing has serious environmental implications. Refining heavier and more contaminated oil passes more pollutants into the environment, requires more intensive processing that increases pollution incident hazard, and requires more energy that increases refinery fuel combustion emissions. Expanding hydrogen use in refineries is implicated in each of these pollutant-generating mechanisms.

14. Fuel combustion for the additional energy needed to make more hydrogen increases pollutant emissions. Steam reforming is the U.S. oil industry's technology of choice for add-on hydrogen plants and is used at each of the five Bay Area refineries. (Attachment 2.) Steam reforming produces hydrogen from light hydrocarbons such as methane and superheated steam, in contact with a catalyst. The process reactions proceed at extremely high temperature, about 1,500 °F, which is achieved by burning fossil fuel. Burning that fuel emits pollutants.

15. For example, as California refineries ran crude oils with increasing sulfur content from 1995-2007 they added 388,000 b/d of hydroprocessing capacity, and 329 million scf/d (mmscf/d) of hydrogen steam reforming capacity to feed this hydroprocessing. (Attachment 5.) That expanded hydroprocessing was associated with a one-percent equivalent increase in crude sulfur content for each 852 scf increase in hydrogen per barrel of crude refined. (Id.) For that additional hydrogen, steam reforming fuel combustion energy increased by approximately 459 British thermal units (Btu) per scf hydrogen produced. (Id.) Carbon dioxide equivalent (CO₂e) emissions from that steam reforming fuel combustion increased by approximately 53.1 kg/MMBtu. (Id.)

16. The processing of lower-quality oil enabled by expanded hydrogen feeds also uses more energy per barrel refined because of the more intensive processing needed before and after the hydrogen is injected into processing. A larger fraction of lower-quality crude streams must be distilled in a vacuum, decontaminated, cracked and/or hydrogenated in vacuum distillation, coking, hydroprocessing and/or catalytic cracking units. For example, the U.S. refining district that processes the lowest-quality crude processes fully *one-third* more of each crude barrel in vacuum distillation and cracking units than the U.S. refining district that runs the highest-quality crude. (Attachment 4.)

17. Results from a statistical analysis of fuel use for hydrogen production and other refinery processes are appended hereto as Attachment 6. The data analyzed account for 96% of U.S. refining capacity.⁶ This analysis shows that increasing energy use in other refinery processes is positively associated with increasing hydrogen production energy. That association is statistically significant ($p < 0.001$), and hydrogen production energy can explain 89% of the variability in other refinery energy (R-squared = 0.89). At the 95% confidence level of this statistical analysis, energy use in other refinery processes increases by 1.046 to 1.487 Btu per barrel of crude refined for each 1.0 Btu/barrel increase in energy use for hydrogen production.

18. Thus, using more hydrogen increases refinery-wide energy consumption. Supplying that additional energy requires burning more fuel and results in more emissions from many parts of the refinery.

19. The processing of heavier and/or more contaminated oil that is enabled by increasing hydrogen supplies also requires more intensive processing, which increases pollution incident hazard. The hydrocracking and other cracking processes that expand to refine lower-quality oil efficiently are among the highest temperature, highest pressure processing units in a typical refinery. Process reactions in these units generate toxic, corrosive and flammable gases. Expanding the amounts of these toxic, corrosive, potentially explosive gases at high temperature and pressure in these processes increases spill, fire and explosion hazards in a refinery.

20. For example, a recent review of relatively high quality data on flaring at four Bay Area refineries found that increasing sulfur content in refinery crude inputs led to an increase in upsets.⁷ These data suggest that the frequency of significant flaring incidents increases by approximately 133%, and the concentration of toxic sulfur compounds in flare emissions from hydroprocessing increases by roughly 400%, for each 0.5% increase in the sulfur content of monthly crude inputs to a refinery.

⁶ Data analyzed in Attachment 6 are given in Attachment 4 (see data for PADDs 1, 2, 3 and 5).

⁷ See CBE's June 5, 2008 Comments to the City of Richmond, appended hereto as Attachment 7; CBE's July 9, 2008 Comments to the City of Richmond, appended hereto as Attachment 8; and Deputy State Attorney General Rose Fua's July 14, 2008 email to the City of Richmond transmitting Dr. Geoffrey Dolbear's concurring opinion, appended hereto as Attachment 9.

21. Added to increased combustion and incident emissions is the pass-through of pollutants from more contaminated refinery oil inputs into the environment. The increasing concentrations of toxic sulfur compounds in flare emissions with increasing sulfur in refinery oil inputs described above is one example of this “dirty in-dirty out” phenomenon. Drastically higher selenium discharge per barrel refined at Bay Area plants running higher-selenium crude during the 1990s is another well-documented example.⁸ Hydrogen interactions with sulfur or selenium in hydroprocessing are a contributing cause in these flaring and selenium pollution impacts of refining lower-quality oil. The potential for higher-mercury crude inputs to double mercury emissions from refineries nationwide⁹ is another example of this pollutant pass-through effect.

22. Each Bay Area refinery has dedicated onsite and/or adjacent hydrogen production. (Attachment 2.) Each is self-supplied hydrogen. No pipeline supplies hydrogen produced at one Bay Area refinery to another. Now, however, the Bay Area industry and its hydrogen suppliers have announced plans that could increase regional refinery hydrogen supplies by as much as 320 million scf/d, and could link all five refineries in a regional hydrogen pipeline network where no such pipelines exist today.¹⁰ The proposed Pipeline is part of this larger project.

23. The information summarized above is important for understanding the Pipeline and its environmental implications, but this information is not included in the DEIR.

Project description

24. The DEIR states that the Pipeline would supply hydrogen for oil refining and would run between the Chevron refinery in Richmond, the ConocoPhillips refinery in Rodeo and the Shell refinery in Martinez. The DEIR provides some information on the proposed length, diameter, operating pressure, control system, route, construction schedule, construction methods and construction materials of the Pipeline. However, the DEIR does not provide certain other information that is normally provided in a project proposal and is necessary for assessing environmental impacts of this project.

⁸ See CBE (1994), appended hereto as Attachment 10.

⁹ Wilhelm et al. (2007), appended hereto as Attachment 11.

¹⁰ See Attachment 5; and EIR SCH# 2005092028, excerpt appended hereto as Attachment 12.

25. The DEIR does not state the anticipated operating life of the proposed Pipeline. This information is needed to evaluate the environmental consequences of the Pipeline over the full span of time during which it could operate. Readily available information suggests hydrogen pipelines can be expected to operate for 50 years or more.¹¹ Some older hydrogen pipelines remain operational after 40-45 years,¹² and one has operated in Germany for more than 65 years. (Attachment 13.)

26. The DEIR does not report the Pipeline's design capacity for hydrogen flow. This must be known to assess the extent of impacts from making and using that hydrogen. Design capacity is the only reliable information we can have now about how much hydrogen the Pipeline could carry over its decades-long operating life. The DEIR's statement at 3-23 that the "normal flow rate in the hydrogen pipeline would be from 200,000 to 1.7 million cubic feet per hour" is not sufficient. It does not disclose the design capacity that could be used over time, what "normal" means, or whether these are "cubic feet" at standard temperature and pressure (standard cubic feet, scf) or a larger amount of compressed gas. A 1.7 mmscf/h (40.8 mmscf/d) maximum capacity is unlikely: it could not provide for reliable operation during outages of the much larger capacity at any refinery tied-in to the Pipeline.¹³ And it is very unlikely that Praxair designed its Pipeline to carry less hydrogen than it designed its hydrogen plant in Richmond to export. Information that the DEIR omits¹⁴ indicates that Praxair designed this plant to export 100 mmscf/d of hydrogen via the Pipeline, and a proposed connecting pipeline has a stated capacity of 300 mmscf/d hydrogen.

27. The DEIR does not report refiners' hydrogen production or consumption capacity. Publicly reported 2008 hydrogen steam reforming capacity is 150, 88 and 101 mmscf/d at the Richmond, Rodeo and Shell Martinez refineries respectively. (Attachment 2.) Each capacity far exceeds the U.S. average/b crude refined. (Id.) Estimated 2007 supply including hydrogen by-production in naphtha reforming (v. estimated demand capacity in

¹¹ Argonne National Laboratory (2007), appended hereto as Attachment 13.

¹² U.S. Dept. of Transportation data downloaded 8/16/09, appended hereto as Attachment 14.

¹³ The reported hydrogen steam reforming capacity at the Shell Martinez, ConocoPhillips Rodeo and Chevron Richmond refineries is 150, 88, and 101 mmscf/d respectively. See Attachment 2.

¹⁴ Excerpts from EIR SCH #2005072117, Attachment 15; Air Liquide (2007), Attachment 23.

hydroprocessing) at the Rodeo and Martinez refineries is 992 (v. 783), and 820 (v. 788) scf/b crude, respectively.¹⁵ These supplies appear sufficient for current operations.

28. Further, the DEIR does not report the reliability component of these capacities. It does not disclose that the Shell Martinez refinery is served by at least three hydrogen plants,¹⁶ an inherently reliable design. It does not disclose that the planned 120 mmscf/d hydrogen plant at Rodeo will enable hydrogen export and is expected to shut down only once per year.¹⁷ The production and reliability capacities of these plants suggest that the Pipeline anticipates changes in refinery processing and/or supply to other refineries.

29. The full scope of proposed new refinery hydrogen pipeline infrastructure is much larger than the DEIR discloses. Another recent County project review states: “[T]here are at least four competing proposals by hydrogen production companies to connect all or some of the Bay Area refineries with a hydrogen pipeline, for potential export and/or import of hydrogen to and from such refineries. ... [including] proposals to link hydrogen producers at the Tesoro Golden Eagle Refinery in Martinez with the Shell Martinez Refinery and Valero in Benicia.” (Attachment 12.) All Bay Area refineries would be linked in a regional hydrogen pipeline network where no such pipelines exist today. (Attachment 5.) New hydrogen plants at Richmond, Rodeo and Benicia could feed 320 mmscf/d to this expansion of hydrogen-intensive oil refining. (Id.) The DEIR does not disclose this larger project to connect all Bay Area refiners’ hydrogen production and use.

30. California refiners use hydrogen to protect process catalysts, hydrogenate heavier oil streams, quench severe hydroprocessing of such lower-quality streams, and meet environmental standards for fuels—and most of their increasing hydrogen consumption is used for processing lower-quality oil streams. (Attachments 3-5; see Background above.) This information is crucial to understanding the full purpose of an increase in refinery hydrogen supply as well as its environmental implications. But the DEIR discusses only the use of hydrogen to meet fuel standards. The DEIR does not provide a complete description of how refineries would use the proposed increase in hydrogen supply.

¹⁵ Based on plant-specific data from the analysis reported in Attachment 5.

¹⁶ See Flare Minimization plans, Attachment 16; and Kramer et al. (1996), Attachment 17.

¹⁷ See excerpts from EIR SCH #2005092028, appended hereto as Attachment 18.

31. Argonne National Laboratory's 2007 *Overview of Interstate Hydrogen Pipeline Systems* found "greater quantities of hydrogen will be required as the quality of the raw crude decreases." (Attachment 13.) Sulfur in U.S. refinery crude inputs increased by 62% (from 0.91-1.47 % wt.) since 1985.¹⁸ California refiners added 388,000 b/d of hydroprocessing and 329 mmscf/d of hydrogen production from 1995-2007 as sulfur in their crude inputs increased from an average of 1.13% to 1.35% wt. (Attachment 5.) Underlying this trend is dwindling domestic supply—crude from California and Alaska was 91% of statewide refinery input in 1995 but could be only 33% in 2025—and the industry's choice to replace it with foreign crude from more contaminated sources. (Id.) From 1995-2008 the foreign crude stream refined by Shell in Martinez grew by 38 times and sulfur in this imported stream increased by 270% (from 0.50-1.86% wt.).¹⁹ From 1995-2008 the total crude slate refined at Richmond went from 9% to 77% foreign crude and its sulfur content increased by about 57% (from 0.98-1.53% wt.).²⁰ Chevron seeks to retool the Richmond refinery for a crude slate with up to 3% sulfur.²¹ The Avon and Benicia refineries plan to retool for heavier and/or more contaminated oil.²² A regional pipeline network with 320 mmscf/d of new hydrogen production at Richmond, Rodeo and Benicia enables such plans. The proposed expansion of Bay Area hydrogen supply will likely be used to refine lower-quality oil. The DEIR does not disclose that.

32. The DEIR does not report the current crude slate quality or the current or planned design slate (oil quality specifications of equipment capacity) of any refinery that could use hydrogen from the Pipeline. This information is necessary to assess localized impacts from the use of Pipeline hydrogen near each such refinery. It should be reported for crude gravity and concentrations of key contaminants—arsenic, mercury, nickel, nitrogen, selenium, sulfur and vanadium—in current oil inputs and design slates.

33. Amounts of pipeline-delivered hydrogen that could be made and used in each refinery are not disclosed by the DEIR, although some of this information is readily

¹⁸ EIA (<http://tonto.eia.doe.gov/dnav/pet/hist/mcrs1us2a.htm>). Downloaded 8/17/09.

¹⁹ EIA Company Level Imports data, appended hereto as Attachment 19.

²⁰ Based on Attachment 19 and conservative estimates of Richmond's ANS-dominated domestic crude quality (ANS API gravity/sulfur: 27.49°/1.00% in 1995, and 33.03°/0.86% in 2008).

²¹ See EIR SCH# 2005072117.

²² See George Avalos' 2007 article in *Downstream Today*, appended hereto as Attachment 20.

available. (See attachments 2-7, 12, 15, 26.) This information is needed for review because the amount of hydrogen produced and/or used in a refinery is related to the extent of impacts from that production and/or use, and some such impacts occur locally.

34. Use of Pipeline hydrogen will result in changes to refinery equipment and operation that could increase pollution.²³ Making that hydrogen will require expansion of hydrogen production. Using that hydrogen will require expansion of hydroprocessing. Using it for lower-quality oil will require expansion of severe hydroprocessing (e.g., hydrocracking), vacuum distillation, coking and/or catalytic cracking, among other refinery processes. (See Background above.) Fuel and flare gas systems would also be affected, as coking, cat-cracking and hydroprocessing are large producers of fuel gas while hydrogen plants are large fuel gas users.²⁴ The DEIR does not disclose the changes in refinery equipment and operation required to produce and use Pipeline hydrogen.

Environmental review

35. The Bay Area is the second largest oil refining center on the U.S. West Coast. (Attachment 2.) Refineries are the largest industrial source of criteria air pollutants²⁵ and five of the six largest greenhouse gas emitting facilities in the region,²⁶ and they cause acute exposures to flared pollutants in nearby communities recurrently.²⁷ The DEIR does not describe their role in this environmental and energy resource setting.

36. Instead of analyzing environmental impacts that could result from making and using the hydrogen supply the Pipeline would transport, the DEIR concludes that those impacts are too remote and speculative to predict and evaluate. (Ch. 4, pp. 5-15, 5-16.) This is an error. As described above, processing changes required for more hydrogen-intensive refining are known, plans to use it for lower-quality oil are known, and resultant emissions can be predicted with readily available information. These impacts are not “too speculative” to predict. The County could have predicted and evaluated them.

²³ The DEIR seems to say this too (p. 5-15), but does not describe such potential process changes.

²⁴ See attachments 16 and 17.

²⁵ California Air Resources Board (2009), appended hereto as Attachment 24.

²⁶ Bay Area Air Quality Management District (2008), appended hereto as Attachment 21.

²⁷ Attachment 8; and CBE (2005), appended hereto as Attachment 22.

37. For example, the County could have estimated the increased greenhouse gas (GHG) emissions, criteria air pollutant emissions and flaring that could result from the new hydrogen supply in refineries using the information reported above. One way to do so—although there may be other and better ways with more data—would be to estimate a range of potential hydrogen supply, the energy needed to make and use that hydrogen, and then the emissions from that fuel combustion energy.

38. Hydrogen supply through the total proposed regional pipeline network could reach 320 mmscf/d, and Praxair reportedly designed its proposed new 280 mmscf/d hydrogen plant in Richmond to export 100 mmscf/d through its proposed Pipeline. (Attachments 5, 12, 15, 23.) The County could have used this information to estimate a 100-320 mmscf/d range of potential hydrogen supply.

39. Fuel combustion energy for making hydrogen by new natural gas-fueled steam reformers is approximately 459 Btu/scf hydrogen produced. (Attachment 5.) Hydrogen-related energy required in other refinery processes is about 1.05-1.49 Btu/b crude refined for each 1.0 Btu/b to make that hydrogen. (Attachments 4, 6.) The County could have applied these factors to a 100 mmscf/d hydrogen supply to estimate Pipeline-only impacts, and to a 320 mmscf/d supply to estimate regional pipeline network impacts.

40. GHG emissions from this fuel combustion are approximately 53.1 kg/MMBtu from hydrogen production and 72.1 kg/MMBtu from other refinery processes. (Attachments 4, 5.) This is based on new natural gas-fueled steam reformers, the average refinery fuel mix for other refinery processes, and Air Resources Board emission factors for CO₂ equivalents (CO₂e) including carbon dioxide, nitrous oxide and methane. (Id.) Nitrogen oxide (NO_x), carbon monoxide (CO), particulate matter (PM) and volatile organic compound (VOC) emissions can be estimated very conservatively as 37.2 pounds, 82.3 lb., 7.45 lb. and 5.39 lb. per billion Btu, respectively, based on EPA emission factors for combustion of natural gas fuel.²⁸ The County could have applied these emission and fuel combustion factors to derive the estimate shown below.

²⁸ US EPA AP 42 emission factors for natural gas combustion by all sources (PM, VOC) or small (<100 mmscf/h) boilers with low-NO_x burners and Selective Catalytic Reduction (NO_x, CO). Note that natural gas fuel factors underestimate emissions from dirtier-burning refinery fuels.

Incremental refinery combustion emissions of selected pollutants, preliminary estimate

	<u>Praxair Pipeline only</u>	<u>Total pipeline network</u>
New H ₂ supply (mmscf/d)	100	320
H ₂ -related energy (MMBtu/d)		
Production at 459 Btu/scf H ₂	45,900	147,000
Use at 1.05-1.49 Btu/Btu H ₂	48,200-68,400	154,000-219,000
Total combustion energy	94,100-114,000	301,000-366,000
CO ₂ e emission (metric tons/y)		
H ₂ prod. at 53.1 kg/MMBtu	890,000	2,850,000
H ₂ use at 72.1 kg/MMBtu	1,270,000-1,800,000	4,050,000-5,760,000
Total combustion emissions	2,160,000-2,690,000	6,900,000-8,610,000
Criteria air emissions (lb/day)		
NO _x at 37.2 lb/billion Btu	3,500-4,240	11,200-13,600
CO at 82.3 lb/billion Btu	7,740-9,380	24,800-30,100
PM at 7.45 lb/billion Btu	701-849	2,240-2,730
VOC at 5.39 lb/billion Btu	507-614	1,620-1,970

Preliminary estimate based on data and methods described in the text of this report. Criteria emissions are underestimated based on 100% natural gas refinery fuel. Figures may not sum due to rounding.

41. The preliminary estimate in this table suggests that GHG emissions could increase by 2.16 to 8.61 million metric tons per year, and NO_x, CO, PM and VOC emissions could increase by 3,500-13,600, 7,740-30,100, 701-2,730 and 507-1,970 pounds per day, respectively. This estimate should be improved upon with information the DEIR omits. (See paras. 25-34.) For example, criteria pollutant emissions are based on natural gas fuel, but refiners use a dirtier-burning fuel mix. That underestimates those emissions. The County could use specific refinery and process fuels data and find higher emissions.

42. Flaring could increase as a result of using Pipeline hydrogen for lower-quality oil. Statewide data show a 1% equivalent increase in the sulfur content of crude inputs for each 852 scf increase in hydrogen/b crude refined. (Attachment 5.) To approximate impacts at the Martinez and Rodeo refineries, the County could have applied this 1% sulfur/852 scf-b hydrogen factor to a 150,000 b/d crude throughput. Had it done so, the County could have found that a 100 mmscf/d Pipeline hydrogen supply could enable a 0.78% increase in the sulfur content of that 150,000 b/d throughput.

43. Bay Area industry data show refining higher-sulfur crude increases flaring due to upsets. (Attachments 7-9.) These data suggest that flaring frequency increases by roughly 133%, and that the concentration of sulfur compounds in emissions from

hydroprocessing flaring increases by roughly 400%, for each 0.5% increase in the sulfur content of a refinery's monthly crude input. (Attachments 7, 8.)

44. The County could have used the data above for hydrogen-related impacts on crude sulfur content, and crude sulfur content impacts on flaring, to calculate that using a 100 mmscf/d Pipeline hydrogen supply to process higher-sulfur crude could increase flaring frequency by roughly 200% and increase flare sulfur compound emissions concentrations by roughly 625% at a 150,000 b/d refinery. This preliminary estimate is only a rough approximation of the potential scale of oil quality-related flaring impacts because other factors affect refinery-specific flaring patterns. Nevertheless, the scale of observed oil quality effects on flaring indicates a real impact. Had it done such analysis, the County could have found that Pipeline hydrogen has the potential to increase the frequency and magnitude of flaring substantially.

45. Flaring could also increase if a refinery buys Pipeline hydrogen instead of spending to maintain and upgrade its onsite/adjacent hydrogen supply reliability. Hydrogen plants are large users of refinery fuel gases that, when they malfunction, can cause fuel gas imbalances that result in flaring. (Attachments 16, 17.) Refiners expected to tie-in and use the Pipeline supply have or plan reliable onsite/adjacent hydrogen production. (Attachments 16, 17, 18.) But if maintenance lags, hydrogen plant problems can cause as much as 30% of total maintenance-related flaring. (Attachment 16.) The County could have analyzed these available data and found that reliance on the Pipeline has the potential to increase flaring resulting from onsite hydrogen plant upsets.

46. The lowest GHG emissions potential estimated above far exceeds emissions found to have significant potential global warming impacts in other environmental reviews. The lowest NO_x, CO, PM and VOC emissions estimated above far exceed applicable Prevention of Significant Deterioration and EIR significance thresholds used by the Air Quality Management District. The potential for flaring estimated above is based on incidents exceeding Air District thresholds that indicate environmental significance. (Attachments 7, 8.) Thus, had the County analyzed impacts resulting from producing and using Pipeline hydrogen at refineries, it could have found that potential impacts of GHG, criteria pollutant and flaring incident emissions would be significant.

47. Other pollutant releases are caused by the refining of lower-quality oil enabled by the Pipeline. These can include, among other releases, refinery upset releases, discharges of toxic pollutants such as selenium, mercury emissions, emissions of sulfur and nitrogen compounds and toxic air contaminant emissions from increased refinery fuel combustion. These other pollutant releases should have been analyzed and addressed by the DEIR.

Energy resource review

48. As the DEIR discusses, curtailment of hydrogen supplies to refineries will slow or interrupt the production of transport fuels at the affected refineries. The DEIR does not, however, discuss the potential for this to result in a concentration of power over energy resource production at multiple refineries that become reliant on the Pipeline, instead of maintaining and upgrading their existing onsite/adjacent hydrogen production.

49. The Pipeline would be operated from Praxair's hydrogen control room at the Richmond refinery. (DEIR at 4.7-23.) This would create a single point of control over hydrogen flow-related production rates at three of the region's five refineries. Including the whole proposed pipeline network (Attachments 5, 12, 23), such concentrated control over production rates could affect all five refineries. This would be wholly new in a refining region that has no hydrogen pipelines linking its refineries today—and is the second largest refining center on the U.S. West Coast.

50. The shutdown/subsequent startup, and/or ramping down/ramping up of processing caused by potential changes in hydrogen supply could result in environmental impacts. Most refinery processes are more vulnerable to upsets that can lead to potentially catastrophic pollution incidents when their production rates are ramping up or down instead of operating in steady-state conditions. (Attachment 16.) Planned and unplanned shutdowns of refinery processes also result in significant flaring. (Id.)

51. Energy market manipulation has been a problem in California with electricity. The DEIR should have alerted the public and other government agencies to the potential for the concentration of market power allowed by this wholly new pipeline infrastructure to invite manipulation of gasoline and diesel fuel markets and prices. At a minimum, it should have addressed the environmental impacts that could result from this problem.

Alternatives review

52. Ignoring the existing and potential reliability of hydrogen production facilities at refineries is a fatal error in the DEIR's alternatives analysis. (Chapter 6, see esp. 6-20.) In the absence of a new pipeline, refiners could be incented to maintain and upgrade their existing onsite/adjacent hydrogen supply production. Indeed, both of the refineries the Pipeline seeks to tie-in to and provide hydrogen to can meet the reliability objective stated in the DEIR without the Pipeline. The ConocoPhillips Rodeo refinery plans a new hydrogen plant that is expected to provide more than enough supply for the refinery and shut down an average of only once per year. (Attachment 18.) The Shell Martinez refinery is served by at least three hydrogen plants. (Attachments 16, 17.) With continued investment in maintenance and upgrading, this inherently reliable redundancy can be expected to provide continued hydrogen supply reliability.

53. Chevron's existing backup natural gas pipeline for the Richmond refinery could remain in natural gas service if the Pipeline is not built. This would also "maximize the use of existing pipeline infrastructure to reduce disturbance associated with new construction" better than building the Pipeline. (See DEIR at 3-1.) Thus, with the continued self-supplied hydrogen reliability discussed above, three of the four project objectives could be met without the Pipeline. (Id.) The only project objective stated in the DEIR that this no project/refinery maintenance alternative would not meet is to: "Create pipeline infrastructure to allow the safe and efficient transport of hydrogen between refineries." (Id.)

54. The no project alternative would avoid all the potential impacts of the Pipeline and has less potential environmental impact than the Pipeline. The DEIR agrees with this conclusion for those impacts that the DEIR identifies.²⁹ Therefore, since it can meet most of the project objectives with less potential environmental impact, the no project/refinery maintenance alternative, and not the proposed Pipeline as the DEIR wrongly concludes on page 6-47, would be the environmentally superior alternative.

²⁹ See DEIR at 6-26, 6-31, 6-33 through 6-36, 6-38 through 6-45 and 6-47.

Conclusions

55. Proposed pipeline infrastructure to send hydrogen between the Richmond, Rodeo and Martinez refineries is part of a larger project to expand hydrogen-intensive processing and related processing of oil that would link all five major Bay Area refineries in a regional hydrogen pipeline network where no such pipelines exist today.

56. This new hydrogen supply will enable the continuation and acceleration of an existing trend toward more hydrogen-intensive processing of heavier and/or more contaminated components of whole crude, which are more abundant in lower-quality crude oils. The proposed hydrogen supply expansion cannot be explained by treating gasoline blendstocks for compliance with fuel standards alone. The project will enable, and likely will be used for, refining heavier and more contaminated oil.

57. Making and using the additional hydrogen to be carried by the proposed pipeline infrastructure in refineries will require more energy from fossil fuel combustion. It will require more intensive processing that increases pollution incident hazard. It will pass more pollutants into the environment from the heavier and more contaminated components of whole crude that require the most hydrogen-intensive processing.

58. Contra Costa County's Draft Environmental Impact Report (DEIR) fails to analyze environmental impacts from producing and using this new hydrogen supply in refineries. It erroneously concludes that those impacts are "too speculative" to predict. Processing changes required for more hydrogen-intensive refining are known. Plans to use hydrogen-intensive processing for lower-quality oil are known. Resultant impacts can be predicted with available information. The County could have analyzed them.

59. For example, data are readily available to estimate the fuel combustion energy required to make a given amount of hydrogen and to use that hydrogen in other refinery processes. Although there are other and better ways to do so with more of the data omitted from the DEIR, the County could have used publicly available data to estimate the range of potential new hydrogen supply, the fuel combustion needed to make and use that hydrogen, and then the refinery emissions from that fuel combustion. Had it

performed such analysis, using available data attached to and discussed in this report, the County could have found that:

- The production and use of hydrogen to be carried by the proposed Pipeline between the Chevron Richmond, ConocoPhillips Rodeo and Shell Martinez refineries could cause 2.16-2.69 million metric tons of CO₂ equivalent emissions from refineries annually. For criteria air pollutants, it could cause 3,500-4,240 pounds/day of nitrogen oxide, 7,740-9,380 lb/d of carbon monoxide, 701-849 lb/d of particulate matter, and 507-614 lb/d of volatile organic carbon emissions.
- The production and use of hydrogen to be carried by the entire proposed regional pipeline network between all five Bay Area refineries could cause 6.90-8.61 million metric tons/year of greenhouse gas, 11,200-13,600 lb/d of nitrogen oxide, 24,800-30,100 lb/d of carbon monoxide, 2,240-2,730 lb/d of particulate matter, and 1,620-1,970 lb/d of volatile organic carbon emissions.

60. Similarly, the County could have used California and Bay Area industry data describing impacts of hydrogen-intensive processing on refinery crude input quality and process upsets to find that the proposed new Pipeline hydrogen supply could result in a substantial increase in the frequency and magnitude of refinery flaring incidents.

61. This preliminary estimate should be improved and expanded using data omitted from the DEIR for specific refineries and their processes. However, the estimate is based on substantial industry-wide data and conservative emission rate assumptions. Thus, more accurate future estimates of potential to pollute using refinery-specific data are likely to exceed the low end of the emission ranges in this estimate. Further, even the lowest emissions estimated far exceed thresholds for environmental significance. Therefore, the County could have concluded, and I conclude, that potential greenhouse gas, criteria air pollutant, and flare incident emission impacts would be significant.

62. The DEIR is deficient and should be revised and recirculated to provide necessary information for adequate public review because it does not disclose, analyze or address:

- the anticipated operating life of the proposed Pipeline;
- how much hydrogen the Pipeline could carry to and from refineries;
- the capacity and usage of hydrogen production at each affected refinery;
- the full scope of new refinery hydrogen pipeline infrastructure proposed;
- a complete description of how refineries could use this hydrogen supply;
- the likely use of this hydrogen for processing lower-quality oil;

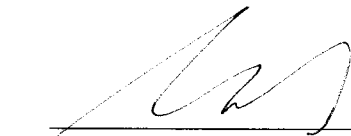
- the current and planned oil input quality of each affected refinery;
- the amounts of pipeline hydrogen that could be made and used at each refinery;
- the changes in refinery equipment and operation that could result from producing and using the hydrogen to be carried by this new pipeline infrastructure;
- the role of affected refineries in the environmental and energy resource setting;
- the fact that potential impacts from producing and using the hydrogen to be carried by the Pipeline in refineries can be predicted and evaluated;
- the potential impacts from producing and using Pipeline hydrogen in refineries;
- significant potential impacts of greenhouse, criteria pollutant and flare emissions;
- potential impacts of reliance on the Pipeline on refinery maintenance; and
- accurately described “no project” and “environmentally superior” alternatives.

63. Lastly, this proposed regional hydrogen pipeline network in the second-largest West Coast refining center, where no such pipelines interconnect refineries today, could concentrate control over hydrogen-related energy resource production. This raises a possibility of concentrated market power that should be evaluated for its potential environmental and energy resource impacts.

64. I have given my opinions on these matters based on my knowledge, experience and expertise and the data, information and analysis discussed in this report.

I declare under penalty of perjury that the foregoing is true of my own knowledge, except as to those matters stated on information and belief, and as to those matters, I believe them to be true.

Executed this 26th day of August 2009 at Oakland, California.



Greg Karras

Attachments list (page 1 of 2)*
Expert report of G. Karras

Karras Attachment-1. Curriculum vitae and publications list.

Karras Attachment-2. Oil & Gas Journal (various dates). Worldwide refining annual surveys, 1995 through 2008.

Karras Attachment-3. Robinson and Dolbear (2007). Commercial Hydrotreating and Hydrocracking. *In* Hydroprocessing of Heavy Oils and Residua. Ancheyta and Speight, eds. Taylor & Francis. Boca Raton, FL.

Karras Attachment-4. CBE (2009). Refinery GHG emissions from dirty crude. Preliminary estimate based on oil input quality, process intensity and energy intensity of U.S. oil refineries, 2003-2007.

Karras Attachment-5. CBE (2008). Increasing GHG emissions from dirty crude. Analysis of publicly available data for one of the oil refining processes expanding for more contaminated oil in California: Hydrogen steam reforming.

Karras Attachment-6. Summary output: Total refinery fuel energy v. hydrogen production energy. Statistical analysis based on actual U.S. refineries performance 2003-2009.

Karras Attachment-7. CBE comment to City of Richmond; June 5, 2008 expert report of G. Karras.

Karras Attachment-8. CBE comment to City of Richmond; July 9, 2008 response to comments by G. Karras.

Karras Attachment-9. July 14, 2008 email from Deputy Attorney General Rose Fua, California DOJ, to Lamont Thompson, City of Richmond. Subject: Dolbear's comments.

Karras Attachment-10. CBE (1994). Dirty Crude. The first oil industry-wide analysis of selenium discharge trends impacting San Francisco Bay.

Karras Attachment-11. Wilhelm et al. (2007). Mercury in Crude Oil Processed in the United States (2004). *Environmental Science and Technology* 41(13): 4509-4514.

Karras Attachment-12. Excerpt from EIR SCH #2005092028. Responses to comments. EIR page 3.8-37.

Karras Attachment-13. Argonne National Laboratory (2007). Overview of Interstate Hydrogen Pipeline Systems. US DOE, ANL/EVS/TM/08-2. November 2007.

Karras Attachment-14. World Pipeline Experience, U.S. Department of Transportation, Challenge of Hydrogen Pipeline Transportation. Data downloaded August 16, 2009.

Karras Attachment-15. Excerpts from EIR SCH #2005072117. Pages 3.13a-2, 3.13a-3, 4.18-23, 4.18-24; App. D-5.

* Attachments submitted electronically. See the compact disk (CD) submitted with this report.

Attachments list (page 2 of 2)*
Expert report of G. Karras

Karras Attachment-16. Flare Minimization plans approved by BAAQMD for San Francisco Bay Area refineries.

Karras Attachment-17. Kramer et al. (1996). Flexible hydrogen plant utilizing multiple refinery hydrocarbon streams. National Petroleum Refiners Association. AM-96-59. 1996 NPRA Annual Meeting. March 17-19, 1996. San Antonio, TX.

Karras Attachment-18. Additional excerpts from EIR SCH #2005092028. Project Description. EIR pages 3-5, 3-31.

Karras Attachment-19. U.S. Energy Information Administration (various dates). Company Level Imports data, 1995-2008.

Karras Attachment-20. George Avalos, Contra Costa Times, May 10, 2007 report in *Downstream Today*.

Karras Attachment-21. BAAQMD (2008). Source Inventory of Bay Area Greenhouse Gas Emissions, Base Year 2007. Bay Area Air Quality Management District. December 2008.

Karras Attachment-22. CBE (2005). Flaring Hot Spots. Assessment of episodic local air pollution associated with oil refinery flaring using sulfur as a tracer. July 2005.

Karras Attachment-23. Air Liquide (2007). Martinez to Benicia Hydrogen Gas Pipeline, Project Execution Plan, Revised Project Description.

Karras Attachment-24. California Air Resources Board (2009). Almanac Emission Projection Data.

Karras Attachment-25. California Energy Commission (2009). Fuels Watch (data in thousands of barrels) and gasoline sales (in gallons).

Karras Attachment-26. Market Wire (2008). Investments in Hydrogen Capacity Continue to Rise, Exceeding \$2 Billion in Future Spending. May 2008; and RedOrbit News (2008). Valero Energy Selects Contractors for \$200 Million Hydrogen Project at California Refinery. July 2, 2008. *Industrial Info News alerts*.

* Attachments submitted electronically. See the compact disk (CD) submitted with this report.