

October 28, 2009

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**Re: Comments on Final EIS for the Mandan, Hidatsa and Arikara (MHA) Nation  
Proposed Clean Fuels Refinery Project**

Dear Representatives of the MHA Nation, the BIA and EPA,

Thank you for this opportunity to comment on the Final Environmental Impact Statement (FEIS) for the proposed new MHA Nations Clean Fuels Refinery (“the Project”). Because of my engineering background and experience over the last 20 years analyzing oil industry emissions and environmental impacts,<sup>1</sup> I have been asked by members of the MHA Nations and by the Environmental Integrity Project to review and comment on the FEIS. I also submitted comments on August 29, 2006 regarding the Draft EIS for the Project. As I will discuss below, the FEIS does not adequately address the concerns raised in the August 29, 2006 comments. Those comments are attached to this document and fully incorporated herein. The August 29, 2006 comments include information and data that have not been adequately addressed by the FEIS and continue to be a basis for the concerns raised in these comments.<sup>2</sup>

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<sup>1</sup> B.S. Engineering, University of Michigan, 1981. Presently Senior Scientist, Communities for a Better Environment, and private Environmental Consultant (1986 to present – Industrial pollution prevention analysis for environmental organizations, community groups, regulatory agencies, and trade unions.) 1981-1985 National Semiconductor Design Engineer

<sup>2</sup> *Comments on DEIS for Mandan, Hidatsa and Arikara Nation’s Proposed Clean Fuels Refinery Project*, Julia May, August 29, 2006; attached MHA Attach01 -- Final comment MHA Nation DEIS.doc

## I. Overview

**I am very concerned about the lack of a permit for Prevention of Significant Deterioration of air pollution (PSD) for the Project, which is required to be issued, and which is needed to protect public health.** The Project has the potential to emit more than 100 tons per year of criteria pollutants including Volatile Organic Compounds (VOCs), Carbon Monoxide (CO), Sulfur Oxides (SO<sub>x</sub>), and Nitrogen Oxides, and perhaps triggers the threshold for toxic air pollutants. The Project is also a major emitter of greenhouse gases. Specific pollution quantities and sources are discussed in detail below.

I urge EPA, BIA, and the MHA Nation tribal government to take a reasonable amount of time to re-evaluate the Project after the public comment period. A careful evaluation of deficiencies and concerns raised in public comments is necessary.

The finding that this Project is a minor source of air pollution is in error, and even if the Project were a minor source, no minor source permit is being provided which would require that emissions stay minor. Without pollution limits through enforceable permits, the community will be left without basic protections that are provided as a matter of course throughout the rest of the country. Only very recently (in the Final EIS released to the public at the end of August) were some specific federal air pollution standards identified that apply to the Project. These were never identified during the Draft EIS process as part of the Project design. Identifying compliance with these federal standards is an important step forward, but they will not by themselves limit the pollution sufficiently to prevent the requirement for a PSD permit, and neither will they limit pollution sufficiently to eliminate significant environmental impacts that can be avoided through enforceable permit limits.

The Project deficiencies and FEIS also create an Environmental Injustice, where tribal and surrounding areas are bearing the brunt of cumulative impacts from multiple fossil fuel energy sources, by geographically concentrating pollution from the proposed refinery, coal-fired power plants, tar sands pipelines, and gas drilling in the region. The FEIS attempts to justify this by repeatedly comparing the proposed refinery emissions to those of very large coal-fired power plant emissions in the region. This view is contrary to national Environmental Justice policy, which seeks to prevent unfair concentrating of pollution in communities of color, and which requires evaluation of the cumulative impacts rather than an attempted justification of new projects in already burdened areas.

Furthermore, a *new* refinery should not be built that has never undergone a Best Available Control Technology (BACT) review.

A BACT review is the heart of the technology forcing provisions of the Clean Air Act and the failure to undertake the review at this new refinery only increases the likelihood that the technologies employed by the Project and resultant emissions will not be adequately protective of public health. It would be vastly easier and less costly to design the best alternative up-front, instead of attempting to retrofit the refinery after the fact. In addition, clean energy alternatives to the Project should have been evaluated. Failure to do the analysis now provides the MHA Nation with a substandard Project and a missed opportunity. Even if the MHA Nation, BIA, and EPA found (incorrectly) that no air permits are required under the Clean Air Act, viable Project alternatives must still be considered under NEPA. The FEIS must consider these less polluting alternatives, utilizing Best Available Control Technology, as determined through a standard

BACT analysis. This alternative would be economically viable and environmentally preferable, but no BACT analysis has been provided as required for the Project.

Oil refineries are inherently polluting and cause significant environmental, health, and safety impacts for communities surrounding these facilities. Although there is really no such thing as a small refinery (because a refinery is by its nature heavy industry), it is evident from many public statements that there are already plans being considered for greatly expanding the proposed refinery in the future after the initial smaller refinery is built (as commented on in the DEIS). Instead of describing the Cumulative Impacts of the entire Project now, a smaller refinery is being described and evaluated, and the full impacts are being piecemealed into smaller bits that do not reflect the actual total potential to emit and impacts. It is essential that the MHA Nation, the EPA, and BIA require that the Cumulative Impacts of the entire refinery capacity that will potentially be built be revealed to the public in detail. If for instance, the plan of the next few years already includes a 55,000 or 100,000 barrel per day oil refinery, this needs to be disclosed, emissions evaluated, a PSD permit and other permitting be evaluated, and mitigation measures be designed for the full project.

**If the proponents claim this is not the case (no future expansion), then there should be no problem setting a mitigation measure and permit requirement for the Project limiting throughput to 10,000 barrels per day of crude oil for the Project lifetime, and limiting the crude oil input to light, low sulfur, low metals crude oil.** This is necessary because no maximum crude oil throughput limit has been identified nor set as any enforceable permit requirement that I could identify in the FEIS documents.

There are many fatal flaws with the FEIS. It should be reissued as a draft. In summary:

- **The Environmental Justice analysis is inadequate**, not reflecting the full impact of this Project;
- **The FEIS includes inaccuracies and incomplete information** that must be corrected. Air emission calculations are entirely left out from the appendices to the Air Quality Technical Report of the FEIS for air emissions (“example” calculations are provided). Without details, the MHA Nation, BIA, and EPA cannot make a decision based on a full revelation of Project impacts;
- **The FEIS failed to include all emissions in project totals:**
  - Certain **Startup/Shutdown and Maintenance** operations are missing, **including tank cleaning, tank degassing, and coating of tanks**
  - **Flaring emissions** were underestimated
  - **Construction air emissions** were not calculated
  - **Fugitive emissions (already estimated to be large) will increase** because no government inspections mechanism is in place to independently identify leaks
  - **Sulfuric acid mist was not evaluated**
  - **Indirect greenhouse gas emissions** were not calculated

- **Increased emissions will almost certainly occur due to lack of a permit to operate with enforceable air emissions limits**, and the lack of an ongoing government site inspection mechanism;
- **A PSD permit is required and a standard and methodical assessment of Best Available Control Technology is required** but was not carried out for criteria pollutants , CO2, or toxics.
- **There is no permit requirement for a key basis of the Project – the use of Syncrude** -- so crude slate could change to heavier, more contaminated crude, and Syncrude itself can vary in quality and environmental impacts;
- **The FEIS grossly underestimated the maximum Potential to Emit**, because, although there are some individual federal regulatory conditions identified, there is no permit to enforce;
- **Environmental, economic, and regulatory conditions have changed drastically over the last several years since the original Project was developed**, and a new draft EIS should be published;
- **Major Cumulative Impacts are missing evaluation** in the DEIS and FEIS, including air quality and water impacts due to coal plants, drilling operations involving flaring, and major new tar sands pipelines;
- **The refinery is likely to be expanded** and cumulative impacts are being improperly piecemealed;
- **Impacts for the Project must assess the economic issues which include the value of safe drinking water and air to public health**, and the cost of clean up of ground water and contaminated soil;
- **An assessment of real and viable alternatives** to the Project should include a least polluting refinery option, and clean alternative energy options; and
- **There has not been adequate time for the public review of the FEIS:**
  - Many members have stated that they did not receive notice of the FEIS even though they did comment on the DEIS, and so they have received a shorter time to comment on the FEIS. Some were not provided documents when they requested them
  - I received notice of the FEIS on Sept. 9<sup>th</sup>, 2009. After a wait of three years after the DEIS comment period, the FEIS was dropped onto the public with no warning, with about 7 weeks (at most) to review the thousands of pages of new documents. The Project proponents took 36 months to review and put together these new documents which the public had to review. This seems unreasonable and not in the interests of the MHA Nation, where a considered evaluation of the details is essential for protecting the people, air and water quality, and the economic viability of the region.

## **II. The Project criteria pollutant air emissions are underestimated and a PSD permit is required**

EPA's website states that the proposed refinery's air emissions would be minor, and that therefore no PSD permit is required:

At this time, EPA has determined that no Clean Air Act permits will be required for the facility because the total quantity of air pollutants emitted throughout the year by the refinery are less than the regulatory thresholds for any air permits.<sup>3</sup>

These findings are in error. Although the FEIS provided some additional information and analysis on air emissions sources that were not included in the original DEIS, the FEIS still failed to identify the full potential to emit or potential maximum air emissions for the Project (also discussed further in later sections of this comment). When additional sources are included the proposed refinery triggers the major source threshold, and a PSD Permit is required.

The idea that a new oil refinery could be sited with neither a major nor minor source permit is unthinkable. Small dry cleaners need air permits. Small auto finishing operations need permits. This is for very good reason. The handling of inherently hazardous and explosive materials, as well as cancer-causing, asthma-inducing and emissions that are reproductive hazards, toxic to humans, fish, and wildlife, and greenhouse gases, on the large scale at an oil refinery without any air permit, is improper and does not comport with the Clean Air Act nor EPA's environmental justice priorities, specifically the priority to ensure compliance. The BIA, EPA, and the MHA Nation need to correct this error before the project goes further. Siting of a new refinery with no air permit at all has not occurred in any other part of the country and should not be allowed to move forward here.

The FEIS summary table of air emissions (page 4-101, Table 4-15, "Estimated Annual Emissions for the Proposed MHA Nation's Proposed Clean Fuels Refinery") gives annual NO<sub>x</sub> of 35.7 tpy, CO of 78.3 tpy, SO<sub>2</sub> of 51.2 tpy, VOCs of 77.0 tpy, and PM<sub>10</sub>/PM<sub>2.5</sub> of 16.8 tpy.

The Final EIS did provide additional analysis showing increased VOC emissions compared to the Draft EIS. DEIS VOC emissions were 38.9 tpy, increased to 77 tpy year in the FEIS because fugitive emissions were added (from leaky components such as valves, flanges, and other seals). Thank you for responding to the DEIS comment on missing fugitive emissions. However, the FEIS still found that no pollutant exceeds the PSD permit threshold of 100 tpy for criteria pollutants or 10 tpy for toxics and as my comments illustrate this is in error.

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<sup>3</sup> <http://www.epa.gov/unix0008/compliance/nepa/summarydeis.html>

## **Flare emissions have been underestimated and basic control equipment is missing**

The FEIS Air Quality Technical Report (page 4-1) states the following:

The normal loading at the Flare was designed for a loading rate of 15 lbs/hr (65.7 tons/yr). A loading rate of 500 lbs/hr (2,190 tons/yr) or 10 million British thermal units per hour (MMBTU/hr) was used to generate conservative emission estimates for NO<sub>x</sub> that would account for potential process upsets and other activities that may increase loading rates. The loading rate of 500 lbs/hour is over 30 times the normal operation loading rate of 15 lbs/hour. The potential flare emissions were also calculated based on operating the flare 24 hours a day, 365 days a year. [See Flare Example NO<sub>x</sub> calculation in Appendix C.] Therefore, potential emissions (from startups, shutdowns and equipment malfunctions, were conservatively estimated for the proposed refinery.

The explanation above, stating that the flare will normally be designed with a loading rate of 15 lbs/hr, so therefore a randomly higher loading rate of 30 times will provide a conservative estimate of annual emissions, is without any basis. Flares are made to operate at drastically varying rates, and are designed with loading rates far higher than the factor of 30 cited in the FEIS. A flare event can emit 15 lbs/hr or 20 tons per/hr, which is a factor of well over 2000. The DEIS cannot use random numbers without basis as a replacement for an analysis. There is no data in the FEIS, Air Quality Technical Report, nor the appendix that I could find that justifies this number. No maximum capacity of the flare was provided, and most importantly, there is no permit which establishes the flare's maximum capacity. In the absence of a permit condition limiting the flare to 10 million BTU/hr, it must be assumed that the maximum potential to emit (PTE) can go far higher. Furthermore, even using the 10 million BTU/hr, flare emissions by themselves can cause the Project to exceed the PSD threshold of 100 tons per year according to the calculations below.

The low estimate of emissions is inconsistent with actual data in the real world, demonstrating that flare emissions are large. I submitted such data in my DEIS comments and include additional flare data in these comments. .

The response to DEIS comments included the following:

**Comment 16:** Comment that the DEIS fails to identify the methods and equipment discussed by EPA such as flaring prevention investigations and methods, sufficient sulfur gas treatment capacity to meet the 230 mg/dscm hydrogen sulfide limit within the flare (which limits SO<sub>x</sub> emissions from the flare) and other NSPS requirements for flares. Additional comments that the DEIS must be corrected to reflect large emissions from flaring currently designed into the proposed refinery, require an air permit for large emissions from flaring, require that BACT and NSPS standards be applied to flares, including sufficient compressor and treatment capacity to prevent routing flaring, with sufficient monitoring.

**Response 16:** Appendix A of the *Air Quality Technical Report* (May 2006) listed the refinery flare as not subject to NSPS. This determination was incorrect. The flare for the proposed refinery will be subject to NSPS, subparts A and Ja. The *Air Quality Technical Report* (December 2007)

has been revised and now includes the specific NSPS requirements for the flare, as well as, the other refinery units. (pages E-56 & 57)

This is only partially responsive to the comments. There is no response to the comment on the need for sufficient compressor capacity to process gases that would otherwise go to the flare. In fact, there is no compressor identified in the equipment list. Does the Project include a compressor? Without one and sufficient associated gas recovery, flaring will be continuous.

An overall gas recovery system, with sufficient capacity is used at other refineries to ensure that flare gases are recycled within the refinery as fuel. The sizing is key in ensuring that flaring is minimized. Complying with NSPS Subparts A (and potentially Ja) is an important addition to the FEIS, but is not enough to minimize the number of flaring episodes. Having the equipment -- a large enough compressor, a backup compressor, a sufficient overall gas recovery system, sufficient flare monitoring with a quality assurance plan as part of an enforced permit, -- and doing the right procedures -- root cause analysis when flaring events occur, and having a Flare Minimization Plan -- will eliminate whole occurrences of flaring events, not just reduce their emissions. This goes beyond what federal flare regulations provide. Such measures are required by the BAAQMD flare monitoring and control regulations (attached<sup>4</sup>), and such equipment and procedures must be included as part of BACT. Furthermore, a BACT standard has been set by the Shell Martinez refinery, discussed later in this comment in the BACT section. Using the stated 10 million BTU/hr, VOCs can be calculated assuming the BTU content of flare gas as methane, and assuming 98% combustion efficiency (favorable to proponents because flare combustion efficiency can go far lower, causing emissions to go far higher). This calculation results in VOC emissions of 36.5 tons per year from the flare.<sup>5</sup>

However, the FEIS Air Quality Report uses flare emissions of only 6.13 tons per year of VOCs, or almost 30 tons per year less than the potential to emit using the above assumptions. Actual potential to emit can go far higher than 36.5 tons per year, because combustion efficiency can easily go lower than 98%, and because there is no permit condition actually limiting the flare to 10 million BTUs per hour. It is unclear how the FEIS arrived at the small 6.13 tons per year as the flare maximum potential to emit (no calculations were provided). Flares at refineries can easily emit 6 tons in one flaring event, in a few hours or less, so this is not a reasonable estimate for the year, without BACT as enforced through a strict permit.

If flare efficiency is only 95%, the maximum potential to emit goes up two and a half times, so VOC emissions from flaring go up to about 91 tons per year (or almost 85 tons per year higher than was estimated for flaring). Since the total VOC estimate for the Project was 77 tons per year, either using 98% combustion efficiency, or using 95% efficiency, the maximum potential to emit for VOC emissions for the refinery would exceed 100 tons per year, and require PSD permitting.

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<sup>4</sup> BAAQMD Regulation 12 Rule 11 (flare monitoring) Attached as MHA Attach02 - BAAQMD reg 1211 flare monitoring.pdf and Regulation 12 Rule 12 flare control, -- MHA Attach03 -- BAAQMD flare control reg1212.pdf

<sup>5</sup>  $(10,000,000 \text{ BTU/hr} \times 24\text{hrs/day} \times 365 \text{ days/year}) / (1012 \text{ BTU/standard cu ft (scf) methane}) / (379 \text{ scf/lb-mole}) \times 16 \text{ lbs/lb-mole (methane molecular weight)} \times 0.02 \text{ (assuming 98\% combustion)}$   
= 77,885 lbs/year or 36.5 tons/year VOC emissions

In reality, combustion efficiency for flares can go far lower than 95%, causing VOC emissions to go even higher. See attached information about combustion efficiency.<sup>6</sup> If combustion efficiency goes down to 90%, emissions are 5 times higher than at 98% (because 10% of the VOCs remains undestroyed compared to only 2% VOCs remaining unburned at 98% efficiency.) At 90% combustion efficiency, flare emissions would go up to 183 tpy (about 177 tpy more than was estimated in the FEIS). This means that the maximum potential to emit for flaring emissions from the refinery can easily exceed 100 tons per year, by itself, not including any other refinery sources. The FEIS should add at least 30 to 175 tons per year to the flare VOC estimate.

The FEIS should also have evaluated specific flaring events from startup/shutdown and maintenance operations. During periods when refinery units are shutdown, either for planned purposes or unplanned reasons, gases from process vessels have nowhere to go, and are vented to the flare. The FEIS did not evaluate such specific flaring events that could occur.

For example, a Sulfur Recovery Unit (SRU) shutdown will mean high concentrations of sulfur-laden gases (such as hydrogen sulfide or H<sub>2</sub>S) going to the flare, resulting in very high emissions of SO<sub>2</sub> from the flare. This is more likely to occur with a small refinery, because there is no backup SRU, so gases are vented to the flare during shutdown. It is unclear how the FEIS justifies the extremely low estimate for SO<sub>2</sub> flare emissions of 0.85 tons per year (no calculation or basis was provided). Once again, one single flare event at a refinery can result in 20 or more tons in a single day of SO<sub>2</sub> emissions. The South Coast Air Quality Management District regulated flaring for the express purpose of reducing SO<sub>2</sub> emissions, since refinery flaring represented by itself one of the largest sources of SO<sub>2</sub> in the region.

A government agency (the Bay Area Air Quality Management District or BAAQMD) provides specific flare data online for refineries in the Bay Area of California, and has other more specific data due to its stringent flare monitoring regulation.<sup>7</sup> At one example refinery (ConocoPhillips Rodeo, California), I have previously totaled emissions annually, compiled hourly data, and data on flaring event causes. The Conoco-Phillips Rodeo refinery reported 20 flare events in 2004 which generated more than 5,000 lbs. of sulfur dioxide and over 26 events at over 1,000 lbs of sulfur dioxide each. Totals for that year were over 240 tons of SO<sub>x</sub> from flaring alone. After 2004, the Bay Area regulatory scrutiny reduced flaring events.<sup>8</sup>

Another refinery which the BAAQMD evaluated had much higher flaring, frequently exceeding 10 tons. (Again, from BAAQMD online data.<sup>9</sup>) In 2004, the Tesoro Martinez refinery (Avon) had 36 flaring events that generated more than 5,000 lbs. of sulfur dioxide each, with the maximum event in one day over 30,000 lbs (15 tons). This was after a drastic reduction in flaring at the refinery, when flaring had been continuous (causing many tons per day of both SO<sub>x</sub> and VOC emissions, due to a lack of sufficient compressor capacity). After the refinery

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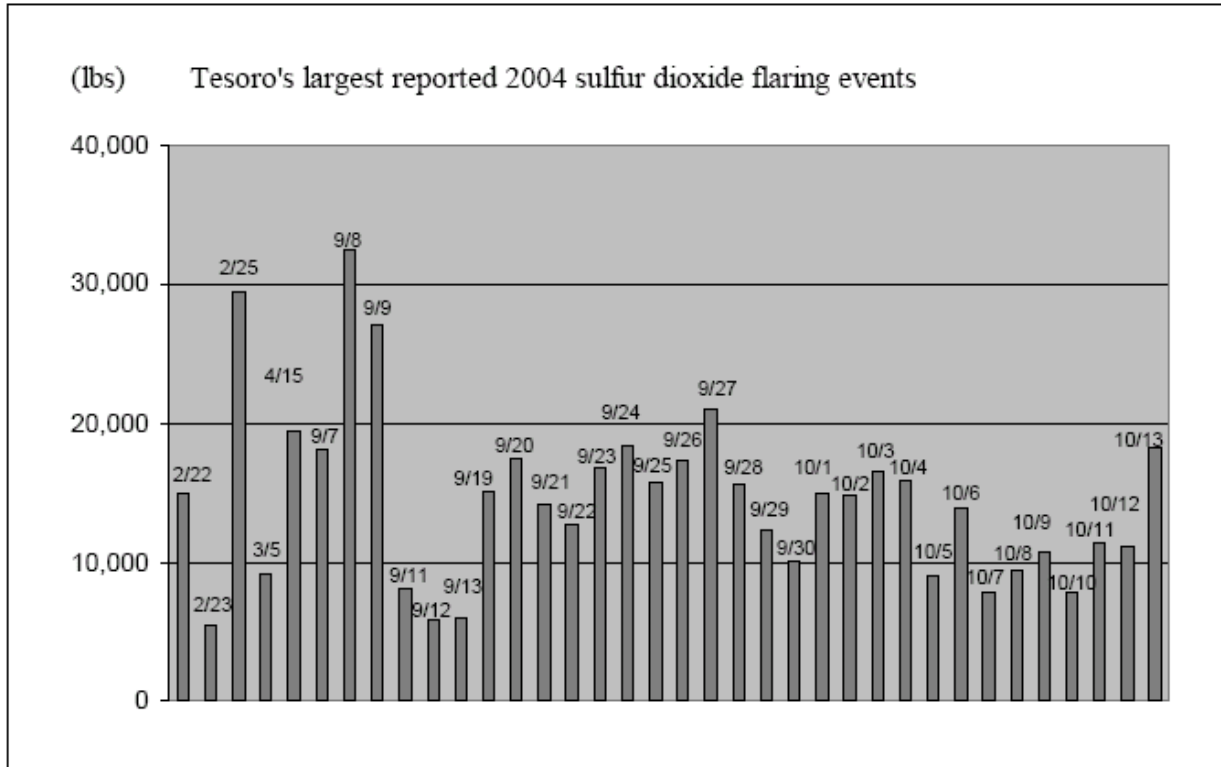
<sup>6</sup> See appendix, page 33 of *Refinery Flaring in the Neighborhood*, Spring 2004. which summarizes studies of flaring which showed that combustion efficiency for flares can be much lower than 98%. This also compiles root causes of flaring events at several refineries and provides other information on flaring emissions, causes, and impacts. Attached as MHA Attach04 -- Refinery Flaring in the Neighborhood CBE.pdf

<sup>7</sup> <http://www.baaqmd.gov/enf/flares/>

<sup>8</sup> January 22, 2007, *Comments on ConocoPhillips Rodeo Refinery Proposed Clean Fuels Expansion Project on Behalf of CBE*, attached as MHA Attach05 -- Comment\_JMay\_ConocoPhillips\_Hydroproc\_Expans.pdf

<sup>9</sup> <http://www.baaqmd.gov/enf/flares/>

purchased two new large compressors, the emissions went down from continuous flaring of dozens of tons every day, to the still high level of 36 flaring events greater than 2.5 tons. Later, after the BAAQMD adopted a flare control regulation requiring a flare minimization plan, flaring reduced further. Here is a chart of the flaring events in 2004 at Tesoro:



Both ConocoPhillips and Tesoro (in the 100,000 barrel per day range) are larger than the MHA Nation refinery, proposed at 10,000 barrels per day. However, individual flaring events at the MHA Nation refinery could easily exceed many tons in one day. Without an analysis and requirements providing sufficient compressor and gas recovery capacity, without any Flare Minimization Plan, without any permit limit on sulfur content in incoming crude oil (that greatly affects sulfur dioxide emissions during flaring), without permit requirements for root cause analysis following flaring events in order to ensure that the same cause is not repeated, the MHA Nation refinery could easily exceed 50 tons per year in SOx emissions from flaring, which in addition to the 51 tons estimated in the FEIS, would trip the PSD threshold for SOx.

Specific limits on sulfur content and specific system design and operational procedures for flaring prevention and Best Available Control Technology (BACT) could minimize flaring. Without them, the MHA Nation refinery will follow the example of other refineries in the U.S., where flaring has historically been a major problem. The federal regulations cited in the FEIS will reduce flaring emissions if they are enforced through a permit, but they do not prevent whole flaring events, and they do not constitute BACT.

Since the MHA Nation has no compressor listed as part of the refinery equipment, and it is unclear whether or not and to what degree flare gas will be recovered, the proposed MHA Nation refinery could have large numbers of flare events.

When power outages occur, refineries usually have to shut down. This causes very large flaring emissions because all the refinery gases have to be burned at once. Usually this causes large black plumes, and even without the smoking, causes large emissions of VOCs, NO<sub>x</sub>, SO<sub>x</sub>, CO, and particulate matter.

In general, flare emissions are well known to have occurred due to many specific causes (planned and unplanned). A BACT analysis for flaring should have been done. A discussion on BACT for flares is included in my attached comments on the ConocoPhillips Wood River Illinois and Rodeo, California, and BP Whiting, Indiana refinery expansions, attached.<sup>10</sup>

The FEIS and Air Quality Technical Report (December 2007) not only fail to appropriately minimize flare emissions, they guarantee and require that unnecessary flare emissions will occur. For example the FEIS states:

Tanks with a fixed roof must be equipped with a closed vent system and **VOC emissions sent to the processes or flare.** (FEIS, page 4-104)

**Many startup/shutdown emission sources are missing including tank cleaning, degassing, and tank coating operations**

EPA requires the evaluation of emissions of startup/shutdown and maintenance to be included when determining whether a refinery is subject to PSD permitting, and these emissions must also be included in the Final EIS under NEPA. The Draft EIS included no startup/shutdown emissions; the Final EIS added some but provided a very incomplete and inaccurate assessment. The discussion below provides information about one type of startup/shutdown/maintenance source of emissions, but the FEIS needs to provide a full assessment of startup / shutdown / maintenance emissions for all sources.

Refinery storage tank cleaning and degassing are one example of these emissions. They are summarized by the FEIS as follows, without a basis for the conclusions that emissions will be low, in the Air Quality Technical Report (page 4-8):

**The working losses calculated by TANKS do not include degassing and cleaning.** They are a result of changes in liquid level, but do not account for times when liquid is completely removed from the tank. According to the description of the refinery operation

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<sup>10</sup> J. May comments on ConocoPhillips Wood River CORE Project (Coker and Refinery Expansion), New Source Review Permit Application, June 14, 2007, to Illinois EPA, attached as MHA Attach06 -- ConocoPhillips\_Wood\_River\_CORE\_Comment\_JMay\_614\_Final.pdf , and MHA Attach07 -- EXHIBITS\_to\_JMay\_Comment\_on\_CP\_Wood\_River\_CORE\_Project.ZIP, and J. May comments on BP Whiting expansion-- Significant Source Modification No.: 089-25484-00453 and Significant Permit Modification No.: 089-25488-00453, March 21, 2008, to Madhurima D. Moulik, IDEM, Office of Air Quality, attached as MHA Attach08 -- Julia May comments BP Whiting expansion.doc and MHA Attach09 -- EXHIBITS to JMay Comment on BP CXHO.ZIP

and maintenance, tank degassings and cleanings will occur every 6-9 years. **Based on the low VOC emissions from each tank and the 6-9 year turn around for a tank, the VOC emissions from tank cleanings and degassing would be minimal;** less than 1 ton per degassing/cleaning event for all of the tanks combined.

The statement above - *“Based on the low VOC emissions from each tank the VOC emissions from tank cleanings and degassing would be minimal”* - is not an assessment of emissions, it is only a conclusion without technical basis. No additional information, data, or calculations are provided in the appendices to support this conclusion that emissions would total *“less than 1 ton per degassing/cleaning for all tanks combined.”* A conclusion without any basis is not an assessment and renders the FEIS inadequate. Moreover, the statement is contrary to specific evidence which shows that tank cleaning emissions are large. Consequently there is no assessment of startup/shutdown and maintenance emissions of storage tanks.

Furthermore the minimal emissions conclusion is contrary to actual tank operations and design. A tank might have low VOC emissions during normal operation, but will have high VOC emissions when the tank is opened for cleaning. Refinery storage tanks develop heavy sludge deposits in the bottom of the tank over the course of their use, which is a large source of evaporative VOC emissions during tank maintenance. Also, when the liquids are removed from a floating roof tank for maintenance, the roof is seated on legs on the bottom. As liquids are completely removed, a vapor space develops under the no longer floating roof. The large surface area of the tank sides are also coated with VOC liquids, which is available to evaporate to the air when tanks are opened. While some of this vapor is usually sent to a refinery’s gas recovery system before the tank is opened for maintenance, some of the vapors remain. This is true even at oil refineries where there are existing, enforced regulations for tank degassing, because a certain percentage of vapors is allowed to be left in the tank. Even with a fraction of vapors still present, the total mass of emissions add up to significant levels because refinery storage tanks are so large. Furthermore, the removal of the sludge from the bottom of the tank, unless carefully controlled in a vapor tight system, causes very large VOC emissions. Spills can also occur. When tank bottoms are sent to a hazardous waste landfill and layed out in the air, this VOC-laden sludge is a major source of evaporation to the air. An EPA Enforcement alert identified refinery wastes as a source of VOC emissions, and found that RCRA also requires VOC emissions from refinery wastes be controlled.<sup>11</sup> Both the air emissions and other impacts of this combination of gaseous/evaporative waste should have been evaluated.

The FEIS apparently confused normal tank operations, where a closed tank may have low VOC emissions, with those of an open tank. It is also apparent in the FEIS response to comments that normal tank operation is being confused with tank cleaning operations:

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<sup>11</sup> EPA Enforcement Alert, Compliance with RCRA Requirements Critical to Protecting Public Health, April 1999, Office of Enforcement and Compliance Assurance (2201A), US EPA 300-N-99-003, <http://www.epa.gov/compliance/resources/newsletters/civil/enfalert/refinery.pdf> , attached as MHA Attach10 -- EPA Enforcement alert refinery RCRA waste VOCs.pdf

**Comment 17:** Comment that the emissions from the storage tanks were underestimated, because an inspection program for tank seals and vents was not required and evaporation of VOCs caused by tank cleaning was also omitted.

**Response 17:** Most of the storage tanks will have to meet specific design requirements or have a closed vent system for recovering volatile organic compounds under NSPS, subpart Kb. These tanks will have to be inspected and seals repaired as needed. Leak detection and repair for valves, flanges, pump seals, etc. is a requirement for the proposed refinery under NSPS, subpart GGGa. As stated on page 2-56 of the DEIS, it was estimated that tank cleanings would be required every 6-9 years. Emissions of VOCs from degassing and cleaning of tanks are minimal (i.e., less than 1.0 tons per tank cleaning event for all tanks combined). (page E-57)

This passage cites tank design requirements, closed vent systems, inspections of seals, and leak detection as relevant to emissions of tank cleaning. These normal tank operations are not the relevant characteristics to use to assess emissions during tank cleaning when tanks are opened up. This is like estimating emissions from a gas can when it is closed tight, to determine emissions when it is left open. This is a logical error that has resulted in the failure in the FEIS to assess tank cleaning emissions at all, unless specialized vapor recovery equipment is put in place as a permit condition, although this would not eliminate emissions from sludge landfilling.

One Italian company identifies tank sludge and the need to minimize environmental hazards associated with tank cleaning, and finds that emissions can be reduced by 90% using their technology. This company states:<sup>12</sup>

Idrabel Italia S.r.L. focuses its activities mainly on the oil industry and provides services directed to minimizing waste contamination, preserving the environment and recovery of valuable fractions of oil waste sediment sludge. Idrabel Italia offers a range of solution for crude oil, fuel oil and slop oil tank cleaning.

Our consolidated experience of over ten years has allowed improving and optimizing our Tank Cleaning Technology, procedures and know how in setting up the BioRecOil™ Process (Biological Recovery Oil) which differs from the other systems. It aims towards maximization of resalable oil recovery (usually over 90%) from the oil tank bottom sludge and therefore minimizing the volume of the residual bottom sludge to be disposed of.

## **SLUDGE MAPPING**

Sludge mapping, thermographic and manual measurements are initially carried out on each tank to assess sludge amounts and distribution profile within the tank.

**Sludge samples are collected to determine its characteristics together with the lab simulations to enable identifying the optimum tank cleaning strategy to be carried out as well as to forecast the amounts of recoverable hydrocarbons and sludge residuals.**

A specific software displays 3D sludge distribution in the tank giving full indication of its quantity/quality and recoverable oil and residues quantities.

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<sup>12</sup> <http://www.hydrocarbons-technology.com/contractors/storage/idrabel-italia/>

## TANK CLEANING AND DEGASSING

**During the tank activities, emissions and hydrocarbons spills represent a critical aspect with negative environmental impacts and safety problems.**

Idrabel Italia S.r.L. has developed activities for tank degassing, through an application of a mobile gas washing column. The additive used is "LECS", which is a specific biotechnological product. The application allow the elimination of VOC emissions and reduction of explosion risks. (emphasis added)

Tank cleaning and degassing vapor recovery systems and sludge handling needs to be assessed for total emissions, and added to the Project total. A BACT analysis then needs to be carried out including the tightest standards achieved for avoiding air emissions and landfilling of refinery tank sludge.

Tank cleaning is not a low VOC operation unless such special technologies are used, and enforced as a permit condition. Otherwise, the FEIS may not assume these emissions are low. An assessment of tank cleaning emissions was done by Dr. Phyllis Fox and was attached to my comments on the Draft EIS, which found that one tank can cause 50 tons of emissions. Adding emissions from the shutdown operations and cleaning of just one tank would cause the annual emissions for the Project to exceed the PSD threshold for VOCs (77 tpy in the FEIS, + 50 tpy = 127 tpy, without including other underestimations in VOCs described in this comment). The FEIS states that cleaning would occur every 6 to 9 years, but there are many tanks proposed to be constructed. Even if there were only an average of 2 tanks cleaned every 6 years, this could add up to about 17 tons on average per year in additional emissions, averaged over a six year period. It is very important that these emissions be assessed, and that a permit condition be set that would not allow this operation during hot weather. This type of operation could greatly add to a smog health standard exceedance (ground-level ozone formation) if 50 tons are emitted in one day. This could also cause local health impacts and smells and should be assessed as a one-day event, instead of averaged over a year.

I have excerpted the following few pages from the preliminary construction permit for the Tesoro Kenai refinery in the state of Alaska.<sup>13</sup> Other regulators also have requirements for sludge handling and degassing, and a BACT analysis needs to be carried out and applied to the MHA Nation proposed facility. The pages below show that the permit has identified equipment expressly for the purpose of controlling VOC emissions from tank bottoms sludge, it has set recordkeeping and reporting for tank cleaning operations, and it has also identified other emissions (NOx and SOx) that are pollutants emitted when the tank cleaning operations use combustion devices to destroy the tank VOC vapors by burning them. This demonstrates that pollution methods are available to control them, but also that care must be taken not to add

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<sup>13</sup> Department of Environmental Conservation Air Quality Control, Construction Permit No. 035CP04, Issue Date: September 7, 2004, Project Number: X-217, Tesoro Alaska Company, Kenai Refinery, <http://www.dec.state.ak.us/AIR/ap/docs/035cp04fin.pdf>, attached MHA Attach11 -- Tesoro Kenai Refinery permit 035cp04fin.pdf

excessive levels of other pollutants through combustion of tank cleaning gases. This excerpt shows over 30 tons per year of NOx emissions:

## Section 1. Authorizations

1. The permittee is authorized to install the emission units listed in Table 1 at this stationary source in accordance with the terms and conditions of this permit and the permit application. These units have specific monitoring, recordkeeping, or reporting conditions in this construction permit. Table 1 lists the source description and capacity for identification purposes only.

Table 1 – New Emissions Units

New Emission Unit or Process	Capacity	Description
Tank Bottom Sludge Drying	NA	new process associated with tank bottom cleaning
Tank Bottom Fluidization	NA	modified process associated with tank bottom cleaning
VOC Control with Thermal Oxidation	NA	new process associated with tank bottom cleaning
VOC Control with Reciprocating Internal Combustion Engines	NA	new process associated with tank bottom cleaning

Table Notes  
NA means Not Available

2. The permittee is authorized to revise the operating limits listed in Exhibit B, Part A of Air Quality Control Construction Permit No. 9923-AC010, for the emission units listed in Table 2 at this stationary source in accordance with the terms and conditions of this permit and the permit application. These units have specific monitoring, recordkeeping, or reporting conditions in this construction permit. Table 2 lists the source description and capacity for identification purposes only.

Table 2 – Emissions Units with Revised Operating Limits

Modified Emission Unit or Process	Capacity		Title V ID	Revised Operating Limit
North Caterpillar CAT G399, "P-605A"	830	bhp	36	2,500 hours per year, combined
North Caterpillar CAT G399, "P-605B"	830	bhp	37	
Cooling Tower CAT G333, "P-719C"	140	bhp	41	1,000 hours per year

## Section 2. Ambient Air Quality Requirements

This section contains monitoring, recordkeeping, and reporting requirements to ensure that refinery emissions and emissions associated with tank maintenance activities do not cause or contribute to a violation of an Alaska Ambient Air Quality Standard listed under 18 AAC 50.010 or Maximum Allowable Increase listed under 18 AAC 50.020.

3. **Tank Maintenance Activities.** For each calendar year, record and report tank maintenance activities as follows.
  - 3.1 Record the Tank ID for each tank cleaned or coated, and, for each *tank maintenance emissions unit* used, the
    - a. make;
    - b. model;
    - c. rated capacity;
    - d. emission rate factor for NO<sub>2</sub>, SO<sub>2</sub>, and PM-10;
    - e. basis for each emission factor;
    - f. date(s) used;
    - g. hours operated; and
    - h. fuel type.
  - 3.2 Calculate and record the maximum hourly emission rates of SO<sub>2</sub> and PM-10 that occurred during the calendar year due to tank maintenance activities, in pounds per hour, for all *tank maintenance emission units*, using the units' rated capacity and assuming worst case simultaneous operation.
  - 3.3 Calculate and record annual emissions of NO<sub>2</sub>, SO<sub>2</sub>, and PM-10 that occurred during the calendar year due to tank maintenance activities, in tons per year (tpy), for all *tank maintenance emission units*, using the units' rated capacity.
  - 3.4 Include the records required under conditions 3.1, 3.2, and 3.3 with the operating report required in Operating Permit No 035TVP01. Include in the report, a comparison of the actual long term, in tpy, and actual maximum short term in lb/hr, emission rates to the following emission rates

Table 3 – Modeled Tank Cleaning Emission Rates

	NO <sub>2</sub>	SO <sub>2</sub>	PM-10
Short Term (lb/hr)	not applicable	1.00	1.58
Long Term (tpy)	31.23	0.69	2.17

- 3.5 Furnish to the department, at the department's written request, a revised ambient impact assessment if the emission from the *tank maintenance emission units* exceed the emission rates in Table 3.

### **Section 3. State Emission Standards**

This section contains terms and conditions that ensure the proposed emissions units will not emit in excess of the State Emission Standards for Fuel Burning Equipment set out in 18 AAC 50.055(b). Opacity and particulate matter requirements do not apply to non-road engines, defined in [40 CFR 89.2](#), that are associated with tank maintenance.

5. **Tank Maintenance Emission Units Sulfur Dioxide Requirements.** The permittee shall not cause or allow 3-hour average sulfur compound emissions from *tank maintenance emission units*, expressed as SO<sub>2</sub>, to exceed the applicable limit listed in conditions 5.a, 5.b, or 5.c.
  - a. **For equipment burning only fuel gas**, the concentration of uncontrolled emissions that would result from burning fuel gas containing 230 milligrams hydrogen sulfide per dry standard cubic meter.
  - b. **For fuel burning equipment that does not burn fuel gas**, 500 ppm.
  - c. **For fuel-burning equipment that burns a combination of fuel gas and other fuels**, a concentration based on the allowable emissions in conditions 5.a and 5.b, prorated by the proportion of fuel gas and other fuels to the total fuel burned in the equipment.
- 5.1 **For Fuel Gas:** Monitor and record the fuel gas in accordance with conditions 35.1d(ii) and 35.1e of Operating Permit No. 035TVP01.
- 5.2 **For Liquid Fuel:** Test and record the fuel sulfur content for diesel fuel used in *Tank Maintenance Emission Units* in accordance with conditions 35.1a, 35.1d and 35.1e for Subpart GG turbines set out in Operating Permit No. 035TVP01. If the liquid fuel contains more than 0.75 percent sulfur by weight, calculate SO<sub>2</sub> emissions in ppmv, using Section 17 of Operating Permit No. 035TVP01, or Method 19 of 40 C.F.R.60, Appendix A-7 adopted by reference in 18 AAC 50.040(a).
- 5.3 Report as excess emissions in accordance with Operating Permit 035TVP01 whenever the fuel combusted causes sulfur compound emissions to exceed the standards of condition 5.
- 5.4 Include the records required by conditions 5.1 and 5.2 in the operating required by Operating Permit No. 035TVP01.

- 3.6 *Tank maintenance emission unit* refers to an emission unit (i.e. boiler, heater, non road engine, thermal oxidation control) brought on site for use in routine tank maintenance operations: fluidization, tank coating, sludge processing. *Tank maintenance emission units* do not include emissions units listed in Section 3, Table 1, of Operating Permits No. 035TVP01, 033TVP01, and 036TVP01.
4. **Stack Height.** The permittee shall increase the stack height of Unit 34, (EG-704) to no less than seven meters above grade, no later than 180 days of this permit's issue date, and shall
  - 4.1 record modified stack profile in as built drawings; and
  - 4.2 submit modified stack as built drawings of existing and modified stack with the operating report required by Operating Permit No. 035TVP01 for the reporting period in which the stack extension was completed.

The FEIS also failed to assess emissions of tank coating (painting the tanks either at installation, or later for maintenance). Coating these large tanks will result in large VOC emissions due to the large surface area. No evaluation of tank coating emissions was provided by the FEIS. Coating the over 30 proposed tanks, which total hundreds of thousands of square feet in tank surface area, can cause tons of VOC emissions, depending on the type of coating used. A requirement for ultra-low VOC-coatings, and an assessment of emissions in any case needs to be carried out for these emissions (which are both construction emissions, and also a maintenance operation).

On the subject of tanks, the FEIS identifies a Project alternative using enclosed tanks instead of open wastewater ponds. Clearly this is an environmentally preferable alternative, although it is not clear that an underground tank is advisable. (Even double-walled tanks can leak.) This issue should be assessed not only for water impacts, but also as part of air impacts. Open wastewater ponds cause major evaporative emissions of VOCs to the air. Although the Project states that water will be pretreated before sent to the holding ponds, the devil is in the detail. In general, wastewater systems include many points where leaks and evaporation of VOCs can occur. The FEIS needs an assessment of air emissions from wastewater systems.

### **Sulfuric Acid Mist was not calculated**

Sulfuric acid mist was not evaluated. Sulfuric acid mist is formed as a combustion by-product at oil refineries. Sulfuric acid mist has the following impacts and sources:

Sulfuric acid is a corrosive chemical and can severely burn the skin and eyes. It may cause third degree burns and blindness on contact. Exposure to sulfuric acid mist can irritate the eyes, nose,

throat and lungs, and at higher levels can cause a buildup of fluid in the lungs (pulmonary oedema). Asthmatics are particularly sensitive to the pulmonary irritation. Repeated exposures may cause permanent damage to the lungs and teeth. The International Agency for Research on Cancer has classified 'occupational exposures to strong-inorganic-acid mists containing sulfuric acid' as carcinogenic to humans. . . .

The primary sources of sulfuric acid emissions are the industries that manufacture it or use it in production. Some of the industries that use it in production are the metal smelters, phosphate fertilizer producers, oil refiners, the chemical industry, battery manufacturers, manufacturers of fabricated metal products, manufacturers of electronic components, and manufacturers of measuring and controlling devices. These are emissions to the air unless there is a spill to water or land. Sulfuric acid spilt to land or water may result in emissions of the acid to air. . . .

Sulfuric acid will exist as particles or droplets in the air if released to the atmosphere. It dissolves when mixed with water. It has moderate acute (short-term) toxicity on aquatic life. Sulfuric acid is very corrosive and would badly burn any plants, birds or land animals exposed to it. It has moderate chronic (long-term) toxicity to aquatic life. Chronic effects on plants, birds or land animals have not been determined. Small quantities of sulfuric acid will be neutralised by the natural alkalinity in aquatic systems. Larger quantities may lower the pH for extended periods of time.<sup>14</sup>

Annual emissions of sulfuric acid mist can be substantial. For example, in the case of power plants (EKPC or East Kentucky Power Cooperative), a large penalty was assessed regarding sulfuric acid mist emissions, and a settlement put in place requiring achievement of sulfuric acid emissions limited to 0.020 lbs/MMBTU:

EKPC will pay a civil penalty in the amount of \$750,000. As an environmental project, EKPC has agreed to install, concurrently with the FGDs, wet electrostatic precipitators (WESPs) to control sulfuric acid mist emissions from Spurlock Units 1 and 2. The settlement requires that the WESPs be designed to achieve an emission rate of 0.020 lbs./mmBtu of sulfuric acid mist, with a goal of achieving an emission rate of no greater than 0.005 lbs./mmBtu. EKPC expects construction and installation to cost approximately \$47 million.

This is actually still a high level of emissions. For example, if the MHA Nation refinery, with listed combustion sources totaling 236.5 million BTUs/hr were to emit 0.020 lbs sulfuric acid mist per million BTUs, this would result in almost 21 tons per year of sulfuric acid mist. Specific calculations need to be carried out taking into account the refinery conditions and materials that could be catalysts encouraging high levels of sulfuric acid mist.

### **Construction air emissions were not evaluated**

Air emissions from construction emissions appear not have been calculated, except for general statements that do not quantify the air emissions, such as the following:

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<sup>14</sup> <http://www.npi.gov.au/database/substance-info/profilevs/78.html#health>

Short-term disruption during construction from the physical intrusion of the crew and equipment, the generation of dust and noise, and the obstruction of traffic would affect one residence located on the northwest side of the project site. The residence would be affected primarily by noise generated by construction activities, **although there would be some air quality impact from dust generated by construction activities and pollutants generated by refinery operations.** Other residences along Highway 23 could be affected by construction traffic. (FEIS page 4-91)

Air emissions from construction are considerable. There are standard analytical methods available for evaluating construction impacts, based on the acres of land disturbed (which causes particulate matter emissions to air), based on the number of diesel and other vehicles operating onsite (causing emissions of criteria pollutants, toxics, and greenhouse gases), based on the number of truck and vehicle trips made to the site to deliver goods and for worker transport, and other factors. The FEIS provides an estimate of the size of the site (190 acres disturbed out of the 468 acres proposed to be annexed, FEIS, pages 4-1 and 2-3), but I did not see information provided on vehicles present. An analysis of direct and indirect offsite construction should have been provided.

As one example, the Chevron Richmond, California refinery is undergoing new construction and equipment modifications. An Environmental Impact Report carried out for this Project provided the following emissions estimate for construction air emissions. Although the Chevron facility is a much larger refinery, the MHA Nation refinery would be an entirely new site, and covers a much larger number of acres (190 acres) than the Chevron expansion (only 8 acres). Both projects involve construction of a number of tanks and process equipment. The MHA site is likely to cause larger construction emissions because it is an entirely new refinery. Regardless, the Chevron project evaluation shows: 1) construction emissions can be quantified in detail, and 2) they add up to large numbers of lbs/day. A summary of the construction emissions claimed by Chevron are as follows:

**TABLE 4.3-8  
WORST-CASE PROJECT CONSTRUCTION EMISSIONS**

Project Construction	Unmitigated Criteria Pollutant Emissions (Lbs/Day)					
	VOC	NO <sub>x</sub>	CO	SO <sub>2</sub>	PM <sub>10</sub>	PM <sub>2.5</sub>
Onsite Fugitive Dust	—	—	—	—	80	17
Total Off Road Emissions – 4 <sup>th</sup> Quarter 2008	170	1,103	1,391	—	43	40
On Road Emissions – 2008	6	83	47	0.16	2	2
<b>Total Emissions</b>	<b>176</b>	<b>1,186</b>	<b>1,438</b>	<b>0.16</b>	<b>125</b>	<b>59</b>

NOTES: Equipment emissions calculated using the Urbemis 8.7 model. The last quarter of 2007 was chosen as the worst case scenario because of the most overlapping earth moving construction activities and the amount of proposed construction equipment at the site during that period as identified by Chevron (Estimated Construction Equipment Counts Table, April 18, 2007). Many of the construction phases overlapped during this quarter. For the onsite fugitive dust worst case scenario, 8 acres were assumed to be disturbed during the peak day of activity using the URBEMIS factor of 10 pounds/acre disturbed. A 20,000 cubic yard import of soil was assumed because a total of 100,000 cubic yards were to be imported over 5 quarters. Assumed usage hours for each piece of equipment were four hours a day, except for the cranes which were assumed to work two hours a day. See Appendix D for the Urbemis output sheet and construction equipment assumptions. PM<sub>2.5</sub> emissions were estimated using methodology developed by the South Coast Air Quality Management District (SCAQMD, 2006).

The Chevron example is provided in terms of lbs/day, which when multiplied by 365 days per year and dividing by 2000 lbs/ton, gives tons/year. This results in about 32 tons/year (tpy) of VOCs, 216 tpy of NO<sub>x</sub>, 262 tpy of CO (Carbon Monoxide), .03 tpy of SO<sub>2</sub> (this low number is likely due to using ultra low sulfur fuel, which is not likely in the MHA Nation case, so that SO<sub>2</sub> would be much higher), 23 tpy of PM<sub>10</sub>, and 11 tpy of PM<sub>2.5</sub>.

This Chevron table is only on the topic of criteria pollutants. Greenhouse gas emissions and toxic emissions from construction were evaluated elsewhere. The MHA Nation refinery construction must also be evaluated.

Taking all these increases and adding them to the Project provides the totals in the following page, which shows that the refinery exceeds the 100 tpy threshold on many counts when additional flaring, tank cleaning, degassing, and coating are considered, construction emissions are added in, etc. Of course, without any permit at all, there is no way to ensure that the Project, as represented in the FEIS, will stay below major source thresholds. In addition to triggering the PSD threshold, construction emissions from diesel engines are toxic. Diesel engines emit a variety of harmful gases and over 40 other known cancer-causing substances. Diesel particulate matter is identified as a toxic air contaminant based on its potential to cause cancer, premature death, and other health problems. Those most vulnerable are children whose lungs are still developing and the elderly who may have other serious health problems. Each year, diesel emissions contribute to thousands of premature deaths and thousands of hospital admissions, asthma attacks, other respiratory symptoms, and lost workdays. In addition, diesel soot causes visibility reduction and is a potent greenhouse agent involved in global warming.

## **Crude Oil slate will have a major impact on emissions**

Choice of crude oil has a major impact on air emissions. There is no pipeline to the proposed refinery site. Please see the discussion in the Cumulative Impacts section on crude oil choice. This is both a Cumulative Impacts issue, and a direct impact on air emissions of the Project. This issue requires quite a detailed evaluation. Data should have been provided on Montana crude quality, since that is one of the crude oils identified as being transported in the closest pipeline to the proposed site, and which is the pipeline that the FEIS says will be used. The FEIS should have provided detailed data on the characteristics of crude oil in the pipelines that go within range of the refinery, unless there is a specific permit condition limiting the crude quality to be used to low sulfur, light, low metals crude oil. If Syncrude is used, there are different types of Syncrude, some heavier, some lighter. Syncrude production also causes severe environmental impacts in Canada. (See Cumulative Impacts section.)

## **Enhanced Enforcement of existing regulation versus no enforcement**

Regulatory agencies use enhanced enforcement of existing regulations (no new regulations, just stepping up oversight to identify violations of regulations that cause unnecessary pollution). It is well known that without enforcement of regulations, emissions go up. This Project is an example of the opposite of enhanced enforcement, using instead no enforcement in terms of inspections and limits on total throughput and total emissions for individual pieces of equipment and the overall refinery. It must be assumed therefore that compliance with the emissions levels stated and assumed in the FEIS will not be perfect, and in fact, compliance with meeting these emission levels will be worse than other refineries that have enforcement mechanisms in place. The total Project emissions assessed will therefore be higher as a result of this problem. It is difficult to quantitatively assess the impact of this lack of enforcement; emissions could go very high. The solution is to fix the problem and provide an enforceable permit.

## **Overall emissions from the Project**

The following table is a compilation of Table 13 and Table 16 of the FEIS Air Quality Technical Report, with lines added at the bottom showing what the total emissions would be if the emissions sources discussed above were included (except for a factor for lack of enforcement, which was not quantified). Even after adding these lines, the table below still does not include all emissions. For example, the FEIS did not include in the Project totals, emissions from accidental releases, which can dwarf other emissions and which should be included. The table shows that the Project is a major source of air pollution, requiring a PSD permit.

Source	Nominal Capacity from Table 13 MMBtu/hr unless otherwise identified	Concentration of Pollutant (tons/year)				
		from Table 16 – “Max. Combustion Emissions”				
		NOx	CO	SO2	VOC	PM10/PM2.5
Crude Heater	35	4.15	6.32	2.99	0.92	1.27
Reformer Heater 1	3	0.36	0.54	0.26	0.08	0.11
Reformer Heater 2	3	0.36	0.54	0.26	0.08	0.11
Reformer Heater 3	8	0.95	1.44	0.68	0.21	0.29
Reformer Heater 4	6	0.71	1.08	0.51	0.16	0.22
Reformer Heater 5	1.5	0.18	0.27	0.13	0.04	0.05
Hydrocracker 1	6	0.71	1.08	0.51	0.16	0.22
Hydrocracker 2	7	0.83	1.26	0.6	0.18	0.25
Hydrocracker 3	10	1.19	1.81	0.85	0.26	0.36
Hydrocracker 4	7	0.83	1.26	0.6	0.18	0.25
Olefin	30	3.56	5.42	2.56	0.79	1.09
Hydrogen	50	5.93	9.03	4.27	1.32	1.82
Boiler 1	20	2.37	3.61	1.71	0.53	0.73
Boiler 2	20	2.37	3.61	1.71	0.53	0.73
Boiler 3	20	2.37	3.61	1.71	0.53	0.73
Flare	20	2.98	16.21	0.85	6.13	0
S Recovery Tail Gas	10	0	20.85	30.84	0	0
Emergency Generator	20,000 scf/hr	4.92	0.36	0.12	0.1	0.04
Fire Pump		0.91	0.04	0.02	0.01	0.01
<b>FEIS Subtotal</b>		<b>35.68</b>	<b>78.34</b>	<b>51.18</b>	<b>12.21</b>	<b>8.28</b>
Storage Tank Emissions Total from Table 19					26.7	
Fugitives emissions Total from Table 21					38.02	
Soy bean extrusion						8.51
<b>Total stated in FEIS</b>		<b>35.68</b>	<b>78.34</b>	<b>51.18</b>	<b>76.93</b>	<b>16.79</b>
<b>Add sources missing from the FEIS:</b>						
Add Flare emissions		Added emissions, needs evaluation	Added emissions, needs evaluation	Could easily exceed 50 tpy without permit conditions	<b>30 to 175</b> or more	Added emissions, needs evaluation

				and BACT		
Add Storage Tank Cleaning and Degassing		Approx. <b>30*</b>	Added emissions, needs evaluation		<b>17</b> or more*	
Add Storage Tank Coating (painting)					Added emissions, needs evaluation	
Add Construction		>Can far exceed <b>200</b>	>Can far exceed <b>250</b>		>Can far exceed <b>30</b>	
Air emissions from wastewater system evaporation					Added VOCs, needs evaluation	
Increased air emissions from different crude oil processing		Added emissions, needs evaluation	Added emissions, needs evaluation	Added emissions, needs evaluation	Added emissions, needs evaluation	Added emissions, needs evaluation
<b>MORE REALISTIC TOTAL</b>		<b>Far exceeds 100 tpy during construct., may exceed after construct.</b>	<b>Far exceeds 100 tpy during construct., likely exceeds after construct.</b>	<b>Probably more than 100 tpy after construct.</b>	<b>Exceeds &gt;100 tpy after construct.</b>	

\* Storage tank Startup/Shutdown/Maintenance will not have both VOCs and NOx for tank cleaning. Either the vapors come out as VOCs, or they are combusted, generating NOx.

### III. The lack of air emission information and enforceable standards in the FEIS is extreme compared to similar projects throughout the U.S.

It almost appears that the FEIS was unfinished.

Portions of Appendices mentioned in certain places in the FEIS as being attached were not actually attached, and in other places “Example Calculations” were appended instead of providing the actual calculations. It is unclear what is even meant by Example Calculations. Does this mean that the refinery may or may not abide by these because they are only examples and not the actual maximum potential-to-emit calculation? I have not seen any similar project application where actual calculations were not provided.

As discussed in this comment, there is no Major or Minor air pollution permit, which makes the incompleteness of the FEIS even more problematic. In many instances, there is no data provided about pieces of equipment, no calculations of emissions, and no permit conditions to enforce the unsubstantiated estimations of emissions.

The FEIS Air Quality Technical Report fails entirely to provide actual calculations for many emission sources. An Appendix C to the Air Quality Technical Report which is said in this report to provide calculations, instead only includes the following short “Example Calculations.” The entire appendix is excerpted below.

## Appendix C Calculations

### TAT Refinery

#### Example Calculations and Constants

##### Fugitive Emissions - Example Calculation for Valves

Assuming 3% are leaking valves and 97% are non-leakers:

$$E_0 = (14,755 \text{ valves} \times 97\%) \times (7.8\text{E-}06 \text{ kg VOC/hr-valve}) \times (2.2 \text{ lb VOC/kg VOC}) = 0.2455 \text{ lb VOC/hr}$$

$$E_{10,000} = (14,755 \text{ valves} \times 3\%) \times (2.29\text{E-}06 \times 10,000^{0.746} \text{ kg VOC/hr-valve}) \times (2.2 \text{ lb VOC/kg VOC}) = 2.168 \text{ lb VOC/hr}$$

$$E_{\text{voc}} = E_0 + E_{10,000} = 0.2455 + 2.168 = 2.414 \text{ lb VOC/hr} \times (8760 \text{ hrs-tons}/2000 \text{ lb-yr}) = 10.57 \text{ TPY}$$

I called BIA and EPA to inquire what happened to the flare calculations which the Air Quality Technical Report states as being in Appendix C, but which were not there. I received an email from EPA stating that these calculations were inadvertently left out. The flare “example calculations” were attached to the email.<sup>15</sup> I appreciate that the EPA official emailed these to me. However, these were not available for others to review as part of the FEIS, were only “Example Calculations”, and only became available to me in the middle of the public comment period. Here are the flare calculations that were emailed to me, in their entirety:

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<sup>15</sup> Email attached as MHA Attach12 Email from EPA MHA App C flare example calc.doc, flare calculations image also attached as MHA Attach13 -- EPA email example flare calculation pic29949.gif

**TAT Refinery  
Example Calculation**

**Flare Sample NOx Calculation**

Hours per Day            24  
Hours per Year           8760

NOx Emis Factor =            0.068 lb/MMBTU (AP-42 Table 13.5-1)  
Flare Heat Input =            10.0 MMBTU/hr

Calculate NOx Emissions

$$10.0000 \frac{\text{MMBTU}}{\text{hr}} * 0.068 \frac{\text{lb}}{\text{MMBTU}} = 0.68 \frac{\text{lb}}{\text{hr}}$$

Instantaneous Emissions

$$0.68 \frac{\text{lb}}{\text{hr}} * \frac{454 \text{ gm-hr}}{3600 \text{ lb-s}} = 0.09 \frac{\text{gm}}{\text{s}}$$

Daily Emissions

$$0.09 \frac{\text{gm}}{\text{s}} * \frac{24 \text{ hr}}{24 \text{ hr}} = 0.09 \frac{\text{gm}}{\text{s}}$$

Annual Emissions

$$0.09 \frac{\text{gm}}{\text{s}} * \frac{8760 \text{ hr}}{8760 \text{ hr}} = 0.09 \frac{\text{gm}}{\text{s}}$$

$$0.09 \frac{\text{gm}}{\text{s}} * 31,536,000 \frac{\text{s}}{\text{yr}} * \frac{1 \text{ ton}}{908,000 \text{ gm}} = 2.98 \frac{\text{ton}}{\text{yr}}$$

These calculations are inadequate. They do not provide actual calculations for any pollutant but NOx, no calculations for other criteria pollutants, toxics, or greenhouse gases are included, and they are “example calculations” only. Appendix B to the report (“Raw Data) only provides calculations for truck traffic to the refinery as part of biodiesel operations, and some information about biodiesel operations. No other air emissions calculations are attached to the Air Quality Technical Report.

The report states that it got the emissions factors for the above sources from AP-42 (a source of emissions factors from EPA). There are many emissions factors in AP-42; some are appropriate for certain sources, others are appropriate for other sources, and the generalized AP-42 emissions factors are used by regulators only when more specific emissions data is not available. In addition, EPA itself has recognized severe deficiencies resulting from utilizing AP-42 emission factors and is currently developing a comprehensive protocol for the estimation of VOC and air toxic emissions from petroleum refineries and chemical plants.<sup>16</sup>

#### **IV. Project Greenhouse Gas emissions sources are missing**

The FEIS found in the following Table that the facility will emit over 100,000 metric tonnes per year of greenhouse gases expressed as CO2 equivalent<sup>17</sup> (FEIS page 4-117), an amount that by any reasonable measure must be considered a major source:

<sup>16</sup> See, April 7, 2009 letter from EPA to Mayor Bill White regarding the City of Houston’s July 9, 2008, filing a Request for Correction (RFC 08003) under the Environmental Protection Agency’s Information Quality Guidelines (EPA IQG); attached as MHA Attach 14 -- EPA Letter to Bill White re DQA.pdf

<sup>17</sup> Carbon dioxide or CO2 “equivalent” means the total weight of CO2 in pounds (or in U.S. tons or the slightly bigger metric tonnes of emissions), plus more heavily weighted greenhouse gases such as methane and nitrous oxides, which are stronger greenhouse gases than CO2. Each stronger greenhouse gas is multiplied by a higher number to count it more heavily than CO2, to make each one equivalent to the CO2. An example is that one pound

**Table 4-24 Projected Annual Greenhouse Gas Emissions from the Proposed Refinery Estimated from Prince George Husky Refinery 2005 Data**

Gases	Sum in metric tonnes	Metric tonnes in CO <sub>2</sub> equivalent
CO <sub>2</sub>	106,000	106,000
CH <sub>4</sub>	33	700
N <sub>2</sub> O	1	300
<b>Totals:</b>		<b>107,000</b>

Source: Environment Canada website: 2005 Greenhouse Gas Sources and Sinks

It is not surprising that a new oil refinery which the FEIS states will burn hundreds of millions of BTUs (British Thermal Units) of fossil fuels per hour, will result in major GHG emissions. However, the FEIS is incorrect in its finding that there are no existing requirements under the Clean Air Act (CAA) for greenhouse gas emissions. The FEIS states (page 4-120):

The facility will need to comply with any CAA requirements applicable at the time the facility is constructed and in operation. **Currently, there are no federal regulatory standards directly limiting greenhouse gas emissions.**<sup>8</sup>

<sup>8</sup> Since the issuance of the April 2, 2007 Supreme Court opinion in Massachusetts, et al. v. EPA, 549 U.S. (2007), EPA has been evaluating the potential effects of the Court's decision with respect to addressing emissions of greenhouse gases under the mobile and stationary source provisions of the Clean Air Act. Thus, this EIS for an individual project does not reflect, and should not be construed as reflecting, the type of judgment that might form the basis for a positive or negative finding, permitting decision or regulation under any provision of the Clean Air Act.

This statement is incorrect, and the associated footnote 8 above further convolutes the issue. The footnote only states that an individual EIS does not reflect a future judgment that may or may not occur. This statement ducks the issue that the courts have already found that greenhouse gases are a regulated pollutant under the Clean Air Act.

Given this finding, the FEIS must evaluate not only the direct emissions, but also the cumulative emissions, and mitigate these emissions. The Project is required to include Best Available Control Technology under the Clean Air Act in order to address these greenhouse gas emissions, but the Project contains no such evaluation or equipment. This means that there are two separate but very inter-related deficiencies for Project greenhouse gas emissions – one is the

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of methane is considered about equivalent to 22 pounds of CO<sub>2</sub>, so 1 pound of methane equals about 22 pounds of CO<sub>2</sub>-equivalent. To get the total of each stronger greenhouse gas, each is multiplied according to its stronger potency compared to CO<sub>2</sub>, and the results are added together with the CO<sub>2</sub> into one lump sum to allow us to easily use one number to weight all the chemicals that are greenhouse gases together.

failure of the FEIS under NEPA to evaluate and mitigate these emissions, and another is the lack of a permit under the Clean Air Act using Best Available Control Technology. The FEIS only identifies the possibility of future regulation by EPA to correct this problem, or voluntary measures that might be taken in the future. However, once the refinery is designed and built, the choices for controlling or preventing (and mitigating) greenhouse gases become much more limited. NEPA and the Clean Air Act of course require the evaluation to be done ahead of time.

### **Greenhouse gas emission are underestimated**

The FEIS failed to calculate specific emissions from the Project, which would require providing the specific fuels to be used by each set of equipment. Instead the FEIS used a refinery in Canada as a similar refinery and found that it should have similar emissions. The FEIS provides the total amount of fuel use in millions of BTUs for each piece of equipment and states in general that natural gas fuel (which is mostly methane) or fuel gas will be used, although there are no permit requirements set to require this. The FEIS does not identify which pieces of equipment may deviate from use of natural gas. If methane is assumed (natural gas is mainly methane), and calculations are done using the named million BTUs listed for the equipment in the FEIS, the direct emissions results are similar to those results given by the FEIS (at about 115 lbs CO<sub>2</sub>/MMBTU methane combusted), but the Project has no permit requirements limiting combustion to methane (the main component of natural gas). If higher carbon fuels are used in parts of the refinery, higher CO<sub>2</sub> direct emissions will result.

The FEIS found 107,000 million metric tons per year of CO<sub>2</sub>-equivalent greenhouse gas emissions. It does not include additional greenhouse gas (GHG) emissions due to the Project caused by indirect sources (such as electricity that the refinery will contract from power plants, and many other sources). Therefore actual emissions due to the Project will be much higher.

The following FEIS table (page 4-118) lists indirect sources of GHG emissions caused by the Proposed Refinery, but does not quantify these emissions:

**Table 4-25 Indirect Greenhouse Gas Emissions from Proposed Refinery**

Process Inputs	Source
Electricity	Coal-fired power plant
Synthetic crude	Tar sands mining, initial refining, and pipeline transportation
Field butane, biodiesel, other feedstocks	Production and transportation
Natural gas	Production, processing and compression
Process Outputs	Source
Gasoline, diesel fuel, propane	Used as fuel by consumers
Product transportation	Truck and rail transportation

The FEIS should have provided a quantification of indirect emissions as well as directly emitted greenhouse gases. GHGs resulting from construction are also omitted from the FEIS. Furthermore, the FEIS should have included non-CO2 GHG emissions (methane, nitrous oxide, and others). All these need to be added to the Project totals, and these quantities need to be mitigated. A BACT analysis for GHGs needs to be done.

A slide show presented at a conference of the American Planning Association on greenhouse gases provided a summary of the current law and court findings on NEPA requirements regarding the need to evaluate cumulative impacts, construction impacts, alternatives, and climate change direct and indirect impacts under NEPA:<sup>18</sup> It states:

- **NEPA requires federal agencies take a “hard look” at the direct, indirect, and cumulative environmental consequences of proposed actions**
- Recent case law indicates that Lead Agencies can no longer wait for answers from policy makers

(Slide 2)

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**Excuses Typically Given for Not Evaluating Global Climate Change in NEPA documents**

- “...It is not required....”
- “...EPA doesn’t regulate it, why should we?...”
- “...we scoped it out of our document....”

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<sup>18</sup> CCAPA Annual Conference, September 2009, NEPA and Federal Transportation Planning Climate Change Regulations, <http://www.calapa.org/attachments/contentmanagers/2846/NEPA%20and%20Federal%20Transportation%20Climate%20Change%20Regs.ppt#17> , attached as MHA Attach15 -- NEPA and Federal Transportation Climate Change Regs.ppt

- “... its not foreseeable....”
- “...its too speculative....”
- “... we are only a small part of the problem...”
- “...we can’t solve the global problem so why discuss it...”

(Slide 3)

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- Effects on air quality are within the scope of NEPA’s definition of “*Human Environment*” (“*interpreted comprehensively to include the natural and physical environment and the relationship of people with that environment*”) 40 CFR 1508.14
- NEPA requires evaluation of “*direct*” and “*indirect*” and “*cumulative*” effects 40 CFR 1502.16, 1508.7, 1508.8
  - GHG emissions are either direct or reasonable foreseeable indirect effects on the human environment
  - Climate change impacts are inherently cumulative (and also fall within NEPA’s definition of “*significantly*” 40 CFR 1508.27(b)(7))

(Slide 4)

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- NEPA requires discussion of “*possible conflicts between the proposed action and the objectives of Federal, State, and local land use plans, policies and controls for the area concerned*” 40 CFR 1502.16(c)
- NEPA documents must be prepared “*concurrently with and integrated with environmental impact analyses ... required by ... environmental review laws and executive orders*” 40 CFR 1502.25
- NEPA requires discussion of the “*means to mitigate adverse environmental impacts*” 40 CFR 1502.16(h)

(Slide 5)

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### **Ten Steps to taking a “hard look” (Cont.)**

#### ***Environmental Consequences***

**Step 4 – Quantify the project’s direct and indirect GHG emissions** and compare them to baseline conditions, include:

- **Construction emissions**
- Operational emissions

**Step 5 – Convert the GHG emissions into CO2 equivalents** using an established “carbon calculator”

**Step 6 – Discuss whether the project would enhance or impede the attainment of state GHG reduction targets and its relationship to local plans and**

(Slide 17)

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### **Conducting the Analysis: Emissions Inventories for a Proposed Action and Alternatives**

- **Construction impacts**
  - Direct, onsite construction activities

- Indirect, “upstream” life cycle analysis (how far up?)
- Indirect, “downstream” life cycle analysis (how far down?)
- Upstream” and “downstream” energy usage (how far?)
- **Operational impacts**
  - Direct, On-site emissions for life of project
  - Indirect, “upstream” and “downstream” issues?

(Slide 22)

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- **Alternatives**
  - Step 9** – Include alternatives that would meet the Purpose and Need but would also reduce GHG emissions
- **Mitigation Measures**
  - Step 10 - identify mitigation measures that would reduce GHG emissions**
    - Project re-design and/or operational changes
    - Compensatory mitigation (e.g. carbon offsets, sequestering etc.)

(Slide 24)

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- **Little doubt that GHG emissions and climate change should be addressed under existing framework of NEPA and CEQ’s NEPA Regulations**
- All the basic NEPA rules/approaches apply
- Most experts consider global climate change to be a “reasonably foreseeable” environmental consequence
- Analysis can be done despite scientific uncertainties (refer to 40 CFR 1502.22)
- Gather best available information
- State assumptions

(Slide 28)

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This slide show, and existing laws and court findings make it clear that direct and indirect greenhouse gases must be quantified and mitigated. The FEIS fails to do so.

## **V. An assessment of Best Available Control Technology is required for this Major New Source of criteria pollutants, toxics, and greenhouse gases**

Because this refinery will be a major source of air pollution, an evaluation of Best Available Control Technology (BACT) should have been performed. This should also have been carried out as a Project Alternative under NEPA. A helpful summary of PSD BACT requirements is

provided in the USEPA New Source Review Workshop Manual (“NSR Manual”) at B-6, as follows:<sup>19</sup>

TABLE B-1. - KEY STEPS IN THE "TOP-DOWN" BACT PROCESS

STEP 1: IDENTIFY ALL CONTROL TECHNOLOGIES.

- LIST is comprehensive (LAER included).

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS.

- A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS.

Should include:

- control effectiveness (percent pollutant removed);
- expected emission rate (tons per year);
- expected emission reduction (tons per year);
- energy impacts (BTU, kWh);
- environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
- economic impacts (total cost effectiveness, incremental cost effectiveness).

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS.

- Case-by-case consideration of energy, environmental, and economic impacts.
- If top option is not selected as BACT, evaluate next most effective control option.

STEP 5: SELECT BACT

- Most effective option not rejected is BACT.

For example, compliance with specific BACT standards has not been met by the Project. Here are a few examples:

- Fugitive Emissions Sources -- BACT for the thousands of leaking seals on valves, flanges, pumps and compressors must be at least as stringent as the tightest regulation which is set for existing refinery fugitive emissions. The tightest standard I know of is Regulation 8 Rule 18 of the BAAQMD, which requires that valves and connectors (flanges) meet a leak standard of 100ppm (compared to 500 ppm cited in the FEIS as the standard that will be met), and for pumps, 500 ppms (compared to 2000 ppm in the FEIS). For compressor seals, the BAQQMD regulation sets a leak standard of 500 ppm, but the FEIS appears to set no standard at all. The BAAQMD standard is being met by existing refinery

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<sup>19</sup> NSR Manual, available at <http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf>.

sources, and so it is certainly feasible for the standards to be met by a new refinery. In fact, a BACT analysis for fugitive emissions sources should do a methodical evaluation to identify whether more stringent standards are being met.

- Flares – BACT for flares is at least as stringent as the emissions levels being met at the Shell Refinery in Martinez, CA. These levels are discussed in my previously attached comments on the BP Whiting expansion. Shells's Flare Minimization Plan is also attached.<sup>20</sup>

An analysis of Best Available Control Technology must be carried out.

## VI. The FEIS grossly underestimates maximum Potential to Emit

The Final EIS for the Project description still does not provide enforceable limits to the overall refinery maximum crude oil throughput in total barrels per day, or enforceable limits to maximum capacity and throughput for individual pieces of equipment. Such limits are essential for the reliability of any technical analysis of total air pollution. Given this lack of such permit conditions, the capacity could increase far beyond the 10,000 barrels per day if the Project is approved as-is. This would allow increased (and unlimited) air emissions and environmental impacts.

The definition of maximum Potential to Emit (PTE) as described by the law, by EPA and by other air pollution agencies, states that PTE must include physical limitations and federal enforceability of these limits, as follows:

Title 40: Protection of Environment, PART 63—NESHAPS, Subpart A — Definitions:<sup>21</sup>

*Potential to emit* means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is **federally enforceable**.

State of Texas: What is potential to emit (PTE)?

Potential to emit is defined in Title 30 Texas Administrative Code (30 TAC) Chapter 122 (herein referred to as Chapter 122) as the **maximum capacity of a stationary source to emit any air pollutant under its physical and operational design or configuration**. Any certified registration or preconstruction authorization restricting emissions or any physical or operational

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<sup>20</sup> *Shell Martinez Refinery, Regulation 12 Rule 12, Flare Minimization Plan*, Redacted Version, Revised March 25 2007, Submitted to: Bay Area Air Quality Management District, attached as MHA Attach16 -- shell martinez CA flare minimiz plan.pdf

<sup>21</sup> <http://law.justia.com/us/cfr/title40/40-9.0.1.1.1.5.2.html>

limitation on the capacity of a stationary source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on type or amount of material combusted, stored, or processed, **shall be treated as part of its design if the limitation is enforceable by the United States Environmental Protection Agency (EPA).**

Ventura County Air Pollution Control District Definition maximum Potential to Emit (PTE):

10. "Potential to Emit": The maximum capacity of a stationary source to emit a regulated air pollutant based on its physical and operational design. **Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design only if the limitation is federally enforceable.**<sup>22</sup>

US EPA Memo on definition of PTE (Potential to Emit) and enforceability

Many MACT standards apply only to major sources, that is, those with a PTE greater than a given level. **A source's PTE, that is, the amount the source could possibly emit, is affected by its maximum physical capacity to operate and emit and by enforceable limits. The current definition of PTE for the MACT program, which is contained in 40 CFR part 63, subpart A, requires that limits affecting a source's PTE must be enforceable by the EPA and citizens in order to be taken into account in the PTE calculation.**<sup>23</sup> (emphasis added)

Since the Project does not include such enforceable limits on total emissions in the form of a permit, the numbers provided in the FEIS listing the volumes of fuels that will be processed are meaningless for calculating the maximum Potential to Emit. The maximum Potential to Emit (PTE) is effectively unlimited, since there is no Major or Minor Source permit for this Project.

The Final EIS did add identification of some important federal requirements which were not included in the Draft EIS. None of these limit the total emissions, and while there are some reporting requirements, there is no mechanism identified for enforcing these measures (such as a permit with regular inspections by an enforcing agency). (See Table A-2, Appendix A and other statements in the Air Quality Technical Report.)

It should also be clearly noted that many of these regulations were written to apply to existing refinery sources, not new sources. New sources such as the proposed MHA Nation refinery can and should meet a higher standard, such as Best Available Control Technology (BACT). The regulatory requirements identified in Table A-2 do not take the place of a BACT analysis. No BACT analysis was performed for the Project.

Furthermore, although these federal requirements are listed and summarized, they are not incorporated into a formal permit in detail, but only by reference. This means that any lack of

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<sup>22</sup> Ventura County Air Pollution Control District, Rule 76 – Federally Enforceable Limits on Potential to Emit, Revised 9/12/06, <http://www.arb.ca.gov/DRDB/VEN/CURHTML/R76.PDF>,

<sup>23</sup> Title V, Memo from USEPA Regarding Extension of Deadline for Two-Year Transition facilities, Extension of January 25, 1995 Potential to Emit Transition Policy, John S. Seitz, Director, Office of Air Quality Planning and Standards (MD-10), Robert I. Van Heuvelen, Director, Office of Regulatory Enforcement (2241A), <http://www.epa.ohio.gov/portals/27/permits/ptemem2.pdf>

clarity about the application of the regulations at the MHA Nation facility will be left to the operator interpretation. Such lack of specific permit conditions which lay out all details, customized for the facility begs for bad interpretation of the regulations.

Here are examples of the federal requirements identified in Appendix A, Table A-2, and other specified FEIS statements:

- “Flares must be smokeless,” with “no visible emission” and with limits on heat content and flare gas velocity. (Page App. A-3)

These limits are important requirements but they do not limit how often a flare is used, which is the key to limiting flare emissions of VOCs, SO<sub>x</sub>, NO<sub>x</sub>, CO, PM, CO<sub>2</sub>, and other pollutants. Without equipment and practices for minimizing how often flaring events occur, flare emissions can become extremely large even when the above conditions are met.

- **Process Heaters/Fuel Gas Combustion Devices**

a. Each process heater and fuel gas combustion device must comply with a SO<sub>2</sub> limit of 20 ppmv on a 3-hour rolling average; and a SO<sub>2</sub> limit of 8 ppmv determined daily on a 365 successive day rolling average.

b. Process heaters with a capacity greater than 20 MMBtu/hr must comply with a NO<sub>x</sub> limit of 80 ppmv on a 24-hour rolling average. **If the total annual benzene (TAB)** is less than 10 Mg/yr, the owner/operator is exempt from managing and treating the facility waste.

**If the TAB is greater than** or equal to 10 Mg/yr, the owner/operator must be in compliance at initial startup of the facility.

**Process Heaters/Fuel Gas Combustion Devices**

a. The owner/operator must use the following EPA test methods (40 CFR part 60, Appendix A) for determining the compliance of the process heaters/fuel gas combustion devices with the SO<sub>2</sub> and NO<sub>x</sub> limits: Method 1 for sample/ velocity traverses; Method 2 for velocity/volumetric flow rate; Method 3, 3A, or 3B for gas analysis; Method 6, 6A, or 6C 40 CFR part 60; and Methods 6, 6A, or 6C must be used for conducting the relative accuracy evaluations.

[See 40 CFR 60.107a(a)(1) for all monitoring specifications.]

b. The owner/operator of a subject process heater must install, operate, calibrate, and maintain an instrument for continuously monitoring/recording the concentration of NO<sub>x</sub> into the air and include an O<sub>2</sub> monitor for correcting data to excess air. The NO<sub>x</sub> monitor must be installed, operated, maintained, and performance evaluations conducted according to EPA’s Performance Specification 2 found in Appendix B of 40 CFR part 60; and Methods 7, 7A, 7C, 7D, or 7E must be used for conducting the relative accuracy evaluations.

[See 40 CFR 60.107a(c) for all monitoring specifications.]

This last set of requirements above would reduce emissions if applied, but as a percentage of total emissions (by limiting the concentration of specific pollutants within certain

gas streams). But these do not limit the total mass of emissions. If the equipment is run at a higher throughput, the percentage of SO<sub>2</sub> and NO<sub>x</sub> would still meet the limits listed above, but the emissions would increase, unless enforceable permit conditions were added limiting the maximum throughput. Some of the provisions state that if emissions turn out to be higher, additional requirements will kick in later. This indicates that current regulatory requirements (in the absence of permit conditions) will allow higher emissions to occur after startup, compared to what was assumed in the FEIS.

This Appendix of the Final EIS also identified exemptions from federal regulations where equipment will not be subject to regulation, and identified areas where EPA will might or could do something later instead of now:

- Boilers: “Not subject to SO<sub>2</sub> limits due to firing only natural gas and refinery fuel gas,” and “Not subject to PM limits due to boiler capacity less than 30 MMBtu/hr.”<sup>24</sup>

Since there is no permit requiring that boilers only use natural gas and refinery fuel gas as a required condition for operating the refinery, it is not appropriate to allow this exemption. There is also no permit ensuring that refinery fuel gas meets a sulfur content limit, which would form the basis of such an exemption. The same goes for the exemption from PM (particulate matter) limits, due to boiler capacity size less than 30 MMBTU/hr. Without a permit limiting boiler size to below 30 MMBTU/hr, this exemption cannot apply.<sup>25</sup>

- “No testing or monitoring requirements, since not subject to SO<sub>2</sub> or PM emission limits” again for boilers.

This exemption is particularly problematic, since it exempts the boilers from SO<sub>2</sub> and PM limits, then it exempts them from monitoring that could ensure that emissions stay low. Because there have been many cases throughout the nation where refinery fuel gas has exceeded sulfur content, without monitoring to ensure that refineries meet SO<sub>2</sub> limits

- “EPA has authority under CAA sections 301(a) and 301(d)(4) to promulgate "Federal Implementation Plans" (FIPs) as necessary or appropriate to protect air quality (40 CFR 49.11). EPA may develop a FIP for the refinery which could include additional monitoring, testing, recordkeeping, and reporting for the refinery units as needed to ensure protection of air quality.” (page 2-4) Such an action is needed now.
- “If promulgated as proposed, NSPS subpart Ja will be applicable to the proposed refinery since construction of the affected refinery units will commence after May 14, 2007. *Finalization of NSPS subpart Ja* will also trigger the requirement for the refinery to apply for a 40 CFR part 71 operating permit within 12 months of commencing operation. *If* promulgated as proposed, NSPS subpart Ja will be

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<sup>24</sup> Air Quality Technical Report, page App A-4

<sup>25</sup> Also, there are three new boilers, each at 20 MMBTU/hr. Is this Project design an attempt to use larger numbers of smaller capacity boilers, in order to avoid standards for boilers greater than 30 MMBTU/hr?

applicable to the proposed refinery since construction of the affected refinery units will commence after May 14, 2007. Finalization of NSPS subpart Ja will also trigger the requirement for the refinery to apply for a 40 CFR part 71 operating permit within 12 months of commencing operation. Subpart Ja *would* require that the sulfur recovery unit meet a 99% sulfur removal efficiency, a hydrogen sulfide (H<sub>2</sub>S) limit of less than 10 ppm determined on a 12-hour rolling average, and continuously monitor for compliance. Process heaters with a capacity greater than 20,000,000 Btu/hr *would* have to meet a NO<sub>x</sub> limit of 80 parts per million (ppm) on a 24-hour rolling average and continuously monitor for compliance. All process heaters and fuel gas combustion devices *would* have to comply with SO<sub>2</sub> limits of 20 ppm on a 3-hour rolling average, of 8 ppm determined daily on a 365 successive day rolling average, and monitor continuously. The refinery combustion units will all have “Low NO<sub>x</sub>” burners.”

Instead of identifying actions that EPA could take later, these standards should be applied now, especially to the extent that emissions calculations assumed these standards were already in place.

- “EPA is promulgating new regulations to establish a preconstruction air permitting program for minor stationary sources throughout Indian country. The rule was proposed in the August 21, 2006 *Federal Register*. The effective date for implementing the new regulations is anticipated to be 60 days after the final regulations are published in the *Federal Register*. These regulations may apply to the refinery depending upon when construction on the refinery commences relative to the effective date of these regulations.” (Air Qual. Tech. Report page 2-2)

### Government inspection mechanisms are almost completely missing

A key part of regulatory requirements is not only to state that the regulations exist, but to have an independent government mechanism to make sure they are enforced through onsite facility inspections, rather than counting exclusively on the industrial facility to self-enforce through owner/operator internal inspections, recordkeeping, and paper reports to EPA.

For example, with fugitive emissions from the thousands of leaking refinery seals of valves, flanges, pumps, and compressors, the standard leak rates established assume that government inspections and enforcement will occur to assure that these leak rates are kept low. The FEIS used these low fugitive leak rate emission factors, but without having any government onsite inspection mechanism identified. EPA only receives written reports from the refinery. At refineries throughout the nation in order to keep fugitive leak rates low, government regulators set penalties when a company has missed detecting a leak, because leaks which go on undetected or unrepaired for long periods cause substantial air emissions. If the regulator identifies a leak during an inspection (instead of being previously identified by the owner and fixed), then this counts as a violation of the regulations and permit, fines must be paid, and the problem must be

fixed immediately. This type of independent inspection procedure ensures that industrial facilities do not become lax in their own inspection and repair programs.

In the past, EPA and state and regional air quality agencies have very regularly identified violations of regulations and permit conditions including leaking fugitive components, through government onsite inspections. They have taken enforcement actions to correct these problems and to abate the pollution exceedance. Unfortunately, the FEIS Table A-2 only identifies independent inspection as an option that EPA has the right to request, for a very few activities. Such inspection mechanisms are not identified at all for regular (or any) inspections of fugitive emissions from valves, flanges, pumps, and compressors.

An enforceable permit, limiting each piece of equipment to the numbers listed in the FEIS for throughput (or millions of BTUs burned per year) would need to be issued in order for the numbers to be used in assessing the maximum Potential to Emit. This is also true for the storage tank sizes provided in Table 12 of the Air Quality Technical Report, and for other statements of equipment size and capacity.

There are also other unenforced assumptions in the FEIS such as:

- 1) Type of crude oil (assumed in the FEIS to be Canada Syncrude but which potentially could be more contaminated crude oils unless permit requirements are set for crude oil sulfur content, API gravity, heavy metal content, etc.),
- 2) Projected refinery tail gas unit exhaust makeup and flow rate,<sup>26</sup> and
- 3) Process fuel gas makeup and quality.<sup>27</sup> Because there is no permit, these attributes are not required as enforceable standards, but are assumed for calculating the Project air pollution.
- 4) Many others

The assumptions made about these and other Project attributes give low air pollution estimates compared to the reality when these characteristics are voluntary. EPA and BIA can only use these assumptions if they are set as permit limits.

## **VII. The FEIS is piecemealing the Project improperly into smaller portions, making it appear that total emissions are smaller than they actually will be**

Project proponents have indicated they plan to expand the refinery

There are many indications that the Project proponents are planning to further expand the refinery during the next few years, without formally disclosing this during and leaves out public statements made regarding plans to further expand the refinery in the future.

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<sup>26</sup> Table 14, "Projected Tail Gas Exhaust Composition at the MHA Nation's Proposed Clean Fuels Refinery, listing flow rate for Ar, CO, CO<sub>2</sub>, H<sub>2</sub>, H<sub>2</sub>O, N<sub>2</sub>, O<sub>2</sub>, SO<sub>2</sub>, page 3-7 Air Quality Technical Report

<sup>27</sup> page 3-8 to 3-9

In a public hearing meant for the purpose of providing the public with information on the proposed Project, it was reported that the President and CEO of Triad Corporation informed the public that the proposed MHA refinery would be expanded beyond the 15,000 barrels per day cited in the DEIS. Here are excerpts from the attached article<sup>28</sup> :

### **Makoti area residents attend public hearing**

Mountrail County Record, by Theodora Bird Bear

A number of area residents were at the public hearing on the draft Environmental Impact Statement (EIS) for the proposed oil refinery a couple of Saturdays ago in Makoti. A panel of officials from the Environmental Protection Agency (EPA) and Bureau of Indian Affairs (BIA) traveled to Makoti to accept public comments. . . .

Robert Wooley, President and CEO of Triad Corporation accompanied the panel throughout the week including the public hearing on Makoti.

**When asked why the tribe would limit production to 15,000 barrels per stream day, Wooley said the relatively short pipeline between the proposed refinery site and Plaza can be redone to increase feedstock to the refinery.”**

**“It can be expanded,”** he said. “Who’s going to be paying for this,” asked another area resident.

**Wooley said other refinery expansions were in the works and investors are always very interested in refineries.** “Investors have to be repaid.” “Will grant money be used to pay the investors?” the man asked. **“It’s very profitable,”** replied Wooley. [emphasis added]

The Final EIS states that the issue of an expanded refinery can be handled in the future through separate PSD permitting. This is improper for many reasons. Under NEPA, the Project may not be cut into small pieces in such a way that would underestimate the total impact of the Project. A permit condition limiting the refinery to 10,000 barrels per day should be set if this is the assumption used in the FEIS.

## **VIII. Cumulative Impacts**

The FEIS did not document the overall and considerable Cumulative Impacts of the major energy overhaul occurring in the Midwest, especially the air impacts of these Projects. This includes:

- The pipeline construction and operation for importing crude oil to the refinery,
- The possibility of diesel trucking of crude temporarily before pipelines are complete (this occurred at a drilling operation in the middle of Los Angeles, California, near the Warren Oil drilling operations, resulting in hundreds of diesel truck trips through a residential area),

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<sup>28</sup> Attached as MHA Attach17 -- Makoti News scan0011.jpg

- The rebuilding of refinery units to process heavy, high sulfur Canada tar sands crude oil throughout the midwest,
- The impacts in Canada from the production and pre-processing of crude oil which has been happening on a grand scale in recent years. For example, Syncrude has processing been found to kill ducks.<sup>29</sup>
- The considerable cumulative impacts of the coal-fired power plants in the region
- Oil and gas drilling and flaring operations in the region. Flaring of gases in oil fields has been shown in studies to have poor combustion or destruction efficiency under many conditions.<sup>30</sup>

This is a major and broadly occurring increase in the infrastructure and processing of high-carbon fossil fuels, with consequent major environmental impacts. A full evaluation of criteria pollutants, toxics, greenhouse gases, water, soil, and wildlife impacts should all be evaluated. There is much existing information available on these sources that should have been compiled as part of the FEIS. I have attached below and elsewhere in this comment a variety of reports that evaluate the impact of tar sands crude oil production in Canada, the comprehensive plans by Canada to widely market tar sands crude oil throughout the U.S.

A partial list of projects in the region that are under construction, recently constructed, or to be constructed which should have been evaluated include:

- The impacts of the Keystone Pipeline and Alberta Clipper Pipeline<sup>31</sup> transporting Canada tar sands crude oil, including the importing of the most contaminated crude oil and harmful diluent, the greenhouse impacts, the construction air emissions, and risks of fire and spills.
- Impacts of Canada Tar Sands oil fields -- Some of the impacts occurring in Canada cause cross-border impacts (such as greenhouse gas emissions, and impacts to migrating birds).<sup>32</sup>, Other impacts occur through Canada's comprehensive plans to widely market tar sands crude oil throughout the U.S.,<sup>33</sup> which is resulting in oil refinery switches to more contaminated crude oil, and to a massive new pipeline infrastructure being built internationally and between states.

<sup>29</sup> Ottawa, *Alberta charge Syncrude over tailings pond duck deaths*, National Post, February 2009, attached, <http://www.nationalpost.com/story-printer.html?id=1270010> , MHA Attach18 -- Ottawa Syncrude tailings kills ducks.pdf

<sup>30</sup> *Efficiency Measurements of Flares in a Cross Flow*, Johnson, et al, Combustion and Environment Group, Department of Mechanical Engineering, University of Alberta, Edmonton, Alberta, Canada, Presented at Combustion Canada, Calgary Alberta, May 26-28,1999, <http://www.mece.ualberta.ca/groups/combustion/flare/papers/CombCan99-Efficiency.pdf> , attached as MHA Attach19 -- CombCan99-Flare Efficiency.pdf

<sup>31</sup> Enbridge Alberta Clipper Pipeline, FEIS, Chapter 4, attached as MHA Attach20 -- Enbridge Alberta Clipper Pipeline FEIS 4.0 Envir Analysis.pdf

<sup>32</sup> *Oil Sands Fever, The Environmental Implications of the Oil Sands Rush*, The Pembina Institute, Woynillowicz, Severson-Baker, Reynolds, November 2005, attached as MHA Attach21 -- Pembina Oil Sands Fever 2005.pdf

<sup>33</sup> *Canada's Oil Sands Opportunities and Challenges to 2015: An Update, An Energy Market Assessment* June 2006, National Energy Board, Canada, attached as MHA Attach22 - Canadian assessment ppxf oil sands energy market assess.pdf

- Impacts of expansions and modifications to use Canada Tar Sands crude oil at oil refineries including
  - The BP Whiting, Indiana
  - Detroit Marathon
  - ConocoPhillips Illinois
  - Murphy Oil Wisconsin
  - Identification of Canada Syncrude pre-processing operations that will provide crude oil to the Project, and associated impacts

One Enbridge pipeline had a rupture and fire pictured below, as reported by the U.S. National Transportation Board in Rupture of Enbridge Pipeline and Release of Crude Oil, near Cohasset, Minnesota, July 4, 2002.<sup>34</sup>



Figure 4. Smoke plume 1 mile high and 5 miles long.

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<sup>34</sup> Attached as MHA Attach23 -- Enbridge pipeline spill and fire 2002 PAR0401.pdf



The FEIS did provide some Cumulative Impacts assessment, but left out air and construction emissions including greenhouse gases, toxics, and criteria pollutants.

The FEIS states that a pipeline and its associated tanks will need to be built in order to transport crude oil to the refinery. The air impacts of the construction and operation of this pipeline should have been evaluated as part of the refinery Project. This is clearly not a separate issue. The refinery cannot operate without its supply of crude oil. If the pipeline is not built, then the crude oil would have to be trucked in, creating thousands of truck trips and diesel air emissions. In either case, air emissions from both the pipeline and the proposed refinery need to be evaluated. This is an improper piecemealing of other parts of this Project from full evaluation. The FEIS finds:

#### ***Oil and Natural Gas Pipeline Impacts***

Enbridge would construct a pipeline to connect the terminus of its Wabek/Plaza field pipeline to the crude oil storage tanks in the refinery's tank farm (Figure 2-12). Additionally, Enbridge would construct four new 30,000-bbl storage tanks between Outlook, Montana and the refinery (Figure 2-1). Construction of the oil storage facilities would occur within existing pads that have previously been developed, thereby avoiding additional soil resource impacts. Two options are provided to deliver natural gas to the refinery: MDU Resources Group, Inc. and Bear Paw Natural Gas Company. MDU would supply natural gas using a new pipeline that would connect its existing Williston Basin Interstate Pipeline to the refinery (Figure 2-12 and Figure 2-13). Under the second option, Bear Paw Natural Gas Company would supply natural gas using a new pipeline that would connect its existing Plaza pipeline to the refinery (Figure 2-12).

#### ***Erosion***

Pipeline construction activities such as clearing, grading, trench excavation, backfilling, and movement of construction equipment along the ROW would affect soil resources. Erosion is a continuing, natural process that can be accelerated by human activities. Clearing, grading, and moving equipment on the ROW would remove the protective vegetation cover and expose soils to the effects of wind, rain, and runoff. These effects would accelerate the erosion process and,

without adequate protection, could result in discharges of sediment to wetlands and waterbodies, and could potentially lower soil fertility. (FEIS, page 4-40)

Also, since the pipeline is not currently connected with the proposed refinery site, there is no guarantee that the crude oil in this particular pipeline will be the crude oil processed by the refinery. Furthermore, the crude oil in this pipeline is a mix of crudes, including Montana crude. The FEIS claims that the refinery will use Canada Syncrude. A full evaluation of the different types of crude oils, their sulfur content, their API gravity (a measure of how heavy they are), their metal content, etc. need to be provided as part of the FEIS. Sulfur content of crude oil makes an immense difference in the resulting SO<sub>x</sub> emissions at an oil refinery. Heavier crude oil requires much more cracking, and results in heavy by-products. This results in increased criteria pollutants and greenhouse gases. Higher heavy metals content of crude oil means increased potential to emit toxic metals into the air, and to introduce these to water effluents and to contaminate soils. The choice of crude oil at the site is more than a cumulative impact issue, it is part of the refinery operation itself, and air emissions would need to be added to the Project totals depending on the crude oil used.

Rather than performing a whole cumulative impacts assessment on this huge missing piece of the FEIS, I am urging that such an assessment be performed, and I am attaching several documents that provide relevant information.

## **IX. Conclusion**

Please take the additional time needed to re-evaluate the deficiencies of the FEIS, failure to require a PSD permit, piecemealing, lack of cumulative impacts assessment, lack of evaluation of clean energy alternatives and re-issue the EIS in draft form for public comment. Thank you for your consideration and work to provide health protections for the community and the environment.

Julia May

Environmental Consultant

The attachments list below includes those listed in the footnotes and text, plus three more attachments on 1) the BAAQMD fugitive emissions regulation, which identifies a tight leak standard, 2) a life cycle analysis of Bitumin crude oil, and 3) a comprehensive, quantitative report *Tackling Climate Change in the U.S., Potential Carbon Emissions Reductions from Energy Efficiency and Renewable Energy by 2030*, American Solar Energy Society, 2007

Attachments list as follows:

MHA Attach01 -- Final comment MHA Nation DEIS.doc  
MHA Attach02 -- BAAQMD reg 1211 flare monitoring.pdf  
MHA Attach03-- BAAQMD flare control reg1212.pdf  
MHA Attach04 -- Refinery Flaring in the Neighborhood CBE.pdf  
MHA Attach05 -- Comment\_JMay\_ConocoPhillips\_Hydroproc\_Ex...  
MHA Attach06 -- ConocoPhillips\_Wood\_River\_CORE\_Comment...  
MHA Attach07 -- EXHIBITS\_to\_JMay\_Comment\_on\_CP\_Wood\_...  
MHA Attach08 -- Julia May comments BP Whiting expansion.doc  
MHA Attach09 -- EPA Enforcement alert refinery RCRA waste V...  
MHA Attach10 -- EXHIBITS to JMay Comment on BP CXHO.ZIP  
MHA Attach11 -- Tesoro Kenai Refinery permit 035cp04fin.pdf  
MHA Attach12 -- Email from EPA MHA App C flare example calc...  
MHA Attach13 -- EPA email example flare calculation pic29949.gif  
MHA Attach14 -- EPA Letter to Bill White re DQA.pdf  
MHA Attach15 -- NEPA and Federal Transportation Climate Chan...  
MHA Attach16 -- shell martinez CA flare minimiz plan.pdf  
MHA Attach17 -- Makoti News scan0011.jpg  
MHA Attach18 -- Ottawa Syncrude tailings kills ducks.pdf  
MHA Attach19 -- CombCan99-Flare Efficiency.pdf  
MHA Attach20 -- Enbridge Alberta Clipper Pipeline FEIS 4.0 Envir...  
MHA Attach21 -- Pembina Oil Sands Fever 2005.pdf  
MHA Attach22 - Canadian assessment ppxf oil sands energy mar...  
MHA Attach23 -- Enbridge pipeline spill and fire 2002 PAR0401.pdf  
MHA Attach24 -- BAAQMD fugit rule rg0818.pdf  
MHA Attach25 -- Heave crude Bitumen Life Cycle Analysis.pdf