**Exhibit 1**:

NPDES Permit No. ND-0030988

# UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, COLORADO 80202-1129

## AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Clean Water Act, as amended, (33 U.S.C. §1251 et seq; the "Act"),

**the MHA Nation Clean Fuels Refinery**

is authorized to discharge from its wastewater treatment facilities located in the NW 1/4 of Section 19, Township 152N, Range 87W, Fort Berthold Indian Reservation, Ward County, North Dakota

to wetlands tributary to the East Fork of Shell Creek,

in accordance with discharge point(s), effluent limitations, monitoring requirements and other conditions set forth herein. Authorization for discharge is limited to those outfalls specifically listed in the permit.

This permit shall become effective October 1, 2011

This permit and the authorization to discharge shall expire at midnight, September 30, 2016.

Signed this 4 day of AUGUST, 2011

Stephen S. Tuber
Authorized Permitting Official

Stephen S. Tuber, Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance
Title

INDUSTRIAL (Rev.02/06)

# TABLE OF CONTENTS

## 1. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

### 1.1. Definitions.

The *30-day (and monthly) average*, other than for fecal coliform bacteria and total coliform bacteria, is the arithmetic average of all samples collected during a consecutive 30-day period or calendar month, whichever is applicable. Geometric means shall be calculated for fecal coliform bacteria and total coliform bacteria. The calendar month shall be used for purposes of reporting self-monitoring data on discharge monitoring report forms.

The *7-day (and weekly) average*, other than for fecal coliform bacteria and total coliform bacteria, is the arithmetic mean of all samples collected during a consecutive 7-day period or calendar week, whichever is applicable. Geometric means shall be calculated for fecal coliform bacteria and total coliform bacteria. The 7-day and weekly averages are applicable only to those effluent characteristics for which there are 7-day average effluent limitations. The calendar week, which begins on Sunday and ends on Saturday, shall be used for purposes of reporting self-monitoring data on discharge monitoring report forms. Weekly averages shall be calculated for all calendar weeks with Saturdays in the month. If a calendar week overlaps two months (i.e., the Sunday is in one month and the Saturday in the following month), the weekly average calculated for that calendar week shall be included in the data for the month that contains the Saturday.

*Daily Maximum* (*Daily Max.*) is the maximum measured value for a pollutant discharged during a calendar day or any 24-hour period that reasonably represents a calendar day for purposes of sampling. For pollutants with daily maximum limitations expressed in units of mass (e.g., kilograms, pounds), the daily maximum is calculated as the total mass of pollutant discharged over the calendar day or representative 24-hour period. For pollutants with limitations expressed in other units of measurement (e.g milligrams/liter, parts per billion), the daily maximum is calculated as the average of all measurements of the pollutant over the calendar day or representative 24-hour period. If only one measurement or sample is taken during a calendar day or representative 24-hour period, the single measured value for a pollutant will be considered the daily maximum measurement for that calendar day or representative 24-hour period.

*Daily Minimum* (*Daily Min*.) is the minimum value allowable in any single sample or instantaneous measurement collected during the course of a day.

*Mean (7-day mean, 30-day mean)* is the arithmetic mean value of all results for samples collected during either a seven day period or calendar week whichever is applicable, or a thirty day period or a calendar month whichever is applicable.

*Grab sample*, for monitoring requirements, is defined as a single "dip and take" sample collected at a representative point in the discharge stream.

*Instantaneous measurement*, for monitoring requirements, is defined as a single reading, observation, or measurement.

*Composite samples* shall be flow proportioned. The composite sample shall, at a minimum, contain at least four (4) samples collected over the compositing period. Unless otherwise specified, the time between the collection of the first sample and the last sample shall not be less than six (6) hours, nor more than twenty-four (24) hours. Acceptable methods for the preparation of composite samples are as follows:

a. Constant time interval between samples, sample volume proportional to flow rate at the time of sampling;

b. Constant time interval between samples, sample volume proportional to total flow (volume) since last sample. For the first sample, the flow rate at the time of the first sample was collected may be used;

c. Constant sample volume, time interval between samples proportional to flow (i.e., sample taken every "X" gallons of flow); and,

d. Continuous collection of sample with sample collection rate proportional to flow rate.

*Bypass* means the intentional diversion of waste streams from any portion of a treatment facility.

*Upset* means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based permit effluent limitations because of factors beyond the reasonable control of the permittee. An upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation.

*Severe property damage* means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

*Director* means the Regional Administrator of EPA Region 8 or an authorized representative.

*EPA* means the United States Environmental Protection Agency.

*Storm Water* or *Stormwater* means storm water runoff, snow melt runoff, and surface runoff and drainage.

*CWA* means the Clean Water Act (formerly referred to as either the Federal Water Pollution Act or the Federal Water Pollution Control Act Amendments of 1972), Pub. L. 92-500, as amended by Pub. L. 95-217, Pub. L. 95-576, Pub. L. 96-483, Pub. L. 97-117, and Pub. L. 100-4. In this permit the CWA may be referred to as "the Act".

*Sewage Sludge* is any solid, semi-solid or liquid residue generated during the treatment of domestic sewage in a treatment works. Sewage sludge includes, but is not limited to, domestic septage; scum or solids removed in primary, secondary or advanced wastewater treatment processes; and a material derived from sludge. Sewage sludge does not include ash generated during the firing of sewage sludge in a sewage sludge incinerator or grit and screenings generated during preliminary treatment of domestic sewage in a treatment works.

*Whole Effluent Toxicity*, Acute toxicity occurs when 50 percent or more mortality is observed for either species (see Part 1.3.) at any effluent concentration. Mortality in the control must simultaneously be 10 percent or less for the effluent results to be considered valid. Chronic toxicity occurs when during a chronic toxicity test, the 25% inhibition concentration ($IC_{25}$) calculated on the basis of test organism survival and growth or survival and reproduction, is less than or equal to 100% effluent concentration.

*Section 313 Water Priority Chemicals* means a chemical or chemical categories which: 1) are listed at 40 CFR 372.65 pursuant to Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA) (also known as Title III of the Superfund Amendments and Reauthorization Act (SARA) of 1986); 2) are present at or above threshold levels at a facility subject of EPCRA Section 313 reporting requirements; and 3) that meet at least one of the following criteria: (i) are listed in Appendix D of 40 CFR 122 on either Table II (organic toxic pollutants), Table III (certain metals, cyanides, and phenols) or Table V (certain toxic pollutants and hazardous substances); (ii)are listed as a hazardous substance pursuant to section 311(b)(2)(A) of the CWA at 40 CFR 116.4; or (iii) are pollutants for which EPA has published acute or chronic water quality criteria.

1.2. Description of Discharge Point(s). The authorization to discharge provided under this permit is limited to those outfalls specifically designated below as discharge locations. Discharges at any location not authorized under an NPDES permit is a violation of the Clean Water Act and could subject the person(s) responsible for such discharge to penalties under Section 309 of the Act.

| Outfall Serial Number(s) | Description of Discharge Point(s) |
|---|---|
| 001 | Any discharge of uncontaminated stormwater from the Evaporation Ponds to the wetland swale located in the NW1/4 Section 19, Township 152 North, Range 87 West. Longitude 47°58’25” Latitude 101°52’11” |
| 002 | Any discharge from the Final Effluent Holding Ponds or the Final Release Tanks to the wetland swale located in the NW1/4 Section 19, Township 152 North, Range 87 West. Longitude 47°58’29” Latitude 101°52’9” |
| 002a | Any discharge from the Stormwater Final Release Tanks to the wetland swale located in the NW1/4 Section 19, Township 152 North, Range 87 West. Longitude 47°58’29” Latitude 101°52’9” |
| 003 | Any discharge from the Sanitary Wastewater Treatment Plant to the wetland swale located in the NW1/4 Section 19, Township 152 North, Range 87 West. Longitude 47°58’??” Latitude 101°52’??” |

## 1.3. Specific Limitations and Self-Monitoring Requirements

1.3.1. Effluent Limitations - Outfall 001. Effective immediately and lasting through the life of this permit, the quality of effluent discharged from the Stormwater Evaporation Ponds by the facility shall, as a minimum, meet the limitations as set forth below:

| Effluent Characteristic | Effluent Limitation | | |
|---|---|---|---|
| | 30-Day Average a/ | 7-Day Average a/ | Daily Maximum a/ |
| Flow, mgd | NA | NA | 0.08 |
| Oil and Grease, mg/L | NA | NA | 15 |
| Biochemical Oxygen Demand (5-day), mg/L | 30 | 45 | N/A |
| Total Suspended Solids, mg/L | 30 | 45 | N/A |
| Phenol, ug/L | 300 | N/A | N/A |
| Iron (tr), ug/L | 300 | N/A | N/A |
| Manganese (tr), ug/L | 50 | N/A | N/A |
| Selenium (tr), ug/L | 5 | N/A | 20 |
| Sulfate, mg/L | 750 | N/A | N/A |
| Nitrate as N, mg/L | 10 | N/A | N/A |
| Dissolved Oxygen, mg/L: | April 1 – Sept 30<br>8.0 (1-day min.)<br>9.5 (7-day mean)<br>6.5 (30-day mean)<br><br>Oct 1 – March 31<br>4.0 (1-day min.)<br>5.0 (7-day mean)<br>6.5 (30-day mean) | | |
| The pH of the discharge shall not be less than 7.0 s.u.or greater than 9.0 s.u.at any time. | | | |

a/ See Definitions, Part 1.1., for definition of terms.

tr – total recoverable

The discharge from Outfall 001 shall be free from oil and grease attributable to wastewater, which causes a visible film or sheen upon the waters or any discoloration of the surface of adjoining shoreline or causes a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines or prevents classified uses of such waters.

1.3.2 Self-Monitoring Requirements - Outfall 001. As a minimum, upon the effective date of this permit, the following constituents shall be monitored at the frequency and with the type of measurement indicated; samples or measurements shall be representative of the volume and nature of the monitored discharge. If no discharge occurs during the entire monitoring period, it shall be stated on the Discharge Monitoring Report Form (EPA No. 3320-1) that no discharge or overflow occurred.

| Effluent Characteristic | Frequency | Sample Type a/ |
|---|---|---|
| Total Flow, mgd b/ | Daily | Continuous, Recorder |
| Biochemical Oxygen Demand (5-day), mg/L | Monthly | Composite |
| Total Suspended Solids, mg/L | Monthly | Composite |
| Phenol, ug/L | Quarterly | Composite |
| Ammonia as N, mg/L | Quarterly | Composite |
| Selenium (tr), ug/L | Quarterly | Composite |
| Manganese (tr), ug/L | Quarterly | Composite |
| Iron (tr), ug/L | Quarterly | Composite |
| Fluoride, mg/L | Quarterly | Composite |
| Sulfate, mg/L | Quarterly | Composite |
| Nitrate as N, mg/L | Quarterly | Composite |
| Total Phosphorous as P, mg/L | Quarterly | Composite |
| pH (s.u.) | Daily | Grab or Continuous |
| Oil and grease, visual c/ | Daily | Visual c/ |
| Dissolved Oxygen, mg/L | Daily | Grab |

a/ See Definitions, Part 1.1., for definition of terms.

b/ Flow measurements of effluent volume shall be made in such a manner that the permittee can affirmatively demonstrate that representative values are being obtained. The average flow rate (in million gallons per day) during the reporting period and the maximum flow rate observed (in mgd) shall be reported.

c/ A daily visual observation is required. If a visible sheen is detected, a grab sample shall be taken and analyzed immediately. The concentration of oil and grease shall not exceed 15 mg/L in any sample.

tr – total recoverable

1.3.3. Effluent Limitations - Outfall 002. Effective immediately and lasting through the life of this permit, the quality of effluent discharged from the Final Effluent Holding Ponds or Effluent Final Release Tanks by the facility shall, as a minimum, meet the limitations as set forth below:

| | Effluent Limitation | | |
|---|---|---|---|
| Effluent Characteristic | 30-Day Average a/ | 7-Day Average a/ | Daily Maximum a/ |
| Flow, mgd | 0.025 | N/A | 0.05 |
| Biochemical Oxygen Demand (5-day), lbs./day | 43 | N/A | 81 |
| Chemical Oxygen Demand, lbs./day | 255 | N/A | 500 |
| Total Suspended Solids, lbs./day | 35 | N/A | 55 |
| Oil and Grease, lbs./day | 13.7 | N/A | 25.4 |
| Benzene, ug/L | 2.2 | N/A | NA |
| Ethyl benzene, ug/L | 530 | N/A | NA |
| Toluene, ug/L | 1300 | N/A | NA |
| Phenol, ug/L | 300 | N/A | NA |
| Phenolic Compounds, lbs./day | 0.29 | N/A | 0.59 |
| Hydrogen Sulfide, ug/L | 2.0 | N/A | NA |
| Ammonia as N, mg/L | 1.1 | N/A | 3.2 |
| Barium (tr), ug/L | 1000 | N/A | NA |
| Aluminum (tr), ug/L | 87 | N/A | 750 |
| Chromium (Total), lbs./day | 0.035 | N/A | 1.22 |
| Chromium (VI) , ug/L | 11 | N/A | 16 |
| Chromium (VI), lbs/day | 0.0018 | N/A | 0.0067 |
| Iron (tr), ug/L | 300 | N/A | N/A |
| Manganese (tr), ug/L | 50 | N/A | N/A |
| Mercury (Total), ug/L | 0.0012 | N/A | 1.4 |
| Nickel (tr), ug/L | 132 | N/A | 1190 |
| Selenium (tr), ug/L | 5 | N/A | 20 |
| Chloride, mg/L | 230 | N/A | 860 |
| Fluoride, mg/L | 4.0 | N/A | N/A |
| Sulfate, mg/L | 750 | N/A | N/A |
| Nitrite as N, mg/L | 1.0 | N/A | N/A |
| Nitrate as N, mg/L | 10 | N/A | N/A |
| Whole Effluent Toxicity, acute | $LC_{50}$ > 100% | | |
| Whole Effluent Toxicity, chronic | $IC_{25}$ > 100% | | |
| The pH of the discharge shall not be less than 7.0 s.u. or greater than 9.0 s.u. at any time. | | | |

| Effluent Characteristic | Effluent Limitation |
|---|---|
| Dissolved Oxygen, mg/L: | April 1 – Sept 30<br>8.0 (1-day min.)<br>9.5 (7-day mean)<br>6.5 (30-day mean)<br><br>Oct 1 – March 31<br>4.0 (1-day min.)<br>5.0 (7-day mean)<br>6.5 (30-day mean) |

a/ See Definitions, Part 1.1., for definition of terms.

tr – total recoverable

The discharge from Outfall 002 shall be free from oil and grease attributable to wastewater, which causes a visible film or sheen upon the waters or any discoloration of the surface of adjoining shoreline or causes a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines or prevents classified uses of such waters.

1.3.4 Self-Monitoring Requirements - Outfall 002. As a minimum, upon the effective date of this permit, the following constituents shall be monitored at the frequency and with the type of measurement indicated; samples or measurements shall be representative of the volume and nature of the monitored discharge. If no discharge occurs during the entire monitoring period, it shall be stated on the Discharge Monitoring Report Form (EPA No. 3320-1) that no discharge or overflow occurred.

Effluent Characteristic Frequency Sample Type a/

| Effluent Characteristic | Frequency | Sample Type a/ |
|---|---|---|
| Total Flow, mgd b/ | Daily | Continuous, Recorder |
| Biochemical Oxygen Demand (5-day), lbs./day | 2X/Week | Composite |
| Chemical Oxygen Demand, lbs./day | Monthly | Composite |
| Total Suspended Solids, lbs./day | 2X/Week | Composite |
| Oil and Grease, lbs/day | Weekly | Grab |
| Benzene, ug/L | Monthly | Grab |
| Ethyl benzene, ug/L | Monthly | Grab |
| Toluene, ug/L | Monthly | Grab |
| Phenol, ug/L | Monthly | Grab |
| Phenolic Compounds, lbs./day | Monthly | Grab |
| Hydrogen Sulfide, ug/L | Weekly | Grab |
| Ammonia as N, mg/L | Weekly | Composite |
| Barium (tr), ug/L | Monthly | Composite |
| Aluminum (tr), ug/L | Monthly | Composite |

| | | |
|---|---|---|
| Chromium (Total), lbs./day | Monthly | Composite |
| Chromium (VI), ug/L | Monthly | Grab |
| Chromium (VI), lbs./day | Monthly | Grab |
| Iron (tr), ug/L | Monthly | Composite |
| Manganese (tr), ug/L | Monthly | Composite |
| Mercury (Total), ug/L | Monthly | Composite |
| Nickel (tr), ug/L | Monthly | Composite |
| Selenium (tr), ug/L | Monthly | Composite |
| Chloride, mg/L | Monthly | Composite |
| Fluoride, mg/L | Monthly | Composite |
| Sulfate, mg/L | Monthly | Composite |
| Nitrite as N, mg/L | Monthly | Composite |
| Nitrate as N, mg/L | Monthly | Composite |
| Total Phosphorous as P, mg/L | Monthly | Composite |
| Whole Effluent Toxicity, acute | Quarterly | Grab |
| Whole Effluent Toxicity, chronic | Quarterly | Composite |
| pH (s.u.) | Daily | Grab or Continuous |
| Temperature, °C | Daily | Grab |
| Oil and grease, visual c/ | Daily | Grab |
| Dissolved Oxygen, mg/L | Daily | Grab |

a/ See Definitions, Part 1.1., for definition of terms.

b/ Flow measurements of effluent volume shall be made in such a manner that the permittee can affirmatively demonstrate that representative values are being obtained. The average flow rate (in million gallons per day) during the reporting period and the maximum flow rate observed (in mgd) shall be reported.

c/ A daily visual observation is required. If a visible sheen is detected, a grab sample shall be taken and analyzed immediately. The concentration of oil and grease shall not exceed 15 mg/L in any sample.

tr - total recoverable

1.3.5 Additional Self-Monitoring Requirements - Outfall 002.

Additional Monitoring Requirement for Outfall 002:

Approximately 90 days and 270 days after startup of the facility, monitoring shall be required for:

Total Metals – Table III §40CFR 122 Appendix D
Volatile, acid, and base/neutral compounds – Table II §40CFR 122 Appendix D

1.3.6 Effluent Limitations - Outfall 002a. Effective immediately and lasting through the life of this permit, the quality of effluent discharged from the Stormwater Final Release Tanks by the facility shall, as a minimum, meet the limitations as set forth below:

| Effluent Characteristic | Effluent Limitation | | |
|---|---|---|---|
| | 30-Day Average a/ | 7-Day Average a/ | Daily Maximum a/ |
| Flow, mgd | 0.0065 | N/A | 0.027 |
| Oil and Grease, mg/L | 15 | N/A | 15 |
| Total Organic Carbon, mg/L | 110 | N/A | 110 |
| Benzene, ug/L | 2.2 | N/A | NA |
| Ethyl benzene, ug/L | 530 | N/A | NA |
| Toluene, ug/L | 1300 | N/A | NA |
| Phenol, ug/L | 300 | N/A | NA |
| Hydrogen Sulfide, ug/L | 2.0 | N/A | NA |
| Ammonia as N, mg/L | 1.1 | N/A | 3.2 |
| Barium (tr), ug/L | 1000 | N/A | NA |
| Aluminum (tr), ug/L | 87 | N/A | 750 |
| Chromium (VI), ug/L | 11 | N/A | 16 |
| Iron (tr), ug/L | 300 | N/A | N/A |
| Manganese (tr), ug/L | 50 | N/A | N/A |
| Mercury (Total), ug/L | 0.0012 | N/A | 1.4 |
| Nickel (tr), ug/L | 132 | N/A | 1190 |
| Selenium (tr), ug/L | 5 | N/A | 20 |
| Chloride, mg/L | 230 | N/A | 860 |
| Fluoride, mg/L | 4.0 | N/A | N/A |
| Sulfate, mg/L | 750 | N/A | N/A |
| Nitrite as N, mg/L | 1.0 | N/A | N/A |
| Nitrate as N, mg/L | 10 | N/A | N/A |
| Whole Effluent Toxicity, acute | $\mathrm{LC}_{50} > 100\%$ | | |
| Whole Effluent Toxicity, chronic | $\mathrm{IC}_{25} > 100\%$ | | |
| The pH of the discharge shall not be less than 7.0 s.u. or greater than 9.0 s.u. at any time. | | | |
| Dissolved Oxygen, mg/L: | April 1 – Sept 30<br>8.0 (1-day min.)<br>9.5 (7-day mean)<br>6.5 (30-day mean)<br>Oct 1 – March 31<br>4.0 (1-day min.)<br>5.0 (7-day mean)<br>6.5 (30-day mean) | | |

a/ See Definitions, Part 1.1., for definition of terms.

tr – total recoverable

The discharge from Outfall 002a shall be free from oil and grease attributable to wastewater, which causes a visible film or sheen upon the waters or any discoloration of the surface of adjoining shoreline or causes a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines or prevents classified uses of such waters.

1.3.7 Self-Monitoring Requirements - Outfall 002a. As a minimum, upon the effective date of this permit, the following constituents shall be monitored at the frequency and with the type of measurement indicated; samples or measurements shall be representative of the volume and nature of the monitored discharge. If no discharge occurs during the entire monitoring period, it shall be stated on the Discharge Monitoring Report Form (EPA No. 3320-1) that no discharge or overflow occurred.

| Effluent Characteristic | Frequency | Sample Type a/ |
|---|---|---|
| Total Flow, mgd b/ | Daily | Continuous, Recorder |
| Biochemical Oxygen Demand (5-day), mg/L | 2X/Week | Composite |
| Total Organic Carbon, mg/L | Monthly | Composite |
| Total Suspended Solids, mg/L | 2X/Week | Composite |
| Benzene, ug/L | Monthly | Grab |
| Ethyl benzene, ug/L | Monthly | Grab |
| Toluene, ug/L | Monthly | Grab |
| Phenol, ug/L | Monthly | Grab |
| Hydrogen Sulfide, ug/L | Weekly | Grab |
| Ammonia as N, mg/L | Weekly | Composite |
| Barium (tr), ug/L | Monthly | Composite |
| Aluminum (tr), ug/L | Monthly | Composite |
| Chromium (VI), ug/L | Monthly | Grab |
| Iron (tr), ug/L | Monthly | Composite |
| Manganese (tr), ug/L | Monthly | Composite |
| Mercury (Total), ug/L | Monthly | Composite |
| Nickel (tr), ug/L | Monthly | Composite |
| Selenium (tr), ug/L | Monthly | Composite |
| Chloride, mg/L | Monthly | Composite |
| Fluoride, mg/L | Monthly | Composite |

| Effluent Characteristic | Frequency | Sample Type a/ |
|---|---|---|
| Sulfate, mg/L | Monthly | Composite |
| Nitrite as N, mg/L | Monthly | Composite |
| Nitrate as N, mg/L | Monthly | Composite |
| Total Phosphorous as P, mg/L | Monthly | Composite |
| Whole Effluent Toxicity, acute | Quarterly | Grab |
| Whole Effluent Toxicity, chronic | Quarterly | Composite |
| pH (s.u.) | Daily | Grab or Continuous |
| Temperature, $^{o}$C | Daily | Grab |
| Oil and Grease, visual c/ | Daily | Grab |
| Oil and Grease, mg/L | Weekly | Grab |
| Dissolved Oxygen, mg/L | Daily | Grab |

a/ See Definitions, Part 1.1., for definition of terms.

b/ Flow measurements of effluent volume shall be made in such a manner that the permittee can affirmatively demonstrate that representative values are being obtained. The average flow rate (in million gallons per day) during the reporting period and the maximum flow rate observed (in mgd) shall be reported.

c/ A daily visual observation is required. If a visible sheen is detected, a grab sample shall be taken and analyzed immediately. The concentration of oil and grease shall not exceed 15 mg/L in any sample.

tr - Total recoverable

1.3.8 Effluent Limitations - Outfall 003. Effective immediately and lasting through the life of this permit, the quality of effluent discharged from the Sanitary Wastewater Treatment Plant by the facility shall, as a minimum, meet the limitations as set forth below:

| Effluent Characteristic | Effluent Limitation | | |
|---|---|---|---|
| | 30-Day Average a/ | 7-Day Average a/ | Daily Maximum a/ |
| Flow, MGD | NA | NA | 0.08 |
| Biochemical Oxygen Demand (5-day), mg/L | 30 | 45 | N/A |
| Total Suspended Solids, mg/L | 30 | 45 | N/A |
| Ammonia as N, mg/L | 1.1 | N/A | 3.2 |
| Total Residual Chlorine, ug/L | 11 | N/A | 19 |
| Iron (tr), ug/L | 300 | N/A | N/A |
| Manganese (tr), ug/L | 50 | N/A | N/A |
| Selenium (tr), ug/L | 5 | N/A | 20 |
| Sulfate, mg/L | 750 | N/A | N/A |
| Nitrite as N, mg/L | 1.0 | N/A | N/A |
| Nitrate as N, mg/L | 10 | N/A | N/A |
| Dissolved Oxygen, mg/L: | April 1 – Sept 30<br>8.0 (1-day min.)<br>9.5 (7-day mean)<br>6.5 (30-day mean)<br>Oct 1 – March 31<br>4.0 (1-day min.)<br>5.0 (7-day mean)<br>6.5 (30-day mean) | | |
| The pH of the discharge shall not be less than 7.0 s.u.or greater than 9.0 s.u.at any time. | | | |

a/ See Definitions, Part 1.1., for definition of terms.

tr – total recoverable

The discharge from Outfall 003 shall be free from floating debris, oil, scum, and other floating materials attributable to municipal, industrial, or other discharges or agricultural practices in sufficient amounts to be unsightly or deleterious.

Percentage Removal Requirements (TSS and $BOD_5$ Limitation): In addition to the concentration limits for total suspended solids and $BOD_5$ indicated above, the arithmetic mean of the concentration for effluent samples collected in a 30-day consecutive period shall not exceed 15 percent of the arithmetic mean of the concentration for influent samples collected at approximately the same times during the same period (85 percent removal).

1.3.9 Self-Monitoring Requirements - Outfall 003. As a minimum, upon the effective date of this permit, the following constituents shall be monitored at the frequency and with the type of measurement indicated; samples or measurements shall be representative of the volume and nature of the monitored discharge. If no discharge occurs during the entire monitoring period, it shall be stated on the Discharge Monitoring Report Form (EPA No. 3320-1) that no discharge or overflow occurred.

| Effluent Characteristic | Frequency | Sample Type a/ |
|---|---|---|
| Total Flow, mgd b/ | Daily | Continuous, Recorder |
| Biochemical Oxygen Demand (5-day), mg/L c/ | Monthly | Composite |
| Total Suspended Solids, mg/L c/ | Monthly | Composite |
| Ammonia as N, mg/L | Quarterly | Composite |
| Total Residual Chlorine, ug/L | Daily | Grab |
| Selenium (tr), ug/L | Quarterly | Composite |
| Manganese (tr), ug/L | Quarterly | Composite |
| Iron (tr), ug/L | Quarterly | Composite |
| Sulfate, mg/L | Quarterly | Composite |
| Nitrite as N, mg/L | Quarterly | Composite |
| Nitrate as N, mg/L | Quarterly | Composite |
| Total Phosphorous as P, mg/L | Quarterly | Composite |
| pH (s.u.) | Daily | Grab or Continuous |
| Dissolved Oxygen, mg/L | Daily | Grab |

a/ See Definitions, Part 1.1., for definition of terms.

b/ Flow measurements of effluent volume shall be made in such a manner that the permittee can affirmatively demonstrate that representative values are being obtained. The average flow rate (in million gallons per day) during the reporting period and the maximum flow rate observed (in mgd) shall be reported.

c/ In addition to monitoring the final discharge, influent samples shall be taken and analyzed for this constituent at the same frequency as required for this constituent in the discharge.

tr – total recoverable

### 1.3.10 Whole Effluent Toxicity Testing - Chronic Toxicity

Starting in the first full quarter after the effective date of this permit, the permittee shall, at least once each quarter, conduct chronic short term toxicity tests on the final effluent from Outfalls 002 and 002a. There shall not be chronic toxicity in 100 percent concentration of the final effluent.

The monitoring frequency shall be quarterly. Quarterly samples shall be collected on a two day progression; i.e., if the first quarterly sample is on a Monday, during the next quarter, the sampling shall begin on a Wednesday. If chronic toxicity is detected, an additional test shall be conducted within two weeks of the date of when the permittee learned of the test failure. The need for any additional samples shall be determined by the permit issuing authority.

The chronic toxicity tests shall be conducted in accordance with the procedures set out in the latest revision of "Short Term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms", EPA 821-R-02-013, Rev. Oct. 2002. Test species shall consist of *Ceriodaphnia dubia* and *Pimephales promelas*. A multi dilution test consisting of five concentrations and a control is required. If test acceptability criteria is not met for control survival, growth, or reproduction, the test shall be considered invalid. Chronic toxicity occurs when, during a chronic toxicity test, the 25% inhibition concentration ($IC_{25}$) calculated on the basis of test organism survival and growth or survival and reproduction, is less than or equal to 100% effluent concentration. The tests shall be done using effluent concentrations of 100%, 50%, 25%, 12.5%, 6.25%, and 0% (control).

Test results shall be reported along with the Discharge Monitoring Report (DMR) submitted for the end of the calendar period during which the whole effluent test was run (e.g. results for the calendar quarter ending March 31 shall be reported with the DMR due April 28, with the remaining reports submitted with DMRs due each July 28, October 28, and January 28). Monthly test results shall be reported along with the DMR submitted for that month. The format for the report shall be consistent with the latest revision of the "Region VIII Guidance for Chronic Whole Effluent Reporting" (Appendix C of Region VIII NPDES Whole Effluent Toxics Control Program, August 1997), and shall include all the physical and chemical testing as specified.

If the results for one year (four consecutive quarters) of whole effluent testing indicate no chronic toxicity, the permittee may request the permit issuing authority to allow the permittee to reduce testing frequency, and/or reduce testing to one species on an alternating basis, and/or modify testing to the acute test program. The permit issuing authority may approve, partially approve, or deny the request based on results and other available information. If approval is given, the modification will take place without a public notice.

### 1.3.11 Whole Effluent Toxicity Testing - Acute Toxicity

Starting in the first full quarter after the effective date of this permit, the permittee shall conduct quarterly acute static replacement toxicity tests on an effluent sample of the discharge from Outfalls 002 and 002a. The effluent shall be obtained from the sample required for the chronic toxicity tests as noted in Part 1.3.10. of this permit.

The replacement static toxicity tests shall be conducted in accordance with the procedures set out in the latest revision of “Methods for Measuring the Acute Toxicity of Effluents to Freshwater and Marine Organisms”, EPA 821-R-02-012 (Rev Oct. 2002). The permittee shall conduct an acute 48-hour static toxicity test using *Ceriodaphnia dubia* an acute 96-hour static toxicity test using *Pimephales promelas*. The tests shall be done using effluent concentrations of 100%, 75%, 50%, 25%, 12.5%, 6.25% and 0% (control).

Acute toxicity occurs when 50 percent or more mortality is observed for either species at any effluent concentration. If more than 10% control mortality occurs, the test shall be repeated until satisfactory control survival is achieved. If acute toxicity occurs, an additional test shall be conducted within two weeks of the date of when the permittee learned of the test failure. If only one species fails, retesting may be limited to this species. Should toxicity occur in the second test, testing shall occur once a month until further notified by the permit issuing authority.

Quarterly test results shall be reported along with the Discharge Monitoring Report (DMR) submitted for the end of the reporting calendar quarter (e.g., whole effluent results for the calendar quarter ending March 31 shall be reported with the DMR due April 28, with the remaining reports submitted with DMRs due each July 28, October 28, and January 28). Monthly test results shall be reported along with the DMR submitted for that month. The format for the report shall be consistent with the latest revision of the "Region VIII Guidance for Acute Whole Effluent Reporting" (Appendix C of Region VIII NPDES Whole Effluent Toxics Control Program, August 1997), and shall include all chemical and physical data as specified.

If the results for four consecutive quarters of testing indicate no acute toxicity, the permittee may request the permit issuing authority to allow a reduction to quarterly acute toxicity testing on only one species on an alternating basis. The permit issuing authority may approve or deny the request based on the results and other available information without an additional public notice. If the request is approved, the test procedures are to be the same as specified above for the test species. If approval is given, the modification will take place without a public notice.

### 1.3.12 Toxicity Identification Evaluation (TIE)/Toxicity Reduction Evaluation (TRE)

Should acute toxicity and/or chronic toxicity be detected in two (2) consecutive tests of the permittee's discharge, a TIE-TRE shall be undertaken by the permittee to establish the cause of the toxicity, locate the source(s) of the toxicity, and develop control of or treatment of the toxicity. Failure to initiate, or conduct an adequate TIE-TRE, or delays in the conduct of such tests, shall not be considered a justification for non-compliance with the whole effluent toxicity limitations contained in Part 1.3.3 and 1.3.6 of this permit. A TRE plan needs to be submitted to the permitting authority within 45 days after confirmation of the continuance of the effluent toxicity.

## 1.4 Stormwater Requirements

### 1.4.1 Storm Water Pollution Prevention Plans

The permittee shall continue to implement all existing best management practices (BMP) that may affect the quality of storm water runoff unless those BMPs are modified or replaced by the storm water pollution prevention plan required below. The permittee shall develop a storm water pollution prevention plan for the MHA Nation Clean Fuels Refinery site. The storm water pollution prevention plan shall be prepared in accordance with good engineering practices and in accordance with the factors outlined in 40 CFR 125.3(d)(2) or (3) as appropriate. The plan shall identify potential sources of pollution which may reasonably be expected to affect the quality of storm water discharges associated with industrial activity from the facility. In addition, the plan shall describe and ensure the implementation of practices which are to be used to reduce the pollutants in storm water discharges associated with industrial activity at the facility and to assure compliance with the terms and conditions of this permit. The facility must implement the provisions of the storm water pollution prevention plan required under this Part as a condition of this permit.

1.4.1.1 Deadlines for Plan Preparation and Compliance.

The plan for a storm water discharge:

1.4.1.2 Shall be prepared and submitted to the permit issuing authority for review for approval no later than six months after the effective date of this permit (and updated at a minimum of every two years or more frequently if deemed appropriate). The plan shall be submitted to the U.S. EPA Region 8 Stormwater Program at the following address:

EPA Region 8 Stormwater Program Coordinator
Mailcode: 8P-W-WW
1595 Wynkoop Street
Denver, CO 80202-1129

A copy of the plan shall also be submitted to the Three Affiliated Tribes Environmental Department at the following address:

Environmental Division
Three Affiliated Tribes
204 West Main
New Town, ND 58763-9404

1.4.1.3 Shall provide for implementation and compliance with the terms of the plan on or before six months after the plan is approved by the U.S. EPA Region 8 Stormwater Program.

1.4.1.5 Upon a showing of good cause, the permit issuing authority may establish a later date in writing for preparation, implementation, and compliance with the plan.

1.4.1.6 Except as provided in Part 1.4.1.3 above, the plan shall be implemented in accordance with the approval of the permit issuing authority no later than one year after the effective date of this permit unless the permit issuing authority approves a later date.

1.4.1.7 The permit issuing authority may notify the permittee at any time that the plan does not meet one or more of the minimum requirements of this Part. Such notification shall identify those provisions of the permit which are not being met by the plan, and identify which provisions of the plan require modifications in order to meet the minimum requirements of this Part. Within 30 days of such notification from the permit issuing authority, (or as otherwise provided by the permit issuing authority), the permittee shall make the required changes to the plan and shall submit to the permit issuing authority a written certification that the requested changes have been made.

1.4.1.8 Keeping Plans Current - The permittee shall amend the plan whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to the waters of the United States or if the storm water pollution prevention plan proves to be ineffective in eliminating or significantly minimizing pollutants from sources identified under Part 1.4.1.9.2 (description of potential pollutant sources) of this permit, or in otherwise achieving the general objectives of controlling pollutants in storm water discharges associated with industrial activity. Amendments to the plan shall be submitted for review to the permit issuing authority in the same manner as Part 1.4.1.2(above).

1.4.1.9 Contents of Plan - The plan shall include, at a minimum, the following:

1.4.1.9.1 Pollution Prevention Team - The plan shall identify a specific individual or individuals within the facility organization as members of a storm water Pollution Prevention Team that are responsible for developing the storm water pollution prevention plan and assisting the facility or plant manager in its implementation, maintenance, and revision. The plan shall clearly identify the responsibilities of each team member. The activities and responsibilities of the team shall address all aspects of the facility's storm water pollution prevention plan.

1.4.1.9.2 Description of Potential Pollutant Sources - The plan shall provide a description of potential sources which may reasonably be expected to add significant amounts of pollutants to storm water discharges or which may result in the discharge of pollutants during dry weather from separate storm sewers draining the facility. Each plan shall identify all activities and significant materials which may potentially be significant pollutant sources. The plan shall include, at a minimum:

1.4.1.9.3 Inventory of Exposed Materials - An inventory of the types of materials handled at the site that potentially may be exposed to precipitation. Such inventory shall include a narrative description of significant materials that have been handled, treated, stored or disposed in a manner to allow exposure to storm water between the time of 3 years prior to the date of the issuance of this permit and the present; method and location of on-site storage or disposal; materials management practices employed to minimize contact of materials with storm water runoff between the time of 3 years prior to the date of the issuance of this permit and the present; the location and a description of existing structural and non-structural control measures to reduce pollutants in storm water runoff; and a description of any treatment the storm water receives. Note: The limitation of three (3) years prior to the date of the issuance of this permit does not apply to radioactive materials.

1.4.1.9.4 Drainage A site map indicating an outline of the portions of the drainage area of each storm water outfall that are within the facility boundaries, each existing structural control measure to reduce pollutants in storm water runoff, surface water bodies, locations where significant materials are exposed to precipitation, locations where major spills or leaks identified under Part 1.4.1.9.6 (Spills and Leaks) of this permit have occurred, and the locations of the following activities where such activities are exposed to precipitation: fueling stations, vehicle and equipment maintenance and/or cleaning areas, loading/unloading areas, locations used for the treatment, storage or disposal of wastes, liquid storage tanks, processing areas and storage areas.

1.4.1.9.5 For each area of the facility that generates storm water discharges associated with industrial activity with a reasonable potential for containing pollutants, a prediction of the direction of flow, and an identification of the types of pollutants which are likely to be present in storm water discharges associated with industrial activity. Factors to consider include the toxicity of chemical; quantity of chemicals used, produced or discharged; the likelihood of contact with storm water; and history of significant leaks or spills of toxic or hazardous pollutants. Flows with a significant potential for causing erosion shall be identified.

1.4.1.9.6 <u>Spills and Leaks:</u> A list of significant spills and significant leaks of toxic, hazardous or radioactive pollutants that have occurred at areas that are exposed to precipitation or that otherwise drain to a storm water conveyance at the facility after the date of 3 years prior to the effective date of this permit. Such list shall be updated as appropriate during the term of the permit. Note: The limitation of three (3) years prior to the date of the issuance of this permit does not apply to radioactive materials:

1.4.1.9.7 <u>Sampling Data</u>: A summary of existing discharge sampling data describing pollutants in storm water discharges from the facility, including a summary of sampling data collected during the term of this permit.

1.4.1.9.8 <u>Risk Identification and Summary of Potential Pollutant Sources:</u> A narrative description of the potential pollutant sources from the following activities: loading and unloading operations; outdoor storage activities; outdoor manufacturing or processing activities; significant dust or particulate generating processes; and on-site waste disposal practices. The description shall specifically list any significant potential source of pollutants at the site and for each potential source, any pollutant or pollutant parameter (e.g., radioactive materials, acids, solvents, etc.) of concern shall be identified.

1.4.1.9.9 <u>Spills and Leaks:</u> The permittee shall develop a description of storm water management controls appropriate for the MHA Nation Clean Fuels Refinery Site, and implement such controls. The appropriateness and priorities of controls in a plan shall reflect identified potential sources of pollutants at the facility. The description of storm water management controls shall address the following minimum components, including a schedule for implementing such controls:

1.4.1.9.10 <u>Good Housekeeping:</u> Good housekeeping requires the maintenance of areas which may contribute pollutants to storm waters discharges in a clean, orderly manner.

1.4.1.9.11 <u>Preventive Maintenance:</u> A preventive maintenance program shall involve timely inspection and maintenance of storm water management devices (e.g., cleaning oil/water separators, catch basins) as well as inspecting and testing facility equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to surface waters, and ensuring appropriate maintenance of such equipment and systems.

1.4.1.9.12 <u>Spill Prevention and Response Procedures:</u> Areas where potential spills which can contribute pollutants to storm water discharges can occur, and their accompanying drainage points shall be identified clearly in the storm water pollution prevention plan. Where appropriate, specifying material handling procedures, storage requirements, and use of equipment such as diversion valves in the plan should be considered. Procedures for cleaning up spills shall be identified in the plan and made available to the appropriate personnel. The necessary equipment to implement a clean up should be available to personnel.

1.4.1.9.13 Inspections: In addition to or as part of the comprehensive site evaluation required under Part 1.4.1.9.18 of this permit, qualified facility personnel shall be identified to inspect designated equipment and areas of the facility at appropriate intervals of no less than one time each year as specified in the plan. A set of tracking or follow-up procedures shall be used to ensure that appropriate actions are taken in response to the inspections. Records of inspections shall be maintained.

1.4.1.9.14 Employee Training: Employee training programs shall inform personnel responsible for implementing activities identified in the storm water pollution prevention plan or otherwise responsible for storm water management at all levels of responsibility of the components and goals of the storm water pollution prevention plan. Training should address topics such as spill response, good housekeeping and material management practices. The pollution prevention plan shall identify periodic dates for such training.

1.4.1.9.15 Record keeping and Internal Reporting Procedures: A description of incidents (such as spills, or other discharges), along with other information describing the quality and quantity of storm water discharges shall be included in the plan required under this part. Inspections and maintenance activities shall be documented and records of such activities shall be incorporated into the plan.

1.4.1.9.16 Sediment and Erosion Control: The plan shall identify areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion, and identify structural, vegetative, and/or stabilization measures to be used to limit erosion.

1.4.1.9.17 Management of Runoff: The plan shall contain a narrative consideration of the appropriateness of traditional storm water management practices (practices other than those which control the generation or source(s) of pollutants) used to divert, infiltrate, reuse, or otherwise manage storm water runoff in a manner that reduces pollutants in storm water discharges from the site. The plan shall provide the measures that the permittees determine to be reasonable and appropriate and these measures shall be implemented and maintained. The potential of various sources at the MHA Nation Clean Fuels Refinery Site to contribute pollutants to storm water discharges associated with industrial activity (see Part 1.4.1.9.2 shall be considered when determining reasonable and appropriate measures. Appropriate measures may include: vegetative swales and practices, reuse of collected storm water (such as for a process or as an irrigation source), inlet controls (such as oil/water separators), snow management activities, infiltration devices, and wet detention/retention devices.

1.4.1.9.18 Comprehensive Site Compliance Evaluation: Qualified personnel shall conduct site compliance evaluations at appropriate intervals specified in the plan, but, in no case less than once a year. Such evaluations shall provide:

1.4.1.9.19 Areas contributing to a storm water discharge associated with industrial activity shall be visually inspected for evidence of, or the potential for, pollutants entering the drainage system. Measures to reduce pollutant loadings shall be evaluated to determine whether they are adequate and properly implemented in accordance with the terms of the permit or whether additional control measures are needed. Structural storm water management measures, sediment and erosion control measures, and other structural pollution prevention measures identified in the plan shall be observed to ensure that they are operating correctly. A visual inspection of equipment needed to implement the plan, such as spill response equipment, shall be made.

1.4.1.9.20 The analytical results from the storm water monitoring required under Parts 1.3.2 and 1.3.7 shall be evaluated with the objective of determining whether or not the storm water discharges from the plant site are causing or contributing to water quality problems in the East Fork of Shell Creek. To the extent that data are available, the evaluation shall include data for the previous 12 months. Earlier data may be included to give an indication of trends. The data should also be evaluated in terms of giving an indication of whether or not the plan is effective in minimizing the discharge of pollutants or whether additional control measures are needed.

1.4.1.9.21 Based on the results of the visual inspection (Part 1.4.1.9.13 above) and the evaluation of the monitoring data (Part 1.4.1.9.20 above), the plan shall be revised as appropriate. The revision shall include, as appropriate, the description of potential pollutant sources identified in the plan and pollution prevention measures and controls identified in the plan. The revision shall be completed within four (4) weeks of such inspection and shall provide for implementation of any changes to the plan in a timely manner, but in no case more than 12 weeks after the inspection unless additional time has been approved by the permit issuing authority.

1.4.1.9.22 A report summarizing the scope of the inspection, personnel making the inspection, the date(s) of the inspection, major observations relating to the implementation of the storm water pollution prevention plan, and actions taken in accordance with Part 1.4.1.9.20 (above) of the permit shall be made and retained as part of the storm water pollution prevention plan for at least one year after coverage under this permit terminates. The report shall identify any incidents of non-compliance. Where a report does not identify any incidents of non-compliance, the report shall contain a certification that the facility is in compliance with the storm water pollution prevention plan and this permit.

1.4.1.9.23 Consistency with other plans: Storm water pollution prevention plans may reflect requirements for spill prevention control and countermeasure (SPCC) plans developed for the MHA Nation Clean Fuels Refinery under section 311 of the CWA; best management practices plans; or other environmental control plans prepared for the MHA Nation Clean Fuels Refinery. Provided such requirement(s) are incorporated into the storm water pollution prevention plan, or referenced by specific document title, volume, heading, and page number(s). All referenced documents must be available for review and inspection upon request.

1.4.2 Additional requirements for storm water discharges associated with industrial activity from facilities subject to EPCRA Section 313 requirements. In addition to the requirements of Part 1.4.1.9 through 1.4.1.9.22 of this permit and other applicable conditions of this permit, storm water pollution prevention plans for facilities subject to reporting requirements under EPCRA Section 313 for chemicals which are classified as 'Section 313 water priority chemicals' in accordance with the definition in PART I.A of this permit, shall describe and ensure the implementation of practices which are necessary to provide for conformance with the following guidelines:

1.4.2.1 In areas where Section 313 water priority chemicals are stored, processed or otherwise handled, appropriate containment, drainage control and/or diversionary structures shall be provided. At a minimum, one of the following preventive systems or its equivalent shall be used:

1.4.2.2 Curbing, culverting, gutters, sewers or other forms of drainage control to prevent or minimize the potential for storm water run-off to come into contact with significant sources of pollutants; or,

1.4.2.3 Roofs, covers or other forms of appropriate protection to prevent storage piles from exposure to storm water, and wind.

1.4.2.4 In addition to the minimum standards listed under Part 1.4.1.10.1 of this permit, the storm water pollution prevention plan shall include a complete discussion of measures taken to conform with the following applicable guidelines, other effective storm water pollution prevention procedures, and applicable Tribal rules, regulations and guidelines:

1.4.2.5 Liquid storage areas where storm water comes into contact with any equipment, tank, container, or other vessel used for Section 313 water priority chemicals.

1.4.2.5.1 No tank or container shall be used for the storage of a Section 313 water priority chemical unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature, etc.

1.4.2.5.2 Liquid storage areas for Section 313 water priority chemicals shall be operated to minimize discharges of Section 313 chemicals. Appropriate measures to minimize discharges of Section 313 chemicals may include secondary containment provided for at least the entire contents of the largest single tank plus sufficient freeboard to allow for precipitation, a comprehensive spill contingency and integrity testing plan, and/or other equivalent measures.

1.4.2.6 Material storage areas for Section 313 water priority chemicals other than liquids. Material storage areas for Section 313 water priority chemicals other than liquids which are subject to runoff, leaching, or wind shall incorporate drainage or other control features which will minimize the discharge of Section 313 water priority chemicals by reducing storm water contact with Section 313 water priority chemicals.

1.4.2.7 Truck and rail car loading and unloading areas for liquid Section 313 water priority chemicals. Truck and rail car loading and unloading areas for liquid Section 313 water priority chemicals shall be operated to minimize discharges of Section 313 water priority chemicals. Protection such as overhangs or door skirts to enclose trailer ends at truck loading/unloading docks shall be provided as appropriate. Appropriate measures to minimize discharges of Section 313 chemicals may include: the placement and maintenance of drip pans (including the proper disposal of materials collected in the drip pans) where spillage may occur (such as hose connections, hose reels and filler nozzles) for use when making and breaking hose connections; a comprehensive spill contingency and integrity testing plan; and/or other equivalent measures.

1.4.2.8 Areas where Section 313 water priority chemicals are transferred, processed or otherwise handled. Processing equipment and materials handling equipment shall be operated so as to minimize discharges of Section 313 water priority chemicals. Materials used in piping and equipment shall be compatible with the substances handled. Drainage from process and materials handling areas shall minimize storm water contact with section 313 water priority chemicals. Additional protection such as covers or guards to prevent exposure to wind, spraying or releases from pressure relief vents from causing a discharge of Section 313 water priority chemicals to the drainage system shall be provided as appropriate. Visual inspections or leak tests shall be provided for overhead piping conveying Section 313 water priority chemicals without secondary containment.

1.4.2.9 Discharges from areas covered by paragraphs 1.4.1.10.2.1 through 1.4.1.10.2.6

1.4.2.9.1 Drainage from areas covered by paragraphs 1.4.1.10.2.1 through 1.4.1.10.2.6 of this Part should be restrained by valves or other positive means to prevent the discharge of a spill or other excessive leakage of Section 313 water priority chemicals. Where containment units are employed, such units may be emptied by pumps or ejectors; however, these shall be manually activated.

1.4.2.9.2 Flapper-type drain valves shall not be used to drain containment areas. Valves used for the drainage of containment areas should, as far as is practical, be of hand operated, open-and-closed design.

1.4.2.9.3 If facility drainage is not engineered as above, the final discharge of all in-facility storm sewers shall be equipped to be equivalent with a diversion system that could, in the event of an uncontrolled spill of Section 313 water priority chemicals, return the spilled material to the facility.

1.4.2.9.4 Records shall be kept of the frequency and estimated volume (in gallons) of discharges from containment areas.

1.4.2.9.5 Facility site runoff other than from areas covered by 1.4.1.10.2.1 through 1.4.1.10.2.6. Other areas of the facility (those not addressed in paragraphs 1.4.1.10.2.1 through 1.4.1.10.2.6, from which runoff which may contain Section 313 water priority chemicals or spills of Section 313 water priority chemicals could cause a discharge shall incorporate the necessary drainage or other control features to prevent discharge of spilled or improperly disposed material and ensure the mitigation of pollutants in runoff or leachate.

1.4.2.9.6 Preventive maintenance and housekeeping. All areas of the facility shall be inspected at specific intervals identified in the plan for leaks or conditions that could lead to discharges of Section 313 water priority chemicals or direct contact of storm water with raw materials, intermediate materials, waste materials or products. In particular, facility piping, pumps, storage tanks and bins, pressure vessels, process and material handling equipment, and material bulk storage areas shall be examined for any conditions or failures which could cause a discharge. Inspection shall include examination for leaks, wind blowing, corrosion, support or foundation failure, or other forms of deterioration or noncontainment. Inspection intervals shall be specified in the plan and shall be based on design and operational experience. Different areas may require different inspection intervals. Where a leak or other condition is discovered which may result in significant releases of Section 313 water priority chemicals to waters of the United States, action to stop the leak or otherwise prevent the significant release of Section 313 water priority chemicals to waters of the United States shall be immediately taken or the unit or process shut down until such action can be taken.

1.4.2.9.7 When a leak or noncontainment of a Section 313 water priority chemical has occurred, contaminated soil, debris, or other material must be promptly removed and disposed in accordance with Federal, Tribal, and local requirements and as described in the plan.

1.4.2.9.8 Facility security. Facilities shall have the necessary security systems to prevent accidental or intentional entry which could cause a discharge. Security systems described in the plan shall address fencing, lighting, vehicular traffic control, and securing of equipment and buildings.

1.4.2.9.9 Training. Facility employees and contractor personnel that work in areas where Section 313 water priority chemicals are use or stored shall be trained in and informed of preventive measures at the facility. Employee training shall be conducted at intervals specified in the plan, but not less than once per year, in matters of pollution control laws and regulations, and in the storm water pollution prevention plan and the particular features of the facility and its operation which are designed to minimize discharges of Section 313 water priority chemicals. The plan shall designate a person who is accountable for spill prevention at the facility and who will set up the necessary spill emergency procedures and reporting requirements so that spills and emergency releases of Section 313 water priority chemicals can be isolated and contained before a discharge of a Section 313 water priority chemical can occur. Contractor or temporary personnel shall be informed of facility operation and design features in order to prevent discharges or spills from occurring.

1.4.2.9.10 Engineering Certification. - The storm water pollution prevention plan for a facility subject to EPCRA Section 313 requirements for chemicals which are classified as 'Section 313 water priority chemicals' shall be reviewed by a Registered Professional Engineer and certified to by such Professional Engineer. A Registered Professional Engineer shall recertify the plan every 3 years thereafter or as soon as practicable after significant modification are made to the facility. By means of these certifications the engineer, having examined the facility and being familiar with the provisions of this Part, shall attest that the storm water pollution prevention plan has been prepared in accordance with good engineering practices. Such certifications shall in no way relieve the owner or operator of a facility covered by the plan of their duty to prepare and fully implement such plan.

1.4.3 Additional Requirements for Salt Storage.

1.4.3.1 Storage piles of salt used for deicing or other commercial or industrial purposes and which generate a storm water discharge associated with industrial activity which is discharged to a water of the United States shall be enclosed or covered to prevent exposure to precipitation, except for exposure resulting from adding or removing materials from the pile.

1.4.3.2 Dischargers shall demonstrate compliance with this provision as expeditiously as practicable, but in no event later than two years after the effective date of this permit. Piles do not need to be enclosed or covered where storm water from the pile is not discharged to waters of the United States.

## 2. MONITORING, RECORDING AND REPORTING REQUIREMENTS

2.1. Representative Sampling. Samples taken in compliance with the monitoring requirements established under Part 1. shall be collected from the effluent stream prior to discharge into the receiving waters. Samples and measurements shall be representative of the volume and nature of the monitored discharge. Sludge samples shall be collected at a location representative of the quality of sludge immediately prior to use-disposal practice.

2.2. Monitoring Procedures. Monitoring must be conducted according to test procedures approved under 40 CFR Part 136, unless other test procedures have been specified in this permit. Sludge monitoring procedures shall be those specified in 40 CFR 503, or as specified in the permit.

2.3. Penalties for Tampering. The Act provides that any person who knowingly falsifies, tampers with, or renders inaccurate, any monitoring device or method required to be maintained under this permit shall, upon conviction, be punished by a fine of not more than $10,000, or by imprisonment for not more than two years, or by both. Second conviction is punishable by a fine of not more than $20,000 per day of violation, or by imprisonment of not more than four years, or both.

2.4. Reporting of Monitoring Results. **The permittee is required to submit an annual report each calendar year from date of issuance of this permit. The annual report is to be postmarked no later than the 28th day of the month following the end of the calendar year, The report is to provide information on the status of the project, including current status and any planned additions and/or changes for the next calendar year.** Once construction commences the premittee is to report effluent monitoring results obtained during the previous **month** shall be summarized and reported on **one** Discharge Monitoring Report Form (EPA No. 3320-1), postmarked no later than the 28th day of the month following the completed reporting period. If no discharge occurs during the reporting period, "no discharge" shall be reported. Until further notice, sludge monitoring results may be reported in the testing laboratory's normal format (there is no EPA standard form at this time), but should be on letter size pages. Whole effluent toxicity (biomonitoring) results must be reported on the most recent version of EPA Region 8's Guidance For Whole Effluent Reporting. Legible copies of these, and all other reports required herein, shall be signed and certified in accordance with the Signatory Requirements (see Part 4.), and submitted to the Planning and Targeting Program, and the TAT Environmental Department at the following addresses:

original to: U.S. EPA, REGION 8
PLANNING AND TARGETING PROGRAM (8ENF-PT)
ATTENTION: PCS/ICIS COORDINATOR
1595 WYNKOOP STREET
DENVER, COLORADO 80202-1129

copy to: Environmental Division
Three Affiliated Tribes
204 West Main
New Town, ND 58763-9404

2.5. Additional Monitoring by the Permittee. If the permittee monitors any pollutant more frequently than required by this permit, using test procedures approved under 40 CFR 136, 40 CFR 503, or as specified in this permit, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR. Such increased frequency shall also be indicated.

2.6. Records Contents. Records of monitoring information shall include:

2.6.1. The date, exact place, and time of sampling or measurements;
2.6.2. The initials or name(s) of the individual(s) who performed the sampling or measurements;
2.6.3. The date(s) analyses were performed;
2.6.4. The time(s) analyses were initiated;
2.6.5. The initials or name(s) of individual(s) who performed the analyses;
2.6.6. References and written procedures, when available, for the analytical techniques or methods used; and,
2.6.7. The results of such analyses, including the bench sheets, instrument readouts, computer disks or tapes, etc., used to determine these results.

2.7. Retention of Records. The permittee shall retain records of all monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, copies of all reports required by this permit, and records of all data used to complete the application for this permit, for a period of at least three years from the date of the sample, measurement, report or application. Records of monitoring required by this permit related to sludge use and disposal activities must be kept at least five years (or longer as required by 40 CFR 503). This period may be extended by request of the Director at any time. Data collected on site, data used to prepare the DMR, copies of Discharge Monitoring Reports, and a copy of this NPDES permit must be maintained on site.

2.8. Twenty-four Hour Notice of Noncompliance Reporting.

2.8.1. The permittee shall report any noncompliance which may endanger health or the environment as soon as possible, but no later than twenty-four (24) hours from the time the permittee first became aware of the circumstances. The report shall be made to the EPA, Region 8, Preparedness, Assessment and Response Program at (303) 293-1788, and the TAT Environmental Division at (701) 627-5469.

2.8.2. The following occurrences of noncompliance shall be reported by telephone to the EPA, Region 8, Technical Enforcement Program at (303) 312-6720 (8:00 a.m. - 4:30 p.m. Mountain Time) or the appropriate EPA State Program Manager, NPDES Program, (toll-free 866-457-2690) (8:00 a.m. - 4:30 p.m. Mountain Time) and the TAT Environmental Division at (701) 627-5469 (8:00 a.m. - 4:30 p.m. Central Time) by the first workday following the day the permittee became aware of the circumstances:

2.8.2.1. Any unanticipated bypass which exceeds any effluent limitation in the permit (See Part 3.7., Bypass of Treatment Facilities.);

2.8.2.2. Any upset which exceeds any effluent limitation in the permit (See Part 3.8., Upset Conditions.); or,

2.8.2.3. Violation of a maximum daily discharge limitation for any of the pollutants listed in the permit to be reported within 24 hours.

2.8.3. A written submission shall also be provided to the USEPA, Office of Enforcement, Compliance and Environmental Justice, and to the TAT Environmental Division within five days of the time that the permittee becomes aware of the circumstances. The written submission shall contain:

2.8.3.1. A description of the noncompliance and its cause;

2.8.3.2. The period of noncompliance, including exact dates and times;

2.8.3.3. The estimated time noncompliance is expected to continue if it has not been corrected; and,

2.8.3.4. Steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance.

2.8.4. The Director may waive the written report on a case-by-case basis for an occurrence of noncompliance listed under Part 2.8.2. above, if the incident has been orally reported in accordance with the requirements of Part 2.8.2.

2.8.5. Reports shall be submitted to the addresses in Part 2.4., Reporting of Monitoring Results.

2.9. Other Noncompliance Reporting. Instances of noncompliance not required to be reported within 24 hours shall be reported at the time that monitoring reports for Part 2.4. are submitted. The reports shall contain the information listed in Part 2.8.3.

2.10. Inspection and Entry. The permittee shall allow the Regional Administrator, or authorized representative (including an authorized contractor acting as a representative of the Administrator) upon presentation of credentials and other documents as may be required by law, to:

2.10.1. Enter upon the permittee's premises where a regulated facility or activity is located or conducted, or where records must be kept under the conditions of this permit;

2.10.2. Have access to and copy, at reasonable times, any records that must be kept under the conditions of this permit;

2.10.3. Inspect at reasonable times any facilities, equipment (including monitoring and control equipment), practices, or operations regulated or required under this permit; and,

2.10.4. Sample or monitor at reasonable times, for the purpose of assuring permit compliance or as otherwise authorized by the Act, any substances or parameters at any location.

## 3. COMPLIANCE RESPONSIBILITIES

3.1. Duty to Comply. The permittee must comply with all conditions of this permit. Any failure to comply with the permit may constitute a violation of the Clean Water Act and may be grounds for enforcement action, including, but not limited to permit termination, revocation and reissuance, modification, or denial of a permit renewal application. The permittee shall give the director advance notice of any planned changes at the permitted facility that will change any discharge from the facility, or of any activity that may result in failure to comply with permit conditions.

3.2. Penalties for Violations of Permit Conditions. The Clean Water Act provides for specified civil and criminal monetary penalties for violations of its provisions. However, the Federal Civil Penalties Inflation Adjustment Act of 1990, as amended by the Debt Collection Improvement Act of 1996, requires EPA to adjust the civil monetary penalties for inflation on a periodic basis. EPA previously adjusted its civil monetary penalties on December 31, 1996 (61 Fed. Reg. 69359-69365), with technical corrections and additions published on March 20, 1997 (62 Fed. Reg. 13514-13517) and June 27, 1997 (62 Fed. Reg. 35037-35041). On February 13, 2004 (69 Fed. Reg. 7121-7127) EPA once again adjusted its civil monetary penalties. The civil and criminal penalties, as of March 15, 2004, for violations of the Act (including permit conditions) are given below:

3.2.1. Any person who violates section 301, 302, 306, 307, 308, 318 or 405 of the Act, or any permit condition or limitation implementing any such sections in a permit issued under section 402, or any requirement imposed in a pretreatment program approved under sections 402(a)(3) or 402(b)(8) of the Act, is subject to a civil penalty not to exceed $37,500 per day for each violation.

3.2.2. Any person who *negligently* violates sections 301, 302, 306, 307, 308, 318, or 405 of the Act, or any condition or limitation implementing any of such sections in a permit issued under section 402 of the Act, or any requirement imposed in a pretreatment program approved under section 402(a)(3) or 402(b)(8) of the Act, is subject to criminal penalties of $2,500 to $25,000 per day of violation, or imprisonment for not more than 1 year, or both. In the case of a second or subsequent conviction for a negligent violation, a person shall be subject to criminal penalties of not more than $50,000 per day of violation, or by imprisonment for not more than 2 years, or both.

3.2.3. Any person who *knowingly* violates sections 301, 302, 306, 307, 308, 318, or 405 of the Act, or any condition or limitation implementing any of such sections in a permit issued under section 402 of the Act, or any requirement imposed in a pretreatment program approved under section 402(a)(3) or 402(b)(8) of the Act, is subject to criminal penalties of $5,000 to $50,000 per day of violation, or imprisonment for not more than 3 years, or both. In the case of a second or subsequent conviction for a knowing violation, a person shall be subject to criminal penalties of not more than $100,000 per day of violation, or imprisonment for not more than 6 years, or both.

3.2.4. Any person who *knowingly* violates section 301, 302, 303, 306, 307, 308, 318 or 405 of the Act, or any permit condition or limitation implementing any of such sections in a permit issued under section 402 of the Act, and who knows at that time that he thereby places another person in imminent danger of death or serious bodily injury, shall, upon conviction, be subject to a fine of not more than $250,000 or imprisonment for not more than 15 years, or both. In the case of a second or subsequent conviction for a knowing endangerment violation, a person shall be subject to a fine of not more than $500,000 or by imprisonment for not more than 30 years, or both. An organization, as defined in section 309(c)(3)(B)(iii) of the CWA, shall, upon conviction of violating the imminent danger provision, be subject to a fine of not more than $1,000,000 and can be fined up to $2,000,000 for second or subsequent convictions.

3.2.5. Any person may be assessed an administrative penalty by the Administrator for violating section 301, 302, 306, 307, 308, 318 or 405 of this Act, or any permit condition or limitation implementing any of such sections in a permit issued under section 402 of this Act. Where an administrative enforcement action is brought for a Class I civil penalty, the assessed penalty may not exceed $16,000 per violation, with a maximum amount not to exceed $37,500. Where an administrative enforcement action is brought for a Class II civil penalty, the assessed penalty may not exceed $16,000 per day for each day during which the violation continues, with the maximum amount not to exceed $177,500.

3.3. Need to Halt or Reduce Activity not a Defense. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

3.4. Duty to Mitigate. The permittee shall take all reasonable steps to minimize or prevent any discharge or sludge use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment.

3.5. Proper Operation and Maintenance. The permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the permittee to achieve compliance with the conditions of this permit. Proper operation and maintenance also includes adequate laboratory controls and appropriate quality assurance procedures.

This provision requires the operation of back-up or auxiliary facilities or similar systems which are installed by a permittee only when the operation is necessary to achieve compliance with the conditions of the permit. However, the permittee shall operate, as a minimum, one complete set of each main line unit treatment process whether or not this process is needed to achieve permit effluent compliance.

3.5.1 The permittee shall, as soon as reasonable and practicable, but no later than six (6) months after the effective date of this permit, do the following as part of the operation and maintenance program for the wastewater treatment facility:

3.5.1.1. Have a current O & M Manual(s) that describes the proper operational procedures and maintenance requirements of the wastewater treatment facility;

3.5.1.2. Have the O & M Manual(s) readily available to the operator of the wastewater treatment facility and require that the operator become familiar with the manual(s) and any updates;

3.5.1.2. Have a schedule(s) for routine operation and maintenance activities at the wastewater treatment facility; and,

3.5.1.3. Require the operator to perform the routine operation and maintenance requirements in accordance with the schedule(s).

3.5.1.4. <u>Deadlines for O&M Manual(s) Preparation</u>.

The O&M Manual(s)

3.5.1.4.1 Shall be prepared and submitted to the permit issuing authority for review and approval no later than six months after the effective date of this permit (and updated at a minimum of every two years or more frequently if deemed appropriate). The plan shall be submitted to the U.S. EPA Region 8 NPDES Permits Unit at the following address:

EPA Region 8 Wastewater Unit
Mailcode: 8P-W-WW
1595 Wynkoop Street
Denver, CO 80202-1129

A copy of the plan shall also be submitted to the Three Affiliated Tribes Environmental Department at the following address:

Environmental Division
Three Affiliated Tribes
204 West Main
New Town, ND 58763-9404

3.5.2. The permittee shall maintain a daily log in a **bound notebook(s)** containing a summary record of all operation and maintenance activities at the wastewater treatment facility. At a minimum, the notebook shall include the following information:

3.5.2.1. Date and time;
3.5.2.2 Name and title of person(s) making the log entry;
3.5.2.3. Name of the persons(s) performing the activity;
3.5.2.4. A brief description of the activity; and,
3.5.2.5. Other information, as appropriate.

The permittee shall maintain the notebook in accordance with proper record-keeping procedures and shall make the log available for inspection, upon request, by authorized representatives of the U.S. Environmental Protection Agency or the TAT Environmental Division.

3.6. Removed Substances. Collected screenings, grit, solids, sludge, or other pollutants removed in the course of treatment shall be buried or disposed in a manner consistent with all applicable federal and tribal regulations (i.e., 40 CFR 257, 40 CFR 258, 40 CFR 503, 40 CFR 268 and in a manner so as to prevent any pollutant from entering any waters of the United States or creating a health hazard. **In addition, the use and/or disposal of sewage sludge shall be done under the authorization of an NPDES permit issued for the use and/or disposal of sewage sludge by the appropriate NPDES permitting authority for sewage sludge.** Sludge/digester supernatant and filter backwash shall not be directly blended with or enter either the final plant discharge and/or waters of the United States.

3.7. Bypass of Treatment Facilities.

3.7.1. Bypass not exceeding limitations. The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of Parts 3.7.2. and 3.7.3.

3.7.2. Notice:

3.7.2.1. Anticipated bypass. If the permittee knows in advance of the need for a bypass, it shall submit prior notice, if possible at least 10 days before the date of the bypass to the USEPA, Technical Enforcement Program, and the TAT Environmental Division.

3.7.2.2. Unanticipated bypass. The permittee shall submit notice of an unanticipated bypass as required under Part 2.8., Twenty-four Hour Noncompliance Reporting, to the USEPA, Technical Enforcement Program, and the TAT Environmental Division.

3.7.3. Prohibition of bypass.

3.7.3.1. Bypass is prohibited and the Director may take enforcement action against a permittee for a bypass, unless:

3.7.3.1.1. The bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

3.7.3.1.2. There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgement to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and,

3.7.3.1.3. The permittee submitted notices as required under Part 3.7.2.

3.7.3.2. The Director may approve an anticipated bypass, after considering its adverse effects, if the Director determines that it will meet the three conditions listed above in Part 3.7.3.1.

3.8. Upset Conditions

3.8.1. Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of Part 3.8.2. are met. No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review (i.e., Permittees will have the opportunity for a judicial determination on any claim of upset only in an enforcement action brought for noncompliance with technology-based permit effluent limitations).

3.8.2. Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

3.8.2.1. An upset occurred and that the permittee can identify the cause(s) of the upset;
3.8.2.2. The permitted facility was at the time being properly operated;
3.8.2.3. The permittee submitted notice of the upset as required under Part 2.8., Twenty-four Hour Notice of Noncompliance Reporting; and,
3.8.2.4. The permittee complied with any remedial measures required under Part 3.4., Duty to Mitigate.

3.8.3. Burden of proof. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.

3.9. Toxic Pollutants. The permittee shall comply with effluent standards or prohibitions established under Section 307 (a) of the Act for toxic pollutants within the time provided in the regulations that establish those standards or prohibitions, even if the permit has not yet been modified to incorporate the requirement.

3.10. Changes in Discharge of Toxic Substances. Notification shall be provided to the Director as soon as the permittee knows of, or has reason to believe:

3.10.1. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

3.10.1.1. One hundred micrograms per liter (100 ug/L);

3.10.1.2. Two hundred micrograms per liter (200 ug/L) for acrolein and acrylonitrile; five hundred micrograms per liter 500 ug/L) for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter (1 mg/L) for antimony;

3.10.1.3. Five (5) times the maximum concentration value reported for that pollutant in the permit application in accordance with 40 CFR 122.21(g)(7); or,

3.10.1.4. The level established by the Director in accordance with 40 CFR 122.44(f).

3.10.2. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following "notification levels":

3.10.2.1. Five hundred micrograms per liter (500 ug/L);

3.10.2.2. One milligram per liter (1 mg/L) for antimony:

3.10.2.3. Ten (10) times the maximum concentration value reported for that pollutant in the permit application in accordance with 40 CFR 122.21(g)(7); or,

3.10.2.4. The level established by the Director in accordance with 40 CFR 122.44(f).

## 4. GENERAL REQUIREMENTS

4.1. Planned Changes. The permittee shall give notice to the Director as soon as possible of any planned physical alterations or additions to the permitted facility. Notice is required only when:

4.1.1. The alteration or addition could significantly change the nature or increase the quantity of pollutant discharged. This notification applies to pollutants which are not subject to effluent limitations in the permit; or,

4.1.2. There are any planned substantial changes to the existing sewage sludge facilities, the manner of its operation, or to current sewage sludge management practices of storage and disposal. The permittee shall give the Director notice of any planned changes at least 30 days prior to their implementation.

4.1.3. The alteration or addition to a permitted facility may meet one of the criteria for determining whether a facility is a new source.

4.2. Anticipated Noncompliance. The permittee shall give advance notice to the Director of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements.

4.3. Permit Actions. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance, does not stay any permit condition.

4.4. Duty to Reapply. If the permittee wishes to continue an activity regulated by this permit after the expiration date of this permit, the permittee must apply for and obtain a new permit. The application should be submitted at least 180 days before the expiration date of this permit.

4.5. Duty to Provide Information. The permittee shall furnish to the Director, within a reasonable time, any information which the Director may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. The permittee shall also furnish to the Director, upon request, copies of records required to be kept by this permit.

4.6. Other Information. When the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or any report to the Director, it shall promptly submit such facts or information.

4.7. Signatory Requirements. All applications, reports or information submitted to the Director shall be signed and certified.

4.7.1. All permit applications shall be signed by either a principal executive officer or ranking elected official.

4.7.2. All reports required by the permit and other information requested by the Director shall be signed by a person described above or by a duly authorized representative of that person. A person is a duly authorized representative only if:

4.7.2.1. The authorization is made in writing by a person described above and submitted to the Director; and,

4.7.2.2. The authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility, such as the position of plant manager, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters. (A duly authorized representative may thus be either a named individual or any individual occupying a named position.)

4.7.3. Changes to authorization. If an authorization under Part 4.7.2. is no longer accurate because a different individual or position has responsibility for the overall operation of the facility, a new authorization satisfying the requirements of Part 4.7.2. must be submitted to the Director prior to or together with any reports, information, or applications to be signed by an authorized representative.

4.7.4. Certification. Any person signing a document under this section shall make the following certification:

> "I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations."

4.8. Penalties for Falsification of Reports. The Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance shall, upon conviction be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than six months per violation, or by both.

4.9. Availability of Reports. Except for data determined to be confidential under 40 CFR Part 2, all reports prepared in accordance with the terms of this permit shall be available for public inspection at the offices of the Director. As required by the Act, permit applications, permits and effluent data shall not be considered confidential.

4.10. Oil and Hazardous Substance Liability. Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee is or may be subject under Section 311 of the Act.

4.11. Property Rights. The issuance of this permit does not convey any property rights of any sort, or any exclusive privileges, nor does it authorize any injury to private property or any invasion of personal rights, nor any infringement of federal, state, tribal or local laws or regulations.

4.12. Severability. The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

4.13. Transfers. This permit may be automatically transferred to a new permittee if:

4.13.1. The current permittee notifies the Director at least 30 days in advance of the proposed transfer date;

4.13.2. The notice includes a written agreement between the existing and new permittees containing a specific date for transfer of permit responsibility, coverage, and liability between them; and,

4.13.3. The Director does not notify the existing permittee and the proposed new permittee of his or her intent to modify, or revoke and reissue the permit. If this notice is not received, the transfer is effective on the date specified in the agreement mentioned in Part 4.13.2.

4.14.1. Permittees in Indian Country. EPA is issuing this permit pursuant to the Agency's authority to implement the Clean Water Act NPDES program in Indian country, as defined at 18 U.S.C. 1151.

4.14.2. Reopener Provision. This permit may be reopened and modified (following proper administrative procedures) to include the appropriate effluent limitations (and compliance schedule, if necessary), or other appropriate requirements if one or more of the following events occurs:

4.15.1. Water Quality Standards: The water quality standards of the receiving water(s) to which the permittee discharges are modified in such a manner as to require different effluent limits than contained in this permit.

4.15.2. Wasteload Allocation: A wasteload allocation is developed and approved by the TAT Tribes and/or EPA for incorporation in this permit.

4.15.3. Water Quality Management Plan: A revision to the current water quality management plan is approved and adopted which calls for different effluent limitations than contained in this permit.

4.16. Toxicity Limitation-Reopener Provision . This permit may be reopened and modified (following proper administrative procedures) to include whole effluent toxicity limitations if whole effluent toxicity is detected in the discharge.

**<u>Exhibit 2</u>**:

Fact Sheet and Statement of Basis for Permit No. ND-0030988

# FACT SHEET/STATEMENT OF BASIS

## MHA NATION CLEAN FUELS REFINERY
## MAKOTI, NORTH DAKOTA

| | |
|---|---|
| Facility Name: | MHA Nation Clean Fuels Refinery |
| NPDES Permit No: | ND-0030988 |
| Responsible Official: | Tex G. Hall, Chairman<br>Three Affiliated Tribes<br>Mandan, Hidatsa, and Arikara Nation |
| Facility Contact: | Richard Mayer MHA Nation CEO |
| Phone Number: | (701) 627-8252 rmayer@mhanation.com |
| Permit Type: | New Major Industrial Facility/Indian Country |

## Background Information

This new permit is proposed for wastewater discharges associated with the planned Mandan, Hidatsa and Arikara Nation (MHA Nation) Clean Fuels Refinery to be located on the Fort Berthold Indian Reservation near Makoti in Ward County, North Dakota. The MHA Nation applied to EPA Region VIII for an NPDES permit on November 9, 2004.

The proposed refinery is a new facility yet to be constructed. Construction is scheduled to begin in 2007. Once operational, the facility will process synthetic crude oil and local butane supplies into various petroleum products including gasoline, diesel and other distillate blending fuels. Anticipated capacity of the facility is 10,000 barrels per stream day (BPSD) of synthetic crude and 3000 BPSD of field butane. Syncrude feedstock for the refinery will originate from northern Alberta, Canada and will be supplied via an already existing pipeline nearby. Field butane and natural gas will be supplied locally. A soybean based 300 BPSD Bio-diesel refinery is also planned for the site but may not be constructed as part of the initial effort.

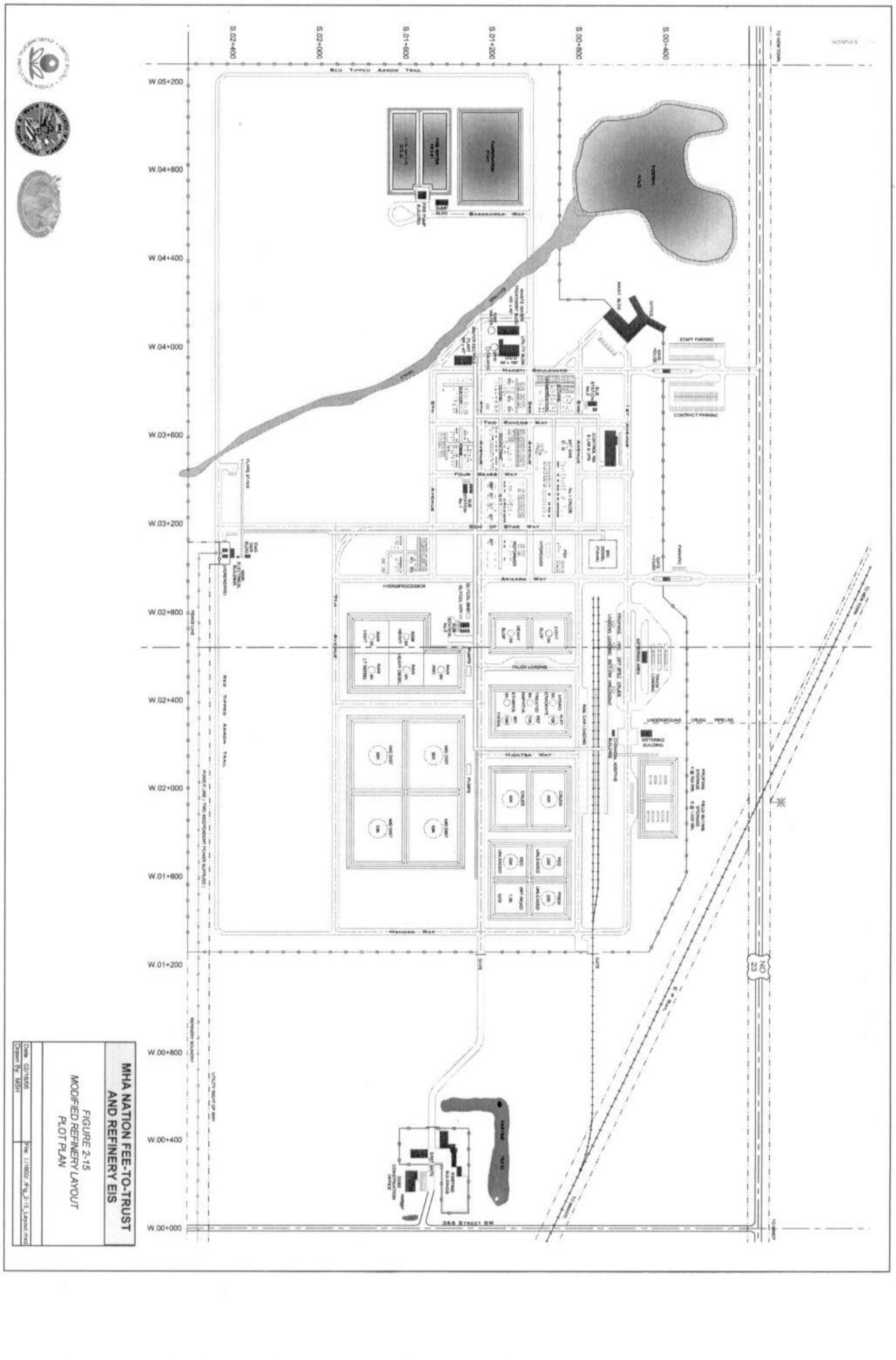
The proposed refinery will include atmospheric distillation, hydrotreating, and hydrocracking processing units for the synthetic crude, a hydrogen plant utilizing natural gas, and butane processing units. Other areas of the proposed refinery affecting wastewater discharges include: rail and truck loading and unloading facilities, a tank farm, blending facilities, office and maintenance buildings, and fire suppression system.

**NOTE: Supplemental Information to this Fact Sheet appears beginning on page 47. This Permit was Public Noticed on June 23, 2006. The comments received and supplemental information provided following public notice did not change the conditions in the NPDES permit.**

Contaminated (oily) stormwater will be managed separately from uncontaminated (non-oily) stormwater.

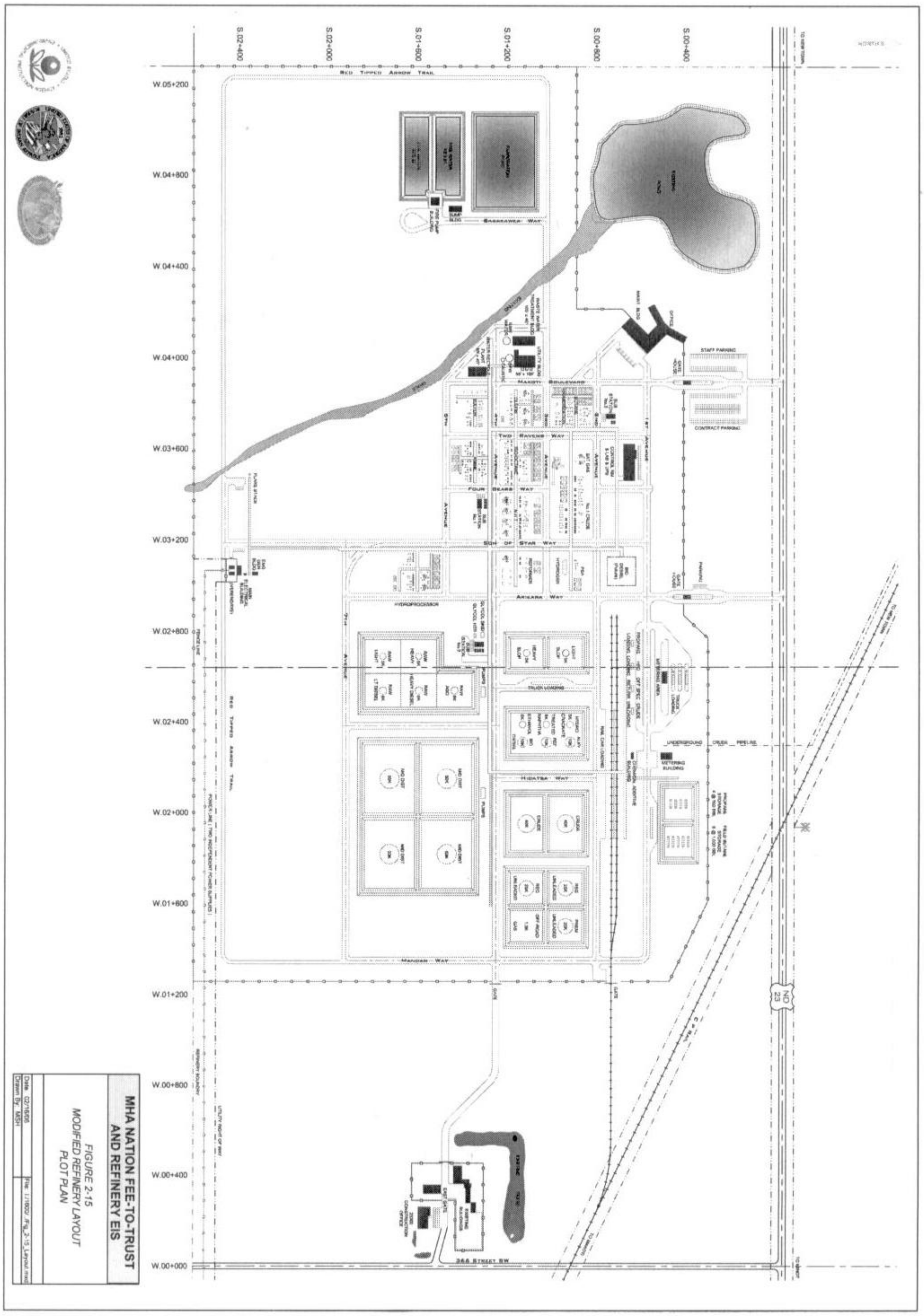
In the DEIS for the proposed facility, there are two different refinery configurations proposed. One is the Proposed Alternative (DEIS Figure 2-7) and the other under Alternative 4, a reconfiguration designed to minimize impacts to onsite wetlands and replacing the wastewater holding ponds with a tank system (DEIS Figure 2-15). Both configurations are being considered for final design and will be evaluated as part of the draft NPDES permit.

DEIS Figure 2-
7



Site Layout (Proposed Alternative DEIS Figure 2-7)

DEIS Figure 2-15



Site Layout (Alternative 4 DEIS Figure 2-15)

## Wastewater Sources and Treatment

There are four sources of wastewater associated with the operation of the proposed MHA Nation Clean Fuels Refinery:

- Process wastewater from refinery operations
- Contaminated (oily) stormwater from process areas of the refinery
- Uncontaminated (non-oily) stormwater from areas outside the process operations of the refinery
- Sanitary wastewater (POTENTIAL)

### Process Wastewater

Process wastewater discharges associated with petroleum refining operations will be collected and treated prior to recycle back to refinery operations or discharged. The raw water source for the refinery operations is well water. The refinery design includes plans to utilize recycled water from certain operations to the extent feasible. Make-up water for process operations is treated prior to use in the boilers and steam generators for the refinery operations (hydrogen production, process units, process heaters). Blowdown from the boilers will be sent to a water recycling plant and recycled as make-up water. Condensate return flow from the process heaters can also be recycled as make-up water or be sent to the wastewater treatment processes if the quality becomes a problem for use as recycle. Other process wastewater includes water that is removed during crude processing operations in individual refinery units. All process wastewater will be collected in segregated closed drainage pipes and routed to either a steam stripper to remove VOCs and benzene or to a sour water stripper (SWS) to remove sulfides and ammonia. The process wastewater is then sent directly to the wastewater treatment plant. The wastewater treatment unit processes include the following units: API separator ►dissolved air floatation ►equalization tank ►biological treatment ►clarifier.

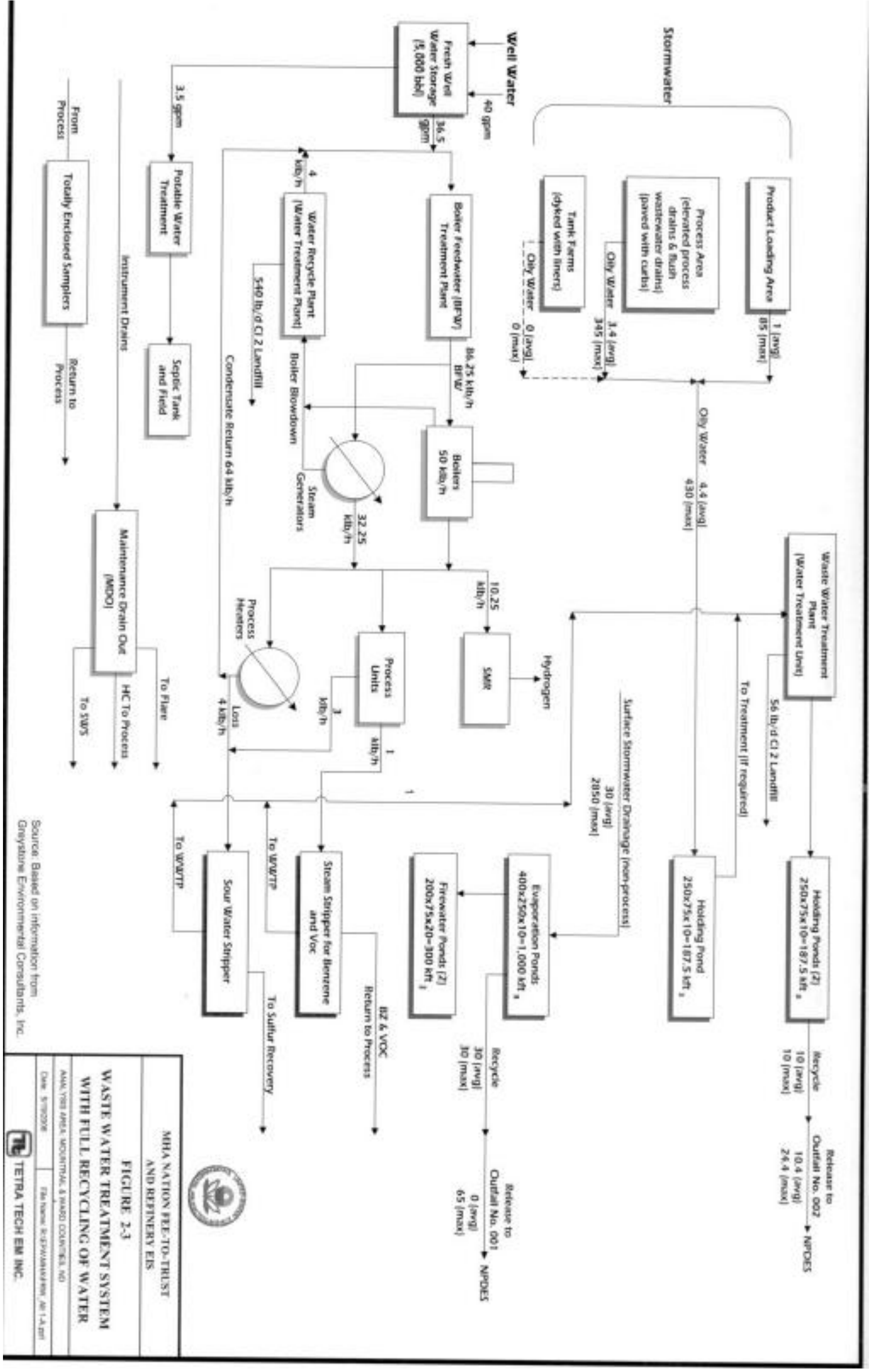
Under the Proposed Alternative in the DEIS, the wastewater (after treatment) will be directed to one of two final holding ponds. The treated process wastewater can then either sent as recycle back to make-up water system for process operations or discharged. DEIS Figure 2-3 shows the operation with no recycling and DEIS Figure 2-4 shows the operation with full recycling of treated wastewater.

Under Alternative 4 in the DEIS, the wastewater treatment system will be designed to meet the definitions of wastewater treatment unit and tank system under RCRA 40 CFR 260. The biological treatment will meet the aggressive biological treatment definition under hazardous waste rules at 40 CFR 261.31(b). The wastewater is then routed to final holding tanks prior to recycle or discharge. See DEIS Figure 2-16.

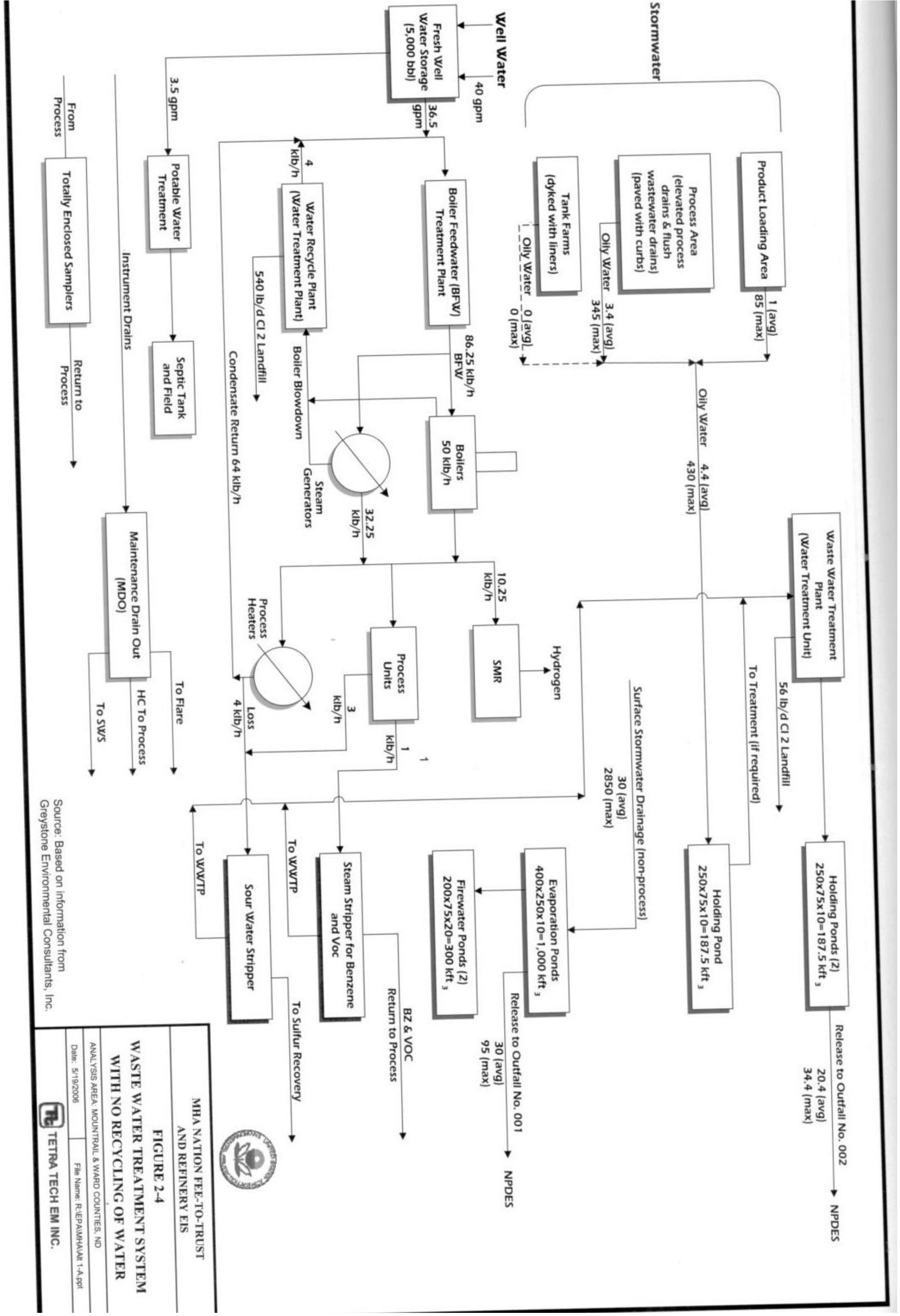
Potential pollutants contained in the discharge of process wastewater will be evaluated and limited under Outfall 002 in the proposed NPDES permit for this facility.

DEIS Figure 2-3

Wastewater Flow Diagram (Proposed Alternative DEIS Figure 2-3)



Wastewater Flow Diagram (Proposed Alternative DEIS Fig.2.4



Source: Based on information from Greystone Environmental Consultants, Inc.

MHA NATION FEE-TO-TRUST AND REFINERY EIS

FIGURE 2-4

WASTE WATER TREATMENT SYSTEM WITH NO RECYCLING OF WATER

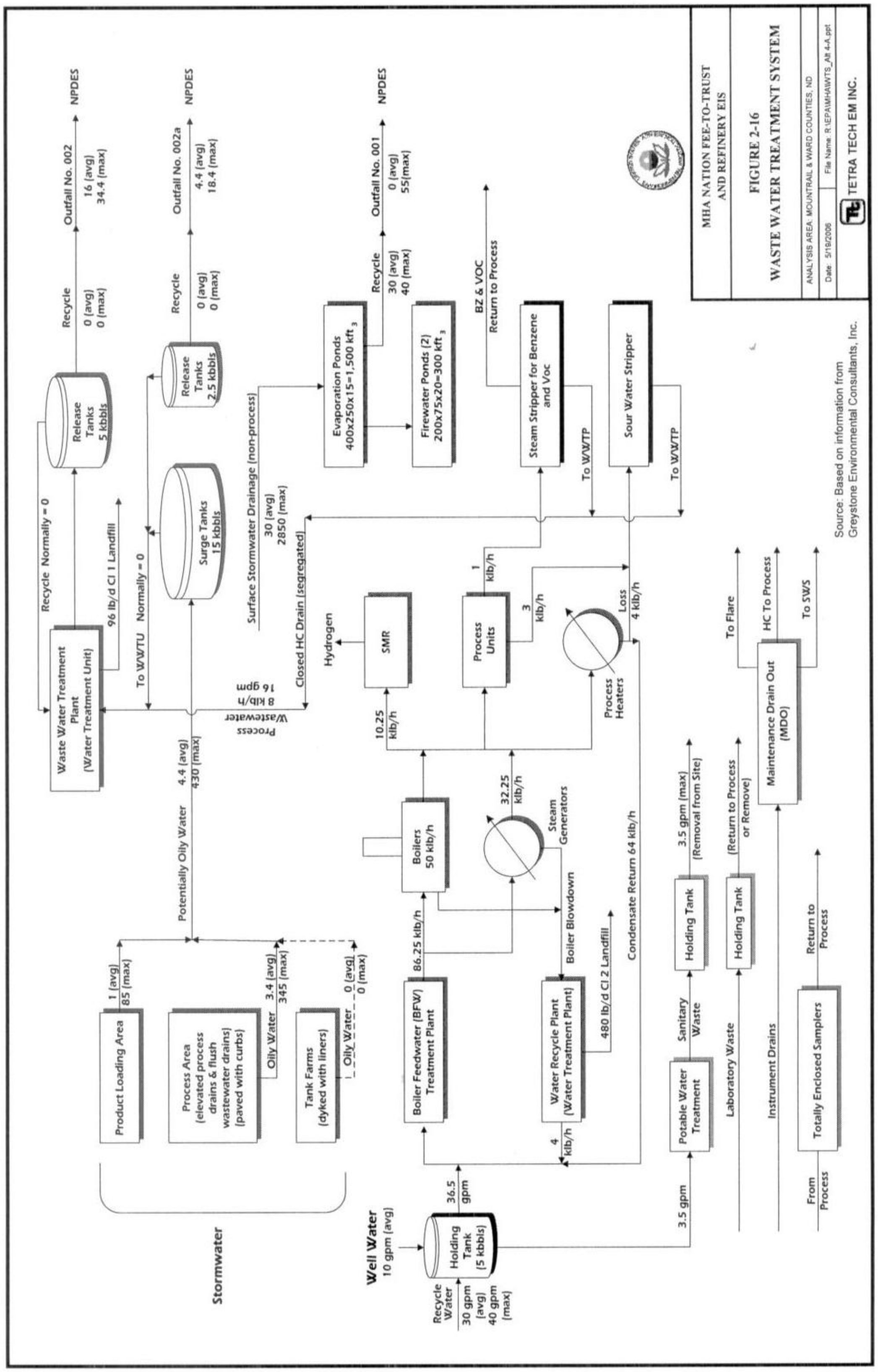
ANALYSIS AREA: MOUNTRAIL & WARD COUNTIES, ND

Date: 5/19/2006

File Name: R:\EPA\MHA\Alt 1-A.ppt

TETRA TECH EM INC.

Wastewater Flow Diagram (Alternative 4 DEIS Figure 2-16)



### Contaminated (oily) Stormwater

Contaminated (oily) stormwater will be collected in segregated drains that collect runoff from precipitation that falls directly on the areas of the refinery that have a high potential for contact with oil, products and byproducts produced during refining operations. Areas surrounding each process unit, the loading and unloading areas, and equipment cleaning areas are considered as having a high potential for contact with those materials. The high potential contact areas will be paved and curbed to prevent precipitation runon and release of the wastewater to the area outside the area.

(Under the Proposed Alternative in the DEIS) Contaminated (oily) stormwater will be collected in segregated drains and sent to a holding pond. The wastewater will be tested and if further treatment is required, it will be routed to the wastewater treatment facility. If further treatment is not required, the wastewater will be directed to one of the two final effluent holding ponds and recycled or discharged through Outfall 002 as described above for the process wastewater.

(Under Alternative 4 in the DEIS) The contaminated (oily) stormwater will be collected in segregated drains and sent to a series of surge tanks. The wastewater will then be normally sent for further treatment in the wastewater treatment unit. In the event the capacity of the surge tanks and/or wastewater treatment unit hydraulic capacity is exceeded, the segregated oily stormwater can be sent to a series of release tanks and discharged or held to return back to the wastewater treatment unit if further treatment is necessary to meet discharge requirements. The treated wastewater could then be recycled or discharged through Outfall 002 as described above for the process wastewater. An additional discharge outfall (002a) will be required under this alternative as the holding capacity for treated wastewater has been substantially reduced and a discharge of segregated stormwater due to precipitation events may be necessary.

Potential pollutants contained in the discharge of contaminated (oily) stormwater will be evaluated and limited under Outfall 002 and Outfall 002a (for Alternative 4 in the DEIS) in the proposed NPDES permit.

### Uncontaminated (non-oily) Stormwater

Uncontaminated (non-oily) stormwater will be collected as segregated runoff from precipitation that falls on areas of the refinery outside the areas considered as high potential contact with oil, product and byproducts. These areas within the boundaries of the site include roads in the process areas, unpaved areas, parking areas, building runoff, etc. The run-off from the site will be conveyed for collection using surface ditches next to roadways, etc. There may also be some site runon contribution from upgradient areas surrounding the refinery property that will contribute to the runoff from the site. The site configuration is designed to let precipitation flow generally towards the lowest elevation of the site where it will be collected, piped and sent to a large holding pond. The wastewater can then be used as make-up water for the firewater system as necessary or discharged.

The management of uncontaminated (non-oily) stormwater will be similar under the Proposed Alternative and Alternative 4 under the DEIS. Potential pollutants contained in the discharge of uncontaminated (non-oily) stormwater are evaluated and limited under Outfall 001 in the proposed NPDES permit.

### (POTENTIAL) Sanitary Wastewater

Sanitary wastewater will be collected and treated in a package wastewater treatment plant. Flow is projected to be approximately 3.5 gpm or 5000 gallons per day. Potential pollutants contained in the discharge of sanitary wastewater are evaluated and limited under Outfall 003 in the proposed NPDES permit.

## New Source Determination

On December 2, 2004, EPA Region 8 issued a New Source Determination for the proposed facility as required by 40 CFR §122.21(l)(2)(ii). EPA Region 8 determined that the proposed facility is in fact a new source (defined in 40 CFR §122.2) and is subject to New Source Performance Standards (NSPS) for the Petroleum Refining Point Source Category pursuant to 40 CFR §419. The New Source Determination was public noticed between December 23 and 29, 2004 in several newspaper publications in the geographical area of the proposed site location. A public comment period of 30 days was opened by the public notice and ended on January 29, 2005. One phone call was received by EPA during the public comment period from the Mountrail County Record requesting additional information on the proposed facility. No challenges to EPA's New Source Determination were received during the public comment period.

## EPA NPDES Major/Minor Determination

EPA completed an NPDES Permit Rating Work Sheet for the proposed MHA Nation Clean Fuels Refinery in accordance with EPA policy on major/minor facility classification. (USEPA Memorandum from James Elder to Regional Water Management Division Directors. June 27, 1990). The proposed facility scored 95 points and received a ranking of "major". A minimum score of 80 is required for a "major" ranking. The Rating Work Sheet is contained in the Administrative Record for this permit.

## EPA's Environmental Review Requirements

Since the proposed facility was determined by EPA to be New Source, and the issuance of an NPDES permit will be a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1970 (NEPA), the MHA Nation is required to comply with EPA's environmental review procedures for the New Source NPDES Program requirements of 40 CFR Part 6, Subparts A-D and F.

The United States Bureau of Indian Affairs (BIA) and EPA in cooperation with the U.S. Army Corps of Engineers, and the MHA Nation are developing an Environmental Impact Statement (EIS) that will fulfill both BIA and EPA environmental review requirements. A draft EIS (DEIS) will be completed prior to public notice of a proposed NPDES permit for the facility [40 CFR §124.10(b)] and will be included in the Administrative Record for the draft permit in accordance with 40 CFR §124.9. A final EIS (FEIS), including a recommendation to issue or deny an NPDES permit, will be included in the Administrative Record for the final NPDES permit in accordance with 40 CFR §124.18. If the FEIS recommends denying the NPDES permit, reasons for the recommendation will be identified and a list of measures, if any, which the MHA nation could take to cause the recommendation to be changed. If the FEIS recommends issuing the final permit, the FEIS will recommend the actions, if any, which the MHA Nation should take to prevent or minimize any adverse environmental impacts.

## Endangered Species Act Coordination

Under the February 22, 2001 Memorandum of Agreement with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service, EPA agreed to implement actions to demonstrate compliance with the Endangered Species Act (ESA) for certain activities under the NPDES permitting program. In accordance with the MOA, EPA must make a determination of effects on Threatened and Endangered Species (both listed and candidate species) for this federal action of issuing an NPDES permit.

For this action, EPA has determined that the issuance of this permit may affect but is not likely to adversely affect Threatened and Endangered species that are present in the project area. EPA will include information regarding its determination and related correspondence between EPA and the U.S. Fish and Wildlife Service in the Administrative Record kept for this permit.

EPA's determination regarding this permit's potential to affect Threatened and Endangered species is based on the permit requirements which have been included in the draft NPDES permit after considering existing Tribally-adopted water quality standards for the Fort Berthold Indian Reservation, and the State of North Dakota water quality standards without an allowance for mixing zones, i.e. end-of-pipe.

Since this is a new facility and there is no existing monitoring data for the discharge, the permit also contains additional monitoring requirements for priority pollutant compounds that may be present but are not anticipated. Re-opener provisions in the permit allow for inserting additional water quality based effluent limits protective of aquatic life and public water supply uses when unanticipated pollutants are detected during this additional monitoring.

## National Historic Preservation Act

Section 106 of the National Historic Preservation Act requires that federal agencies take into account the effects of a federal undertaking on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register. According to Section 301 of the act, "undertaking" means a project, activity, or program funded in whole or in part under the direct or indirect jurisdiction of a federal agency, including (a) those carried out by or on behalf of the agency, (b) those carried out with federal financial assistance, (c) those requiring a federal permit license, or approval, and (d) those subject to state or local regulation administered pursuant to a delegation or approval by a federal agency. Section 106 compliance also applies to non-federal lands when federal funding, licensing, permitting, and approval are required.

This permitted effluent discharge is not expected to affect historic or cultural resources. Moreover, because the locations of the outfalls were disturbed previously, construction of the outfalls would not affect historic or cultural resources.

The proposed facility is not expected to substantially affect cultural resources. The till plain and pothole setting of the project area has soils that are generally good for cultivation, but support a comparatively low diversity of natural resources. These conditions correspond to a low potential for prehistoric or historic cultural resources other than readily visible farm complexes.

A records search for the project site was completed through the North Dakota State Historical Society. The records search indicated that no cultural resource investigations and no known sites are on file for the project area. The North Dakota SHPO (Swenson 2005) and the Cultural Preservation Office of the Three Affiliated Tribes (Crows Breast 2005) have reviewed the available information for the project area. Both offices have concurred that there is a low potential for significant cultural resources in the project area, and both have recommended a determination of no historic properties affected.

The farm complex near the refinery site will not be affected by the proposed action and the farm complexes near the pipeline and power line corridors can be avoided. The primary affect resulting from implementation of this alternative would be modification of the old Soo Line Railroad branch line that runs through the property. The line itself would not be moved or removed, but a new siding would be constructed from the line into the refinery. This addition would not adversely impact the historic character of the rail line. The farm house and outbuildings would not be disturbed for construction of the refinery or production of the forage for buffalo.

## Project Location

The proposed MHA Nation Clean Fuels Refinery will be located on 190 acres of land that is part of a 469 acre parcel of land purchased by the Three Affiliated Tribes (MHA Nation) on July 22, 2003. The remaining land, 279 acres, is proposed for growing feed for the MHA Nation buffalo herd. The land is located in the northeast corner of the Fort Berthold Indian Reservation and in Ward County, North Dakota. Following the purchase of the land, the MHA Nation requested the Department of the Interior, Bureau of Indian Affairs (BIA) accept the land into trust status. The land transfer is considered a major federal action and subject to environmental review in accordance with the National Environmental Policy Act (NEPA). BIA (in cooperation with EPA, F&WS and the MHA Nation) has primary responsibility to fulfill the NEPA requirements for the land transfer.

The general land area encompassing the proposed MHA Nation Clean Fuels Refinery site consists of nearly level glacial till plains and rolling hills. The area is within the glaciated prairie pothole region and includes numerous seasonal, semi-permanent, and permanent wetlands that capture seasonal snowmelt and rainwater. Prior to agricultural development of the land, mixed cool and warm season prairie grasses were predominant with intermix broad-leaved annual and perennial forbs and numerous legumes. Current land use is generally dry land farming of cereal crops (wheat and barley) intermixed with cattle ranching in the drier and hillier portions of the region.

The site itself is largely underdeveloped agricultural property with adjacent land primarily planted with wheat and barley. The site elevation ranges between 2074 and 2112 feet above mean sea level and its topography is relatively flat with slopes less than three percent. Drainage in the site area is generally east to west towards tributaries of the Missouri River (Lake Sakakawea). The East Fork of Shell Creek runs adjacent to the northern border of the project site and generally flows west towards Lake Sakakawea. Characteristics of the site include seasonal and semi-permanent wetlands, mixed grass prairie, wooded draws, intermittent seasonal drainages, and seasonal crops.

The climate of the site area is characterized by wide seasonal and diurnal temperature and precipitation variations. Average annual precipitation is 16.06 inches with the highest average monthly values (3.66 inches) in June and the lowest monthly average (0.33 inches) in February. Summer thunderstorms occur on about 34 days in the year and account for a majority of the total annual precipitation amounts. Approximately 80 percent of the annual precipitation total occurs between April and September. Spring snowmelt drains into wetland depressions and the depth of ponded water varies dependant on the amount of snow cover. In late spring and summer, these wetland depressions receive direct precipitation and runoff from the surrounding watershed and by late summer, the wetlands draw down or dry through evaporation and seepage.

## Prairie Pothole Wetlands

Within the proposed MHA Nation Clean Fuels Refinery site boundaries, sixteen prairie pothole wetland areas totaling 33.6 acres were identified in a field investigation performed by Greystone Environmental Consultants, Inc. during development of the DEIS. Wetlands delineation was done in accordance with Level 2 Routine On-site Method as described in the *Corps of Engineers Wetland Delineation Manual* (Environmental Laboratory 1987). The prairie pothole wetlands within the project area were classified as palustrine wetlands and further characterized as Palustrine-Emergent-Temporarily-Flooded (PEMA), Palustrine-Emergent-Seasonally-Flooded (PEMC) and Palustrine-Emergent-Semi-permanently-Flooded (PEMF).

The largest wetland characterized in the field investigation was an 11.7 acre wetland in the NW1/4 of Section 19. The location is on the lowest elevation contour in Section 19 and was classified as a PEMF wetland. The wetland collects precipitation and runoff primarily from the local watershed. This wetland likely contains areas of open water during certain times of the year and is drained by a culvert on the northern boundary. The culvert is constructed under Highway 23 and after flowing under an additional culvert under the railroad, drains to a tributary of the East Fork of Shell Creek. The large wetland appears to receive water from a north-south wetland swale that traverses the site on the west side of the proposed site. This wetland swale appears to receive surface flow from an off-site wetland across the south property boundary. Flow of the water is generally from south to north across the site. According to the preliminary site plans, the wetland swale is the location where treated process wastewater and stormwater discharges will be located. Soils in this wetland swale were characterized as Parnell (Pa) and consist of a silt loam with low chromas. The delineation also indicated that the hydrology may be influenced by groundwater due to the depth of the elevation contour; however, the area was dry during the October 2003 field investigation.

Both the 11.7 acre wetland and the wetland swale have been determined to be jurisdictional wetlands by the U.S. Army Corps of Engineers(2005) and will be considered waters of the U.S. for establishing effluent limitations and conditions in the proposed NPDES permit.

## Receiving Water

As described above, the location receiving discharges from the proposed MHA Nation Clean Fuels Refinery will be the wetland swale located in the NW1/4 of Section 19, Township 152N, Range 87W. The wetland swale is tributary to the East Fork of Shell Creek through natural drainageways (wetlands, sloughs, swales) and constructed culverts under Highway 23 and the railroad, north of the wetland areas. Major site construction activities are not expected to occur in this area. Some modification of the north-south wetland swale that feeds into the wetland will take place during construction of the facility and drainage of direct precipitation on the site and watershed runoff into the wetland area may somewhat change the hydrologic characteristics of the wetland.

Tributaries of the East Fork of Shell Creek including the natural drainageways and the wetland swale discharge location best describe the receiving water for discharges from the proposed facility. No historic flow measurements are available for the tributaries but are assumed to be zero cubic feet per second (cfs). due to the hydrologic characteristics of the East Fork of Shell Creek described above. No flow data is available for the wetland swale or wetland system that will receive discharges from the facility but it will be assumed that there are times of the year that the low flow in the wetlands is zero cfs.

The East Fork of Shell Creek flows generally in a westerly direction towards Lake Sakakawea before entering the Van Hook Arm of the Lake at Parshall Bay, near Parshall, ND. The East Fork of Shell Creek is generally ephemeral and likely has extended periods with very low or no flow during the year. A USGS gage station is located on the East Fork of Shell Creek near Parshall, ND approximately fifteen miles from the project site location. There are no other monitoring stations closer to the site. The gage station (06332523) was established in 1991 and collects continuous data on stream flow. For the period from 1991 through 2002, annual mean flow ranges from 2.19 cubic feet per second (cfs) in 1992 to 15.1 cfs in 1999. Peak daily flows for the same period of record range from 31 cfs on May 12, 2000 to 1,170 cfs on March 27, 1999. Flow in the East Fork of Shell Creek is highly dependant on summer precipitation events and runoff that occurs during March and April. Low flows occur during winter months each year and in 2001, monthly low flows of zero cfs were recorded in January, February, August and September.

The East Fork of Shell Creek remains primarily within the external boundaries of the Fort Berthold Indian Reservation as it travels towards Lake Sakakawea, however, approximately one mile from the proposed project site it traverses the boundary of the

Reservation into the State of North Dakota for a short distance, prior to returning back to the Reservation. As such, water quality based effluent limits (WQBELs) developed for the proposed facility will take into consideration both Tribally-adopted water quality standards and State of North Dakota water quality standards.

## Monitoring Data for East Fork of Shell Creek

Limited data is available on water quality for the East Fork of Shell Creek in the vicinity of the proposed project location. Data was collected periodically on USGS gage station 06332523 located near the mouth below Parshall, ND. In 2001, Confluence Consulting performed additional monitoring at three locations of the East Fork of Shell Creek. The following data was presented in the *Water Resources Technical Report* developed by Greystone Environmental Consultants Inc. as part of the DEIS.

USGS April 1990 – June 1991

| | Maximum | Minimum | Median |
|---|---|---|---|
| pH (s.u.) | 9.9 | 8.4 | 8.9 |
| Dissolved oxygen (mg/L) | 10.8 | 7.3 | -- |
| Hardness (mg/L as $CaCO_3$) | 420 | 240 | -- |

July 1991 – September 1992

| | Maximum | Minimum | Median |
|---|---|---|---|
| pH (s.u.) | 9.1 | 8.1 | 8.7 |
| Dissolved oxygen (mg/L) | 11.6 | 4.6 | 6.8 |
| Hardness (mg/L as $CaCO_3$) | 470 | 250 | 350 |

USGS 1991-2002

| | Maximum | Minimum | Median | Mean |
|---|---|---|---|---|
| pH (s.u.) | 8.80 | 7.80 | 8.37 | 8.40 |
| Dissolved oxygen (mg/L) | 12.50 | 4.60 | 8.82 | 9.05 |

2001 Stream Survey

| | 2A | 2B | 2C |
|---|---|---|---|
| Temperature $^0$C | 20.2 | 18 | 18.9 |

# Water Quality Standards (WQS)

## Tribally-adopted Water Quality Standards

The MHA Nation adopted water quality standards for surface waters within the external boundaries of the Fort Berthold Indian Reservation (Tribally-adopted WQS) through a resolution adopted by the Tribal Business Council of the Three Affiliated Tribes of the Fort Berthold Reservation on May 11, 2000. The Tribally-adopted WQS are intended to protect surface water designated uses through specific numeric and narrative water quality criteria and antidegradation provisions. The Tribally-adopted WQS have not yet been federally approved by EPA, however, they will be considered for establishing effluent limitations for discharges from the proposed MHA Nation Clean Fuels Refinery in accordance with EPA's *Guidance on EPA's NPDES and Sludge Management Permit Procedures on Federal Indian Reservations* (November 16, 1993).

Wetlands: The Tribally-adopted WQS apply to all wetlands on the Reservation that are not constructed and considered "waters of the Tribes". The wetland located in the NW1/4 of Section 19 falls within these criteria. The Tribally-adopted WQS indicate wetlands shall be subject to narrative criteria and applicable antidegradation provisions and shall be generally considered capable of supporting aquatic biota (e.g. fish, macroinvertebrates, amphibians or hydrophytic vegetation) on a regular or periodic basis. The goal of water quality is described as maintaining naturally occurring levels within the natural range of variation for the individual wetland. For substances that are not naturally occurring, water quality requirements shall be based on protecting uses of the wetland consistent with antidegradation requirements, the Tribes narrative water quality criteria assigned to hydrologically connected surface waters, or appropriate criteria guidance issued by the Environmental Protection Agency.

The Tribally-adopted WQS include a Mixing Zone and Dilution Policy that prohibits mixing zones for point source discharges into wetlands. Paragraph (d) of the policy states "*Where dilution flow is not available at critical conditions, the discharge limits will be based on achieving water quality criteria at the end-of-pipe. In addition, discharge limits for all point source discharges to a wetland will be based on achieving water quality criteria at the end-of-pipe.*"

East Fork of Shell Creek: The Tribally-adopted WQS also apply to the East Fork of Shell Creek within the external boundaries of the Fort Berthold Indian Reservation. The Tribally-adopted WQS list designated uses for the East Fork of Shell Creek including Public Water Supply, Primary Contact Recreation, Secondary Contact Recreation, Coldwater Aquatic Life, Warmwater Aquatic Life, Industrial Water Supply, Agriculture and Navigation. Numeric criteria applicable to support aquatic life and public water supply (human health) are listed in Tables 1 & 2 of the Tribally-adopted WQS. The criteria include acute and chronic concentrations for organic constituents, pesticides, and metals as well as non-conventional pollutants such as hydrogen sulfide, ammonia nitrogen, temperature, etc., and indicator parameters such as dissolved oxygen.

These criteria were evaluated against information provided by the MHA Nation in their NPDES permit application, EPA Effluent Guidelines and Standards for the Petroleum Refining Point Source Category (40 CFR Part 419) and the *Development Document for Effluent Limitations Guidelines and Standards for the Petroleum Refining Point Source Category, Final October 1982, EPA 440/1-82/014*, in assessing reasonable potential for discharges to cause or contribute to exceedances of water quality standards. The list of appropriate criteria for this permit includes all pollutants that have been reported as expected to be present in the discharge at any concentration above the applicable analytical detection limit for the pollutant and where a water quality standard for that pollutant exists. Table 1 below lists the criteria for pollutants expected to be present in the discharges from the proposed MHA Nation Clean Fuels Refinery.

TABLE 1

Tribally-Adopted WQS (concentrations are dissolved ug/L)

| Pollutant | CAS No. | Aquatic Life Acute (CMC) | Aquatic Life Chronic (CCC) | Aquatic Life Fish Cons. | Public Water Supply |
|---|---|---|---|---|---|
| Benzene | 71-43-2 | -- | -- | 71 | 1.2 |
| Ethyl benzene | 100-41-4 | -- | -- | 29000 | 700 |
| Toluene | 108-88-3 | -- | -- | 200000 | 1000 |
| Xylenes | 1330-20-7 | -- | -- | -- | 10000 |
| Phenol | 108-95-2 | -- | -- | 4600000 | 300 |
| Hydrogen Sulfide | 7783-06-4 | -- | 2 | -- | -- |
| Ammonia as N | 7664-41-7 | (b) | (b) | -- | -- |
| Barium (tr) | 7440-39-3 | -- | -- | -- | 2000 |
| Aluminum (tr) | 7429-90-5 | 750 | 87 | -- | -- |
| Cadmium (tr) | 7440-43-9 | 13.5 (a) | 2.7 (a) | 84 | 5.0 |
| Chromium (III) (tr) | 7440-47-3 | 4270 (a) | 509 (a) | -- | 100 (T) |
| Chromium (VI) | | 16 | 11 | 3400 | 100 |
| Copper (tr) | 7440-50-8 | 49.9 (a) | 30.2 (a) | -- | 1000 |
| Iron (tr) | 7439-89-6 | -- | 1000 | -- | 300 |
| Manganese (tr) | 7439-96-5 | -- | -- | -- | 50 |
| Lead (tr) | 7439-92-1 | 331 (a) | 12.9 (a) | -- | 15 |
| Mercury (T) | 7439-97-6 | 2.4 | 0.012 | 0.051 | 0.050 |
| Nickel (tr) | 7440-02-0 | 3592 (a) | 399 (a) | 4600 | 100 |
| Selenium (tr) | 7782-49-2 | 20 | 5 | 9000 | 50 |
| Silver (tr) | 7440-22-4 | 26.8 (a) | -- | 110000 | 170 |
| Zinc (tr) | 7440-66-6 | 297 (a) | 269 (a) | 69000 | 5000 |
| Chlorine (TRC) | 7782-50-5 | 19 | 11 | -- | -- |
| Chloride | 16887-00-6 | 860000 | 230000 | -- | -- |
| Fluoride | 7782-41-4 | -- | -- | -- | 4000 |
| Nitrite as N | 14797-65-0 | -- | -- | -- | 1000 |
| Nitrate as N | 14797-55-8 | -- | -- | -- | 10000 |
| pH (s.u.) | | 7.0-9.0 | 7.0-9.0 | 7.0-9.0 | -- |

tr- total recoverable; T- total

(a) *Hardness based concentrations for metals calculated using a hardness of 300 mg/L as $CaCO_3$ and the following formulas:*

**CMC** = *exp{ma[ln(hardness)}+ba}* **CCC** = *exp{mc[ln(hardness)]+bc}*

| | *ma* | *ba* | *mc* | *bc* |
|---|---|---|---|---|
| *cadmium* | *1.128* | *-3.828* | *0.7852* | *-3.490* |
| *copper* | *0.9422* | *-1.464* | *0.8545* | *-1.465* |
| *chromium (III)* | *0.8190* | *3.688* | *0.8190* | *1.561* |
| *lead* | *1.273* | *-1.460* | *1.273* | *-4.705* |
| *nickel* | *0.8460* | *3.3612* | *0.8460* | *1.1645* |
| *silver* | *1.72* | *-6.52* | - | - |
| *zinc* | *0.8473* | *0.8604* | *0.8473* | *0.7614* |

(b) *Ammonia as N (unionized) is calculated using the following formula:*

**CMC** = *0.52/FT/FPH/2 where:*

*FT* $=10^{0.03(20-TCAP)}$ ; $TCAP \leq T \leq 30$
$=10^{0.03(20-T)}$ ; $0 \leq T < TCAP$

*FPH* $= 1$ ; $8 \leq pH \leq 9$
$= (1+ 10^{7.4-pH})/1.25$ ; $6.5 \leq pH < 8$

*TCAP* = *20 C ; coldwater aquatic life use (IIIA)*
= *25 C ; warmwater aquatic life use (IIIB)*

*The usual CMC averaging period of one hour may not be appropriate if excursions of concentrations greater than 1.5 times the average occur during the hour; in such cases, a shorter averaging period may be needed. To convert these values to mg/L as N, multiply by 0.822.*

**CCC** = *0.80/FT/FPH/RATIO where FT and FPH are as above and :*

*RATIO* $= 13.5$ ; $7.7 \leq pH \leq 9$
$= 20\ (10^{7.7-pH}/1 + 10^{7.4-pH})$ ; $6.5 \leq pH < 7.7$

*TCAP* = *15 C ; coldwater aquatic life use (IIIA)*
= *20 C ; warmwater aquatic life use (IIIB)*

Temperature:

*Eighty-five degrees Fahrenheit (29.44 degrees Celsius). The maximum increase shall not be greater than five degrees Fahrenheit (2.78 degrees Celsius) above background conditions.*

### Dissolved Oxygen:

| | *Aquatic Life (IIIA) Use* | | *Aquatic Life (IIIB) Use* | |
|---|---|---|---|---|
| | *Early Life Stages*[1,2] | *Other Life Stages* | *Early Life Stages*[2] | *Other Life Stages* |
| 30-Day Mean | NA | 6.5 | NA | 5.5 |
| 7-Day Mean | 9.5 (6.5) | NA | 6.0 | NA |
| 7-Day Mean Minimum[3] | NA | 5.0 | NA | 4.0 |
| 1-Day Minimum[3] | 8.0 (5.0) | 4.0 | 5.0 | 3.0 |

[1] *These are water column concentrations to achieve the required intergravel dissolved oxygen concentrations shown in parentheses.*

[2] *Includes all embryonic and larval stages and all juvenile forms to 30-days following hatching.*

[3] *All minima should be considered as instantaneous concentrations to be achieved at all times.*

### Narrative Tribally-adopted Water Quality Standards:

Narrative Tribally-adopted Water Quality Standards describe general characteristics of surface waters and discharges. The narrative standards include the following:

a) *All surface waters on the Reservation shall be free from substances attributable to wastewater discharges or other pollutant sources that:*
   - *(1) settle to form objectionable deposits,*
   - *(2) float as debris, scum, oil, foam or other matter forming nuisances,*
   - *(3) produce objectionable color, odor, taste or turbidity,*
   - *(4) cause injury to, or are toxic to, or produce adverse physiological responses in humans, animals, or plants; or*
   - *(5) produce undesirable or nuisance aquatic life.*

## State of North Dakota Standards

The State of North Dakota has adopted water quality standards (State WQS) for surface waters of the State including the East Fork of Shell Creek within the State jurisdiction (NDAC 33-16-02.1). The East Fork of Shell Creek remains primarily within the external boundaries of the Fort Berthold Indian Reservation as it travels towards Lake Sakakawea, however, approximately one mile from the proposed project site it traverses the boundary of the Reservation into the State of North Dakota for a short distance, prior to returning back to the Reservation. The State WQS standards became effective June 1, 2001 and have been approved by EPA. The standards indicate designated uses for waters of the State, specify narrative and numeric criteria to protect those uses, and antidegradation provisions. The State has classified the East Fork of Shell Creek as a Class III stream. According to §33-16-02.1-09, Class III streams are suitable for agriculture and industrial uses such as stock watering, irrigation, washing and cooling. They are of limited seasonal value for immersion recreation, fish life, and aquatic biota. The quality of these waters must be maintained to protect recreation, fish, and aquatic biota. The State WQS were evaluated against the MHA Nation NPDES permit application, etc. as described above to determine reasonable potential for exceedance of water quality standards. Appropriate numeric criteria for Class III streams include values listed in Table 2 and the following additional numeric standards:

| Substance or Characteristic | Maximum Limit |
|---|---|
| Barium (total) | 1.0 mg/L |
| Chlorides (total) | 250 mg/L |
| Chlorine Residual (total) | acute 0.019 mg/L<br>Chronic 0.011 mg/L |
| Dissolved Oxygen | not less than 5 mg/L |
| Fecal Coliform | 200 fecal coliforms per 100 mL. (applies May 1 – Sept 30) |
| Nitrates (N) (diss.) | 1.0 mg/L |
| pH | 7.0 – 9.0 |
| Phenols (total) | 0.3 mg/L (organoleptic criterion) |
| Phosphorous (P) (total) | 0.1 mg/L |
| Sulfate (total) | 750 mg/L |
| Temperature | Eighty-five degrees Fahrenheit (29.44 degrees Celsius)<br>The maximum increase shall not be greater than five degrees Fahrenheit (2.78 degrees Celsius) above natural background conditions. |

## TABLE 2
## North Dakota State WQS
## (concentrations are dissolved, ug/L)

| Pollutant | CAS No. | Aquatic Life Value Classes I, IA, II, III | | Human Health Value | |
|---|---|---|---|---|---|
| | | Acute | Chronic | Classes I, IA, II | Class III |
| Benzene | 71-43-2 | -- | -- | 1.2 | 71 |
| Ethyl benzene | 100-41-4 | -- | -- | 700 | 29000 |
| Toluene | 108-88-3 | -- | -- | 1000 | 200000 |
| Xylenes | 1330-20-7 | -- | -- | 10000 | |
| Phenol | 108-95-2 | -- | -- | 21000 | 4600000 |
| Cadmium (tr) | 7440-43-9 | 15.6 (a) | 5.8 (a) | 5 | -- |
| Chromium (III) (tr) | 7440-47-3 | 4430 (a) | 212 (a) | -- | 100 (T) |
| Chromium (VI) | | 16 | 11 | -- | 100 (T) |
| Copper (tr) | 7440-50-8 | 39.4 (a) | 23.8 (a) | -- | 1000 |
| Lead (tr) | 7439-92-1 | 331 (a) | 12.9 (a) | -- | 15 |
| Mercury (T) | 7439-97-6 | 1.7 | 0.91 | 0.050 | 0.051 |
| Nickel (tr) | 7440-02-0 | 1190 (a) | 132 (a) | 100 | 4600 |
| Selenium (tr) | 7782-49-2 | 20 | 5 | 50 | -- |
| Silver (tr) | 7440-22-4 | 26.8 (a) | -- | -- | -- |
| Zinc (tr) | 7440-66-6 | 304 (a) | 304 (a) | 9100 | 69000 |
| Fluoride (T) | 7782-41-4 | -- | -- | 4000 | -- |
| Nitrite as N | 14797-65-0 | -- | -- | 1000 | -- |

tr- total recoverable; T- total

*(a) Hardness based concentrations for metals calculated using a hardness of 300 mg/L as* $CaCO_3$ *and the following formulas:*

$\mathbf{CMC} = exp\{ma[ln(hardness)\}+ba\}$ $\mathbf{CCC} = exp\{mc[ln(hardness)]+bc\}$

| | *ma* | *ba* | *mc* | *bc* |
|---|---|---|---|---|
| *cadmium* | *1.128* | *-3.6867* | *0.7852* | *-2.715* |
| *copper* | *0.9422* | *-1.700* | *0.8545* | *-1.702* |
| *chromium (III)* | *0.8190* | *3.7256* | *0.8190* | *0.6848* |
| *lead* | *1.273* | *-1.460* | *1.273* | *-4.705* |
| *nickel* | *0.8460* | *2.255* | *0.8460* | *0.0584* |
| *silver* | *1.72* | *-6.52* | *-* | *-* |
| *zinc* | *0.8473* | *0.884* | *0.8473* | *0.884* |

Ammonia:

Ammonia (Total as N)

Acute Standard – The one hour average concentration of total ammonia (expressed as N in mg/L) does not exceed more often than once every three years on the average the numerical value given by the following formula:

$$\frac{0.411}{1 + 10^{7.204 - pH}} \quad + \quad \frac{58.4}{1 + 10^{pH-7.204}}$$

Where salmonids are absent; or

$$\frac{0.275}{1 + 10^{7.204 - pH}} \quad + \quad \frac{39.0}{1 + 10^{pH-7.204}}$$

Where salmonids are present.

Chronic Standard- The 30-day average concentration of total ammonia (expressed as N in mg/L) does not exceed more often than once every three years on the average the numerical value given by the following formula; and the highest 4-day average concentration of total ammonia within the 30-day averaging period does not exceed 2.5 times the numerical value given by the following formula:

$$\frac{0.0577}{1 + 10^{7.688 - pH}} \quad + \quad \frac{2.487}{1 + 10^{pH-7.688}} \quad * \quad CV$$

Where: $CV = 2.85$ when $T \leq 14^{0}C$; or

$CV = 1.45 * 10^{0.028*(25-T)}$ when $T > 14^{0}C$.

Narrative North Dakota State Water Quality Standards

The State of North Dakota water quality standards at 33-16-02.1-08 also include general narrative provisions that are applied to surface waters.

"The following minimum conditions are applicable to all waters of the State except Class II ground waters. All waters of the state shall be:

> "Free from substances attributable to municipal, industrial, or other discharges or agricultural practices that will cause the formation of putrescent or otherwise objectionable sludge deposits.
>
> Free from floating debris, oil, scum, and other floating materials attributable to municipal, industrial, or other discharges or agricultural practices in sufficient amounts to be unsightly or deleterious.
>
> Free from materials attributable to municipal, industrial, or other discharges or agricultural practices producing color, odor, or other conditions to such a degree as to create a nuisance or render any undesirable taste to fish flesh or, in any way, make fish inedible.

> Free from substances attributable to municipal, industrial, or other discharges or agricultural practices in concentrations or combinations which are toxic or harmful to humans, animals, plants, or resident aquatic biota. For surface water, this standard will be enforced in part through appropriate whole effluent toxicity requirements in North Dakota pollutant discharge elimination system permits.
>
> Free from oil and grease attributable to wastewater, which causes a visible film or sheen upon the waters or any discoloration of the surface of adjoining shoreline or causes a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines or prevents classified uses of such waters."

## EPA §304(a) Water Quality Criteria

EPA's Office of Science and Technology publishes water quality criteria (EPA Criteria) as guidance for use by States and/or Tribes for use in adopting numeric criteria for protection of designated uses. The EPA Criteria are updated periodically with the latest major revision published in November 2002, *National Recommended Water Quality Criteria: 2002, EPA-822-R-02-047*. Revisions to the aquatic life criteria for cadmium, mercury and ammonia and human health criteria for benzene and mercury were included in the 2002 revisions. In addition, the calculation of hardness dependant metals criteria was updated. EPA also updated its criteria in December 2003, *EPA-822-F-03-012,* for 15 human health water quality criteria including ethylbenzene and toluene. The Tribally-adopted WQS and State WQS did not include some or part of the 2002 and 2003 updates as they were developed prior to publication EPA Region 8 anticipates that both the Tribes and the State will adopt the updated EPA Criteria within the term of the permit. The updated hardness dependant metals criteria are calculated using the following factors:

$\mathbf{CMC} = exp\{ma[ln(hardness)\}+ba\}$ $\qquad$ $\mathbf{CCC} = exp\{mc[ln(hardness)]+bc\}$

| | *ma* | *ba* | *mc* | *bc* |
|---|---|---|---|---|
| *cadmium* | *1.0166* | *-3924* | *0.7409* | *-4.719* |
| *copper* | *0.9422* | *-1.700* | *0.8545* | *-1.702* |
| *chromium (III)* | *0.8190* | *3.7256* | *0.8190* | *0.6848* |
| *lead* | *1.273* | *-1.460* | *1.273* | *-4.705* |
| *nickel* | *0.8460* | *2.255* | *0.8460* | *0.0584* |
| *silver* | *1.72* | *-6.59* | - | - |
| *zinc* | *0.8473* | *0.884* | *0.8473* | *0.884* |

### Ammonia:

The updated ammonia criterion is calculated as follows:

(CMC) Acute Criterion – The one-hour average concentration of total ammonia nitrogen (in mg N/L) does not exceed, more often than once every three years on the average, the CMC (acute criterion) calculated using the following equations:

$$\frac{0.411}{1 + 10^{7.204 - \mathrm{pH}}} \quad + \quad \frac{58.4}{1 + 10^{\mathrm{pH}-7.204}}$$

Where salmonids are absent; or

$$\frac{0.275}{1 + 10^{7.204 - \mathrm{pH}}} \quad + \quad \frac{39.0}{1 + 10^{\mathrm{pH}-7.204}}$$

Where salmonids are present.

(CCC) Chronic Criterion- The thirty-day average concentration of total ammonia nitrogen (expressed as N in mg/L) does not exceed, more often than once every three years on the average, the CCC (chronic criterion) calculated using the following equations:

$$\frac{0.0577}{1 + 10^{7.688 - \mathrm{pH}}} \quad + \quad \frac{2.487}{1 + 10^{\mathrm{pH}-7.688}} \quad * \quad \mathrm{MIN}\,(2.85,\ 1.45*10^{0.028(25-T)})$$

When early life stages are present;

$$\frac{0.0577}{1 + 10^{7.688 - \mathrm{pH}}} \quad + \quad \frac{2.487}{1 + 10^{\mathrm{pH}-7.688}} \quad * \quad 1.45*10^{0.028(25-\mathrm{MAX}(T,7))}$$

When early life stages are absent.

In addition, the highest 4-day average within the 30-day period should not exceed 2.5 times the CCC.

Benzene:

The human health based criterion for benzene was changed to maximum values of 2.2 ug/L for water consumption and 51 ug/L for water plus fish consumption.

Mercury:

The human health based criterion for water plus fish consumption for mercury was changed to a methylmercury fish tissue concentration of 0.3 mg/kg. The updated aquatic life criteria CMC (acute criterion) is 1.4 ug/L and the CCC (chronic criterion) is 0.77 ug/L. EPA Region 8 is recommending that the previous CCC for mercury of 0.012 ug/L be applied to assure protection of the new methylmercury fish tissue criterion.

Ethylbenzene:

The human health based criterion for water + organism and organism only were changed to 530 ug/L and 2,100 ug/L respectively.

Toluene:

The human health based criterion for water + organism and organism only were changed to 1,300 ug/L and 15,000 ug/L respectively.

## Summary of Tribally-adopted WQS and State WQS and EPA 304(a) Criteria

The East Fork of Shell Creek remains primarily within the external boundaries of the Fort Berthold Indian Reservation as it travels towards Lake Sakakawea, however, approximately one mile from the proposed project site it traverses the boundary of the Reservation into the State of North Dakota for a short distance, prior to returning back to the Reservation. As such, WQBELs developed for the proposed facility will take into consideration both Tribally-adopted WQS and State of North Dakota WQS.

Narrative Tribally-adopted WQS and State WQS for prohibiting discharges of toxics in toxic amounts [NDAC 33-16-02.1-08: General Water Quality Standards 1.a.(4)], and Tribal *Narrative Water Quality Criteria a. (4)*, will be considered for the proposed facility.

Tribally-adopted WQS and State WQS for temperature will also be considered for the proposed facility. The standard is eighty-five degrees Fahrenheit (29.44 degrees Celsius) and a maximum increase of greater than five degrees Fahrenheit (2.78 degrees Celsius) above natural background condition.

Tribally-adopted WQS for dissolved oxygen will also be considered for the proposed facility. They will be expressed as a seasonal standards for April 1-September 30 of 8.0 mg/L (1-day minimum), 9.5 mg/L (7-day mean), and 6.5 mg/L (30-day mean); and October 1-March 31 of 4.0 mg/L (1-day minimum), 5.0 mg/L (7-day mean), and 6.5 mg/L (30-day mean).

Table 3 presents a summary of the combined Tribally-adopted WQS, State WQS and EPA Criteria that will be evaluated for effluent limitations and monitoring requirements in this permit. The most stringent WQS are in bold. Where the EPA Criteria are more or less stringent than the Tribally-adopted WQS and/or State WQS, the EPA Criteria have been designated as the applicable value in anticipation of adoption of the EPA Criteria by the State or Tribes. Hardness dependant metals standards are calculated using a hardness of 300 mg/L as $CaCO_3$.

In order to determine if there is reasonable potential for pollutants expected in the discharge to cause or contribute to a violation of water quality standards, a comparison of expected discharge pollutant concentrations with Tribally-adopted WQS, State WQS and EPA water quality criteria was completed. The reasonable potential analysis is presented in Table 4.

## TABLE 3
## Comparison of Tribally-adopted and StateWQS and EPA Criteria

| Pollutant | Tribally-adopted WQS | | State WQS | | EPA Criteria | |
|---|---|---|---|---|---|---|
| | Acute | Chronic | Acute | Chronic | Acute | Chronic |
| Benzene | -- | 1.2[1] | -- | 71 | -- | **2.2** |
| Ethyl benzene | -- | 700 | -- | 29000 | -- | **530** |
| Toluene | -- | 1000[1] | -- | 200000 | -- | **1300** |
| Xylenes | -- | **10000** | -- | -- | -- | -- |
| Phenol | -- | **300** | -- | **300** | -- | **300** |
| Hydrogen Sulfide | -- | **2** | -- | -- | -- | **2.0** |
| Ammonia as N | 1.9[1] | 0.43[1] | **3.2**[2] | **1.1**[2] | **3.2**[2] | **1.1**[2] |
| Barium (tr) | -- | 2000 | -- | **1000** | -- | **1000** |
| Aluminum (tr) | **750** | **87** | -- | -- | **750** | **87** |
| Cadmium (tr) | 13.5 | 2.7 | 15.6 | 5.8 | **6.5** | **0.61** |
| Chromium (III) (tr) | 4270[1] | 100[1] | **4430** | **212** | **4430** | **212** |
| Chromium (VI) | **16** | **11** | **16** | **11** | **16** | **11** |
| Copper (tr) | 49.9 | 30.2 | **39.4** | **23.8** | **39.4** | **23.8** |
| Iron (tr) | -- | **300** | -- | -- | -- | **300** |
| Manganese (tr) | -- | **50** | -- | -- | -- | **50** |
| Lead (tr) | **331** | **12.9** | **331** | **12.9** | **331** | **12.9** |
| Mercury (T) | 2.4 | **0.012** | 1.7 | 0.051 | **1.4** | **0.012**[3] |
| Nickel (tr) | 3592 | 100[1] | **1190** | **132** | **1190** | **132** |
| Selenium (tr) | **20** | **5** | **20** | **5** | **20** | **5** |
| Silver (tr) | 26.8 | -- | 26.8 | -- | **25.0** | -- |
| Zinc (tr) | 297[1] | 269[1] | **304** | **304** | **304** | **304** |
| Chlorine (TRC) | **19** | **11** | **19** | **11** | **19** | **11** |
| Chloride | **860000** | **230000** | -- | 250000 | **860000** | **230000** |
| Fluoride | -- | **4000** | -- | -- | -- | -- |
| Sulfate | -- | -- | -- | **750000** | -- | -- |
| Nitrite as N | -- | **1000** | -- | -- | -- | -- |
| Nitrate as N | -- | **10000** | -- | 1000[4] | -- | **10000** |
| Phosphorous as P | -- | -- | -- | 100[4] | -- | -- |
| PH (s.u.) | **7.0 – 9.0** | | **7.0 – 9.0** | | 6.5 - 9 | |

[1] Tribally-adopted WQS is more stringent than EPA Criteria and will be updated to EPA Criteria value.

[2] Ammonia-N values calculated using a pH of 8.5 and a temperature of $15^0$C. For State WQS and EPA Criteria, salmonid fish are presumed absent (acute) and early life stages are presumed present (chronic).

[3] EPA Region 8 recommends using a water column concentration of 0.012 ug/L Hg (T) to protect the chronic methylmercury fish tissue criterion.

[4] The values for nitrate and phosphorous are interim guidance. In no case shall the standard for nitrates exceed 10 mg/L for any waters used as municipal drinking water supply.

# TABLE 4

## Reasonable Potential Analysis
## (Treated Process Wastewater and Contaminated Stormwater)
## (in ug/L unless otherwise indicated)

| Pollutant | NPDES Permit Application | | Applicable WQS | | Reasonable Potential | |
|---|---|---|---|---|---|---|
| | Daily Maximum | Average Daily | Acute | Chronic | Acute | Chronic |
| Benzene | 10 | 10 | -- | 2.2 | -- | Yes |
| Ethyl benzene | 0.0 | 0.0 | -- | 530 | -- | No[1] |
| Toluene | 0.0 | 0.0 | -- | 1300 | -- | No[1] |
| Xylenes | NE | NE | -- | 10000 | -- | No |
| Phenol | 300 | 300 | -- | 300 | -- | Yes |
| Hydrogen Sulfide | 0.0 | 0.0 | -- | 2.0 | -- | No[2] |
| Ammonia as N (mg/L) | 145 | 90 | 3.2 | 1.1 | Yes | Yes |
| Barium (tr) | 200 | 10 | -- | 1000 | -- | Yes |
| Aluminum (tr) | 80 | 10 | 750 | 87 | Yes | Yes |
| Cadmium (tr) | 0.0 | 0.0 | 6.5 | 0.61 | No[3] | No[3] |
| Chromium (III) (tr) | 0.0 | 0.0 | 4430 | 212 | No[2] | No[2] |
| Chromium (VI) | NR | NR | 16 | 11 | No[2] | No2 |
| Copper (tr) | 0.0 | 0.0 | 39.4 | 23.8 | No[3] | No[3] |
| Iron (tr) | 250 | 40 | -- | 300 | -- | Yes |
| Manganese (tr) | 50 | 20 | -- | 50 | -- | Yes |
| Lead (tr) | 0.0 | 0.0 | 331 | 12.9 | No[3] | No[3] |
| Mercury (T) | 0.0 | 0.0 | 1.4 | 0.012 | No[1] | No[1] |
| Nickel (tr) | 50 | 50 | 1190 | 132 | Yes | Yes |
| Selenium (tr) | 10 | 10 | 20 | 5 | Yes | Yes |
| Silver (tr) | 0.0 | 0.0 | 25.0 | -- | No[3] | -- |
| Zinc (tr) | 0.0 | 0.0 | 304 | 304 | No[3] | No[3] |
| Chlorine (TRC) | 0.0 | 0.0 | 19 | 11 | No | No |
| Chloride | NR | NR | 860000 | 230000 | No[1] | No[1] |
| Fluoride | 3500 | 1000 | -- | 4000 | -- | Yes |
| Sulfate | 150000 | 90000 | -- | 750000 | -- | Yes |
| Nitrite as N | NR | NR | -- | 1000 | -- | No[1] |
| Nitrate as N | 40 | 20 | -- | 10000 | -- | Yes |
| Phosphorous as P | 200 | 120 | -- | 100[4] | -- | Yes[4] |
| PH (s.u.) | 8.00– 8.50 | | 7.0 – 9.0 | | Yes | |

[1] Reported as 0.0 ppm in permit application but likely to be present in discharge. Limits and monitoring will be required for this parameter.

[2] Reported as 0.0 ppm in permit application but likely to be present in discharge. Also covered by ELG. Limits and monitoring will be required for this parameter.

[3] Reported as 0.0 ppm in permit application but likely to be present in the discharge at low concentration so monitoring only will apply.

[4] State WQS is a guideline only, so monitoring only will be required.

NE- reported as not expected to be present

NR- not reported in application

note: Boron was reported in the permit application at 1500 ug/L (daily maximum) and 100 ug/L (average daily) but there are no applicable WQS or EPA Criteria.

## Technology Based Effluent Limitations

The proposed MHA Nation Clean Fuels refinery will be a new source and must comply with New Source Performance Standards (NSPS) under the Effluent Limitations Guidelines and Standards for the Petroleum Refining Point Source Category pursuant to §40 CFR 419.36. The proposed refinery size is 10,000 bpsd of synthetic crude plus 3,000 bpsd of field butane for a total refinery throughput of of 13,000 bpsd. The proposed refinery process configuration is covered under Subpart C Petrochemical Subcategory of the Petroleum Refining Point Source Category.

### Process Effluent Limitations

Process Configuration (1000 bbl/day) [see §40 CFR 419.42(b)(3)]

| Feedstock Process | Feedstock Rate | Relative Rate | Weight Factor | Process Configuration |
|---|---|---|---|---|
| Crude- Atm. Dist | 10 | 0.769 | 1 | 0.769 |
| Cracking (Hydrocracking) | 6.872 | 0.529 | 6 | 3.17 |
| Isomerization | 3 | 0.231 | 13 | 3.00 |
| **Total** | | | | **6.94** |

Using the above Process Configuration (6.94) and a 13, 000 bbl/day capacity, a Size Factor (SF) of 0.73 and a Process Factor (PF) of 1.08 are derived pursuant to §40 CFR 419.36(b).

New Source Performance Standards (NSPS): Using the above Capacity, Size and Process factors, the following table shows applicable effluent limitations for this facility. [Limit (lbs/1000 bbl) X (PF) X (SF) = Effluent Limit (lbs/day)] [§40 CFR 419.36(a)]:

TABLE 5

| | Effluent Limitation | | Effluent Limitations | |
|---|---|---|---|---|
| Pollutant | Daily Maximum (lbs/1000 bbl) | Average Daily (lbs/1000 bbl) | Daily Maximum (lbs/day) | Average Daily (lbs/day) |
| $BOD_5$ | 7.7 | 4.1 | 78.92 | 42.02 |
| TSS | 5.2 | 3.3 | 53.30 | 33.82 |
| COD | 47.0 | 24.0 | 481.71 | 245.98 |
| Oil and Grease | 2.4 | 1.3 | 24.60 | 13.32 |
| Phenolic Compounds | 0.056 | 0.027 | 0.57 | 0.28 |
| Ammonia as N | 8.3 | 3.8 | 85.07 | 38.95 |
| Sulfide | 0.050 | 0.022 | 0.51 | 0.23 |
| Total Chromium | 0.116 | 0.068 | 1.19 | 0.70 |
| Hexavalent Chromium | 0.0096 | 0.0044 | 0.098 | 0.045 |
| pH | | | 6.0 to 9.0 | |

BAT, BPT, BCT : Limitations for BAT, BPT, and BCT were also evaluated using the above factors. Only BAT limitations for ammonia as N were more stringent than NSPS standards above. The following BAT limits will be evaluated against water quality standards [§40 CFR 419.33(a)]:

| | Daily Maximum (lbs./day) | Average Daily (lbs./day) |
|---|---|---|
| Ammonia as N | 84.56 | 38.95 |

## Contaminated Runoff Allowance

### Best Professional Judgment (BPJ)

The NSPS do not contain pollutant allowances for contaminated stormwater runoff from process areas. Regulations under §40 CFR 419.36(e) were reserved. The BPT [§40 CFR 419.32(e), BAT [§40 CFR 419.33(f)], and BCT [§40 CFR 419.34(e)] allowances for contaminated runoff were evaluated using best professional judgment (BPJ) for this proposed facility. The BPT/BAT/BCT allowances are based on flow and for this facility, average contaminated stormwater flows of 4.4 gallons per minute (6,336 gallons per day) as reported in the NPDES permit application was used for the allowance calculation. BPT allowances were equivalent to BAT and BCT except for BAT for total chromium was more stringent. The stormwater allowances shown in Table 6 will be added to the process allowances for the total facility effluent limitations (see Table 7).

TABLE 6

| | Effluent Limitation | | Effluent Limitations | |
|---|---|---|---|---|
| | Daily Maximum (lbs/1000 gal) | Average Daily (lbs/1000 gal) | Daily Maximum (lbs/day) | Average Daily (lbs/day) |
| Pollutant | | | | |
| $BOD_5$ | 0.40 | 0.22 | 2.53 | 1.39 |
| TSS | 0.28 | 0.18 | 1.77 | 1.14 |
| COD | 3.0 | 1.5 | 19.01 | 9.5 |
| Oil and Grease | 0.13 | 0.067 | 0.82 | 0.42 |
| Phenolic Compounds | 0.0029 | 0.0014 | 0.0184 | 0.0089 |
| Ammonia as N | 0 | 0 | 0 | 0 |
| Sulfide | 0 | 0 | 0 | 0 |
| Total Chromium | 0.0050 | 0.0018 | 0.032 | 0.011 |
| Hexavalent Chromium | 0.00052 | 0.00023 | 0.0033 | 0.0015 |
| pH | 6.0 to 9.0 | | 6.0 to 9.0 | |

**Total Technology Effluent Limitations**

(Process + Stormwater = Total)

TABLE 7

| | Process Effluent Limitation | | Stormwater Effluent Limitations | | Total Effluent Limitations | |
|---|---|---|---|---|---|---|
| | Daily Maximum (lbs/day) | Average Daily (lbs/day) | Daily Maximum (lbs/day) | Average Daily (lbs/day) | Daily Maximum (lbs/day) | Average Daily (lbs/day) |
| Pollutant | | | | | | |
| $BOD_5$ | 78.92 | 42.02 | 2.53 | 1.39 | 81.45 | 43.41 |
| TSS | 53.30 | 33.82 | 1.77 | 1.14 | 55.07 | 34.96 |
| COD | 481.71 | 245.98 | 19.01 | 9.50 | 500.72 | 255.48 |
| Oil and Grease | 24.60 | 13.32 | 0.82 | 0.42 | 25.42 | 13.74 |
| Phenolic Compounds | 0.57 | 0.28 | 0.0184 | 0.0089 | 0.59 | 0.29 |
| Ammonia as N | 84.56 | 38.95 | 0 | 0 | 84.56 | 38.95 |
| Sulfide | 0.51 | 0.23 | 0 | 0 | 0.51 | 0.23 |
| Total Chromium | 1.19 | 0.70 | 0.032 | 0.011 | 1.222 | 0.711 |
| Hexavalent Chromium | 0.098 | 0.045 | 0.0033 | 0.0015 | 0.101 | 0.046 |
| pH | 6.0 to 9.0 | | | | 6.0 to 9.0 | |

**Conversion of Technology Based Mass Limits to Concentration Limits**

The mass based technology limits above were converted to concentration based limits using flow information provided in the NPDES Permit Application (Table 8). Under the proposed alternative in the DEIS, with full recycle, the average daily flow is anticipated to be approximately 15,000 gallons per day (gpd) and the maximum daily flow of approximately 35,000 gpd. (See DEIS Figure 2-3) Without recycle average daily and maximum daily flows are anticipated to be approximately 30,000 gpd and 50,000 gpd. (See DEIS Figure 2-4.) Under Alternative 4 of the DEIS, maximum flow is expected to be 76,320 gpd and average 28,800 gpd. For this conversion, the highest maximum flow (Alternative 4) will be used as it would be protective of technology requirements regardless of recycle rates or choice of discharge alternative. Conversion factors are 3.785 l/gal, and 454,500 mg/lb.

TABLE 8

| | Effluent Limitation | | Effluent Limitations | |
|---|---|---|---|---|
| | Daily Maximum (lbs/day) | Average Daily (lbs/day) | Daily Maximum (mg/L) | Average Daily (mg/L) |
| Pollutant | | | | |
| $BOD_5$ | 81.45 | 43.41 | 128 | 68 |
| TSS | 55.07 | 34.96 | 87 | 55 |
| COD | 500.72 | 255.48 | 788 | 402 |
| Oil and Grease | 25.42 | 13.74 | 40 | 22 |
| Phenolic Compounds | 0.59 | 0.29 | 0.93 | 0.45 |
| Ammonia as N | 84.56 | 38.95 | 133 | 61 |
| Sulfide | 0.51 | 0.23 | 0.8 | 0.4 |
| Total Chromium | 1.222 | 0.711 | 1.9 | 1.1 |
| Hexavalent Chromium | 0.101 | 0.046 | 0.16 | 0.07 |

## Comparison of Water Quality Based and Technology Based Effluent Limitations

Table 9 contains a comparison of water quality and technology based requirements. The more stringent limit will be carried forward as an effluent limitation in the proposed permit:

TABLE 9

| Pollutant | Technology Based Limit (ug/L) | | Water Quality Based Limit (ug/L) | | Most Stringent Limit (ug/L) | |
|---|---|---|---|---|---|---|
| | Daily Maximum | Average Daily | Daily Maximum | Average Daily | Daily Maximum | Average Daily |
| $BOD_5$ (lbs/day) | **81** | **43** | **(a)** | **(a)** | 81 (a) | 43 (a) |
| COD (lbs/day) | **500** | **255** | **(a)** | **(a)** | 500 (a) | 255 (a) |
| TSS (lbs/day) | **55** | **35** | N/A | N/A | 55 | 35 |
| Oil and Grease (lbs/day) | **25.4** | **13.7** | N/A | N/A | 25.4 | 13.7 |
| Benzene | N/A | N/A | -- | **2.2** | -- | 2.2 |
| Ethyl benzene | N/A | N/A | -- | **530** | -- | 530 |
| Toluene | N/A | N/A | -- | **1300** | -- | 1300 |
| Phenol | N/A | N/A | -- | **300** | -- | 300 |
| Phenolic Compounds (lbs/day) | **0.59** | **0.29** | N/A | N/A | 0.59 | 0.29 |
| Hydrogen Sulfide | 800 | 400 | -- | **2.0** | -- | 2.0 |
| Ammonia as N (mg/L) | 133 | 61 | **3.2** | **1.1** | 3.2 | 1.1 |
| Barium (tr) | N/A | N/A | -- | **1000** | -- | 1000 |
| Aluminum (tr) | N/A | N/A | **750** | **87** | 750 | 87 |
| Cadmium (tr) | N/A | N/A | **6.5** | **0.61** | MON | MON |
| Chromium (III) (tr) | **1900** | 1100 | 4430 | **212** | MON | MON |
| Chromium (Total) (lbs/day) | **1.22** | 0.71 | 1.84 | **0.035** | 1.22 | 0.035 |
| Chromium (VI) | 160 | 70 | **16** | **11** | 16 | 11 |
| Chromium (VI) (lbs/day) | 0.101 | 0.046 | **0.0067** | **0.0018** | 0.0067 | 0.0018 |
| Copper (tr) | N/A | N/A | **39.4** | **23.8** | MON | MON |
| Iron (tr) | N/A | N/A | -- | **300** | -- | 300 |
| Manganese (tr) | N/A | N/A | -- | **50** | -- | 50 |
| Lead (tr) | N/A | N/A | **331** | **12.9** | MON | MON |
| Mercury (T) | N/A | N/A | **1.4** | **0.012** | 1.4 | 0.012 |
| Nickel (tr) | N/A | N/A | **1190** | **132** | 1190 | 132 |
| Selenium (tr) | N/A | N/A | **20** | **5** | 20 | 5 |
| Silver (tr) | N/A | N/A | **25.0** | -- | MON | -- |
| Zinc (tr) | N/A | N/A | **304** | **304** | MON | MON |
| Chloride | N/A | N/A | **860000** | **230000** | 860000 | 230000 |
| Fluoride | N/A | N/A | -- | **4000** | -- | 4000 |
| Sulfate | N/A | N/A | -- | **750000** | -- | 750000 |
| Nitrite as N | N/A | N/A | -- | **1000** | -- | 1000 |
| Nitrate as N | N/A | N/A | -- | **10000** | -- | 10000 |
| Phosphorous as P | N/A | N/A | -- | **100** | -- | MON |
| pH (s.u.) | 6.0– 9.0 | | **7.0 – 9.0** | | 7.0 – 9.0 | |

(a) Oxygen demanding parameters (BOD, COD) will also be limited by WQS for dissolved oxygen.
MON- Monitor Only

## Whole Effluent Toxicity Limitations (Outfall 002)

The MHA Nation Water Quality Standards (Tribally-adopted WQS) contain narrative conditions that ensure surface waters of the Reservation are free from substances in wastewater discharges that "*cause injury to, or are toxic to, or produce adverse physiological responses in humans, animals or plants…"* Implementation of the narrative Tribally-adopted WQS for purposes of NPDES permits "*shall result in appropriate acute and chronic effluent quality limitations consistent with the federal water quality-based permitting found at 40 CFR 122.44(d),* ***including whole effluent toxicity (WET) limitations*** *as required in the latest edition of the EPA Region VIII NPDES Whole Effluent Toxics Control Program document."* (1997 Region 8 WET Policy)

Since the proposed MHA Nation Clean Fuels Refinery will have discharges from Outfall 002 that may contain substances that alone or in combination with other substances that exhibit toxicity to aquatic organisms, whole effluent toxicity (WET) limitations will be imposed in the proposed permit. In accordance with the Region 8 WET Policy, the permit will require both acute and chronic WET limits and monitoring for two species, *ceriodaphnia dubia* and *pimephales promelas* on a quarterly basis. The requirement for both acute and chronic WET limits and monitoring is due to the uncertain nature of the treated process wastewater discharge from this new facility. If the results of at least ten WET tests during this permit term show there is no reasonable potential for acute and/or chronic WET the discharge, the permittee may request a reduction in test frequency and/or number of species. The WET monitoring data collected during this proposed permit term will also be evaluated at the time of permit reissuance for reasonable potential and if a reduction in test frequency and/or number of species tested is warranted.

Proposed effluent limitations and monitoring frequencies for Outfall 002 are presented in Tables 10 and 11 respectively.

## Proposed Numeric Effluent Limitations (Outfall 002)

TABLE 10

| Pollutant | Effluent Limit (ug/L) | | Basis for Effluent Limitation |
|---|---|---|---|
| | Daily Maximum | Average Daily | |
| Flow, MGD | 0.08 | 0.03 | Permit Application , DEIS |
| BOD$_5$ (lbs/day) | 81 | 43 | §40 CFR 419 |
| COD (lbs/day) | 500 | 255 | §40 CFR 419 |
| TSS (lbs/day) | 55 | 35 | §40 CFR 419 |
| Oil and Grease (lbs/day) | 25.4 | 13.7 | §40 CFR 419 |
| Benzene | NA | 2.2 | EPA 304(a) Criterion |
| Ethyl benzene | NA | 530 | EPA 304(a) Criterion |
| Toluene | NA | 1300 | EPA 304(a) Criterion |
| Phenol | NA | 300 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Phenolic Compounds (lbs/day) | 0.59 | 0.29 | §40 CFR 419 |
| Hydrogen Sulfide | NA | 2.0 | EPA 304(a) Criterion, Tribal WQS |
| Ammonia as N (mg/L) | 3.2 | 1.1 | EPA 304(a) Criterion, State WQS |
| Barium (tr) | NA | 1000 | EPA 304(a) Criterion, State WQS |
| Aluminum (tr) | 750 | 87 | EPA 304(a) Criterion, Tribal WQS |
| Cadmium (tr) | MON | MON | EPA 304(a) Criterion |
| Chromium (Total) (lbs/day) | 1.22 | 0.035 | §40 CFR 419, State WQS,EPA 304(a) Criterion |
| Chromium (VI) | 16 | 11 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Chromium (VI) (lbs/day) | 0.0067 | 0.0018 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Copper (tr) | MON | MON | EPA 304(a) Criterion, State WQS |
| Iron (tr) | NA | 300 | EPA 304(a) Criterion, Tribal WQS |
| Manganese (tr) | NA | 50 | EPA 304(a) Criterion, Tribal WQS |
| Lead (tr) | MON | MON | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Mercury (T) | 1.4 | 0.0012 | EPA 304(a) Criterion, Tribal WQS |
| Nickel (tr) | 1190 | 132 | EPA 304(a) Criterion, State WQS |
| Selenium (tr) | 20 | 5 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Silver (tr) | MON | MON | EPA 304(a) Criterion |
| Zinc (tr) | MON | MON | EPA 304(a) Criterion, State WQS |
| Chloride | 860000 | 230000 | EPA 304(a) Criterion, Tribal WQS |
| Fluoride | NA | 4000 | Tribal WQS |
| Sulfate | NA | 750000 | State WQS |
| Nitrite as N | NA | 1000 | Tribal WQS |
| Nitrate as N | NA | 10000 | EPA 304(a) Criterion, Tribal WQS |
| Phosphorous as P | MON | MON | State WQS |
| pH (s.u.) | 7.0– 9.0 | | State WQS, Tribal WQS |
| WET, acute | LC$_{50}$ > 100% | | Narrative Tribal WQS and State WQS |
| WET, chronic | IC$_{25}$ > 100% | | Narrative Tribal WQS and State WQS |
| Dissolved Oxygen (mg/L) | April 1 – Sept 30<br>8.0 (1-day min.)<br>9.5 (7-day mean)<br>6.5 (30-day mean)<br>Oct 1 – March 31<br>4.0 (1-day min.)<br>5.0 (7-day mean)<br>6.5 (30-day mean) | | Tribal WQS |

MON- Monitor Only

The discharge from Outfall 002 shall be free from oil and grease attributable to wastewater, which causes a visible film or sheen upon the waters or any discoloration of the surface of adjoining shoreline or causes a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines or prevents classified uses of such waters.

## Proposed Effluent Monitoring Requirements (Outfall 002)

TABLE 11

| Pollutant | Monitoring Frequency | Sample Type |
|---|---|---|
| Flow, MGD | Daily | Continuous, Recorder |
| $BOD_5$ , lbs/day | 2X/Week | Composite |
| COD, lbs/day | Monthly | Composite |
| TSS, lbs/day | 2X/Week | Composite |
| Oil and Grease, lbs/day | Weekly | Grab |
| Benzene, ug/L | Monthly | Grab |
| Ethyl benzene, ug/L | Monthly | Grab |
| Toluene, ug/L | Monthly | Grab |
| Phenol, ug/L | Monthly | Grab |
| Phenolic Compounds, lbs/day | Monthly | Grab |
| Hydrogen Sulfide, ug/L | Weekly | Grab |
| Ammonia as N, mg/L | Weekly | Composite |
| Barium (tr), ug/L | Monthly | Composite |
| Aluminum (tr), ug/L | Monthly | Composite |
| Chromium (Total), lbs/day | Monthly | Composite |
| Chromium (VI), ug/L | Monthly | Grab |
| Chromium (VI), lbs/day | Monthly | Grab |
| Iron (tr), ug/L | Monthly | Composite |
| Manganese (tr), ug/L | Monthly | Composite |
| Mercury (T), ug/L | Monthly | Composite |
| Nickel (tr), ug/L | Monthly | Composite |
| Selenium (tr), ug/L | Monthly | Composite |
| Chloride, ug/L | Monthly | Composite |
| Fluoride, ug/L | Monthly | Composite |
| Sulfate, ug/L | Monthly | Composite |
| Nitrite as N, ug/L | Monthly | Composite |
| Nitrate as N, ug/L | Monthly | Composite |
| Phosphorous as P, ug/L | Monthly | Composite |
| pH (s.u.) | Daily | Grab or Continuous |
| WET, acute | Quarterly | Composite |
| WET, chronic | Quarterly | Grab |
| Dissolved Oxygen, mg/L | Daily | Grab |
| Temperature, $^{o}C$ | Daily | Grab |

Additional Monitoring Requirement for Outfall 002:

Approximately 90 days and 270 days after startup of the facility, monitoring shall be required for:

Total Metals – Table III §40CFR 122 Appendix D
Volatile, acid, and base/neutral compounds – Table II §40CFR 122 Appendix D

## Contaminated (oily) Stormwater (Outfall 002a)

Under Alternative 4 of the DEIS, an additional Outfall (002a) is proposed for discharges of segregated contaminated (oily) stormwater. The discharge of this wastewater may be necessary due to the lack of storage capacity in the wastewater tank system to contain all runoff resulting from unusual or episodic precipitation events.

### Technology Limitations

Best Professional Judgment (BPJ)

The NSPS for Petroleum Refining (§40 CFR 419.36) also do not contain provisions for release of segregated contaminated stormwater runoff from process areas. As discussed under Outfall 002 above, regulations under §40 CFR 419.36(e) were reserved.

The BPT [§40 CFR 419.32(e)], BAT [§40 CFR 419.33(f)], and BCT [§40 CFR 419.34(e)] provisions for discharge of segregated contaminated runoff were evaluated using best professional judgment (BPJ) for this proposed facility. The BPT/BAT/BCT provisions limit discharge to segregated contaminated (oily) stormwater that is not commingled or treated with process wastewater that meets the following limitations:

| | |
|---|---|
| BPT | Oil and Grease <15 mg/L |
| BAT | Total Organic Carbon <110 mg/L |
| BCT | Oil and Grease <15 mg/L |

The limits cannot be exceeded in either a grab or composite sample of the discharge.

### Water Quality Based Effluent Limitations

Numeric and Narrative Water Quality Standards and Criteria

Numeric water quality standards considered in establishing limitations for this discharge would be the same as presented in Table 3 above.

Narrative water quality standards (dissolved oxygen, whole effluent toxicity, etc.) considered in establishing effluent limitations would also be the same as described for discharges through Outfall 002 above.

Reasonable Potential

Water quality standard based effluent limitations will also be evaluated for the discharges of segregated contaminated (oily) stormwater. Pollutants reported in the permit application for the combined process and contaminated (oily) stormwater for Outfall 002 were compared with Tribally-adopted WQS, State WQS and EPA criteria. Table 12 shows the comparison. Tables 13 and 14 show proposed effluent limits and monitoring requirements for Outfall 002a.

Reasonable Potential Analysis (Contaminated (oily) Stormwater)
(in ug/L unless otherwise indicated)
Table 12

| Pollutant | NPDES Permit Application | | Applicable WQS | | Reasonable Potential | |
|---|---|---|---|---|---|---|
| | Daily Maximum | Average Daily | Acute | Chronic | Acute | Chronic |
| Benzene | 10 | 10 | -- | 2.2 | -- | Yes |
| Ethyl benzene | 0.0 | 0.0 | -- | 530 | -- | No[1] |
| Toluene | 0.0 | 0.0 | -- | 1300 | -- | No[1] |
| Xylenes | NE | NE | -- | 10000 | -- | No |
| Phenol | 300 | 300 | -- | 300 | -- | Yes |
| Hydrogen Sulfide | 0.0 | 0.0 | -- | 2.0 | -- | No[2] |
| Ammonia as N (mg/L) | 145 | 90 | 3.2 | 1.1 | Yes | Yes |
| Barium (tr) | 200 | 10 | -- | 1000 | -- | Yes |
| Aluminum (tr) | 80 | 10 | 750 | 87 | Yes | Yes |
| Cadmium (tr) | 0.0 | 0.0 | 6.5 | 0.61 | No[3] | No[3] |
| Chromium (III) (tr) | 0.0 | 0.0 | 4430 | 212 | No[2] | No[2] |
| Chromium (VI) | NR | NR | 16 | 11 | No[2] | No2 |
| Copper (tr) | 0.0 | 0.0 | 39.4 | 23.8 | No[3] | No[3] |
| Iron (tr) | 250 | 40 | -- | 300 | -- | Yes |
| Manganese (tr) | 50 | 20 | -- | 50 | -- | Yes |
| Lead (tr) | 0.0 | 0.0 | 331 | 12.9 | No[3] | No[3] |
| Mercury (T) | 0.0 | 0.0 | 1.4 | 0.012 | No[1] | No[1] |
| Nickel (tr) | 50 | 50 | 1190 | 132 | Yes | Yes |
| Selenium (tr) | 10 | 10 | 20 | 5 | Yes | Yes |
| Silver (tr) | 0.0 | 0.0 | 25.0 | -- | No[3] | -- |
| Zinc (tr) | 0.0 | 0.0 | 304 | 304 | No[3] | No[3] |
| Chlorine (TRC) | 0.0 | 0.0 | 19 | 11 | No | No |
| Chloride | NR | NR | 860000 | 230000 | No[1] | No[1] |
| Fluoride | 3500 | 1000 | -- | 4000 | -- | Yes |
| Sulfate | 150000 | 90000 | -- | 750000 | -- | Yes |
| Nitrite as N | NR | NR | -- | 1000 | -- | No[1] |
| Nitrate as N | 40 | 20 | -- | 10000 | -- | Yes |
| Phosphorous as P | 200 | 120 | -- | 100[4] | -- | Yes[4] |
| PH (s.u.) | 8.00– 8.50 | | 7.0 – 9.0 | | Yes | |

[1] Reported as 0.0 ppm in permit application but likely to be present in discharge. Limits and monitoring will be required for this parameter.

[2] Reported as 0.0 ppm in permit application but likely to be present in discharge. Also covered by ELG. Limits and monitoring will be required for this parameter.

[3] Reported as 0.0 ppm in permit application but likely to be present in the discharge at low concentration so monitoring only will apply.

[4] State WQS is a guideline only, so monitoring only will be required.

NE- reported as not expected to be present
NR- not reported in application

note: Boron was reported in the permit application at 1500 ug/L (daily maximum) and 100 ug/L (average daily) but there are no applicable WQS or EPA Criteria.

## Proposed Numeric Effluent Limitations (Outfall 002a)

TABLE 13

| Pollutant | Effluent Limit (ug/L) | | Basis for Effluent Limitation |
|---|---|---|---|
| | Daily Maximum | Average Daily | |
| Flow, MGD | 0.027 | 0.0065 | Permit Application, DEIS |
| Oil and Grease, mg/L | 15 | 15 | BPJ (40 CFR 419) |
| Total Organic Carbon, mg/L | 110 | 110 | BPJ (40 CFR 419) |
| Benzene | NA | 2.2 | EPA 304(a) Criterion |
| Ethyl benzene | NA | 530 | EPA 304(a) Criterion |
| Toluene | NA | 1300 | EPA 304(a) Criterion |
| Phenol | NA | 300 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Hydrogen Sulfide | NA | 2.0 | EPA 304(a) Criterion, Tribal WQS |
| Ammonia as N (mg/L) | 3.2 | 1.1 | EPA 304(a) Criterion, State WQS |
| Barium (tr) | NA | 1000 | EPA 304(a) Criterion, State WQS |
| Aluminum (tr) | 750 | 87 | EPA 304(a) Criterion, Tribal WQS |
| Cadmium (tr) | MON | MON | EPA 304(a) Criterion |
| Chromium (VI) | 16 | 11 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Copper (tr) | MON | MON | EPA 304(a) Criterion, State WQS |
| Iron (tr) | NA | 300 | EPA 304(a) Criterion, Tribal WQS |
| Manganese (tr) | NA | 50 | EPA 304(a) Criterion, Tribal WQS |
| Lead (tr) | MON | MON | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Mercury (T) | 1.4 | 0.0012 | EPA 304(a) Criterion, Tribal WQS |
| Nickel (tr) | 1190 | 132 | EPA 304(a) Criterion, State WQS |
| Selenium (tr) | 20 | 5 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Silver (tr) | MON | MON | EPA 304(a) Criterion |
| Zinc (tr) | MON | MON | EPA 304(a) Criterion, State WQS |
| Chloride | 860000 | 230000 | EPA 304(a) Criterion, Tribal WQS |
| Fluoride | NA | 4000 | Tribal WQS |
| Sulfate | NA | 750000 | State WQS |
| Nitrite as N | NA | 1000 | Tribal WQS |
| Nitrate as N | NA | 10000 | EPA 304(a) Criterion, Tribal WQS |
| Phosphorous as P | MON | MON | State WQS |
| pH (s.u.) | 7.0– 9.0 | | State WQS, Tribal WQS |
| WET, acute | $LC_{50}$ > 100% | | Narrative Tribal WQS and State WQS |
| WET, chronic | $IC_{25}$ > 100% | | Narrative Tribal WQS and State WQS |
| Dissolved Oxygen (mg/L) | April 1 – Sept 30<br>8.0 (1-day min.)<br>9.5 (7-day mean)<br>6.5 (30-day mean)<br><br>Oct 1 – March 31<br>4.0 (1-day min.)<br>5.0 (7-day mean)<br>6.5 (30-day mean) | | Tribal WQS |

MON- Monitor Only

The discharge from Outfall 002a shall be free from oil and grease attributable to wastewater, which causes a visible film or sheen upon the waters or any discoloration of the surface of adjoining shoreline or causes a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines or prevents classified uses of such waters.

## Proposed Effluent Monitoring Requirements (Outfall 002a)

Table 14

| Pollutant | Monitoring Frequency | Sample Type |
|---|---|---|
| Flow, MGD | Daily | Continuous, Recorder |
| TOC, mg/L | Weekly | Composite |
| Oil and Grease, mg/L, visual | Daily | Visual[1] |
| Oil and Grease, mg/L | Weekly | Grab |
| Benzene, ug/L | Monthly | Grab |
| Ethyl benzene, ug/L | Monthly | Grab |
| Toluene, ug/L | Monthly | Grab |
| Phenol, ug/L | Monthly | Grab |
| Hydrogen Sulfide, ug/L | Weekly | Grab |
| Ammonia as N, mg/L | Weekly | Composite |
| Barium (tr), ug/L | Monthly | Composite |
| Aluminum (tr), ug/L | Monthly | Composite |
| Chromium (VI), ug/L | Monthly | Grab |
| Iron (tr), ug/L | Monthly | Composite |
| Manganese (tr), ug/L | Monthly | Composite |
| Mercury (T), ug/L | Monthly | Composite |
| Nickel (tr), ug/L | Monthly | Composite |
| Selenium (tr), ug/L | Monthly | Composite |
| Chloride, ug/L | Monthly | Composite |
| Fluoride, ug/L | Monthly | Composite |
| Sulfate, ug/L | Monthly | Composite |
| Nitrite as N, ug/L | Monthly | Composite |
| Nitrate as N, ug/L | Monthly | Composite |
| Phosphorous as P, ug/L | Monthly | Composite |
| pH (s.u.) | Daily | Grab or Continuous |
| WET, acute | Quarterly | Composite |
| WET, chronic | Quarterly | Grab |
| Dissolved Oxygen, mg/L | Daily | Grab |
| Temperature, $^{o}$C | Daily | Grab |

[1] A daily visual observation is required. If a visible sheen is detected, a grab sample shall be taken and analyzed immediately. The concentration of oil and grease shall not exceed 15 mg/L in any sample.

# Uncontaminated (non-oily) Stormwater (Outfall 001)

## Water Quality Based Effluent Limits

Water quality based effluent limits are evaluated for the discharges of uncontaminated (non-oily) stormwater from Outfall 001. A reasonable potential analysis for pollutants expected to be in the discharge from Outfall 001 is presented in Table 15.

TABLE 15
Reasonable Potential Analysis (Uncontaminated (non-oily) Stormwater)
(in ug/L unless otherwise indicated)

| Pollutant | NPDES Permit Application | | Applicable WQS | | Reasonable Potential | |
|---|---|---|---|---|---|---|
| | Daily Maximum | Average Daily | Acute | Chronic | Acute | Chronic |
| Benzene | 0.0 | 0.0 | -- | 2.2 | -- | No |
| Ethyl benzene | 0.0 | 0.0 | -- | 530 | -- | No |
| Toluene | 0.0 | 0.0 | -- | 1300 | -- | No |
| Xylenes | NE | NE | -- | 10000 | -- | No |
| Phenol | 300 | 0.0 | -- | 300 | -- | Yes |
| Hydrogen Sulfide | 0.0 | 0.0 | -- | 2.0 | -- | No |
| Ammonia as N (mg/L) | 0.0 | 0.0 | 3.2 | 1.1 | No | No |
| Barium (tr) | 0.0 | 0.0 | -- | 1000 | -- | No |
| Aluminum (tr) | 0.0 | 0.0 | 750 | 87 | No | No |
| Cadmium (tr) | 0.0 | 0.0 | 6.5 | 0.61 | No | No |
| Chromium (III) (tr) | 0.0 | 0.0 | 4430 | 212 | No | No |
| Chromium (VI) | NR | NR | 16 | 11 | No | No |
| Copper (tr) | 0.0 | 0.0 | 39.4 | 23.8 | No | No |
| Iron (tr) | 200 | 0.0 | -- | 300 | -- | Yes |
| Manganese (tr) | 50 | 0.0 | -- | 50 | -- | Yes |
| Lead (tr) | 0.0 | 0.0 | 331 | 12.9 | No | No |
| Mercury (T) | 0.0 | 0.0 | 1.4 | 0.012 | No | No |
| Nickel (tr) | 0.0 | 0.0 | 1190 | 132 | No | No |
| Selenium (tr) | 10 | 0.0 | 20 | 5 | Yes | Yes |
| Silver (tr) | 0.0 | 0.0 | 25.0 | -- | No | -- |
| Zinc (tr) | 0.0 | 0.0 | 304 | 304 | No | No |
| Chlorine (TRC) | 0.0 | 0.0 | 19 | 11 | No | No |
| Chloride | NR | NR | 860000 | 230000 | No | No |
| Fluoride | 0.0 | 0.0 | -- | 4000 | -- | Yes |
| Sulfate | 60000 | 0.0 | -- | 750000 | -- | Yes |
| Nitrite as N | NR | NR | -- | 1000 | -- | No |
| Nitrate as N | 40 | 0.0 | -- | 10000 | -- | Yes |
| Phosphorous as P | 300 | 0.0 | -- | 100[4] | -- | Yes |
| pH (s.u.) | 8.00– 8.50 | | 7.0 – 9.0 | | Yes | |

[4] State WQS is a guideline only, so monitoring only will be required.
NE- reported as not expected to be present
NR- not reported in application

note: Boron was reported in the permit application at 1000 ug/L (daily maximum) but there are no applicable WQS or EPA Criteria.

Limits for Outfall 001

Uncontaminated (non-oily) wastewater discharges from Outfall 001 will meet the effluent limitations shown in Table 16. The limits are based on numeric and narrative water quality standards. Proposed monitoring requirements for Outfall 001 are shown in Table 17.

## Proposed Numeric Effluent Limitations (Outfall 001)

TABLE 16

| Pollutant | Effluent Limit (ug/L) | | Basis for Effluent Limitation |
|---|---|---|---|
| | Daily Maximum | Average Daily | |
| Flow, MGD | 0.095 | NA | Permit Application, DEIS |
| Oil and Grease | 15 | NA | Narrative Tribal WQS |
| Biochemical Oxygen Demand 5-Day (mg/L) | 45 | 30 | Narrative Tribal WQS |
| Total Suspended Solids (mg/L) | 45 | 30 | Narrative Tribal WQS |
| Phenol | NA | 300 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Iron (tr) | NA | 300 | EPA 304(a) Criterion, Tribal WQS |
| Manganese (tr) | NA | 50 | EPA 304(a) Criterion, Tribal WQS |
| Selenium (tr) | 20 | 5 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Sulfate | NA | 750000 | State WQS |
| Nitrate as N | NA | 10000 | EPA 304(a) Criterion, Tribal WQS |
| Phosphorous as P | MON | MON | State WQS |
| pH (s.u.) | 7.0– 9.0 | | State WQS, Tribal WQS |
| Dissolved Oxygen (mg/L) | April 1 – Sept 30<br>8.0 (1-day min.)<br>9.5 (7-day mean)<br>6.5 (30-day mean)<br>Oct 1 – March 31<br>4.0 (1-day min.)<br>5.0 (7-day mean)<br>6.5 (30-day mean) | | Tribal WQS |

MON- Monitor Only

The discharge from Outfall 001 shall be free from oil and grease attributable to wastewater, which causes a visible film or sheen upon the waters or any discoloration of the surface of adjoining shoreline or causes a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines or prevents classified uses of such waters.

## Proposed Effluent Monitoring Requirements (Outfall 001)

TABLE 17

| Pollutant | Monitoring Frequency | Sample Type |
|---|---|---|
| Flow, MGD | Daily | Continuous, Recorder |
| Oil and Grease, mg/L | Daily | Visual[1] |
| Biochemical Oxygen Demand 5-Day, mg/L | Monthly | Composite |
| Total Suspended Solids, mg/L | Monthly | Composite |
| Ammonia as N, mg/L | Quarterly | Composite |
| Phenol, ug/L | Quarterly | Composite |
| Iron (tr), ug/L | Quarterly | Composite |
| Manganese (tr), ug/L | Quarterly | Composite |
| Selenium (tr), ug/L | Quarterly | Composite |
| Fluoride, ug/L | Quarterly | Composite |
| Sulfate, ug/L | Quarterly | Composite |
| Nitrate as N, ug/L | Quarterly | Composite |
| Phosphorous as P, ug/L | Quarterly | Composite |
| pH (s.u.) | Daily | Grab or Continuous |
| Dissolved Oxygen, mg/L | Daily | Grab |

[1] A daily visual observation is required. If a visible sheen is detected, a grab sample shall be taken and analyzed immediately. The concentration of oil and grease shall not exceed 15 mg/L in any sample.

## Best Management Practices (BMPs)

In addition to the numeric effluent limits and monitoring requirements for process and contaminated stormwater discharges (Outfall 002 and 002a) and uncontaminated stormwater (Outfall 001), additional requirements will be added to the permit for control of pollutants that are likely to be present in the stormwater systems at the proposed facility.

The permittee will be required to develop and implement a Stormwater Pollution Prevention Plan (SWPPP). The SWPPP will identify members of the facility's pollution prevention team, contain a site description, a summary of potential pollutant sources and pollutants, and stormwater controls that will be implemented at the site. Specific Best Management Practices (BMPs) will be identified by the permittee in the SWPPP. Examples of appropriate BMPs for this facility include good housekeeping, eliminating or minimizing exposure, preventative maintenance, spill prevention, runoff management, routine facility inspections, and employee training programs, as well as any more stringent measures necessary to meet the water quality standards provisions of the permit. The SWPPP must remain compliant with relevant State, Tribal and local regulations.

There are two distinct stormwater systems proposed for the facility, one to manage oily or contaminated stormwater from process areas and the other for uncontaminated stormwater. For the SWPPP, the permit will require the permittee to evaluate both stormwater systems, uncontaminated and contaminated, for appropriate controls and actions that will minimize pollutants discharged via stormwater from the facility.

The SWPP must be completed and the contents approved for compliance with the terms of this permit by the EPA Region 8 Stormwater Program Coordinator.

## (POTENTIAL) Sanitary Wastewater (Outfall 003)

### Technology Limitations (BPJ)

Technology requirements for sanitary wastewater discharges (POTWs) are found in 40 CFR Part 133, Secondary Treatment Requirements. The proposed package plant to treat sanitary wastewater is not a POTW but will treat the sanitary wastewater in a similar manner and should be capable of meeting the POTW technology standards. The following technology requirements (40 CFR 133.102) in Table 18 are applied as Best Professional Judgment (BPJ) to discharges from Outfall 003:

TABLE 18

| Pollutant | Effluent Limitation<br>7-Day Average (mg/L) | Average Daily (mg/L) |
|---|---|---|
| $BOD_5$ | 45 | 30 |
| TSS | 45 | 30 |
| pH | 6.0 to 9.0 | |

Percentage Removal Requirements

85% $BOD_5$
85% TSS

### Water Quality Based Effluent Limitations

Numeric and Narrative Water Quality Standards and Criteria

Water quality based effluent limits are evaluated for the discharges of treated sanitary wastewater from Outfall 003. The NPDES Permit application for this facility did not include information on the potential sanitary wastewater discharge due to recent design changes for the proposed project that are described under Alternative 4 of the DEIS. Therefore estimates of pollutants present in the discharge were obtained from similar types of sanitary wastewater treatment facilities and the potable water supply information provided in the DEIS. A reasonable potential analysis for pollutants expected to be in the discharge from Outfall 003 is presented in Table 19.

## TABLE 19
## Reasonable Potential Analysis (Sanitary Wastewater)
## (in ug/L unless otherwise indicated)

| Pollutant | NPDES Permit Application | | Applicable WQS | | Reasonable Potential | |
|---|---|---|---|---|---|---|
| | Daily Maximum | Average Daily | Acute | Chronic | Acute | Chronic |
| Ammonia as N (mg/L) | NR | NR | 3.2 | 1.1 | Yes | Yes |
| Barium (tr) | NR | NR | -- | 1000 | -- | No |
| Aluminum (tr) | NR | NR | 750 | 87 | No | No |
| Cadmium (tr) | NR | NR | 6.5 | 0.61 | No | No |
| Chromium (III) (tr) | NR | NR | 4430 | 212 | No | No |
| Chromium (VI) | NR | NR | 16 | 11 | No | No |
| Copper (tr) | NR | NR | 39.4 | 23.8 | No | No |
| Iron (tr) | NR | NR | -- | 300 | -- | Yes |
| Manganese (tr) | NR | NR | -- | 50 | -- | Yes |
| Lead (tr) | NR | NR | 331 | 12.9 | No | No |
| Mercury (T) | NR | NR | 1.4 | 0.012 | No | No |
| Nickel (tr) | NR | NR | 1190 | 132 | No | No |
| Selenium (tr) | NR | NR | 20 | 5 | Yes | Yes |
| Silver (tr) | NR | NR | 25.0 | -- | No | -- |
| Zinc (tr) | NR | NR | 304 | 304 | No | No |
| Chlorine (TRC) | NR | NR | 19 | 11 | Yes | Yes |
| Chloride | NR | NR | 860000 | 230000 | No | No |
| Fluoride | NR | NR | -- | 4000 | -- | No |
| Sulfate | NR | NR | -- | 750000 | -- | Yes |
| Nitrite as N | NR | NR | -- | 1000 | -- | Yes |
| Nitrate as N | NR | NR | -- | 10000 | -- | Yes |
| Phosphorous as P | NR | NR | -- | 100[1] | -- | Yes |
| pH (s.u.) | NR | | NR | | Yes | |

[1] State WQS is a guideline only, so monitoring only will be required.

NR- No information provided in application.

Narrative water quality standards (dissolved oxygen, whole effluent toxicity, etc.) considered in establishing effluent limitations would also be the same as described for discharges through Outfall 002 above, however toxicity is not reasonably expected to be present in the sanitary wastewater discharge.

Proposed effluent limitations and monitoring requirements for Outfall 003 are presented in Tables 20 and 21 respectively.

## (POTENTIAL) Proposed Numeric Effluent Limitations (Outfall 003)

TABLE 20

| Pollutant | Effluent Limit (ug/L) | | | Basis for Effluent Limitation |
|---|---|---|---|---|
| | Daily Maximum | 7-Day Average | Daily Average | |
| Flow, MGD | 0.007 | NA | 0.005 | DEIS |
| Biochemical Oxygen Demand 5-Day (mg/L) | NA | 45 | 30 | BPJ (40 CFR 133) |
| Total Suspended Solids (mg/L) | NA | 45 | 30 | BPJ (40 CFR 133) |
| Ammonia as N (mg/L) | 3.2 | NA | 1.1 | EPA 304(a) Criterion, State WQS |
| Total Residual Chlorine | 19 | NA | 11 | EPA 304(a) Criterion, State WQS |
| Iron (tr) | NA | NA | 300 | EPA 304(a) Criterion, Tribal WQS |
| Manganese (tr) | NA | NA | 50 | EPA 304(a) Criterion, Tribal WQS |
| Selenium (tr) | 20 | NA | 5 | EPA 304(a) Criterion, State WQS, Tribal WQS |
| Sulfate | NA | NA | 750000 | State WQS |
| Nitrite as N | NA | NA | 1000 | Tribal WQS |
| Nitrate as N | NA | NA | 10000 | EPA 304(a) Criterion, Tribal WQS |
| pH (s.u.) | 7.0– 9.0 | | | State WQS, Tribal WQS |
| Dissolved Oxygen (mg/L) | April 1 – Sept 30<br>8.0 (1-day min.)<br>9.5 (7-day mean)<br>6.5 (30-day mean)<br><br>Oct 1 – March 31<br>4.0 (1-day min.)<br>5.0 (7-day mean)<br>6.5 (30-day mean) | | | Tribal WQS |

The discharge from Outfall 003 shall be free from floating debris, oil, scum, and other floating materials attributable to municipal, industrial, or other discharges or agricultural practices in sufficient amounts to be unsightly or deleterious.

Percentage Removal Requirements (TSS and $BOD_5$ Limitation): In addition to the concentration limits for total suspended solids and $BOD_5$ indicated above, the arithmetic mean of the concentration for effluent samples collected in a 30-day consecutive period shall not exceed 15 percent of the arithmetic mean of the concentration for influent samples collected at approximately the same times during the same period (85 percent removal).

## (POTENTIAL) Proposed Effluent Monitoring Requirements (Outfall 003)

TABLE 21

| Pollutant | Monitoring Frequency | Sample Type |
|---|---|---|
| Flow, MGD | Daily | Continuous, Recorder |
| Biochemical Oxygen Demand 5-Day, mg/L a/ | Monthly | Composite |
| Total Suspended Solids, mg/L a/ | Monthly | Composite |
| Total Residual Chlorine, ug/L | Daily | Grab |
| Ammonia as N, mg/L | Quarterly | Composite |
| Iron (tr), ug/L | Quarterly | Composite |
| Manganese (tr), ug/L | Quarterly | Composite |
| Selenium (tr), ug/L | Quarterly | Composite |
| Sulfate, ug/L | Quarterly | Composite |
| Nitrite as N, ug/L | Quarterly | Composite |
| Nitrate as N, ug/L | Quarterly | Composite |
| Phosphorous as P, ug/L | Quarterly | Composite |
| pH (s.u.) | Daily | Grab or Continuous |
| Dissolved Oxygen, mg/L | Daily | Grab |

a/ In addition to monitoring the final discharge, influent samples shall be taken and analyzed for this constituent at the same frequency as required for this constituent in the discharge.

## Solids

Solids generated in the process wastewater treatment unit processes and other solid and hazardous wastes associated with the refinery operations will be managed in accordance with all applicable laws.

Refinery unit processes will generate both listed and characteristic hazardous wastes under RCRA Part 261.

### Proposed Alternative DEIS

Under the proposed alternative in the DEIS, the facility would be classified as a Treatment, Storage, and Disposal Facility (TSDF) under RCRA. . The wastewater treatment facility would be designed to meet all RCRA construction requirements for a TSDF. Wastewater management units (ponds, tanks, etc.) would generate sludges that are either listed or characteristic hazardous wastes. Solids removed will be containerized and sent to a third party off-site facility that handles hazardous waste. All treatment storage and disposal of hazardous wastes would comply with 40 CFR Part 268.

Alternative 4 DEIS

Under Alternative 4 of the DEIS, The MHA Nation Clean Fuels Refinery is expected to maintain a status as a Large Quantity Generator under RCRA. All hazardous waste generated at the refinery will be managed in accordance with RCRA regulations. The wastewater treatment unit would be designed to meet the RCRA definitions at 40 CFR 260.10 for wastewater treatment unit, tank, and tank system. The wastewater unit will also meet the requirements under 40 CFR 261.31(b)(2) for aggressive biological treatment. As long as the sludges remain in the wastewater treatment system, they would be exempt from listing under F037.

Sludges generated and removed from the wastewater treatment processes (API Separator, DAF, biological treatment sludge) via the sludge thickening process, possibly a centrifuge with a solvent wash (naptha) will be managed as hazardous waste. Solids removed will be containerized and sent to a third party off-site facility that handles hazardous waste. All disposal of hazardous wastes would comply with 40 CFR Part 268.

In addition, the package sanitary wastewater treatment plant would generate biological sludges that would be disposed of in accordance with 40 CFR Part 503 regulations for biosolids.

## Reporting Requirements

Since this facility is classified as a major discharger, monthly reporting requirements will apply. Monitoring results from the previous month's discharge will be required to be reported on a standard Discharge Monitoring Report (DMR) Form, *EPA 3320-1*.

Bruce Kent, USEPA Region VIII
6/16/2006

## Addendum to the Fact Sheet and response to comments

Minor Changes to the permits were made prior to issuance (e. g. update addresses and phone numbers).

Updated Section 3of the permit. COMPLIANCE RESPONSIBILITIES to reflect current regulatory requirements, specifically the penalty provisions which increase periodically.

Updated NEPA Regulatory Language. The EPA revised Procedures for Implementing the National Environmental Policy Act and Assessing the Environmental Effects Abroad of EPA Actions, Final Rule, 40 C.F.R. Part 6, was published on September 19, 2007 (72 Fed. Reg. 53652 (Sept. 19, 2007)).

Added a provision to the permit's reporting requirements that required annual reports of status of the refinery/potential discharges until regular reporting is required through DMRs.

Response to comments on the public notice are included in Appendix E „Response to comments are in the Final Environmental Impact Statement for the Mandan, Hidatsa and Arikara Nations' Proposed Clean Fuels Refinery Project; August 2009. NPDES specific comments begin on page E-33.

MHA Clean Fuels Proposed Refinery notified EPA of a change in feed stock and minor changes to process equipment used in refining Bakken crude. Both crudes are light sweet (low Sulfur) pipeline quality and can be processed with the existing overall refinery configuration.

The supplemental information report of April 20 2010 contained the notice in the change of feedstock and minor process train equipment changes. This supplemental information will not result in changes in the permit, permit limits and requirements. The NPDES permit contains both technology based effluent limits and water quality based effluent limits. Neither of the permit limits (technology or water quality) are based on the feedstock but rather on the quantity and type of production at the facility. The discharge limits, monitoring requirements and authorized outfalls remain unchanged from the original public noticed permit The water quality impacts of the facility discharging under permit conditions would be the same for either feedstock scenario (Bakken or synthetic crude) as the limits remain unchanged.

Updated the Facility Contact from Horace Pipe to Richard Mayer MHA Nation CEO

Robert B. Brobst, P.E. USEPA Region VIII
6/16/2011

The decision to issue the permit is based on the Final Environmental Impact Statement (FEIS) prepared by EPA and the Bureau of Indian Affairs (BIA). The FEIS selected the NPDES Permit as the preferred Alternative. For this action, as documented in the FEIS, EPA determined that the issuance of this permit would have no effect on threatened and endangered species that are present in the project area. The Record of Decision for the FEIS was signed by James B. Martin Regional Administrator for Region 8 on Wednesday August 3, 2011.

Robert B. Brobst, P.E. USEPA Region VIII
August 3, 2011

**Exhibit 3**:
Final Environmental Impact Statement (Aug. 2009)

Document Available Online at:

http://www.epa.gov/region8/compliance/nepa/refineryfeis.html.

**Exhibit 4**:

Comment Letters from Public Comment Period

- Theodora Bird Bear
- Joletta Bird Bear
- Citizens of Mandaree (These citizens preferred to remain anonymous. Several of the signatories are members of the Environmental Awareness Committee).
- Julia May (Julia May submitted comments on behalf of the Environmental Awareness committee. Her comments on the EIS are not attached because of their size. The comments are available at: ftp://ftp.epa.gov/r8/tatrefinery/Appendix_F/Letters/. Hers are labeled JM 1-4.

September 13, 2006

William Benjamin
Area Director
Bureau of Indian Affairs
115-4th Ave SE
Aberdeen SD 57401

Diane Mann-Klager
Great Plains Regional Office
Bureau of Indian Affairs
115-4th Ave SE
Aberdeen SD 5740

Bruce Kent
EPA Region 8 (8P-W-22)
999 18th St., Suite 200
Denver CO 80202-2466

RE: Comment on the Draft Environmental Impact Statement (EIS) for the Three Tribes proposed oil refinery in Makoti ND

Sir:

The Executive Order 12898, 'Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations," states that:

> "each federal agency shall make achieving environmental justice part of its mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority populations and low-income populations."

In the publication, "Environmental Justice: Guidance Under the National Environmental Policy Act," published by the Council on Environmental Quality (CEQ), it notes on page 1 that "The Executive Order makes clear that its **provisions apply fully to programs involving Native Americans."**

The CEQ publication notes that the Executive Order 12898 identifies four (4) issues "that are pertinent to the NEPA process" and states that the Executive Order:

1. "requires the development of agency-specific environmental justice strategies." According to the CEQ publication on environmental justice, **"Early and meaningful public participation in the federal agency decision-making process is a paramount goal of NEPA. CEQ regulations require agencies to make diligent efforts to involve the public throughout the NEPA process."** CEQ goes on to note that, "for this participation to be meaningful, the public should have access to enough information so that it is well informed and can provide constructive input."
2. " recognizes **the importance of research, data collection and analysis, particularly in respect to multiple and cumulative exposures to environmental hazards for low-income populations, minority populations, and Indian tribes.** Thus **data on these exposure issues should be incorporated into NEPA analyses as appropriate."**
3. "provides for agencies to collect, maintain, and analyze information on patterns of subsistence consumption of fish, vegetation, and wildlife. **Where an agency action may affect fish, vegetation, or wildlife, that agency action may also affect subsistence patterns of consumption and indicate the potential for disproportionate high and adverse human health or environmental effects on low-income populations, minority populations, and Indian tribes."**
4. **" requires agencies to work to ensure public participation and access to information."**

According to CEQ's environmental justice publication, "agencies should...acknowledge and seek to overcome linguistic, cultural, institutional, geographic, and other barriers to meaningful participation, and should incorporate active outreach to affected groups."

The BIA and EPA, lead agencies responsible for NEPA and the tribal government of the Three Affiliated Tribes, as participating sovereign nation, failed to assure minimal or adequate NEPA compliance in the draft Environmental Impact Statement (EIS) for the proposed oil refinery, in regard to the above pertinent issues. This is a substantive deficiency by the lead agencies and the tribal government. In the scoping and draft EIS process and documents.

- The Environmental Justice offices of both Region 8 EPA and the EPA Headquarters failed to assure public participation in all stages, including the scoping and draft Environmental Impact Statement. Until pointed out in a public hearing for the current draft EIS document in August, both lead agencies and the tribal government of the Three Affiliated Tribes failed to acknowledge that their draft EIS and 'environmental justice' analysis document was incomplete and unfinished. The draft EIS, published in June 2006, had listed the environmental justice document as completed and implied it was available.

  Despite a letter in June 2004 requesting her assistance, the Region 8 Environmental Justice Office representative, Jean Belile, was unresponsive and unavailable to members of the Environmental Awareness Committee of Fort Berthold until just prior to a November 2004 public hearing on the oil refinery. This limited the input of concerned tribal members into the scoping hearing and ultimately on the draft EIS. Despite telephone calls and conversations with Dan Gogol, EPA Headquarters Environmental Justice, Region 8 has failed to assure public participation strategies to assure constructive input. Both EPA Region 8 and EPA Headquarters have compromised their mission to protect the environment for the benefit of the tribal government's proposed oil refinery and to the detriment of individual tribal members.

  In this process, the lead federal agency, the BIA, has also neither identified nor utilized its agency environmental justice plan to benefit the individual tribal members of the Three Affiliated Tribes. As a result, neither agency nor the tribal government of the Three Affiliated Tribes has provided adequate information to tribal members and other concerned low-income communities on the potential environmental and health impacts of the refinery and has further limited or denied constructive and meaningful input by tribal members and other members of the public, in both the Scoping and draft EIS.

- There are seven coal-fired power plants on the southeast corner of the Fort Berthold Indian Reservation. The BIA, EPA, and tribal government of the Three Affiliated Tribes failed to incorporate data on multiple and cumulative daily exposures to the individual tribal members of Fort Berthold Indian Reservation from the power plants in the draft EIS for the proposed oil refinery.

  Using the EPA's own standard methodology, Clear The Air, a national public education campaign to improve air quality by reducing emissions, analyzed data and determined that, on average, people exposed to power plant toxic emissions " lost an average of 14 years, dying earlier than they otherwise would."

  Premature deaths from lung cancer, cardiovascular diseases including heart attacks, asthma and respiratory conditions requiring emergency room visits are among other serious health impacts from coal-fired power plants. The health of Fort Berthold tribal members have been similarly impacted. Indian Health Services, the primary healthcare provider on Fort Berthold, is only able to meet 40% of the actual medical need of Fort Berthold tribal members. With 63% unemployment on Fort Berthold, a majority of tribal members must utilize Indian Health Services for routine and urgent care.

  In 2004, over 140,000 <u>tons</u> of sulfur dioxide was emitted by ND power plants on or near Fort Berthold. The same ND plants released over 75 tons of oxides of nitrogen. Over 2,200 <u>tons</u> of mercury was also emitted on or near Fort Berthold Indian Reservation by the power plants in 2004. These toxic emissions are only for one (1) year. These power plants have been in place for over twenty years. Because of the location of the seven power plants across the river from the Fort Berthold Indian Reservation, the health of tribal members has been impacted. The emissions from the proposed oil refinery will further cause further deterioration of the health of tribal members and contribute to further pollution of the environment.

According to the October 2004 Dakota Resource Council publication, Dakota Counsel, the North Dakota power plants emitted over 3 tons of toxic arsenic and 3 tons of lead. Over 4 million pounds of chromium were also released on or near Fort Berthold. Chromium damages the respiratory tracts of humans and other living animals. According to CEQ's publication on environmental justice, "Agencies should consider these multiple or cumulative effects, even if certain effects are not within the control or subject to the discretion of the agency proposing the action." The human cumulative and multiple exposures to current pollution and a " new source" of pollution, namely the oil refinery, has been omitted in the draft EIS and environmental justice analysis.

- The BIA and EPA have determined that no Clean Air Act permit is required for the proposed oil refinery. No other refinery in the United States is exempt from air emissions monitoring. Lack of an air monitor permit means that that the proposed oil refinery in Makoti may release an unlimited and unmonitored amount of toxic air emissions.

Despite this, the Region 8's environmental justice analysis for the draft EIS limits the scope of environmental justice to a ten mile radius around the site of the proposed oil refinery. No information was provided in the environmental justice analysis to justify this conclusion.

This analysis excludes the majority of individual tribal members of Fort Berthold who reside within a 30-mile radius from the refinery site in Makoti. Tribal members fish, do subsistence hunting on Fort Berthold, and also gather and eat wild plums, chokecherries, juneberries, wild turnips, and buffalo Berries .The intake of heavy metals emitted by the refinery into the air, water, ground, and plant life will add or exacerbate health problems of tribal members.

As an example, cadmium, a toxic chemical from refining, is taken up into plant life. The tribal government proposes to feed its buffalo from the forage around the refinery site. Buffalo meat provided at pow-wows and other tribal gatherings will become a conveyor of toxic chemicals to tribal members. This will disrupt the integrity of a long-held social and cultural practice.

According to a Defenders of Wildlife report, more than 225 bird species have been recorded at the Lostwood Wildlife Refuge. In October 2004, the Lostwood Refuge was identified as one of America's Ten Most Endangered National Wildlife Refuges. 4,000 glaciated lakes dot the refuge proving prime Habitats for ducks, geese, and other breeding waterfowl. Besides human health, birds and other wildlife will be negatively impacted by the unlimited and unmonitored air emissions of toxic chemicals from the proposed oil refinery in Makoti.

The Fox Hills-Hell Creek aquifer is under the site of the proposed oil refinery. This same acquifer underlies the entire Fort Berthold Indian Reservation. The EPA, BIA, and tribal government of the Three Affiliated Tribes propose injecting treated waters used to process both hazardous and non-hazardous chemicals from the refinery into the ground on the refinery site. The BIA, EPA, and current tribal government of the Three Affiliated Tribes will endanger the acquifer under the entire Fort Berthold Reservation.

Due to the drought throughout the entire western United States, including Fort Berthold, the Volume of water in the Missouri River continues to slowly diminish each year. Putting the acquifers underneath Fort Berthold in jeopardy will potentially strain the future water resources for Fort Berthold and will potentially affect human, wildlife, and vegetation on Fort Berthold. The BIA's acquiescence in this project is a failure to uphold its trust responsibilities to the individual tribal members who will be affected by this agency action.

- The BIA is also failing its trust responsibilities to the individual tribal members of Fort Berthold by proposing an incomplete and inadequate draft Environmental Impact Study as satisfying its' responsibility as lead agency. According to CFR 151.10, the BIA Regional Director must make a conclusive statement regarding jurisdictional problems, potential land use conflicts, and must include an independent assessment of the impact **on the BIA** should the land be acquired in trust.
    - **a.** According to a 2004 letter from the EPA to the tribal government of the Three Affiliated Tribes, "Leaks and spills over time will eventually contaminate surficial groundwater and soil under and near the refinery." Further, the letter reiterates that "it is inevitable that leaks and spills will occur." **Does the Fort Berthold BIA have adequate staff to carry out the additional responsibilities to monitor, address, and manage contamination by the oil refinery on trust land?**
    - b. The Cobell lawsuit over the BIA mismanagement of IIM accounts of individual Indians is currently projected to be an $8 billion settlement by the federal government. If Aberdeen BIA allows the land taken into trust for the refinery, **how will the added responsibilities of emergencies, environmental concerns, roads, traffic, and other aspects of the oil refinery affect the capability of the present BIA staff to manage its existing trust responsibilities?**
    - c. According to the draft EIS, (Page 4-51), "If the waste water is not properly treated prior to irrigation, the irrigated land parcel could potentially become a RCRA hazardous waste land treatment unit (LTU). Such a designation would significantly change the nature of the proposal under this alternative, as there would be greater likelihood of releases to soils, ground water and surface water, and there would be additional requirements related to human food chain considerations." **Does the BIA have adequate staff and resources to address the 'human food-chain issues from this potential superfund site?**
    - **d.** Under Alternative 4 in the draft EIS (Page 4-50), "...there would be no RCRA permitting requirements for ground water monitoring and correction action." Further, "...there would is no requirement for financial assurance under EPA's RCRA regulations. Without the funding available through financial assurance, cleanup activities and other remedial actions may be delayed or may not be implemented." **Is the BIA ready to assume financial assurance for corrective actions, cleanup activities, and other remedial actions which will not otherwise be assured at the refinery site, in Alternative 4?**

My response is affiliated with the letter from the Center on Race, Poverty, & the Environment, dated August 30, 2006, and also the letter by Julia May, through the Environmental Integrity Project, dated August 29, 2006, in response to your offices on the substantive deficiencies in the draft EIS and environmental justice analysis.

I support sustainable energy development as an alternative to a fossil fuel oil refinery and a centerpiece to the tribal government's economic plan.. I remain opposed to the transfer of the land into trust status for the proposed oil refinery at Makoti or any other location. Historically, the Mandan, Arikara, and Hidatsa have resided along the Grand, Heart, and Knife rivers of the Missouri River. As agricultural tribes, we recognized, understood, and prayed to spiritual entities linked to land, water, sky, and plants. Our identify as tribal people was with the earth. Non-polluting sustainable energy development is reflective of our cultural values. Adhering to our cultural values remains our true strength. Anything else will weaken us.

Theodora Bird Bear
P.O. Box 616
New Town ND 58763

August 9, 2006

Cert: 70041350000296695878 EPA
Cert: 70041350000296695861 BIA

Mr. Robert Roberts
EPA Regional Director,Region 8
Environmental Protection Agency
999 18th Street Suite 200
Denver Co 80202-8917

Mr. William Benjamin
Great Plains Regional BIA Director
Bureau of Indian Affairs
115 4th Avenue SE
Aberdeen SD 57401

Re: Executive Order 12898 failure to
Implement, EJ analysis missing

Dear Mr. Roberts and Mr. Benjamin,

The public hearings held by EPA Region 8 and Great Plains Regional Bureau of Indian Affairs agencies to receive public comment on the proposed MHA Refinery and the draft NPDES publicly revealed the fact that the Environmental Justice Analysis, referenced on page 3-100 of the DEIS was missing, and therefore, unavailable for public review and public comment during this critical comment period of June 29 through August 29, 2006. Please respond to how and why the EPA Region 8 staff and the Great Plains Bureau staff would release the DEIS as a complete document for public review and comment when EPA staff and Bureau staff knew the DEIS was released without the EJ analysis being complete and or existent. Your agencies are charged with the responsibility to the public to disclose information to that public that may be impacted by this project. Your Environmental Justice staff at the EPA Region 8 and the Great Plains Bureau have failed to implement Executive Order 12898 and have failed the public, the people of Fort Berthold Reservation.

The proposed refinery will adversely impact not only the residents of the town of Makoti, but the 3500 plus tribal residents of the Fort Berthold Reservation for the refinery if approved will be sited on our collective tribal fee patent or tribal land. The area that would be affected by the proposed refinery is larger than the one mile radius from the project site, furthermore, it is greater than the 10 mile radius which someone at EPA and/or BIA selected "to providea more conservative anaylsis." According to EPA: What is Environmental Justice fact sheet:

> "An EJ community is any aggregated or dispersed population that (a) is a low income population based on the Bureau or Census Current population reports, (b) is over 50-percent minority, or (c) contains a minority population percentage meaningfully greater than the minority population percentage in the general population or other appropriate unit of geographic analysis. Federally recognized Indian tribes or groups within tribes, which are made up of minority individuals, may be EJ communities."

As emphasized in the June 29th released DEIS, Executive Order 12898 directs your federal agencies, the co-lead agencies for this major project, to determine whether your activities have disproportionately high and adverse human health or environmental effects on minority populations and low income populations and, further, that these populations are to be provided by your agencies an opportunity to effectively participate in any actions affecting them.

Based upon the missing EJ analysis data of the released DEIS, I request that the process be halted in its entirety until such time as the two co-lead agencies are able to fully implement public participation by fully disclosing supporting information of this proposal and that a sufficient public comment period be re-established to incorporate public response to all the data associated with this major project. If the EJ analysis document is available after the June 29th DEIS release date, then I request a copy of that document as referenced in the DEIS and further request that the public comment period be extended to 90 days beyond the August 29th deadline and that public hearings be held once more to address this document.

For your information in a letter dated June 27, 2004, I sent a letter to EPA Region 8, to Jean Belile, Environmental Justice Coordinator, requesting her assistance in written form. I had met her in SD in June 2004 and made the verbal request at that time, as she was a presenter at a Protect the Earth conference and she requested of me that I write her a letter officially requesting her help, My request was to make certain with her help (EPA Region 8) that Environmental Justice was present in this entire process of the preparing for and reviewing the Scoping Analysis, the DEIS, and the final EIS, as well as the final decisions (RODs). As attested to by the comments at the public hearings the people of Fort Berthold do NOT support the proposal for the refinery and this was so from the beginning of the this proposal.

I look forward to your responses and the EJ document if it is available.

Sincerely,

Joletta Bird Bear

Joletta Bird Bear
PO Box 474
Mandaree ND 58757

September 13, 2006

Mr. William Benjamin
Great Plains Regional Director
Bureau of Indian Affairs
115 4th Avenue SE
Aberdeen SD 57401

MR. Robert Roberts
United States Environmental
Protection Agency Region 8
999 18th Street Suite 200
Denver CO 80202-8917

Re: DEIS response on MHA
Proposed REfinery

Dear Mr. Benjamin and Mr. Roberts,

In response to the Draft Environmental Impact Statement of the Proposed Mandan, Hidatsa, and Arickara Refinery Project to be sited upon land recently purchased, we submit the following comments:

1. FRom the alternatives presented in the DEIS we support Alternative 2--Accept the land into trust WITHOUT CONSTRUCTION OF THE PROPOSED REFINERY and we support Effluent discharge alternative D--NO ACTION,UNDER THIS ALTERNATIVE,EPA WOULD NOT ISSUE AN PERMITS FOR THE DISCHARGE OF EFFLUENTS FROM THE PROPOSED REFINERY.
2. We are concerned and believe that Alternative 1 (construction of a refinery,land into trust, and the granting of pollution permits) and Alternative 4 (construction of a re-designed refinery) will present legal conflicts with the state over taxation, zoning, and jurisdiction that will lead to erosion of our tribal sovereignty.
3. We believe that Alternative 1 and Alternative 4 presents an immediate material threat of many hazardous and toxic substances generated by the proposed refinery. The release of these hazardous materials and toxic substances will be present in any structures of the proposed refinery and workers will be directly and adversely impacted. These hazardous materials and toxic substances will damage the air, soil, sediment, surface water, and ground water of the MHA nation.
4. Under Alternative 1 and Aleernative 4 we challenge the designated :affected area; of the Environmental Analysis (EJ) which limits the population of residents to within a 10-mile radious of the project site and we maintain that the affected area is at least a 30-mile radius from the project site, according to the DEIS the fefinery will release at least 207 TONS of hazardous pollutants

of nitrogen oxides(NOx),carbon Monoxides (CO), non-methane-ethane volatile organic compounds (VOCs), sulfur dioxide (SO 2), particulate matter (PM 10 and PM 25) and toxic carcinogens (HAPS) which will contaminate our air and water and become a pathway for increased diseases and increased mortality affecting tribal members and families of the MHA nation. Already, the air we breath contains more than 140 tons of nitrogen oxides and more than 70 tons of sulfur dioxides per year released from the gasification plants in close proximity to our communities and homes as reported in the MInot Daily or Bismarck Tribune (August 2006).

5. We believe that Alternative 1 and Alternative 4 attempts to change the stringent Tribally adopted Water Quality Standards (WQS) to lesser WQS of the EPA, and, therefore, diminishes our high standards and tribal sovereignty, "Where the EPA Criteria are more or less stringent than the Tribally adopted WQS and/or state WQS, the EPA Criteria have been adesignated as the applicable value in anticipation of adoption of the EPA Criteria by the State or Tribes," (Summary of Tribally ADopted WQS and State WQS and EPA 3049a) Criteria)

6. We believe and are concerned that Alternative 1 and Alternative 4 will create great potential environmental liability against the Bureau of Indian Affairs local agency and against the MHA nation and its membership, and that the additional acquired costs of a high risk industry will adversely impact the funding of services we receive through the current funding level of PL 93-638 federally funded programs of Fort Berthold.

7. We believe in sustainable economic development such as solar powered energy or wind generated energy and submit this as a viable alternative to this proposal.

We request that our names be withheld from publication.

Sincerely,

**Exhibit 5**:

Record of Decision (Aug. 2011)

# RECORD OF DECISION

# MANDAN, HIDATSA, AND ARIKARA NATION'S PROPOSED CLEAN FUELS REFINERY PROJECT

U.S. Environmental Protection Agency
Region 8

## I. DECISION TO BE MADE

This Record of Decision (ROD) documents the decision of the U.S. Environmental Protection Agency (EPA) Region 8 pertaining to the issuance of a Clean Water Act (CWA) National Pollutant Discharge Elimination System (NPDES) permit for discharges of treated process wastewater associated with the operation of the Three Affiliated Tribes' [Mandan, Hidatsa, and Arikara (MHA) Nation's] proposed clean fuels petroleum refinery.

This ROD is issued by the EPA pursuant to the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321 et seq., the Council of Environmental Quality (CEQ) NEPA regulations, 40 C.F.R. Parts 1500-1508, and EPA's regulations implementing NEPA at 40 C.F.R. Part 6 (Procedures for Implementing the National Environmental Policy Act and Assessing the Environmental Effects Abroad of EPA Actions). This ROD is based upon analysis and information set forth in the NEPA documents prepared by the EPA, the Department of the Interior (DOI) and Bureau of Indian Affairs (BIA), as well as the analysis in the Supplemental Information Report (SIR) prepared by EPA. EPA and DOI/BIA issued the Final Environmental Impact Statement (FEIS) on August 20, 2009. The MHA Nation notified EPA and BIA in 2010 of their decision to change the refinery feedstock from synthetic crude to the local Bakken formation crude oil. A separate ROD prepared by the DOI/BIA will document the DOI/BIA decision on whether to accept certain lands, including lands on which the proposed refinery would be built, into trust for the MHA Nation.

## II. INTRODUCTION

The MHA Nation proposes to construct, own and operate a 13,000 barrels-per-day petroleum refinery on the Fort Berthold Indian Reservation near Makoti in North Dakota. The MHA Nation owns the 468.39 acre site within the exterior boundaries of the Fort Berthold Indian Reservation on which they intend to construct and operate the refinery. All lands within the exterior boundaries of the Fort Berthold Indian Reservation are "Indian country" as defined at 18 U.S.C. § 1151. The proposed facility would refine Bakken crude oil into gasoline, diesel fuels, and propane. The refinery would be on 190 acres of the site. The remaining acres would be used to grow forage for the Tribes' buffalo herd (buffalo would not be located at the site). Following their purchase of the property, the MHA Nation requested DOI/BIA to accept the property into trust status. The MHA Nation also applied to the EPA for a NPDES wastewater discharge permit for the refinery.

As a general matter, federal agencies such as BIA and EPA must comply with NEPA before approving any major federal actions that may have a significant effect on the human environment. The project as proposed would require an NPDES permit from EPA. Because the project is defined as an NPDES new source (33 U.S.C. 1316(a)(2); 40 C.F.R. §§ 122.2 and 122.29), EPA is required to comply with NEPA prior to final action on the NPDES permit, 33 U.S.C. § 1371(c)(1). BIA's decision whether to accept the land into trust for purposes of the proposed project constitutes a major federal action and also invokes NEPA.

The BIA and EPA jointly issued a Draft EIS in June 2006. The public comment period on the DEIS formally started on June 29, 2006, and ran through September 14, 2006. During the public comment period, BIA and EPA held seven public hearings. Responses to the written and oral comments received are included in the FEIS. The August 2009 FEIS also included additional analysis on potential human health impacts, revisions to the Environmental Justice analysis and identified the agencies' preferred alternatives.

In 2003, the MHA Nation initially proposed to refine synthetic crude from Canada. Since that time, there has been rapid development of oil from the Bakken formation in North Dakota and Montana. On February 4, 2010, the MHA Nation informed EPA via phone of its intent to refine Bakken crude oil instead of synthetic crude from Alberta at its proposed refinery. Both the Alberta synthetic crude and Bakken crude feedstocks are light, sweet crude oils. The refinery designs for either feedstock are expected to be similar. The proposed refinery will be in the same location with the same general site footprint as described in the FEIS. In July 2011, EPA completed a Supplemental Information Report (SIR) comparing the environmental impacts associated with refining the Bakken crude with the FEIS environmental analysis to determine whether EPA needed to prepare a supplemental EIS pursuant to 40 C.F.R.§ 1502.9(c). EPA concluded that a Supplement to the FEIS is not warranted, since a change in feedstock to Bakken crude, as compared to the refinery using synthetic crude, will not significantly change the proposed action or its impacts, as described in the FEIS.

## III. NEPA ANALYSIS AND ALTERNATIVES ANALYZED

The EIS analyzed five facility construction/non-construction alternatives (Alternatives 1 through 5) for the proposed refinery site and four alternatives for wastewater disposal for the proposed refinery (Alternatives A through D). A short description of each alternative follows. Further detailed information on the project alternatives can be found in the FEIS.

### **Construction Alternatives**

*Alternative 1* (*Proponent's Original Proposed Action):* BIA would accept the 468.39-acre project site into trust for the refinery and forage. The MHA Nation would construct and operate a refinery utilizing a feedstock of: 10,000 barrels per stream day (BPSD) of synthetic crude oil, 3,000 BPSD of field butane, 6 million standard cubic feet per day of natural gas, and 300 barrels of bio-diesel or 8,500 bushels per day of soybeans. The refinery would produce about 5,750 BPSD of diesel fuel, 6,770 BPSD of gasoline, and 300 BPSD of propane.

*Alternative 2*: BIA would accept the land into trust without construction of the proposed refinery. Under this alternative, BIA would accept the 468.39-acre site into trust status but would not approve the MHA Nation's proposal to construct, operate, and maintain a clean fuels refinery. The entire site would continue to be used for agricultural purposes similar to those that have been occurring on the property for decades.

*Alternative 3 (DOI/BIA Preferred Alternative in FEIS)*: BIA would not accept the land into trust, but the MHA Nation may still construct the proposed refinery. This alternative was analyzed in the EIS based on the original design. It is BIA's recommendation that the design of the refinery, if constructed, be modified consistent with Alternative 4.

*Alternative 4*: (*Proponent's Modified Proposed Action*). A modification of Alternative 1 was developed to reduce impacts to wetlands and to revise the design of the proposed refinery to avoid triggering regulatory requirements under the Resource Conservation and Recovery Act (RCRA) (federal hazardous waste control law). Under this alternative, BIA would accept the 468.39 acres into trust for the construction and operation of the refinery. The refinery would be reconfigured from the MHA Nation's original proposal in order to minimize impacts to the jurisdictional wetland; use tanks instead of ponds for potentially contaminated (oily) stormwater and contaminated process wastewater; and use a sanitary collection tank or sanitary waste treatment plant instead of a leach field. The refinery would continue to be regulated as a RCRA large quantity generator. The proposed septic tank for employee wastewater would also be replaced with either a small treatment plant or wastewater would be trucked to a municipal wastewater treatment plant.

*Alternative 5*: No action. Under this alternative, BIA would not accept the 468.39 acres into trust status. The MHA Nation would continue to own the property outside of trust status. This alternative was analyzed based on the refinery not being constructed.

## Effluent Discharge Alternatives

*Alternative A*: (*EPA's Preferred Alternative*) Discharge of effluent through an NPDES permit. Through the NPDES permit, EPA would authorize the MHA Nation to discharge treated wastewater from the refinery in compliance with permit limits, outfall locations, and monitoring and reporting requirements. Any discharges from the facility would need to meet the NPDES effluent limitations which incorporate the more stringent requirements of the technology-based effluent limits for the petroleum refining industry and water quality standards and criteria. All outfalls discharge into the wetlands at the northeast corner of the site, flowing north under Highway 23 into a tributary of the East Fork of Shell Creek. The number of the outfalls and the manner in which waste streams are combined differ among the refinery construction alternatives as described below.

### Alternative 1 and A, and Alternative 3 and A

The refinery would be configured and designed according to the proponent's original proposal. The NPDES permit would authorize wastewater discharge through three outfalls:

001 – Uncontaminated stormwater
002 – Treated wastewater and oily stormwater
003 – Treated employee wastewater

Alternative 4 and A
The refinery design would be modified by using tanks instead of ponds and reconfigured to avoid most wetland impacts from the discharge of dredged or fill material. The NPDES permit would authorize wastewater discharge through four outfalls:

001 – Uncontaminated stormwater
002 – Treated wastewater
002a – Potentially oily stormwater after treatment and/or water quality testing
003 – Treated employee sanitary wastewater

Under Alternatives 1 and A, and 3 and A, uncontaminated stormwater would be collected and routed to the evaporation pond (water storage reservoir). Water from the evaporation pond would be used in refinery processes and in the fire water system which includes two fire water reservoirs. Surplus uncontaminated stormwater would be discharged through Outfall 001. Process wastewater from the refinery (primarily from the sour water stripper) would be routed directly to the wastewater treatment unit (WWTU). For Alternatives 1 and A, and 3 and A, the MHA Nation would need to obtain a hazardous waste Treatment Storage and Disposal permit for the facility under resource conservation Resource Conservation and Recovery Act (RCRA). After treatment the water would be stored in two effluent holding ponds. Potentially contaminated stormwater (oily) from the refinery process area, product loading area and tank farm would be conveyed to a 1.4 million gallon holding pond. Depending on water quality, the wastewater from the holding pond would be conveyed to the effluent holding ponds or sent to the WWTU for treatment and then into the effluent holding ponds. Effluent from the holding ponds would either be recycled back to the refinery or discharged through a NPDES Outfall 002.

Under Alternative 4 and A, uncontaminated stormwater would be collected and routed to the evaporation pond (water storage reservoir). Water from the evaporation pond would be used in refinery processes and in the fire water system which includes two fire water reservoirs. Surplus uncontaminated stormwater would be discharged through Outfall 001. Process wastewater from the refinery (primarily from the sour water stripper) would be routed directly to the wastewater treatment unit (WWTU). After treatment, the water would be conveyed to a series of final effluent release tanks before discharge from Outfall 002. Wastewater would be tested prior to release and if it does not meet discharge limits it would be recycled back to the wastewater treatment plant for further treatment. Potentially contaminated stormwater (oily) from the refinery process area, product loading area and tank farm would be conveyed to a group of surge tanks of sufficient volume to handle a certain storm event, and designed/engineered to required specifications. Depending on water quality, the wastewater in the surge tanks would be conveyed to either a release tank or to WWTU for treatment. Wastewater from the effluent release tanks would be discharged through NPDES Outfall 002a.

Under Alternatives 1 and A, 3 and A, and 4 and A, the refinery may decide to collect and haul employee wastewater off-site. In that case, the refinery would report that the facility is not discharging through Outfall 003. The proponent's proposal included the use of a septic tank and leach field for treatment of employee wastewater. However, upon additional evaluation, the proponent concluded that the soils in the area were unsuitable for the proposed standard septic tank and leach field. Therefore, the proposed refinery would either need to install a package domestic wastewater treatment unit or haul employee wastewater to another wastewater treatment plant.

For Construction Alternatives 2 and 5, no refinery would be constructed; therefore no NPDES permit (Alt. A) would be needed.

*Alternative B*: Treated wastewater from the refinery would be disposed of through a combination of land application to irrigate crops and discharged through NPDES permitted outfalls. The NPDES portion of the alternative would be the same as Alternative A. Wastewater would be treated in the wastewater treatment units and then stored in ponds or release tanks. The refinery could use treated wastewater to irrigate trees and routed forage on the project site. Land application of wastewater would only be possible during the growing season, when saturated soil conditions do not exist.

*Alternative C*: The MHA Nation would discharge all effluent from the wastewater treatment units to a Class I underground injection control (UIC) well that would be drilled on the project site. This well would dispose of wastewater into isolated formations beneath the lowermost underground source of drinking water. A Class I UIC permit would need to be obtained from EPA prior to construction of the well to ensure that the well is properly designed.

*Alternative D*: No action. Under this alternative, EPA would not issue any permits for the discharge of effluents from the proposed refinery. This includes permits for NPDES regulated discharges, discharges to a Class I UIC well, and discharges from the septic system to a leach field (UIC Class V). Thus, no discharges of water of any kind from a refinery would be permitted.

## IV. FINAL EIS PREFERRED ALTERNATIVE

The "agency's preferred alternative" is the alternative which the agency believes would fulfill its statutory mission and responsibilities, giving consideration to economic, environmental, technical and other factors. The FEIS identifies EPA's preferred effluent discharge alternative as Alternative A, discharge of effluent through an NPDES permit, and recommends the refinery design modifications described in Alternative 4.

## V. NEPA ANALYSIS - COMPARISON OF THE ENVIRONMENTAL CONSEQUENCES OF THE ALTERNATIVES

Chapters 3 and 4 of the EIS evaluate the environmental effects associated with the proposed project alternatives. A comparison of the environmental effects is provided in Table 2-8 in the FEIS. Below are highlights of these findings applicable to the EPA preferred alternatives, Alternatives 4 A and C:

### A. *Ground water, Soils and Spills*

- Ground water occurs beneath the refinery site. Ground water is in the underlying material called “till” which was deposited by glaciers in an approximately 100-foot thick layer. Ground water generally moves slowly in till layers due to low permeability. Depth to water in the till aquifer typically ranges from 5-15 feet. Ground water in the till appears to flow toward the southwest at about 0.4 to 2.4 ft/year. Ground water also occurs in the Ft. Union Formation, which underlies the till and the Fox Hills Formation which underlies the Ft. Union Formation.

- It is anticipated that there would be spills and leaks at the proposed refinery facility. Almost all refineries and other petrochemical facilities such as, gas stations eventually have spills and leaks. The majority of spills and leaks would be completely contained within the facility and would not impact the environment. However, over time, it is expected that there would be some contamination of soils and ground water immediately underneath the refinery site due to leaks and spills because some areas of the refinery are not paved. The contamination would remain generally within the refinery site unless a major spill occurred or a series of spills and leaks occurred over time.

- Areas within the refinery storing crude or refinery products would be required to be lined and have secondary containment (e.g., berms) to hold the entire contents of storage tanks. Areas with a high potential for spills such as the loading area for trucks and railcars would also be paved and curbed which should contain most spills.

- Due to the shallow depths to water, ground water resources in proximity to the refinery could be affected by leaks and spills. Adverse impacts to ground water withdrawn by individual well users and public supply systems are not anticipated, except for the well that was at the existing farmhouse. That well has been decommissioned. Other individual wells are not anticipated to be impacted because of the relatively low permeability of the till underlying the refinery site. The next closest farmstead is 1/3 of a mile from the proposed refinery site.

- Communities in the area such as Makoti and Plaza located three and five miles from the proposed refinery, respectively, use ground water as a source of drinking water. These communities use either the Fox Hills-Hell Creek or buried valley aquifers. Water quality in these aquifers is not expected to be impacted by the proposed facility because the buried valley aquifers do not occur in the vicinity of the refinery and the depth to the top of the Fox Hills–Hell Creek aquifer is more than 1,000 feet beneath the proposed refinery location. For wastewater disposal through an underground injection well (Alternative C), the injection zone would be required to be below any aquifer that could be used for drinking water.

- Water supply for the refinery would be from a combination of sources including the Fox Hills-Hell Creek aquifer, recycled water from the refinery and run-off collected from the site. If the refinery uses the Fox Hills-Hell Creek aquifer for the majority of its water supply, there may be localized draw down in the aquifer.

### *B. Surface Water*

- The site is located in the headwaters of a small unnamed tributary of the East Fork of Shell Creek which is tributary to Lake Sakakawea. With regard to effluent discharge Alternative A (in the FEIS), stormwater and treated wastewater from the refinery would be discharged at the surface. For Alternative C (in the FEIS), only stormwater would be discharged at the surface and process water would be discharged through an underground injection well.

- The proposed refinery construction alternatives would need surface water discharge permits (NPDES) for stormwater discharges and wastewater discharges. The proposed NPDES permit would require that wastewater discharges be protective of aquatic life, drinking water, agriculture and wildlife uses. No NPDES permits would be needed for the non-construction alternatives and water quality would remain the same as existing conditions.

- Construction and operation of the proposed refinery would change the quantity and flow pattern of the drainage from the site. The paving/hardening of the refinery site would increase runoff and reduce infiltration. If the refinery collects most of the runoff for use as water supply, there would be less water flow from the site for the majority of storm events.

### *C. Solid and Hazardous Waste*

- The proposed refinery would operate as a large quantity generator of hazardous waste under the Resource Conservation Recovery Act (RCRA). The facility, through the RCRA generator regulations, would be required to transport the waste to approved hazardous waste facilities for the treatment and disposal of the waste. Many of the waste streams from refineries are specifically listed under the RCRA regulations as hazardous wastes.

- Each refinery construction alternative, except for the combination of Alternatives 4 and A, could also make the facility a Treatment Storage and Disposal (TSD) facility under RCRA. The facility would potentially need to obtain a TSD permit from EPA for any of these alternatives. The TSD permit includes requirements for design, operation, location, monitoring, financial assurance, inspections and facility closure plans.

- With regard to solid waste, the facility would be required to comply with EPA "Criteria for Classification of Solid Waste Disposal Facilities and Practices" at 40 C.F.R. Part 257, as appropriate.

### *D. Vegetation, Wetlands*

- The portion of the site that would be used for the proposed refinery would be changed from an agricultural to industrial use.

- Both jurisdictional and non-jurisdictional wetlands exist on the proposed refinery site. Jurisdictional wetlands are those wetlands which are considered to be waters of the U.S. for purposes of the Clean Water Act. Non-jurisdictional wetlands are waters that are not subject to Clean Water Act jurisdiction.

- The USACE determined one wetland, which covers 11.7 acres in the northwest corner of the site, to be subject to Clean Water Act jurisdiction. According to the initial site plan (Alternative 1), 0.5 acres of the jurisdictional wetland would be filled by the proposed refinery. An alternative site plan (Alternative 4) was developed in part to reduce filling of jurisdictional wetlands to 0.1 acres. A Clean Water Act Section 404 permit for the discharge of dredged or fill material would be needed from the USACE prior to construction.

- The jurisdictional wetland would be impacted by the proposed refinery. Changes in the quality and quantity of water flowing into this wetland would change the hydrology and vegetation in the wetland.

- Non-jurisdictional wetlands would also be impacted during construction of the refinery.

- Any filling of jurisdictional wetlands would be mitigated as required under the applicable Nationwide Permit and the Compensatory Mitigation for Losses of Aquatic Resources; Final Rule, April 10, 2008.

### *E. Wildlife, Threatened and Endangered Species*

- EPA determined that issuance of an NPDES permit for the proposed refinery would have “no effect” on the threatened or endangered species in the area or their designated critical habitat. The U.S. Fish and Wildlife Service (FWS) agreed with EPA’s determination. The FWS did express concerns about potential effects to the threatened piping plover and endangered whooping cranes from landing on open water areas in the refinery wastewater treatment facilities or colliding with overhead power lines. The FWS identified mitigation measures to discourage birds from using ponds within the refinery site, including adding netting to prevent birds from landing in open tanks or ponds with oily wastewater and placing cobbles on the sideslopes of the constructed ponds to discourage plovers from nesting. They also recommended that electrical transmission lines be constructed to minimize collision and electrocution risks to birds.

### *F. Transportation*

- For all of the refinery construction alternatives, the refinery would increase traffic on local roads and on the rail line. With the shipment of refinery products, as well as the transportation of hazardous waste off-site for treatment and disposal, there would be an increased probability of petroleum products spills along the pipeline corridor, transportation corridors and the rail line. To mitigate the impacts of increased traffic on US 23, EPA recommends that right turn lanes be added on US Highway 23 at the two access points to the highway. An acceleration lane should also be added for east bound US 23. As part of the final design, we also recommend conducting a traffic study to evaluate the need for left turn lanes into the refinery.

### *G. Air Quality*

- The FEIS presents modeling of potential refinery air emissions conducted by the MHA Nation assuming use of synthetic crude as the refinery feedstock. This modeling demonstrated that the proposed facility would not cause any exceedances of the National Ambient Air Quality Standards (NAAQS) or Prevention of Significant Deterioration (PSD) Class I increments. As discussed below in Section VII, in 2011, the MHA Nation submitted to EPA additional air emissions calculations and modeling related to refining of Bakken crude. This new information is presented and evaluated in the attached Supplemental Information Report (SIR). Also explained in the FEIS, in 2005 EPA made a determination that no Clean Air Act PSD pre-construction permit would be required for the facility; however, as discussed below in Section VII, EPA has withdrawn this determination.

- The facility will need an air emissions permit for operations. The requirement for the refinery to apply for a Clean Air Act Title V operating permit within 12 months of commencing operation was triggered by the promulgation of New Source Performance Standards. For example, 40 C.F.R. Part 60, Subpart GGGa, Standards of Performance for equipment leaks of volatile organic compounds in petroleum refineries, was issued on November 16, 2007 and this requirement and others would make the facility subject to the Clean Air Act Title V permitting requirements as defined by Clean Air Act Title V permitting requirements (40 C.F.R. § 71.3).

### *H. Human Health*

- With proper operation of the refinery, potential impacts to human health are anticipated to be negligible to the general public. Pollutants or materials which would be of concern to public health would be contained within the refinery, treated to nontoxic levels or disposed of at approved hazardous waste facilities.

- Transporting, handling, storing, and disposing of chemicals and hazardous materials inherently pose a risk of a release to soil, ground water, air, surface water, and sediment. Numerous regulatory programs would be implemented at the proposed facility to prevent or control potential releases such as the emergency response planning, oil spill response planning and containment measures, NPDES permits, RCRA, and OSHA requirements.

- In the remote event of a catastrophic spill or fire, there could be emissions from the facility that would be of concern to public health in the immediate area of the refinery;

however, there are currently no residences or businesses located in the immediate area of the refinery site that would remain occupied once refinery operations commenced.

- The air modeling analyses in the FEIS show that the potential impacts of hazardous air pollutants would be below levels of concern to human health through both direct inhalation and food chain pathways outside of the proposed refinery site process area.

- Epidemiological and toxicological studies, as discussed in Chapter 4 of the EIS, did not identify any increases in health effects for people living near petroleum refineries. One occupational health study observed increased rates for one type of cancer for workers in the petrochemical industry.

### *I. Environmental Justice, Socioeconomics*

- Environmental justice concerns include many of the issues addressed above, such as air pollution emissions, discharge of pollutants into surface waters and ground water, and hazardous waste generation. Other issues include the socioeconomic effects of constructing and operating a new refinery. EPA conducted an environmental justice analysis in conjunction with the EIS and draft NPDES permit, and concluded that there would be no disproportionately high and adverse effects on minority or low-income communities.

- Economic benefits associated with the refinery could increase the quality of life for members of the MHA Nation. However, the communities surrounding the facility could experience negative effects to their quality of life due to increases in highway traffic, noise, and light pollution during construction and operation of the facility.

## VI. SUBSTANTIVE COMMENTS RECEIVED ON FEIS

Fifteen individuals and/or entities commented on the FEIS and raised various issues including: opposition to the refinery; support for the refinery; impacts analyses for air quality; absence of a CAA PSD permit; greenhouse gas emissions; cumulative impacts; human health; concerns about lack of controls and monitoring for air and ground water impacts; concerns about lack of Tribal and regulatory capacity to protect the environment from the refinery; and Environmental Justice. Most comments were very similar to or the same as the comments on the DEIS. EPA and DOI/BIA previously addressed these comments in the response to comments on the DEIS, which the Agencies included as an appendix in the FEIS The FEIS comments regarding air included more detail about the air emissions calculations and objected to EPA's 2005 determination that a PSD permit would not be needed for the facility. In the comments on the FEIS, there was one new area of concern – the potential unavailability of synthetic crude as a feedstock for the refinery.

## VII. REVISED FEEDSTOCK AND CONSTRUCTION

As discussed above, following issuance of the Final EIS, the Tribes informed EPA of their intent to change the refinery feedstock from synthetic crude as described in the EIS to the local Bakken crude oil. The change in feedstock modified the preliminary design of the construction alternatives analyzed in the EIS. Consequently, EPA has evaluated the changes in impacts resulting from the switch to the Bakken crude feedstock and the EIS to determine: (1) if substantial changes have been made to the project since completion of the FEIS in 2009 that are relevant to environmental concerns, and (2) if significant new circumstances or information relevant to environmental concerns and bearing on the proposed refinery or its impacts have occurred since the FEIS was completed. EPA summarized its evaluation in a Supplemental Information Report (SIR) (attached). Following are highlights from the SIR:

- The Tribes are still proposing to build a refinery on the same site and at the same capacity as described in the EIS. While the synthetic and Bakken crudes are both light, sweet crudes, the Tribes plan to add several additional process units to the refinery to process the Bakken crude, besides those described in the EIS for Alternative 4.

- The MHA Nation submitted to EPA additional air emissions modeling related to refining of Bakken crude. Refinery air emissions will increase because of the additional refinery process units; however, no exceedances of the National Ambient Air Quality Standards (NAAQS) are anticipated with the potential exception of the $SO_2$ hourly standard. The hourly $SO_2$ standard may be exceeded if the flare operates more frequently than anticipated, and both the sulfur recovery unit and the back-up unit are down at the same time.

- Under the Clean Air Act (CAA), the allowable deterioration to air quality is expressed as an incremental increase to ambient concentrations of criteria pollutants, referred to as PSD increment. The revised air modeling predicted $PM_{10}$ concentrations at nearfield receptors levels greater than the Class II PSD increment. The model comparison to the Class II increments was solely for informational purposes and does not represent a regulatory PSD increment consumption analysis under the CAA. The main refinery unit contributing $PM_{10}$ emissions in the model was soybean crushing for biodiesel. The MHA Nation has determined that they no longer plan to produce biodiesel at the refinery. Instead they plan to purchase biodiesel from other facilities if needed.

- Given the Tribes' decision to use the Bakken crude as the refinery feedstock and based on additional analysis EPA conducted on the potential to emit from the proposed refinery, EPA concluded, in a letter to the Tribes dated March 24, 2010, that the project information no longer supports EPA's April 25, 2005 applicability determination that a preconstruction PSD permit would not be required for the proposed refinery. In a May 5, 2011 letter, EPA notified the Tribes that the March 9, 2011, Addendum to the *Air Quality Technical Report for the FEIS for the MHA Nation Proposed Clean Fuels Refinery Project* did not have the information needed for EPA to concur with the Tribes assessment that the facility would be a minor source for air emissions. EPA recommended that the Tribes apply for a PSD permit.

- With the proximity of the Bakken oil field to the refinery, other crude transportation options besides the pipeline described in the FEIS are feasible. The refinery operator may opt to receive crude oil via a local pipeline, truck or rail or a combination of these alternatives.

- A new brine waste stream would be produced from the new desalter at the refinery. This waste stream would be disposed of through a Class I UIC well. The FEIS analyzed the option of disposal of refinery wastewater into an underground injection well (Alternative C). The brine waste stream would be an additional source of wastewater.

- EPA determined the feedstock change would not alter EPA's determination of "no effect" on listed and potentially listed Threatened and Endangered species for the issuance of the NPDES discharge permit. EPA informally consulted with FWS regarding this reevaluation of the "no effect" determination.

## VIII. ENVIRONMENTALLY PREFERABLE ALTERNATIVE

The environmentally preferable alternative is the alternative that causes the least damage to the biological and physical environment and meets the purpose and need of the project. It also means the alternative which best protects, preserves and enhances historic, cultural and natural resources. Under Alternative D, the No Action alternative, no refinery would be constructed and EPA would not issue an NPDES or other federal effluent discharge permits. Alternative D best meets the definition of the environmentally preferable alternative; however, this alternative does not meet the applicant's purpose and need.

Based on the analysis in the FEIS, EPA's environmentally preferable action alternative for the effluent discharge is Alternative A, the preferred alternative. Alternative A is the environmentally preferable action alternative because:

- There would be effluent discharge limits, monitoring and reporting requirements; and
- EPA has the authority to take enforcement action if the conditions of the NPDES permit are not met.

Following EPA's reevaluation of the project described in the SIR, EPA's environmentally preferred alternative for effluent discharge continues to be Alternative A (as described above) with the addition of Alternative C for the brine waste stream. The MHA Nation would discharge brine to a Class I underground injection control (UIC) well that would be drilled on the project site. Alternative C would be the environmentally preferred action alternative for disposing of brine waste streams because:

- Brine or salty wastewaters are difficult to treat to the limits needed for discharges to surface waters and generating a concentrated saline or salt waste stream;
- There would be well construction requirements, injection permit limits and monitoring and reporting requirements to protect groundwater.
- EPA has the authority to take enforcement action if the conditions of the UIC permit are not met.

In addition, EPA recommends that the design of the refinery be modified consistent with the Alternative 4, and incorporate the changes described in the SIR to refine Bakken crude.

## IX. EPA DECISION

This ROD documents EPA's decision to issue an NPDES permit for the refinery (Alternative A). The NPDES permit specifies discharge effluent limitations, outfalls, monitoring and reporting requirements, and other legal conditions governing discharges from the refinery. EPA developed effluent limits in consideration of Tribal water quality standards, North Dakota water quality standards for the purpose of ensuring compliance with the applicable water quality requirements of a downstream state, EPA CWA Section 304(a) water quality criteria, and the Effluent Limitation Guidelines and Standards for the Petroleum Refining Point Source Category pursuant to 40 C.F.R. § 419.36. The NPDES permit allows the discharge of effluent only through specific outfalls and when effluent water quality meets or is cleaner than the discharge limitations in the permit. The permittee is also required to frequently monitor the water quality of the effluent and report the analysis results to EPA.

The required mitigation measures set forth in this ROD and the NPDES permit conditions reflect EPA's authority to place limitations and conditions related to the NPDES discharge. Mitigation measures not directly related to EPA's NPDES authorities are recommended actions.

EPA's decision is based on several assumptions: First, the capacity of the refinery and refinery process units will be consistent with the revised proposal described in the SIR. Specifically, the refinery will have a capacity of 13,000 barrels per day of products. The feedstock will be the Bakken crude. The refining of heavier or sour crude oil feedstocks were not analyzed in the NEPA analysis. The EIS environmental analyses were also based on a properly designed, operated and maintained facility.

The second group of assumptions is that the layout of the refinery units will follow the configuration described in Alternative 4. Specifically, tanks will replace all ponds that have the potential to contain or generate hazardous waste and the refinery layout will be changed to avoid most wetland impacts from the discharge of dredged or fill material so that the project can avail itself of a U.S. Army Corps of Engineers Clean Water Act Section 404 nationwide permit rather than an individual permit. If the ponds proposed in the original proposal (Alternative 1) are constructed instead of tanks, or if the tanks are operated in a manner that does not meet the definition of an exempt wastewater treatment unit under RCRA the facility would need to apply to EPA for a RCRA TSD permit. Similarly, if the layout of the facility follows the Alternative 1 configuration or a similar layout, the MHA Nation would need an individual Section 404 permit under the Clean Water Act from the Army Corps of Engineers for the discharge of dredged or fill material into waters of the U. S.

## X. FACTORS CONSIDERED IN THE DECISION

In reaching the decision to grant the NPDES permit for the proposed refinery, EPA is required to take into account "any significant beneficial and adverse impacts of the proposed action and a review of the recommendations contained in the EIS…" 40 C.F.R. § 122.29(c)(3).

EPA has taken into consideration the evaluations as described in the FEIS. The FEIS analyzes project alternatives, associated environmental impacts, and the extent to which the impacts can be mitigated. EPA has also considered the objectives of the project proponent and public comments received during the EIS and NPDES permit review periods, and comments received following issuance of the Final EIS.

The federal government has a trust responsibility to federally-recognized Indian tribes that arises from Indian treaties, statutes, executive orders and the historical relations between the United States and Indian tribes. This is also reflected in Executive Order 13175, entitled, "Consultation and Coordination with Indian Tribal Governments" (Nov. 6, 2000); EPA Policy on Consultation and Coordination With Indian Tribes (May 4, 2011); the Presidential Memorandum issued on November 5, 2009, directing agencies to develop a plan to implement fully Executive Order 13175; and EPA's 1984 Policy for the Administration of Environmental Programs on Indian Reservation. With regard to the proposed project, EPA and BIA have continuously consulted with the Three Affiliated Tribes on a government-to-government basis. EPA and BIA have consulted with the Tribal Business Council at each major milestone in the NEPA process. EPA has taken into consideration the views of the MHA Nation as appropriate.

EPA has also consulted with the U.S. Fish and Wildlife Service, tribal and state historic preservation officers to determine compliance of EPA's permit action with the Endangered Species Act (ESA) and the National Historic Preservation Act (NHPA). With respect to ESA, on August 22, 2006, the U.S. Fish and Wildlife Service (FWS) sent a letter to EPA, concurring with EPA's determination that issuance of the new NPDES permit would have “no effect” on the identified species or their designated critical habitat, as described in EPA's biological evaluation in the DEIS. Also on August 22, 2006, FWS sent a memorandum to BIA, concurring with BIA's determinations that the construction and operation alternatives discussed in the DEIS will have “no effect” on the gray wolf, Dakota skipper, interior least tern, bald eagle, and pallid sturgeon. Further, FWS concurred with BIA determination that the construction and operation alternatives “may affect, but are not likely to adversely affect” piping plovers and whooping cranes. The “not likely to adversely affect” determination was based on the implementation of conservation measures the FWS described in a memorandum dated January 11, 2006. The FWS stated in the memorandum “that 4 to 6 inch rock (as opposed to gravel) should be used to line exposed in-slopes of all wastewater/storage ponds. Any ponds having the potential to hold contaminated water should be netted. The larger rock and netting will prevent the creation of an attractive nuisance for piping plovers and other migratory shorebirds.” EPA and BIA notified the FWS of the completion of the FEIS in correspondence dated October 28, 2009, and September 11, 2009, respectively. EPA determined the change in refinery feedstock would not alter EPA's "no effect" determination regarding issuance of the NPDES permit. EPA informed the FWS of this finding by memo, dated July 15, 2011.

The State Historical Society of North Dakota, in a March 24, 2005 letter to the MHA Nation Cultural Preservation Office, identified a low probability for cultural resources on the proposed refinery site and recommended a "no historic properties affected" determination. Similarly, the MHA Nation Cultural Preservation Office, in an April 4, 2005 letter to Horace Pipe, made a "No Historic Properties Affected" determination for the two tracts of land in the proposed site.

Executive Order 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, was published in February 1994 and directs agencies, to the greatest extent practicable and permitted by law, to identify and address, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies, and activities on minority and low-income populations in the United States and its territories. The Environmental Justice analysis in the EIS evaluates whether there are any disproportionately high and adverse human health or environmental effects on any communities, including minority and low-income communities. EPA also conducted an Environmental Justice analysis for the proposed project to assess whether the occurrence and severity of possible adverse impacts that might result from environmental sources of stress, including, but not limited to, potential release of contaminants to air, surface water, ground water and soils are disproportionately higher in the potentially affected community than in a larger reference community. EPA concluded that there would be no disproportionately high and adverse effects on minority or low-income communities.

## XI. MITIGATION MEASURES; PERMITS, DISCHARGE LIMITATIONS AND MONITORING REQUIREMENTS

The following table summarizes the permits, plans, monitoring, inspecting and mitigation measures for the agencies' preferred alternatives. The table also describes: whether or not the measures are required or are likely to be implemented; who would be responsible for implementing the mitigation measures; reporting and monitoring requirements, if any; and the agency that could enforce the measure, if applicable.

## Mitigation Measures, Environmental Permits, Plans, Monitoring, Inspections, Reporting and Follow-up for the Agencies' Preferred Alternatives: Revised Construction Alternative (designed following Alt. 4) and Alternatives A (issue NPDES permit) and C (issue UIC permit) for brine waste water

| Mitigation Measures, Permits, Plans, Monitoring, Reporting and Follow-up | Is the measure required? | Measure likely to be implemented? | Who Imple-ments? | Reason for Mitigation | Report to? | Enforced by? |
|---|---|---|---|---|---|---|
| **NPDES Permits** | | | | | | |
| **NPDES permit during refinery operations** | | | | | | |
| Wastewater discharges must meet or be cleaner than permit effluent limits | Permit requirement | Yes | MHA Nation | Protect water quality. | EPA | EPA |
| Monitoring of effluent quality may also include downstream water quality monitoring | Permit requirement | Yes | MHA Nation | Determine if effluent water quality is in compliance with permit | EPA and TAT Environ. Division | EPA |
| Best Management Practices (BMP), separation of contaminated and uncontaminated stormwater | Permit requirement | Yes | MHA Nation | Prevent/reduce contamination of water. | | EPA |
| Develop and Implement a Stormwater Pollution Prevention Plan (SWPPP) | Permit requirement | Yes | MHA Nation | Prevent/reduce contamination of water. | Maintain records on site | EPA |
| Facility inspections – Implementation of BMP, and SWPPP | Permit requirement | Yes | MHA Nation | Evaluate implementation of BMPs and SWPPP | Maintain records on site | EPA |
| **NPDES general stormwater construction permit** | | | | | | |
| Develop and Implement a Stormwater Pollution Prevention Plan. Typical measures include: silt fences, erosion protection | Permit requirement | Yes | MHA Nation | Protect water quality | Maintain records on site | EPA |
| Inspect/monitor implementation of Stormwater Pollution Prevention Plan. Typical measures include: silt fences, erosion protection | Permit requirement | Yes | MHA Nation | Determine if SWPPP is being properly implemented and if the plan is sufficient to protect water quality. | Maintain records on site | EPA |
| **UIC Permit for Brine Disposal** | | | | | | |
| Obtain a Class I UIC permit before constructing a brine disposal injection well. | Required | Yes | MHA Nation | Protect underground sources of drinking water | EPA | EPA |

| Mitigation Measures, Permits, Plans, Monitoring, Reporting and Follow-up | Is the measure required? | Measure likely to be implemented? | Who Implements? | Reason for Mitigation | Report to? | Enforced by? |
|---|---|---|---|---|---|---|
| **Financial Assurance** | | | | | | |
| Bonding/Financial Assurance<br>Financial assurance for cleanup during operations and closure | Recommended. | MHA Nation considering implementation, no action to date. | MHA Nation | Money to pay for clean-up | N/A | N/A |
| | May be required later, under RCRA generator regulations, if the refinery cannot demonstrate clean closure | | MHA Nation/ | “ “ | EPA | EPA |
| **During Operations -- Inspections, Monitoring and Clean-up of Hazardous Wastes, Oil, and Petroleum Products** | | | | | | |
| **Ground Water** | | | | | | |
| Ground water monitoring during operation following ground water quality monitoring program | General ground water monitoring recommended | MHA Nation considering implementation, no action to date. | MHA Nation | To determine if ground water has become contaminated, the extent of contamination, and to help evaluate remediation options. | N/A | N/A |
| Ground water monitoring for UIC Permit | Required | Yes | MHA Nation | Determine if UIC permit conditions are being met | EPA | EPA |
| Tribal ground water protection program | Recommended | MHA Nation considering implementation, no action to date. | MHA Nation | Protection of Tribes’ groundwater resources | N/A | N/A |
| **Cleanup of Spills and Leaks** | | | | | | |
| Clean-up spills and leaks of hazardous waste, oil and petroleum products and oily water. | Required | Yes | MHA Nation | Reduce/prevent contamination Clean up contamination | Reporting depends on spill type/volume EPA or Coast Guard | EPA |
| | Cleanup actions required under RCRA included in the RCRA, SPCC and FRP plans | | | | | |

| Mitigation Measures, Permits, Plans, Monitoring, Reporting and Follow-up | Is the measure required? | Measure likely to be implemented? | Who Imple-ments? | Reason for Mitigation | Report to? | Enforced by? |
|---|---|---|---|---|---|---|
| Inspections for spills or leaks from process units & tanks for the entire facility | Required | Yes | MHA Nation | Determine presence of spills and leaks. Check the integrity of tanks and containment. Indentify problems early to quickly initiate corrective actions such as repairs and clean-up. | Maintain records on site | EPA |
| RCRA Inspection of hazardous wastes accumulation areas –RCRA Part 262 and other regulations cross referenced by 262, such as Parts 263 and 265 and 268, as applicable | Required | Yes | MHA Nation | Determine if wastes properly stored and contained. | Maintain records on site | EPA |
| Inspection of hazardous waste tanks regulated by RCRA –RCRA Part 262 regulations | Required | Yes | MHA Nation | Determine if hazardous wastes are properly contained ( e.g., overtopping, ruptures, air releases, deterioration of tanks and ancillary equipment, no spills or leaks, covers and valves properly operating). | Maintain records on site | EPA |
| **Closure of Refinery** | | | | | | |
| General refinery closure & reclamation plan<br>- Monitoring of soil and ground water<br>- Inspection of the site during closure<br>- Plan to decommission the refinery | Recommended | MHA Nation considering implementation, no action to date. | MHA Nation | To determine if the site is sufficiently cleaned up and reclaimed to return to agricultural use. | N/A | N/A |
| RCRA closure plan for entire facility<br>Includes closure requirements, financial assurance, monitoring. and inspection of specific hazardous waste management units (HWMU) | Recommended | Unlikely to be implemented. | MHA Nation | To determine if hazardous waste units have been successfully closed and if cleanup has been sufficient | Recommended | N/A |
| RCRA Closure Plan for temporary hazardous waste storage areas –RCRA Part 262 regulations | Required for temporary hazardous waste storage areas | Yes | MHA Nation | Plan to decommission and clean up if needed temporary hazardous waste storage areas. | EPA | EPA |
| RCRA Closure Monitoring of hazardous waste storage areas –RCRA Part 262 regulations | Required | Yes | MHA Nation | Determine if the area(s) used to temporarily store hazardous wastes have become contaminated. | EPA | EPA |

| Mitigation Measures, Permits, Plans, Monitoring, Reporting and Follow-up | Is the measure required? | Measure likely to be implemented? | Who Imple-ments? | Reason for Mitigation | Report to? | Enforced by? |
|---|---|---|---|---|---|---|
| **Air Quality Protection** | | | | | | |
| Part 60 New Source Performance Standards and Part 61 National Emission Standards for Hazardous Air Pollutants | Required | Yes. | MHA Nation | Air quality emission limitations and monitoring requirements for specific petroleum refinery process units. | EPA | EPA |
| Operating permit (Part 71) for the facility, Air Title V CAA permit.<br>Refinery must submit Part 71 application within 12 months of start-up. Within 18 months of receipt of a complete application, Region 8 must issue the operating permit | Required | Yes | MHA Nation | Outlines applicable air quality emission limits and monitoring requirements. | EPA | EPA |
| Unit emissions monitoring to be required through mix of NSPS, NESHAP, or future operating permit | Required, for specific units of the refinery. | Yes | MHA Nation | Determine compliance with air quality regulations and permit. | EPA | EPA |
| Tribal air quality monitoring near proposed site | Recommended | Monitoring station now installed near Makoti. | MHA Nation | Determine air quality in the vicinity of the refinery. | EPA | N/A |
| Air quality mitigation measures:<br>- Control flaring to a maximum of a hundred hours per year and add a flare gas recovery unit<br>- Install a second sulfur recovery unit as a full backup | Recommended | Yes, MHA Nation included in revised air information reports | MHA Nation | Reduce air emissions | N/A | N/A |
| **Refinery operations plans** | | | | | | |
| Refining of light, sweet crude only | Modified Refinery proposal | Yes | MHA Nation | Fewer refinery processes, and few heavier petroleum compounds reducing air and water pollution. | N/A | N/A |

| Mitigation Measures, Permits, Plans, Monitoring, Reporting and Follow-up | Is the measure required? | Measure likely to be implemented? | Who Imple-ments? | Reason for Mitigation | Report to? | Enforced by? |
|---|---|---|---|---|---|---|
| Recycling of wastewater, operation of wastewater treatment plants. | Included as part of MHA Nation proposal | Yes | MHA Nation | Reduce water consumption and reduce volume of wastewater discharges from facility. | N/A | N/A |
| **Refinery design and construction plans** | | | | | | |
| Double-liners and leak detectors, evaporation and holding ponds. | Included as part of refinery redesign for Alternative 4 | Yes | MHA Nation | Prevent/reduce potential for contamination from leaks and spills. | N/A | N/A |
| Hazardous waste containers/tanks, e.g., double-walled tanks | Required, Generator regs. | Yes | MHA Nation | Prevent/reduce potential for contamination from leaks and spills. | N/A | EPA |
| Separate oil and non oily stormwater handling systems | Partially required by NPDES permit | Yes | MHA Nation | Reduce volume of oily waste water and reduce wastewater treatment costs. | N/A | EPA |
| Controls to prevent mixing of uncontaminated stormwater with potentially contaminated stormwater | Partially required by NPDES permit | Yes | MHA Nation | Reduce volume of oily waste water and reduce wastewater treatment costs. | N/A | EPA |
| Pave vulnerable areas such as the loading and unloading areas.<br>Potentially contaminated (oily) wastewater conveyed in pipes or paved ditches. | Partially required by SPCC regulations and included in refinery design | Yes | MHA Nation | Protect soil and groundwater from contamination and contain spills on site. | EPA | EPA |
| Desalter wastewater holding tanks with sufficient storage for at least one weeks brine volume. | Recommended | Unknown | MHA Nation | Backup for brine disposal UIC well. | N/A | N/A |
| **Emergency and spill response plans** | | | | | | |
| Spill Prevention, Control, and Countermeasure, Plans (SPCC) -- Oil Pollution Act | Required | Yes | MHA Nation | Prevent/contain oil and oily water spills to protect surface waters | EPA | EPA |
| Facility Response Plan (FRP) – Oil Pollution Act | Required | Yes | MHA Nation | Prevent/contain oil and oily water spills to protect surface waters provide. Develop measures to respond to oil spills that could reach surface waters. | EPA | EPA |

| **Mitigation Measures, Permits, Plans, Monitoring, Reporting and Follow-up** | **Is the measure required?** | **Measure likely to be implemented?** | **Who Imple-ments?** | **Reason for Mitigation** | **Report to?** | **Enforced by?** |
|---|---|---|---|---|---|---|
| CAA Risk Management Plan Hazardous Materials | Required | Yes | MHA Nation | | EPA | EPA |
| Superfund Emergency Plan | Required | Yes | MHA Nation | | EPA | EPA |
| RCRA Preparedness and Prevention Plans: Hazardous Waste Contingency Plan (HWCP) and refinery employee training for hazardous waste management and emergency response | Required | Yes | MHA Nation | | EPA | EPA |
| Transportation Act (HMTA) Response Plan | Required | Yes | MHA Nation | | EPA | EPA |
| **Wetlands Permits and Mitigation** | | | | | | |
| Plan to replace or mitigate any non-jurisdictional wetlands filled by project (fill and other impacts) | Recommended | Unlikely to be implemented | MHA Nation | Protect/reduce impacts to wetlands resources | | |
| Jurisdictional wetlands impacted by the project will need a Nationwide 404 permit, if the project is designed to following Alternative 4. If the layout follows Alternative 1, an individual 404 permit will be required. | Required | Yes | MHA Nation | Protects/reduce impacts to wetlands resources | COE | COE |
| **Wildlife mitigation measures** | | | | | | |
| Cobbles to discourage plovers from water impoundments<br>Bird friendly power line construction specifications | Recommended | Yes, Tribes have agreed to implement. No action to date. | MHA Nation | Protect piping plover, whooping cranes and raptors. | FWS | FWS |
| | | | | Failure to implement these requirements could result in an unauthorized taking pursuant to the ESA. | | |
| Netting of ponds with oily water | Measure no longer needed. Ponds with oily water have been replaced with tanks per design modifications for alternative 4. | | N/A | Protect birds from oily or hazardous wastes | N/A | N/A |

## XI. CONTACTS

Further information regarding this Record of Decision may be obtained by contacting:

Dana Allen
U.S. Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, CO 80202
(303) 312-6870
Allen.dana@epa.gov

Further information regarding the NPDES permit may be obtained by contacting:

Robert Brobst, P.E.
U.S. Environmental Protection Agency Region 8
1595 Wynkoop Street
Denver, CO 80202
(303) 312-6129
Brobst.bob@epa.gov

Approved by:

James B. Martin
Regional Administrator

August 3, 2011
Date

**Exhibit 6:**

Supplemental Information Report (Jul. 29, 2011)

# Supplemental Information Report
## July 29, 2011

# Mandan, Hidatsa and Arikara Nations
# Proposed
# Refinery Project
# Environmental Impact Statement

**U.S. Environmental Protection Agency**
**Region 8**
**1595 Wynkoop Street**
**Denver, CO 80202-1129**

# I. Introduction

The Three Affiliated Tribes (Tribes) comprising the Mandan, Hidatsa and Arikara (MHA) Nation have proposed to construct and operate a petroleum refinery with a capacity of 13,000 barrels per day on the Fort Berthold Indian Reservation in North Dakota. The MHA Nation originally proposed that the refinery would process synthetic crude produced from the Alberta, Canada tar sands mines. In 2010, the Tribes decided to change the proposed refinery feedstock from the Alberta synthetic crude to the local Bakken crude oil. The Bakken oil fields have been developing rapidly over the last five years.

The MHA Nation owns the 468.39 acre site. The refinery footprint is projected to cover approximately 190 acres of the site. The remaining 278 acres would be used to grow forage for the Tribes' buffalo herd, although buffalo would not be located at the site. The proposed refinery location is in the northeast corner of the Fort Berthold Indian Reservation in Ward County as show in Figure 1.

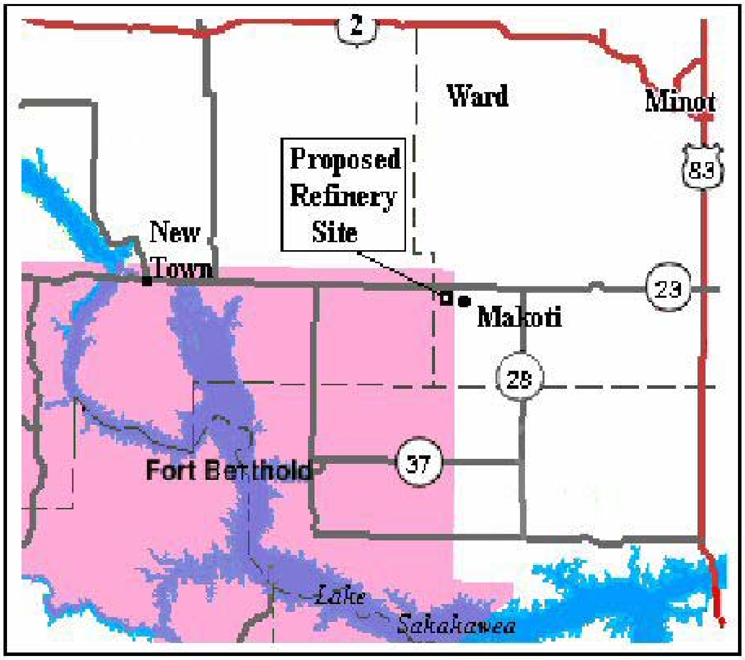


**Figure 1 - Proposed Refinery Location**

**National Environmental Policy Act (NEPA) Background:** The proposed refinery invokes NEPA compliance responsibilities for both the U.S. Environmental Protection Agency (EPA) and the Bureau of Indian Affairs (BIA). EPA's NEPA compliance responsibilities arise from the Tribes' request that EPA issue a Clean Water Act (CWA) National Pollutant Discharge Elimination System (NPDES) "new source" wastewater discharge permit for the proposed refinery in accordance with CWA § 511(c)(1). EPA's Clean Air Act (CAA) actions, including permitting activities, are not subject to NEPA pursuant to the Energy Supply and Environmental Coordination Act, 15 U.S.C. § 793(c)(1). BIA's NEPA responsibilities arise from the Tribes' request that BIA accept Tribally-owned land into trust status for purposes of constructing and operating the proposed refinery and to produce forage for buffalo. EPA and BIA are co-leads in the NEPA process for this project. The U.S. Army Corps of Engineers is a cooperating agency and the MHA Nation is a cooperating Sovereign Nation.

EPA and BIA began the NEPA process in 2003, issued the Draft Environmental Impact Statement (DEIS) in June 2006, and the Final Environmental Impact Statement (FEIS) in August 2009. EPA and BIA provided the public opportunities to submit verbal and written comments on the DEIS and FEIS. Tribal members, non-governmental organizations and other individuals submitted comments raising various issues including concerns regarding: the impacts analyses for air quality; absence of a CAA Prevention of Significant Deterioration (PSD) permit; cumulative impacts; greenhouse gas emissions; human health impacts; and Environmental Justice. After release of the FEIS, the Tribes informed EPA and BIA of their intent to change the refinery feedstock from the Alberta synthetic crude to the local Bakken crude.

## II. Supplemental Information Report

This Supplemental Information Report (SIR) documents EPA's evaluation and consideration of the change in feedstock for the MHA Nations' Proposed Clean Fuels Refinery Project. The Council on Environmental Quality (CEQ) regulations provide direction regarding the review of an EIS and preparation of supplemental statements. The CEQ regulations at 40 C.F.R. § 1502.9(c) state:

> *Agencies shall prepare supplements to either draft or final EIS's if:*
> 1. *The agency makes substantial changes in the proposed action that are relevant to environmental concerns; or*
> 2. *There are significant new circumstances or information relevant to environmental concerns and bearing on the proposed action or its impacts.*

This report summarizes EPA's evaluation of the changes in impacts resulting from the switch to the Bakken crude feedstock and the EIS to determine: (1) if substantial changes have been made to the Project since completion of the FEIS in 2009 that are relevant to environmental concerns, and (2) if significant new circumstances or information relevant to environmental concerns and bearing on the proposed refinery or its impacts have occurred since the FEIS was completed. This SIR also provides technical information to the decision maker to assist him in determining whether to issue an NPDES new source wastewater discharge permit for the proposed refinery.

## III. Feedstock Change

In 2010, the Tribes informed EPA of their intent to change the feedstock for their proposed refinery from synthetic crude to the local Bakken crude oil. In comparing the two feedstocks, EPA notes that both the synthetic and Bakken crudes are light, sweet crudes. Refineries with heavier or sour crude feedstocks have more refinery process units and additional waste streams increasing potential environmental impacts. The Bakken crude has a higher salt content, has a bottoms (residual oil) component, and has more variability of composition than the synthetic crude, since the latter would be partially refined in Canada. The Tribes have not changed the site location or the proposed capacity of the refinery from what is described in the FEIS.

# IV. Changes to the Refinery to Process Bakken Crude

## A. Refinery

The preliminary refinery design and site plans used to determine the environmental impacts of the proposed projects in the FEIS are the same for both the synthetic and the Bakken crudes with the following process units added for the Bakken crude:

- Vacuum crude heater
- Two decant oil tank heaters
- Desalter
- Desalter brine disposal facilities
- Additional air pollution control units: second sulfur recovery, tail gas treating, and amine treating.

For most environmental resources and issues of concern, the environmental analysis for a refinery using Bakken crude is similar to that of a refinery using Alberta synthetic crude as analyzed in the FEIS. The refinery is still projected to be a relatively small refinery using a light, sweet crude feedstock:

- Same location and general site layout;
- The output capacity does not increase;
- The above additional process units are expected to fit within the existing site boundaries. No additional area of disturbance for the refinery is anticipated.

## B. Crude Oil Transportation and Traffic Considerations

The pipeline analyzed in the FEIS for transporting synthetic crude to the proposed refinery remains the most likely alternative to convey Bakken crude to the proposed refinery. A 4-mile pipeline would be constructed from the refinery to an existing Enbridge pipeline spur to the Wabeck/Plaza oil field. The Enbridge pipeline currently transports Bakken crude. As shown in Figure 2, the proposed pipeline spur parallels the existing railroad tracks.

The FEIS described four synthetic crude storage “breakout” tanks proposed along the Enbridge pipeline between Outlook, MT, and the proposed refinery site. When the refinery was first proposed, those tanks were needed because the refinery would have been the main customer for that synthetic crude pipeline. These storage tanks are no longer needed for the project. The proximity of the Bakken crude facilities and several pipeline and terminal projects completed in the last few years eliminate the need for crude storage along the route. The entire pipeline system is being expanded and revised to transport crude oil from North Dakota to refineries throughout the U.S.

With the proximity of the Bakken oil field to the refinery, other crude transportation options besides the pipeline described in the FEIS are feasible. The refinery operator may opt to receive crude oil via a local pipeline, truck or rail or a combination of these alternatives. Based on discussions with the Tribes’ contractors, the Tribes’ plan for crude oil conveyance continues to be piping crude to the refinery via the nearby Enbridge pipeline, following the same alignment analyzed in the FEIS (spur from Wabek/Plaza to the refinery site). However, Bakken crude may be trucked to the refinery during the first years of operation if the pipeline system has not been completed prior to the refinery coming online. There may be other periods of trucking crude depending on pipeline capacity and the cost of transporting crude via the pipeline system.

In the long-term EPA understands from discussions with representatives of the Tribes that the refinery would receive crude via a pipeline either through the Enbridge pipeline, as described in the FEIS, or a local pipeline. No specific plans have been developed to date; however, the most likely pipeline route, shown in Figure 2, would be the same as was analyzed in the FEIS. For these pipeline options, the potential impacts would be generally comparable to those described in the FEIS, except that the potential impacts of the four storage tanks would be eliminated. An alternate route for the local pipeline could be along Highway 23. The pipeline length and resources that will be affected would be very similar to the analysis in the EIS.

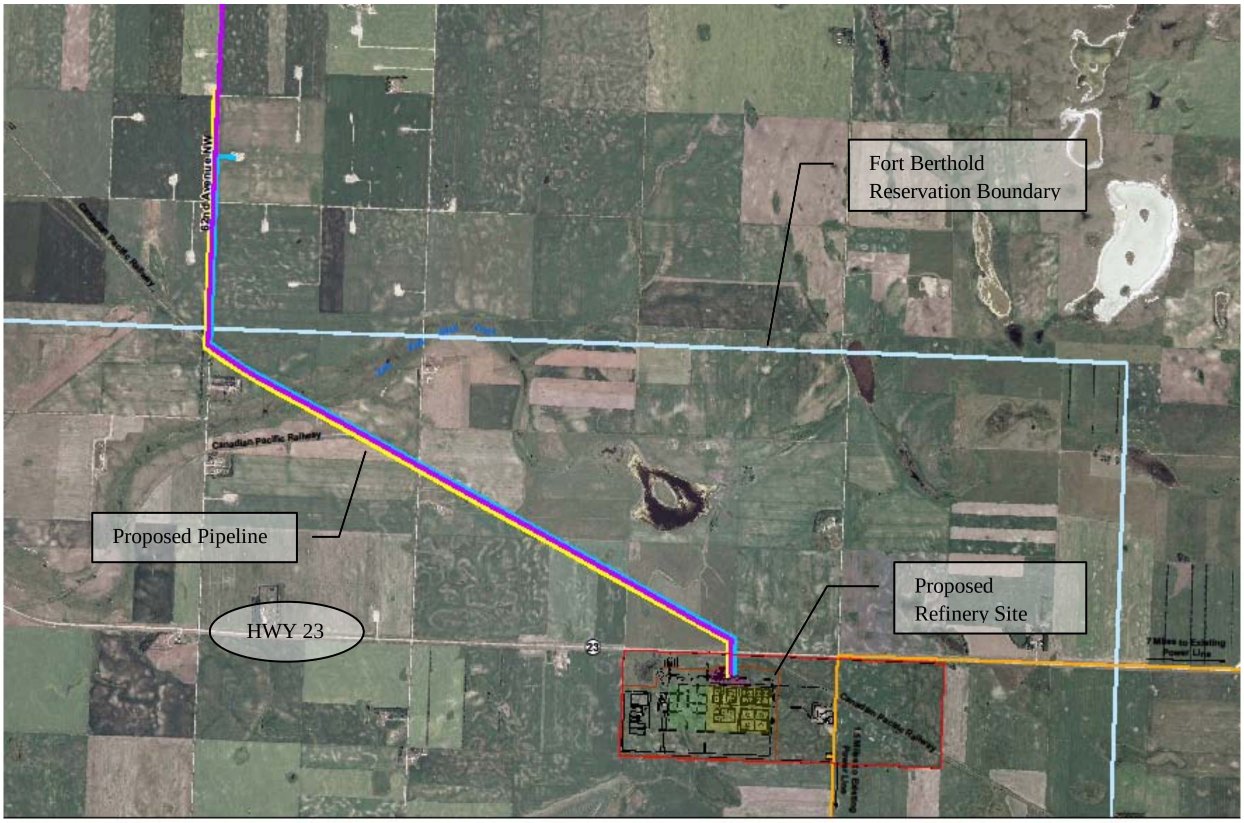


**Figure 2 - MHA Refinery and Pipeline**

[Legend: Blue line = oil pipeline, light blue = reservation boundary, fuchsia & yellow = gas lines, orange = power lines]

While transporting crude oil to the refinery via truck was not considered in the FEIS, the FEIS did analyze trucking and rail for non-crude feedstocks and product shipment, as well as increases associated with employees commuting to and from the refinery. There would be some additional truck or train traffic, beyond what was analyzed in the FEIS, if crude were to be delivered to the refinery via truck or rail. The analysis predicted a 30% increase in traffic (FEIS, page 4-93) on US 23. We estimate an increase in commercial truck traffic to deliver Bakken crude of 100 trucks per day or 200 trips per day (100 trucks for crude delivery and 100 return trips). EPA based this estimate on a combination of oilfield size trucks and semis operating on a five-day work week. This additional truck traffic represents a 64% increase in truck traffic from what was estimated in the FEIS. The estimated increase in traffic for the refinery with crude trucking is a 29% increase over 2010 annual average daily traffic (AADT) on US 23. While this increase in traffic will be noticeable, the potential impacts from accidents and spills will be comparable to those discussed in the EIS.

With regard to other roads, use of the local Bakken feedstock is anticipated to result in less crude truck traffic (200 trucks) in other areas of the Reservation and State. Currently, crude is being trucked to the refinery in Mandan. The primary routes used are Hwy 22 and I-94 west and south of Lake Sakakawea.

As shown below in Table 5, traffic has increased along US 23 by about 50% as a result of the Bakken oil development. Existing traffic levels now exceed the North Dakota Department of Transportation criteria for installing turn lanes. Right turn lanes are recommended mitigation measures for the proposed refinery. Depending on the anticipated westbound traffic turning left into the refinery, a left turn lane may also be warranted. EPA also recommends the MHA Nation prepare a traffic study as part of the final design of the refinery to determine if left turn lanes and other traffic mitigation measures are needed.

Table 5 – Changes in Traffic on US 23

| Highway Segment | EIS 2002/03 AADT | EIS 2002/03 Trucks | 2009 AADT[1] | 2009 Trucks [1] | 2010 AADT[1] | Trucks 2010 [1] |
|---|---|---|---|---|---|---|
| S.H. 23 east of refinery site between refinery and Makoti intersection (338th St SW) | 1175 | No Data | 1680 | 250 | 1800 | 250 |
| S.H. 23 east of Plaza/ Wabek intersection (64th Ave. NW) | 1450 | No Data | 1675 | 210 | 2125 | No Data |
| S.H. 23 east of S.H 37 (road to Parshall) | 1,550 | 180 | 1855 | 275 | 2260 | No Data |
| Traffic Increase from Refinery .(30% in EIS) | + 465 | + 54 | + 465 | + 54 | + 465 | No Data |
| Sum of Existing Traffic + FEIS Refinery Traffic | 2015 | 234 | 2320 | 329 | 2725 | -- |
| Adding Bakken crude oil trucks (mix of small & semi-trucks) | +200 | +200 | +200 | + 200 | +200 | -- |
| **Total Projected Traffic increase FEIS & crude trucks** | 2215 | 434 | 2520 | 529 | 2925 | -- |

[1] Traffic data from the North Dakota Department of Transportation
AADT = Annual average daily traffic

As discussed above, the proposed refinery could choose to receive crude via rail. The main rail route runs east along Highway 2. The impacts of the proposed refinery to rail traffic were evaluated in the FEIS for shipping out products, disclosing typical accident rates for bulk liquids, such as gasoline. The EIS did not quantify the anticipated number of trains. The frequency and length of crude trains would be dependent on the number of cars. To deliver 10,000 barrels per day of crude, EPA estimates three 30 car trains per week or one longer train per week.

## V. Environmental Consequences of Change in Feedstock

### Air Quality

As noted above, EPA received comments regarding air quality and whether the refinery would need to obtain a PSD permit from EPA. In response to those comments and the feedstock change, EPA asked the MHA Nation to prepare an addendum to the *Air Quality Technical Report for the FEIS for the MHA Nation Proposed Clean Fuels Refinery Project*. The Addendum, dated March 9, 2011, is included in this report as Appendix A. The Addendum updates the Tribes' air emissions calculations to include emissions from the additional refinery units needed to refine the Bakken crude, explains more thoroughly the basis for the air emission calculations and corrects some typographical errors. On June 6, 2011, the Tribes submitted to EPA a modeling analysis of the projected emissions from the refinery using Bakken crude as feedstock.

Refinery air emissions will increase because of the additional process units (vacuum crude heater, and two decant oil heaters). Table 3 summarizes the potential air emissions changes based on the change to Bakken crude as feedstock. Table 4 summarizes the changes in air quality concentrations. As shown in these tables, no exceedances of the National Ambient Air Quality Standards (NAAQS) are anticipated; with the potential exception of the $SO_2$ hourly standard. The hourly $SO_2$ standard may be exceeded if the flare operates more frequently than anticipated, and both the sulfur recovery unit and the back-up unit are down at the same time.

Table 3 - Potential Air Emissions Changes

| NAAQS Pollutant | PSD Permit Thresholds tons/yr | FEIS Annual Emission[1] tons/yr | Bakken Annual Emission[2] tons/yr | Change in Annual Emissions FEIS to SIR % |
|---|---|---|---|---|
| $NO_2$ | 100 | 35.7 | 55.8 | ↑ 56 |
| CO | 100 | 78.3 | 83.3 | ↑ 6 |
| $PM_{2.5}$ /$PM_{10}$ | 100 | 16.8 | 38.8 | ↑ 131 |
| $SO_2$ | 100 | 51.2 | 80.5 | ↑ 57 |
| VOCs | 100 | 77 | 86.2 | ↑ 12 |

1. From Table 1, Appendix 1
2. From Table 2, Appendix 1

Table 4 – Changes in Air Quality Concentrations

| Pollutant | Period | NAAQS (µg/m$^3$)[1] | From FEIS, Table 4-17 | | | SIR – Revised Air Emissions | | | Changes[5] |
|---|---|---|---|---|---|---|---|---|---|
| | | | Back-ground (µg/m$^3$) | Modeled Impact (µg/m$^3$)[2] | Modeled Impact w/Back-ground (µg/m$^3$) | Back-ground (µg/m$^3$) | Modeled Impact (µg/m$^3$) | Modeled Impact w/Back-ground (µg/m$^3$) | from FEIS to SIR Modeled w/ Background % |
| $NO_2$ | 1-Hour | 188[3] | | New standard | | 41 | 33 | 74 | n/a |
| | Annual | 100 | 7.1 | 0.79 | 7.89 | 4 | 1 | 5 | ↓ 37 % |
| CO | 1-Hour | 40,000 | 10,832 | 67.7 | 10,900 | 7,980 | 56 | 8,036 | ↓ 26 % |
| | 8-Hour | 10,000 | 5,474 | 30.3 | 5,504 | 3,124 | 38 | 3,162 | ↓ 43 % |
| $PM_{2.5}$ | 24-Hour | 35[3] | 16.07 | 16.44[3] | 32.5 | 16 | 8 | 24 | ↓ 26 % |
| | Annual | 15 | 5.82 | 2.94 | 8.76 | 6 | 1 | 7 | ↓ 20 % |
| $PM_{10}$ | 24-Hour | 150 | 37 | 26.3 | 63.3 | 45 | 51 | 96 | ↑ 52 % |
| $SO_2$ | 1-Hour | 196[4] | | New standard | | 96 | 63 | 159 | n/a |
| | | | | | | | Model did **not** include intermittent flare[6] | | |
| | ″ ″ | ″ ″ | | ″ ″ | | 96 | 155 | 251 | n/a |
| | | | | | | | Modeled for continuous flaring with no operating sulfur recovery units[6] | | |
| | 3-Hour | 1300 | 106.5 | 45.5 | 152 | | Revised to 1-hr | | n/a |
| | 24-Hour | 365 | 31.9 | 17.5 | 49.4 | 21 | 16 | 37 | ↓ 25 % |
| | Annual | 80 | 4.3 | 1.34 | 5.64 | 3 | 1 | 4 | ↓ 29 % |

Notes :

1. µg/m³ = micrograms per cubic meter
2. For 1-, and 8-, and 24-hour standards the modeled impacts are 1st highest short term values, except PM2.5.
3. 98th Percentile value, per the standard requirements.
4. 99th Percentile
5. FEIS model - ISCST3, SIR remodeling -AERMOD
6. The refinery anticipates needing to run the flare a maximum of 100 hours per year. The first modeling run for the1- hour $SO_2$ NAAQS [Result = 159 µg/m$^3$] did not include flare emissions. The second modeling run for the 1- hour $SO_2$ [Result = 251 µg/m$^3$] assumed continuous flaring (8760 hours/ year) with both sulfur recovery units not working. The proposed refinery would have two sulfur recovery units, one unit would be a full backup. Modeling for the annual $SO_2$ NAAQS assumed 100 hours/year of flaring.

EPA also evaluated the information submitted by the MHA Nation to determine whether the refinery needed to obtain a CAA Prevention of Significant Deterioration (PSD) permit. Under the CAA, new industrial facilities with major air emissions are required to obtain a PSD permit from EPA before starting construction. These requirements are also referred to as New Source Review (NSR). During preparation of the DEIS, EPA made an initial PSD applicability determination in an April 25, 2005 letter to the Tribes that stated that "the proposed refinery would not be considered a major source as defined in the PSD regulations" because the potential emissions were estimated by the Tribes to be below 100 TPY based on the proposed equipment and feedstock. On March 24, 2010, EPA issued a letter withdrawing the 2005 PSD applicability determination because of the change in crude feedstock and because of EPA's reevaluation of the Tribes' initial emission estimates from 2004. In a May 5, 2011 letter (in Appendix A), EPA notified the Tribes that the March 9, 2011 Addendum to the *Air Quality Technical Report for the FEIS for the MHA Nation Proposed Clean Fuels Refinery Project* did not have the information needed for EPA to concur with the Tribes assessment that the facility would be a minor source for air emissions. Due to the preliminary nature of design, EPA was not able at that time to make a determination of PSD applicability. EPA recommended that the Tribes apply for a PSD permit. Final design is not anticipated until many months after the conclusion of the NEPA process. On June 29, 2011, the MHA Nation sent a letter to EPA indicating that they had begun construction on the footing for the refinery flare stack.

### Groundwater Quality and Underground Injection

The new brine waste stream from the desalter would be disposed of through a Class I UIC well. Triad (2010) estimated 700 bpsd (barrels per stream day) of briny water from the desalter would be injected into the well. Typical wastewaters from desalters contain salts, water soluble hydrocarbons such as benzene and potentially metals (depending on the chemistry of the crude oil). In addition, it is likely that reverse osmosis (RO) reject water (wastewater from RO treatment of operational water obtained from the Fox Hills aquifer) would also be disposed of via the UIC well. In the FEIS, the RO reject water was to be disposed of with other wastewater discharged in compliance with the proposed NPDES discharge permit.

The FEIS analyzed the option of disposal of refinery wastewater into an underground injection well as Alternative C. The desalter waste stream would be an additional source of wastewater. Impacts from the injection well would be controlled through a Class I UIC well permit which would specify well construction, well operations, closure requirements, and financial responsibility. In order to obtain a Class I UIC permit, the MHA Nation must demonstrate that the waste water would be injected below any underground sources of drinking water (as defined by SDWA). The purpose of the UIC permit is to control and limit environmental impacts associated with wastewater disposal. The MHA Nation will be required to apply for and obtain a Class I UIC well permit prior to construction of the UIC well. EPA also recommends that the MHA Nation include additional tanks at the refinery to store brine in case there are problems with the UIC well. As a minimum, the refinery should have the capacity to store desalter wastewater for one week's operations.

In the application process, the Tribes will be required to determine whether the proposed injection formation is an USDW and whether any USDWs occur below the likely injection zone. In western North Dakota, the Dakota Group is commonly used for disposal of produced fluids via Class II

UIC wells (Class II UIC wells are for the disposal of produced water from oil production). The Dakota group is a likely injection target for the refinery wastewater.

In some USGS reports, water quality in the Dakota Group is of high enough quality to be considered a USDW under the refinery site. If the Dakota Group aquifers are determined to be an USDW, the refinery would have to inject into a deeper formation or request an aquifer exemption[1] for the portion of the Dakota that will comprise the injection zone. The EPA and North Dakota UIC program have approved an aquifer exemption for large areas of the Dakota Group formations in western North Dakota. However, this exemption applies only to Class II wells, and no exemption has been approved for the Dakota Group aquifers beneath the TAT Reservation. The SDWA requires that Class I wells inject below the lowermost USDW, therefore the applicant would also need to evaluate the numerous underlying formations to determine if any are USDWs. While some of the lower formations in this part of the Williston Basin would be likely to yield significant volumes of water, TDS (total dissolved solids, salinity) concentrations in groundwater in these formations tend to be very high, with TDS typically exceeding 10,000 mg/l, the threshold for assessing whether the aquifer is a USDW. Therefore it is not likely that there is a USDW below the Dakota Group aquifer.

If the wastewater that the MHA Nation proposes to dispose of via a Class I UIC well is determined to be hazardous additional RCRA requirements would apply, including but not limited to a waste analysis plan, the land disposal restrictions, monitoring, financial, and closure. For the UIC permit, the Tribes would need to submit a no-migration petition demonstrating several things including that there is a low-permeability confining zone to prevent vertical migration of the injected fluids and the injection zone has sufficient permeability, porosity, thickness and areal extent to prevent migration of fluids into USDWs (40 C.F.R. §148.20). The no-migration petition would need to demonstrate that fluid movement would not migrate within 10,000 years vertically upward out of the injection zone. Regulations governing Class I hazardous waste wells can be found at 40 C.F.R. Parts 146 and 148. If the wastewater is determined to be hazardous, treatment will be necessary prior to injecting via a non-hazardous Class I UIC well.

### Spills and Emergency Response

The environmental impacts from spills and emergency response planning would be generally comparable for either crude feedstock with the exception of crude transportation. The FEIS'probability analysis and impacts assessment of spills covered a range of spill scenarios, so remains valid for the Bakken crude refinery. If the Bakken crude is transported by truck or rail, there would be a small increase in risk for spills during crude offloading and transportation to the refinery. In the proposed design for the refinery, the loading/offloading area would be paved and curbed to prevent the release of spills to the environment.

---

[1] Injection of waste into a USDW via a Class I well is prohibited. Thus, an aquifer exemption would be necessary in order to exempt the aquifer from being a USDW. Aquifer exemptions can be granted pursuant to the criteria at 40 C.F.R. § 146.4.

## Surface Water Quality

As noted above, the requirement for EPA to prepare an FEIS for the proposed MHA Nation refinery was triggered by the Tribes' application for an NPDES discharge permit for the proposed refinery. The draft NPDES permit was included in both the DEIS and FEIS. The draft NPDES permit contains both technology based effluent limits and water quality based effluent limits. Neither of the permit limits are based on the feedstock, but rather on the quantity and type of production at the facility for the technology limits and the water quality standards for the water quality based limits. The discharge limits, monitoring requirements and authorized outfalls would remain unchanged from the original public noticed permit. The water quality impacts of the facility discharging under permit conditions would be the same for either feedstock scenario as the limits remain unchanged.

## Solid and Hazardous Waste

The refinery would generate an additional hazardous waste stream through the refining of Bakken crude. A desalter unit would produce desalter sludge and additional wastes would be produced from cleaning the desalter during turnaround. These desalter wastes are EPA listed hazardous wastes -- F037. The FEIS identified other F037 wastes that would be generated at the refinery, and these desalter wastes would be managed in the same manner as the previously identified wastes as discussed in the FEIS. As described in FEIS, other process units would generate waste and or wastewater exhibiting characteristics of hazardous waste. All hazardous wastes generated by the refinery are required to be transported offsite within 90 days and disposed of at a Treatment, Storage and Disposal Facility in compliance with RCRA.

## Vegetation and Wetlands

If the crude oil pipeline is realigned to follow Hwy 23 instead of the railroad grade as discussed in the FEIS, different wetland and riparian resources would be impacted. The National Wetlands Inventory map shows similar wetland and riparian resources for both routes. The types of wetlands impacted would be similar and the extent (acres) of impacts (construction disturbance) would be comparable to the analysis of wetlands and vegetation impacts analyzed in the FEIS.

## Wildlife, Threatened and Endangered Species

EPA has not identified any potential impacts to wildlife, threatened and endangered species from the Bakken feedstock refinery that would be different from the potential impacts from the synthetic fuels refinery, as disclosed in the FEIS. EPA's “no effect” finding for issuance of the NPDES permit remains valid.

## Climate Change

The addition of several new refinery units to accommodate refining of Bakken crude will increase greenhouse gas emissions. However, the greenhouse gas emissions estimate in the FEIS was not based on actual modeled emissions from the refinery, given the uncertainties associated with the refinery design. The FEIS estimate was based on a similarly sized petroleum refinery operating in Canada. Since the estimate is not specific to the design of the refinery, but rather size, and since the size has not changed, the estimated emissions would be similar to those estimated in the FEIS.

Environmental Justice and Socioeconomics

The Environmental Justice (EJ) analysis in the FEIS determined that there would be no disproportionate adverse impacts from the proposed refinery. Based on EPA's evaluation of impacts associated with refining Bakken crude, the conclusion reached in the FEIS remains valid.

Although there would be increases of air emission from the refinery, no EJ communities or other residents are located immediately adjacent to the refinery and only six residences are located within a one-mile radius of the proposed facility. As described on page 4-125 of the FEIS, there will be negligible human health impacts to the closest towns to the proposed refinery (Makoti and Plaza), and no impacts to towns further way such as Parshall and Ryder.

Socioeconomic impacts from the proposed refinery will continue to be a mix of positive and negative impacts as described in the FEIS. However, because the Tribes and Tribal members own some of the local Bakken oil that would be used as feedstock, there will be increased profitability for the Tribes and Tribal members.

Baseline economic conditions used in the FEIS EJ and socioeconomic analyses have improved for the area through increased employment opportunities and mineral royalties for the Tribes and other owners of mineral rights. Tribal and state information releases and newspaper stories have described the improved employment situation for this area of North Dakota and the Fort Berthold Indian Reservation. The 2000 census was the primary source of demographic information used in the FEIS analysis. Comparable 2010 census data for the EJ analysis area is not yet available from the Census Bureau. Tables 5 and 6 show the changes in unemployment rates for North Dakota and the counties surrounding the refinery since the 2006.

**Unemployment Rates - Annual Average by Year**

| (Source: US BLS) | 2006 | 2010 |
|---|---|---|
| ND | 3.2 % | 3.9 % |
| Rank by State | 7 | 1 |
| U.S. | 4.6 % | 9.6 % |

**Unemployment Rates – by County Annual Average** (Source: US BLS)

| | 2006 | | Feb 2010 - March 2011 | |
|---|---|---|---|---|
| County | Unemply. Rate | Labor Force | Unemply. Rate | Labor Force |
| Ward (Minot, Makoti & refinery site) | 3.1 % | 28,646 | 3.1 % | 29,240 |
| Mountrail (Parshall, New Town & Stanley) | 6.0 % | 2,903 | 2.4 % | 5,119 |
| McLean (White Shield & Washburn) | 4.5 % | 4,653 | 4.7 % | 4,588 |
| McKenzie (Watford City & Mandaree) | 3.2 % | 2,809 | 1.9 % | 3,662 |
| Dunn (Killdeer & Twin Buttes) | 3.3 % | 1,730 | 2.8 % | 2,171 |
| Mercer (Beulah) | 3.8 % | 4,764 | 4.7 % | 3,936 |

## VI. Bakken Oil Fields Development

In the last five years, there has been a large increase in oil and gas drilling and production in eastern Montana and western North Dakota, including on the Fort Berthold Indian Reservation. Figure 3 illustrates the number of producing wells per year in North Dakota. Since 2005, the number of producing oil wells in North Dakota has increased from 3503 wells to 5455 in 2010. The majority of the new wells have targeted the Bakken and Three Forks formations. Figure 4 illustrates the historic increase in monthly oil production in North Dakota, and highlights the substantial growth in this production since 2007.

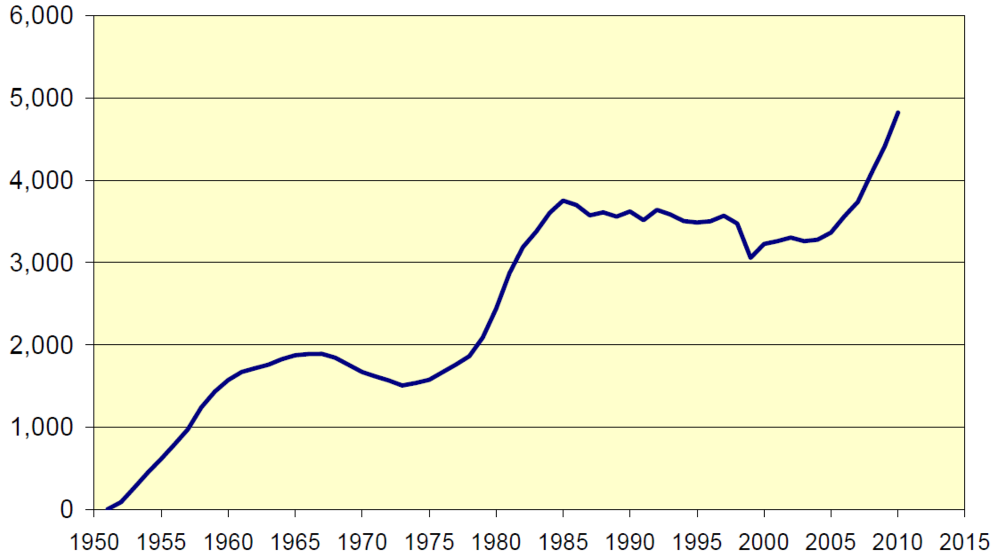


**Figure 3 - ND # of wells producing each year** [Source: NDIC]

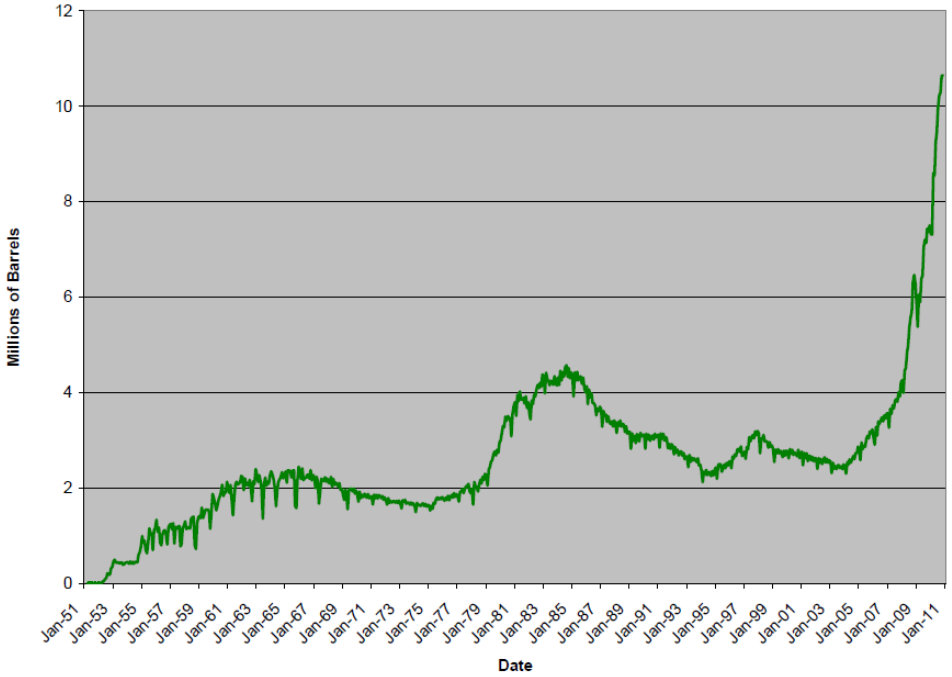


**Figure 4 - ND Historical Monthly Oil Production [*Data from NDIC* ]**

The FEIS generally discussed the oil and gas development in the Bakken oilfield through 2005 and included background air quality information through 2008. The additional Bakken oilfield development will affect the environment in a similar manner to historic development; however, the numbers of oil wells and drill rigs have increased dramatically. Potential impacts associated with the Bakken oilfield include:

- Increased potential for impacts to groundwater resources through improper well construction, hydraulic fracturing and well closure;
- Increased water consumption for hydraulic fracturing practices.
- Increased sediment loadings to lakes, streams wetlands from increased runoff from construction sites, well pads and dirt roads;
- Increased injection of produced water from oil production
- Increased water quality impacts from spills from wells, pipelines and transportation accidents;
- Changes in stream and wetland hydrology due to increased rates of runoff and construction of well/tank pads and impoundments;
- Increased disturbance of soils and vegetation from construction of well pads, tank batteries, pipelines, and additional or expanded roads;
- Increased disturbance of wetlands and riparian habitat from construction of well pads, tank batteries;
- Increased disturbance of wildlife habitat due to construction, noise and traffic;
- Increased air emissions from drill rigs, oilfield installations such as heater-treaters, and tank batteries;
- Increased dust from more traffic on dirt and paved roads;
- Increased traffic for roads, highways and rail;

- Increased need for emergency response for fires, oil spills, industrial accidents and traffic accidents;
- Increased population;
- Reduced unemployment, more jobs, increased wages; and
- Increased housing costs, housing shortages.

The BIA has been completing environmental assessments (EAs) to address their NEPA responsibilities for oil and gas development on the Fort Berthold Indian Reservation. Since 2008, there have been over 100 EAs (ranging from 1 to 20 wells per EA) prepared for over 550 exploratory oil and gas wells on Fort Berthold. The BIA recently released a second scoping notice (the first scoping notice was issued in 2008) for the Fort Berthold Oil and Gas Development Programmatic EA, which it intends to be used as a five year planning document to facilitate oil and gas development on the Reservation. There are approximately 260 producing oil wells on the Fort Berthold Indian Reservation as of September 2010. [North Dakota Industrial Commission (NDIC) GIS data, April 2011]

The Bureau of Land Management (BLM) has prepared environmental assessments for each Field Office in western Montana and North Dakota to analyze the impacts of greenhouse gas emissions from oil and gas development. The North Dakota Field Office of the BLM is currently preparing a revision to their Resource Management Plan which will include analysis of the environmental impacts of the continued development of the Bakken oilfield. BLM's air quality impact analysis, including a cumulative impacts analysis, is scheduled to be completed by the summer of 2011.

## VII. Conclusion

This SIR summarizes EPA's analysis of whether the impacts associated with refining Bakken crude, beyond the refinery-related impacts already analyzed in the FEIS, are significant enough to warrant preparing a supplemental EIS. EPA considered the following criteria:

- Are there any new, substantial environmental impacts from the project?
- Are there any new resources or issues with significant impacts to the human environment which were not considered in the EIS?
- Do the proposed project changes substantially change the environmental impacts or the methodologies needed to analyze the environmental impacts?

After considering the above criteria and the regulation at 40 C.F.R. § 1502.9(c), EPA finds that a Supplement to the FEIS is not warranted. After a thorough interdisciplinary review, we find that a change in feedstock to Bakken crude as compared to the refinery using synthetic crude will not significantly change the proposed action or its impacts.

## Appendices

1. Addendum, Air Quality Technical Report for the FEIS for the MHA Nation Proposed Clean Fuels Refinery Project, March 9, 2011

2. EPA letter to MHA Nation dated May 9, 2011, regarding Applicability of Clean Air Act Requirements for the MHA Nation Refinery

3. Air Quality Modeling Update for the FEIS for the MHA Nation Proposed Clean Fuels Refinery Project, June 6, 2011

4. Air Dispersion Modeling Analysis of Uncontrolled $SO_2$ Emissions, July 12, 2011

5. NDDOT Memorandum regarding Highway 23 Corridor, Turn Lane Request, November 10, 2009

6. Map --Traffic Counts 2002-2010 for North Dakota Highway 23

**Exhibit 7**:
Addendum, Air Quality Technical Report for the FEIS (Mar. 9, 2011)

# Addendum

# Air Quality Technical Report
# for the Final Environmental Impact Statement
# for the Mandan, Hidatsa, and Arikara Nation's
# Proposed Clean Fuels Refinery Project

March 9, 2011

See EPA's May 9, 2011 letter regarding the applicability of the Clean Air Act requirements to the proposed MHA Nation Refinery. EPA did not concur with this report's conclusion that the proposed refinery would have potential emissions less than the Prevention of Significant Deterioration (PSD) permitting threshold. The preliminary design information and estimated air emission used in the EIS process are estimates of anticipated air emission. Whereas the determination of “potential to emit” for PSD permit applicability are a summation of the maximum air emissions that could be emitted from each specified refinery unit or air pollution unit.

# Table of Contents

# List of Tables

# List of Appendices

# Chapter 1 - Introduction

This document has been prepared as an addendum to the December 2007 Air Quality Technical Report for the Final Environmental Impact Statement for the Mandan, Hidatsa, and Arikara Nation's Proposed Clean Fuels Refinery Project (MHA Refinery). The final analyses and assumptions included in this document are a result of a meeting with EPA Air Quality Technical Staff and Tribal Representatives held on March 8, 2011.

This addendum addresses the Potential To Emit (PTE) calculations for oxides of nitrogen ($NO_x$), carbon monoxide (CO), sulfur dioxide ($SO_2$), non-methane-ethane volatile organic compounds (VOC), and particulate matter (PM) for the sources at the MHA Refinery shown on Table 1.

**Table 1 MHA Refinery Sources Included in the PTE Calculations**

| Source ID | Source |
|---|---|
| 00001 | Atmospheric Crude Heater |
| 00002 | Reformer Heater 1 |
| 00003 | Reformer Heater 2 |
| 00004 | Reformer Heater 3 |
| 00005 | Reformer Heater 4 |
| 00006 | Reformer Heater 5 |
| 00007 | Hydrocracker 1 |
| 00008 | Hydrocracker 2 |
| 00009 | Hydrocracker 3 |
| 00010 | Hydrocracker 4 |
| 00011 | Olefin |
| 00012 | Hydrogen |
| 00013 | Boiler 1 |
| 00014 | Boiler 2 |
| 00015 | Boiler 3 |
| 00016 | Flare |
| 00017a | Sulfur Recovery Tail Gas (main) |
| 00017b | Sulfur Recovery Tail Gas (backup) |
| 00018 | Vacuum Crude Heater |
| 00019 | Decant Oil Tank Heater 1 |
| 00020 | Decant Oil Tank Heater 2 |

The Vacuum Crude Heater and two Decant Oil Tank Heaters have been added to this analysis since the December 2007 Air Quality Technical Report. In addition, fugitive emissions of VOC from the Vacuum Unit process and the two Decant Oil Tanks have been included in this analysis.

A backup Amine, Sulfur Recovery Unit (SRU), and Tail Gas system has also been added to the MHA Refinery Design to limit SRU downtime and $SO_2$ emissions from the flare. This backup system will only operate when the main SRU system is not operating.

Table 2 summarizes the revised estimated annual emissions of $NO_x$, CO, $SO_2$, VOC, and PM for the MHA Nation's proposed clean fuels refinery.

Emissions of $NO_x$, CO, and $SO_2$ from the emergency generator and fire pump engine have not been updated. Therefore the previous estimates for these sources included in the December 2007 Air Quality Technical Report have been included in these totals.

**Table 2 Revised Estimated Potential Annual Emissions for the MHA Refinery**

| Pollutant | Annual Project Emission Rate (ton/yr) |
|---|---|
| $NO_x$ | 55.8 |
| CO | 83.2 |
| $SO_2$ | 80.5 |
| VOC | 86.2 |
| PM | 38.8 |

## Chapter 2 - MHA Refinery PTE Calculations

Local Williston Basin crude with a preference for MHA wells will be used as the feedstock for the MHA Refinery. This crude is currently transported by truck to refineries in North Dakota and Oklahoma. Processing this crude locally will result in a net reduction in truck traffic and associated impacts.

Emission factors and assumptions for the revised calculations are presented below. Documentation for vendor data is provided in Appendix A. Additional data and calculations are provided in Appendix B.

### Heater Normal Operation Calculations

Heater $NO_x$ emission estimates and fuel sulfur concentrations (to estimate $SO_2$ emissions) are based on maximum allowable concentrations under the federal regulation 40 CFR Part 60 Subpart Ja (Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007). Heater CO emissions are based on information provided by John Zink.

General assumptions:

- Boilers operate at 100% load and continuous operation except for startup, shutdown, and malfunction events.
- 10 percent contingency added to normal emission rate estimates.

The normal heater emission estimates are based on the following concentrations:

- $NO_x$ emissions = 40 parts per million (ppm) corrected to 0 percent oxygen ($O_2$).
- CO emissions = 50 ppm corrected to 3 percent $O_2$.
- $SO_2$ emissions based on fuel sulfur (as hydrogen sulfide ($H_2S$)) concentration of 60 ppm (annual average).
- VOC emissions = 5.5 pounds per million standard cubic feet (lb/MMscf) (USEPA uncontrolled emission factor from AP-42 Table 1.4-2).
- PM emissions = 7.6 lb/MMscf (USEPA uncontrolled emission factor from AP-42 Table 1.4-2).

John Zink has also provided an estimate of 20 ppm corrected to 3 percent $O_2$ for $NO_x$ emissions. Therefore the $NO_x$ emission concentration used in the calculations is approximately twice the anticipated concentration. The John Zink $NO_x$ emission concentration is based on the following assumptions:

- Ultra LoNox burners,
- No air preheat (APH), and
- Natural gas and fuel gas combust at similar temperatures.

The CO emission concentration is based on the following assumption:

- Natural gas and fuel gas burn at similar temperatures.

## Boiler Normal Operation Calculations

Boiler NOx and CO emissions are based on information published by Webster Engineering and Blesi Evans, a Webster vendor, in Minneapolis, Minnesota. Documentation for these data is provided in Appendix A.

General assumptions:

- Assume 100% load and continuous operation except for startup, shutdown, and malfunction events.
- $NO_x$ and CO data assumed to be based on 3 percent excess oxygen.
- 10 percent contingency added to normal emission rate estimates.

The normal boiler emission estimates are based on the following concentrations:

- $NO_x$ emissions = 30 ppm (Webster Engineering burners can achieve 9 ppm).
- CO emissions = 50 ppm (Webster Engineering and Manufacturing flyer and Blesi Evans).
- $SO_2$ emissions based on fuel sulfur concentration of 60 ppm.
- VOC emissions = 5.5 lb/MMscf (USEPA uncontrolled emission factor from AP-42 Table 1.4-2).
- PM emissions = 7.6 lb/MMscf (USEPA uncontrolled emission factor from AP-42 Table 1.4-2).

## Heater and Boiler Startup, Shutdown, and Malfunction Calculations

General assumptions:

- 500 hours per year of startup, shutdown, or malfunction (SSM) events for each heater and boiler.
- This estimated startup emission rates represent 1-hour averages.

The industry standard is to run the refinery for five years, with the exception of mandated inspection intervals. The mandated inspections may shut down equipment for one or two days each year. Once every five years, the refinery will shutdown for approximately 20 days for maintenance.

As stated above, the heaters and boilers are assumed to operate continuously. For the startup and shutdown emission calculations, emissions were increased to startup and shutdown emissions levels, but no downtime emissions (zero emissions) were included in the calculations.

For $NO_x$, the USEPA uncontrolled emission factor for natural gas boilers less than 100 million BTU per hour (MMBTU/hour) in size (AP-42 Table 1.4-1) was used to represent startup/shutdown emissions.

- $NO_x$ emissions = 100 pounds per million standard cubic feet (lb/MMscf)
- CO emissions = 200 ppm. Maximum startup concentration provided by John Zink.
- $SO_2$ emissions based on fuel sulfur (as $H_2S$) concentration of 162 ppm (allowable 3-hour average under 40 CFR Part 60 Subpart Ja).
- VOC and PM based on the same AP-42 emission factors used for normal operation calculations.

## Sulfur Recovery Unit Calculations

To calculate the Sulfur Recovery Unit (SRU) emissions, the project tail gas data from Table 14 in the Air Quality Technical Report were used to calculate emissions presented on Table 3. These estimated tail gas emissions were based on Canadian synthetic crude processing, thus should reflect conservative sulfur concentrations relative to Williston Basin crude processing.

**Table 3 SRU Emission Estimates**

| Species | SRU Tail Gas Exhaust Flow (lb-mol/hr) | Molecular Weight (lb/lb-mol) | Emission Rate (lb/hr) |
|---|---|---|---|
| CO | 0.17 | 28.010 | 4.8 |
| $SO_2$ | 0.11 | 64.063 | 7.0 |

The $SO_2$ concentration shown on Table 3 is equivalent to an SRU Tail Gas exhaust concentration of 2,490 ppm. Under 40 CFR Part 60 Subpart Ja, the allowable concentration is 3,000 ppm. Therefore the SRU Tail Gas exhaust rate for $SO_2$ was increased to 0.13 lb-mol/hr (which is equivalent to 3,000 ppm) to recalculate the $SO_2$ emissions from this source. Only one SRU Tail Gas system will be running at any time, therefore the emission calculations treat this as a single source.

No preheating or tail gas incineration is included in the refinery design, therefore it is assumed that $NO_x$ emissions from this source would be negligible.

## Flare Calculations

For estimating normal and SSM flaring emissions of $NO_x$ and CO, USEPA flaring emission factors were used along with a normal operation heat input of 10 million British thermal units per hour (MMBtu/hr). The flare emission were taken from AP-42 Table 13.5-1 (English Units) - Emission Factors for Flare Operations.

As was stated in the 2007 Air Quality Technical Report, the normal loading at the Flare is designed for a loading rate of 15 pounds per hour (lb/hr). This loading rate accounts for potential upsets during normal operations.

The 15 lb/hr loading rate was increased to 500 lb/hr - or 10 MMBtu/hr – in order to calculate conservative emission estimates that would account for extreme process upsets. This 500 lb/hr loading rate was used for calculating normal $NO_x$, CO, VOC, $SO_2$, and $PM_{10}$ emissions. This loading rate was also used for calculating startup and shutdown $NO_x$, CO, VOC, and $PM_{10}$ emissions.

The loading rate of 500 lb/hr is over 30 times the normal operation loading rate of 15 lb/hr, and would likely represent an event that would shut down the refinery, and would result in a period of zero emissions. This period of zero emissions is not accounted for in the emission estimates for this source. Flare operations were assumed to be continuous.

Normal $SO_2$ emissions were based on fuel sulfur (as $H_2S$) concentration of 60 ppm (annual average).

General assumptions:

- Normal emission calculations are based on a 10 MMBtu/hr loading rate.
- SSM emission calculations are based on a 10 MMBtu/hr loading rate for CO and $NO_x$.
- Potential SSM $SO_2$ emissions are based on the SRU capacity of 3 long-tons per day of sulfur and 100 hours of SRU shutdown (note that the backup Amine, SRU, and Tail Gas system would make any operating hours without sulfur recovery very unlikely, therefore the 100 hours of SRU shutdown is more of a force majeure event).
- During SRU shutdown the sulfur would be routed to the flare would be completely converted to $SO_2$.
- Additional SSM sulfur loading from other sources is assumed to be negligible relative to the SRU shutdown sulfur loading.

## Reformer Catalyst Regeneration

The MHA Refinery design for reformer catalyst regeneration employs “in-situ” regeneration. This will occur infrequently over the period of a year and may only occur once per year. During in-situ regeneration the reformer will be shut down and the catalyst will be regenerated inside the reformer. Because the reformer must be shut down for this process, it’s assumed that regeneration would result in a negligible increase and, possibly, a reduction of criteria pollutant emissions.

In addition, no hydrofluoric acid will be used in any of the MHA Refinery processes.

## Fugitive VOC Calculations

The addition of the Vacuum Unit and two Decant Oil Tanks will create additional emissions of VOC.

Fugitive emissions from loading docks, pumps, seals, valves, etc. associated with the Vacuum Unit would be controlled as described for fugitive VOC sources in the 2007 Air Quality Technical report. Although an accounting of potential fugitive emission sources associated with the Vacuum Unit is not currently available, it is assumed that this source will increase the current estimated fugitive VOC by 20 percent. This assumes a 20 percent increase in fugitive VOC sources which is a very conservative assumption.

Emissions from the two Decant Oil Tanks were estimated using EPA's TANKS software. For these calculations it was assumed that the decant oil would be physically similar to residual oil no. 6.

## Vehicle Traffic Fugitive $PM_{10}$ Calculations

The amount of additional traffic required for the Vacuum Unit and Decant Oil Tanks was accounted for by increasing the current estimated vehicle traffic fugitive $PM_{10}$ by 20 percent. As with the Vacuum Unit fugitive VOC calculation, this is a very conservative assumption.

# Appendix A - Vendor Documentation

From: Clayton, Jim [jim.clayton@johnzink.com]
Sent: Wednesday, November 03, 2010 4:05 PM
To: Frisbie, Gordon/DEN
Subject: RE: Refinery Heater Specs

Gordon,

The basis provided looks pretty typical for process heaters that do not have air preheat (APH) systems included.

In general, and for the basis of these values, I have assumed Natural gas with "some heavies" (not much with a specified heating value of 1000 btu/scf (net)), 1400 deg F bridgewall temperature (BWT), 3% excess firebox O2, and ambient combustion air. I have included NOx values for a standard burner (no NOx control), Staged Fuel LoNOx burner, and Ultra LoNOx burner.

Standard Burner
100 ppm predicted - Note; We do not make NOx guarantees on standard burners as there is no means to make design adjustments to meet emissions guarantees.

Staged Fuel LoNOx Burner
30 ppm predicted / 35 ppm guaranteed

Ultra LoNOx Burner
17 ppm predicted / 20 ppm guaranteed

A rough correction for firebox temperature increases above the specified 1400 deg F BWT is ~ 8-10% increase for every 100 deg F above the 1400 values.

CO values would be pretty close for all designs. BWTs above 1250 deg F would be <50 ppm. It is common for sites to request & receive a variance for start-up, shut-down, and upset conditions as CO generation is temperature dependant. If possible, I recommend requesting <200 ppm.

Another rule-of-thumb multiplier is that for APH. Should they choose to add combustion APH systems, 600 deg F APH will about double NOx emissions from ambient air operation. The line is pretty straight, so 300 deg APH will add ~ 50% to ambient air NOx emissions.

As you get more definitive information, please do not hesitate to call and we'll firm-up these values.

Thanks & Best Regards,

Jim Clayton
Director, North American Sales
John Zink Company
11920 East Apache
Tulsa, Oklahoma 74116
Tel: (918) 234-5741

Cell: (713) 502-3097
Fax: (918) 234-1806
jim.clayton@johnzink.com
http://www.johnzink.com

---

From: Gordon.Frisbie@CH2M.com [mailto:Gordon.Frisbie@CH2M.com]
Sent: Thursday, October 21, 2010 12:11 PM
To: Clayton, Jim
Subject: Refinery Heater Specs
Jim,

Thanks for taking the time to talk with me this morning.

As I said, I’m looking for air pollutant emission specs (primarily NOx and CO) for various process heaters that will be part of a proposed refinery in North Dakota.  It’s currently proposed to fire the heaters on both natural gas and refinery fuel gas.

The general specs on the heaters are as follows:

Atmospheric Crude Heater 35 MMbtu/hr
Reformer Heaters 1.5 to 8 MMbtu/hr
Hydrocrackers 6 to 10 MMbtu/hr
Olefin Process 30 MMbtu/hr
Hydrogen Process 50 MMbtu/hr
Vacuum Crude Heater 5 MMbtu/hr
Oil Tank Heaters 1 MMbtu/hr

I don’t have much on the fuel gas, but I would assume it’s heat content would be 950 – 1000 btu/scf and would have an H2S concentration of about 100 ppm.

Let me know if you have any questions or need more information.

Thanks,

Gordon

Gordon Frisbie
Senior Air Quality Specialist
Industrial Systems Business Group

CH2M HILL
9193 South Jamaica Street
Englewood, CO 80112-5946
Direct 720.286.1585
Fax 720.286.9719
Mobile 303.330.4347
Email gordon.frisbie@ch2m.com
www.ch2mhill.com

From: Betsy Torvick [etorvick@blesi-evans.com]
Sent: Thursday, December 23, 2010 8:40 AM
To: Frisbie, Gordon/DEN
Subject: Webster Burners and CO

Hello Gordon,

Ideally, there would be no CO in the flue gases of a boiler/burner using natural gas. It is desired to keep it under 100 ppm. 50 ppm should not be a problem.

Have a good Holiday!
Betsy

Betsy Evans Torvick
Blesi Evans Company
612-721-6237 ph
612-721-7466 fax
952-457-6052 cell

WEBSTER
Engineering and Manufacturing Co. LLC

# Model HDRMB™

## Ultra-Low Emissions Rapid Mix Burner for Gas or Gas-Oil Firing Applications

**Webster Engineering & Manufacturing Co. L.L.C.**
619 Industrial Rd.
Winfield, KS  67156
Phone; 620-221-7464
Email: sales@webster-engineering.com
www.webster-engineering.com

## *Don't Get Burned!* Use Webster's Proven Ultra Low NOx Technology

Your 9ppm project is too important to trust anyone but Webster and our Rapid Mix Burner (RMB). The RMB has been a dependable ultra low NOx solution for nearly 20 years.

The **Model HDRMB** provides reliable ultra low emissions utilizing the patented* rapid mix burner technology, which has been proven on hundreds of applications. Combined with the well established performance of Webster's HD series burners, and the unique capability to easily fire gas or oil without any modifications to the burner, the Webster **HDRMB** is the perfect choice for ultra low NOx applications.

## Webster burners – The Fastest Payback for Your Investment

The inherently low excess air design of the HDRMB ensures fuel and energy will not be wasted and your equipment will run efficiently. Webster customers enjoy the lowest energy costs, and fastest payback on their investment. Please visit our web site for more details at www.webster-engineering.com.

* United States of America Patent Numbers 5,407,347 and 5,470,224

*The Leader in Combustion Innovation*

## Standard Equipment

### General

- Blower motor and fan
- Air inlet louver box
- Air-FGR mixing box
- Modulating FGR control Damper

### Control Cabinet

- Combustion flame safeguard control
- Indicator lights and control switch
- Linkage-less control system
- Motor starter with overload protection
- Raised terminal strip for easy service and accessibility

### Gas Control

- Safety pilot burner
- Ignition transformer
- Pilot solenoid valve
- Pilot shutoff cock
- Pilot regulator
- Safety test cock
- Automatic gas valves

All Webster burners are factory –wired, assembled and tested.

Refractory front plates are supplied with every HDRMB.

Due to their high performance requirements, all HDRMB burners must be started-up by a Webster Factory Authorized service technician.

For complete engineering data contact your local Webster representative.

# Model HDRMB™

## Ultra-Low Emissions Rapid Mix Burner

### Features

- Linkage-less controls systems.
- Patented design reduces both prompt and thermal NOx for ultra-low emissions.
- Compact, stable flame is ideal for firetube and watertube boilers.

### Capacities

- 5 – 105 MMBtu/hr
- 125 – 2500 boiler horsepower.
  A wide range of sizes are available for maximum efficiency and performance

### Applications

- Firetube boilers
- Watertube boilers
- Thermal heaters.

### Fuels Burned

**Gases:**

- Natural, LP, Bio Gases

**Oil:**

- #2 Oil, Low Sulfur Diesel or Amber 363 firing for applications requiring back-up fuel

### Emissions

**Guaranteed emissions firing gas as low as:**

- Less than 9 ppm NOx.
- Less than 50 ppm CO

Contact your local Webster representative for emissions and performance guarantees

WEBSTER
Engineering and Manufacturing Co. LLC

# Appendix B - Emission Calculations

## MHA Refinery Potential Air Pollutant Emission Calculations

### Total Emissions

| Source ID | Source | Annual Hours | NOx (ton/yr) | CO (ton/yr) | SO2 (ton/yr) | VOC (ton/yr) | PM (ton/yr) |
|---|---|---|---|---|---|---|---|
| 00001 | Atmospheric Crude Heater | 8784 | 6.940 | 6.595 | 2.145 | 1.011 | 1.397 |
| 00002 | Reformer Heater 1 | 8784 | 0.595 | 0.565 | 0.184 | 0.087 | 0.120 |
| 00003 | Reformer Heater 2 | 8784 | 0.595 | 0.565 | 0.184 | 0.087 | 0.120 |
| 00004 | Reformer Heater 3 | 8784 | 1.586 | 1.507 | 0.490 | 0.231 | 0.319 |
| 00005 | Reformer Heater 4 | 8784 | 1.190 | 1.131 | 0.368 | 0.173 | 0.240 |
| 00006 | Reformer Heater 5 | 8784 | 0.297 | 0.283 | 0.092 | 0.043 | 0.060 |
| 00007 | Hydrocracker 1 | 8784 | 1.190 | 1.131 | 0.368 | 0.173 | 0.240 |
| 00008 | Hydrocracker 2 | 8784 | 1.388 | 1.319 | 0.429 | 0.202 | 0.279 |
| 00009 | Hydrocracker 3 | 8784 | 1.983 | 1.884 | 0.613 | 0.289 | 0.399 |
| 00010 | Hydrocracker 4 | 8784 | 1.388 | 1.319 | 0.429 | 0.202 | 0.279 |
| 00011 | Olefin | 8784 | 5.948 | 5.653 | 1.839 | 0.867 | 1.198 |
| 00012 | Hydrogen | 8784 | 9.914 | 9.422 | 3.064 | 1.444 | 1.996 |
| 00013 | Boiler 1 | 8784 | 3.538 | 3.769 | 1.226 | 0.578 | 0.798 |
| 00014 | Boiler 2 | 8784 | 3.538 | 3.769 | 1.226 | 0.578 | 0.798 |
| 00015 | Boiler 3 | 8784 | 3.538 | 3.769 | 1.226 | 0.578 | 0.798 |
| 00016 | Flare | 8784 | 2.987 | 16.250 | 28.560 | 6.757 | 0.401 |
| 00017 | S Recovery Tail Gas | 8784 | 0.000 | 20.675 | 36.868 | 0.000 | 0.000 |
| 00018 | Vacuum Crude Heater | 8784 | 2.974 | 2.827 | 0.919 | 0.433 | 0.599 |
| 00019 | Decant Oil Tank Heater 1 | 8784 | 0.198 | 0.188 | 0.061 | 0.029 | 0.040 |
| 00020 | Decant Oil Tank Heater 2 | 8784 | 0.198 | 0.188 | 0.061 | 0.029 | 0.040 |
|  | Emergency Generator |  | 4.920 | 0.360 | 0.120 | 0.100 | 0.040 |
|  | Fire Pump Engine |  | 0.910 | 0.040 | 0.020 | 0.010 | 0.010 |
|  | Fugitive VOC (Original) |  |  |  |  | 38.020 |  |
|  | Fugitive VOC (Additional) |  |  |  |  | 7.604 |  |
|  | Storage Tank VOC (Original) |  |  |  |  | 26.700 |  |
|  | Storage Tank VOC (Additional) |  |  |  |  | 0.006 |  |
|  | Soybean Processing |  |  |  |  |  | 8.510 |
|  | Vehicle Traffic Fugitive Dust (Original) |  |  |  |  |  | 16.740 |
|  | Vehicle Traffic Fugitive Dust (Additional) |  |  |  |  |  | 3.348 |
|  | **Total** |  | **55.814** | **83.209** | **80.491** | **86.232** | **38.769** |

## MHA Refinery Potential Air Pollutant Emission Calculations

## Normal Operations

| Source ID | Source | Annual Hours | NOx (ton/yr) | CO (ton/yr) | SO2 (ton/yr) | VOC (ton/yr) | PM (ton/yr) |
|---|---|---|---|---|---|---|---|
| 00001 | Atmospheric Crude Heater | 8284 | 5.983 | 5.313 | 1.868 | 0.959 | 1.325 |
| 00002 | Reformer Heater 1 | 8284 | 0.513 | 0.455 | 0.160 | 0.082 | 0.114 |
| 00003 | Reformer Heater 2 | 8284 | 0.513 | 0.455 | 0.160 | 0.082 | 0.114 |
| 00004 | Reformer Heater 3 | 8284 | 1.368 | 1.214 | 0.427 | 0.219 | 0.303 |
| 00005 | Reformer Heater 4 | 8284 | 1.026 | 0.911 | 0.320 | 0.164 | 0.227 |
| 00006 | Reformer Heater 5 | 8284 | 0.256 | 0.228 | 0.080 | 0.041 | 0.057 |
| 00007 | Hydrocracker 1 | 8284 | 1.026 | 0.911 | 0.320 | 0.164 | 0.227 |
| 00008 | Hydrocracker 2 | 8284 | 1.197 | 1.063 | 0.374 | 0.192 | 0.265 |
| 00009 | Hydrocracker 3 | 8284 | 1.710 | 1.518 | 0.534 | 0.274 | 0.378 |
| 00010 | Hydrocracker 4 | 8284 | 1.197 | 1.063 | 0.374 | 0.192 | 0.265 |
| 00011 | Olefin | 8284 | 5.129 | 4.554 | 1.601 | 0.822 | 1.135 |
| 00012 | Hydrogen | 8284 | 8.548 | 7.589 | 2.669 | 1.369 | 1.892 |
| 00013 | Boiler 1 | 8284 | 2.992 | 3.036 | 1.068 | 0.548 | 0.757 |
| 00014 | Boiler 2 | 8284 | 2.992 | 3.036 | 1.068 | 0.548 | 0.757 |
| 00015 | Boiler 3 | 8284 | 2.992 | 3.036 | 1.068 | 0.548 | 0.757 |
| 00016 | Flare | 8684 | 2.953 | 16.065 | 0.560 | 6.687 | 0.397 |
| 00017 | S Recovery Tail Gas | 8684 | 0.000 | 20.675 | 36.868 | 0.000 | 0.000 |
| 00018 | Vacuum Crude Heater | 8284 | 2.564 | 2.277 | 0.801 | 0.411 | 0.568 |
| 00019 | Decant Oil Tank Heater 1 | 8284 | 0.171 | 0.152 | 0.053 | 0.027 | 0.038 |
| 00020 | Decant Oil Tank Heater 2 | 8284 | 0.171 | 0.152 | 0.053 | 0.027 | 0.038 |
|  | Total |  | 43.297 | 73.701 | 50.425 | 13.355 | 9.612 |

## MHA Refinery Potential Air Pollutant Emission Calculations

## Startup/Shutdown Operations

| Source ID | Source | Annual Hours | NOx (ton/yr) | CO (ton/yr) | SO2 (ton/yr) | VOC (ton/yr) | PM (ton/yr) |
|---|---|---|---|---|---|---|---|
| 00001 | Atmospheric Crude Heater | 500 | 0.956 | 1.283 | 0.277 | 0.053 | 0.073 |
| 00002 | Reformer Heater 1 | 500 | 0.082 | 0.110 | 0.024 | 0.005 | 0.006 |
| 00003 | Reformer Heater 2 | 500 | 0.082 | 0.110 | 0.024 | 0.005 | 0.006 |
| 00004 | Reformer Heater 3 | 500 | 0.219 | 0.293 | 0.063 | 0.012 | 0.017 |
| 00005 | Reformer Heater 4 | 500 | 0.164 | 0.220 | 0.047 | 0.009 | 0.012 |
| 00006 | Reformer Heater 5 | 500 | 0.041 | 0.055 | 0.012 | 0.002 | 0.003 |
| 00007 | Hydrocracker 1 | 500 | 0.164 | 0.220 | 0.047 | 0.009 | 0.012 |
| 00008 | Hydrocracker 2 | 500 | 0.191 | 0.257 | 0.055 | 0.011 | 0.015 |
| 00009 | Hydrocracker 3 | 500 | 0.273 | 0.366 | 0.079 | 0.015 | 0.021 |
| 00010 | Hydrocracker 4 | 500 | 0.191 | 0.257 | 0.055 | 0.011 | 0.015 |
| 00011 | Olefin | 500 | 0.820 | 1.099 | 0.237 | 0.045 | 0.062 |
| 00012 | Hydrogen | 500 | 1.366 | 1.832 | 0.395 | 0.075 | 0.104 |
| 00013 | Boiler 1 | 500 | 0.546 | 0.733 | 0.158 | 0.030 | 0.042 |
| 00014 | Boiler 2 | 500 | 0.546 | 0.733 | 0.158 | 0.030 | 0.042 |
| 00015 | Boiler 3 | 500 | 0.546 | 0.733 | 0.158 | 0.030 | 0.042 |
| 00016 | Flare | 100 | 0.034 | 0.185 | 28.000 | 0.070 | 0.004 |
| 00017 | S Recovery Tail Gas | 100 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 00018 | Vacuum Crude Heater | 500 | 0.410 | 0.550 | 0.119 | 0.023 | 0.031 |
| 00019 | Decant Oil Tank Heater 1 | 500 | 0.027 | 0.037 | 0.008 | 0.002 | 0.002 |
| 00020 | Decant Oil Tank Heater 2 | 500 | 0.027 | 0.037 | 0.008 | 0.002 | 0.002 |
| | Total | | 6.687 | 9.108 | 29.926 | 0.436 | 0.510 |

# MHA Refinery Potential Air Pollutant Emission Calculations

## Calculation Constants

| Pollutant | Mol Wt<br>lb/lbmol |
|---|---|
| NO2 | 46.005 |
| CO | 28.010 |
| VOC (as CH4) | 16.043 |
| SO2 | 64.063 |
| S | 32.065 |

## Normal Operations Fuel - Natural Gas and Fuel Gas

**Fuel S Content** 60 ppmvd

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 60 | lb-mol S | 32.065 | lb S | 1 | lb-mol CH4 | = | 5.36E-06 | lb S/scf |
| 1000000 | lb-mol CH4 | | lb-mol S | 359 | scf | | | |

| | | |
|---|---|---|
| **Nat Gas Heat Content (LHV)** | 915.0 | BTU/scf |
| **Nat Gas Heat Content (HHV)** | 1050.0 | BTU/scf |

## Startup/Shutdown/Maintenance (SSM) Operations Fuel - Natural Gas and Fuel Gas

**Fuel S Content** 162 ppmvd Allowable 3-hour average under 40 CFR Part 60 Subpart Ja

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 162 | lb-mol S | 32.065 | lb S | 1 | lb-mol CH4 | = | 1.45E-05 | lb S/scf |
| 1000000 | lb-mol CH4 | | lb-mol S | 359 | scf | | | |

| | | | | |
|---|---|---|---|---|
| **Fuel Gas Heat Content (LHV)** | 968.2 | BTU/scf | | |
| **Fuel Gas Heat Content (HHV)** | 968.2 | BTU/scf | | |
| **Base Temperature =** | 459.69 | deg R | | |
| **Standard Temperature =** | 32 | deg F | | |
| **Standard Temperature =** | 491.69 | deg F | | |
| **Standard Pressure** | 14.696 | psi | 1 | atm |
| **Gas Constant** | 0.73 | atm*scf/lbmol*R | | |
| **Exhaust Molar Density =** | 359 | scf/lb-mol | | |
| **NOx Factor Excess O2** | 0 | percent | | |
| **CO Factor Excess O2** | 3 | percent | | |
| **Heat Rate and Exhaust Flow Adjustment Factor =** | | | 1 | |
| **Site Elevation** | 2080 | feet | | |
| **Site Ambient Pressure** | 13.59 | psi | | |
| **Emission Rate Contingency** | 10% | | | |

## MHA Refinery Process and Exhaust Data and Calculations

| Source ID | Furnace | Duty | Net Heat Const (LHV) (BTU/h) | Adjusted CT Heat Const (LHV) (BTU/h) | Natural Gas Usage (scf/hr) | Fuel Gas Usage (scf/hr) | Mfg's Exhaust Flow (lb/hr) | Adjusted Exhaust Flow (1) (lb/hr) |
|---|---|---|---|---|---|---|---|---|
| 00001 | Atmospheric Crude Heater | 100% | 35,000,000 | 35,000,000 | 38,251 | 36,150 | 28,216 | 28,216 |
| 00002 | Reformer Heater 1 | 100% | 3,000,000 | 3,000,000 | 3,279 | 3,099 | 2,419 | 2,419 |
| 00003 | Reformer Heater 2 | 100% | 3,000,000 | 3,000,000 | 3,279 | 3,099 | 2,419 | 2,419 |
| 00004 | Reformer Heater 3 | 100% | 8,000,000 | 8,000,000 | 8,743 | 8,263 | 6,449 | 6,449 |
| 00005 | Reformer Heater 4 | 100% | 6,000,000 | 6,000,000 | 6,557 | 6,197 | 4,837 | 4,837 |
| 00006 | Reformer Heater 5 | 100% | 1,500,000 | 1,500,000 | 1,639 | 1,549 | 1,209 | 1,209 |
| 00007 | Hydrocracker 1 | 100% | 6,000,000 | 6,000,000 | 6,557 | 6,197 | 4,837 | 4,837 |
| 00008 | Hydrocracker 2 | 100% | 7,000,000 | 7,000,000 | 7,650 | 7,230 | 5,643 | 5,643 |
| 00009 | Hydrocracker 3 | 100% | 10,000,000 | 10,000,000 | 10,929 | 10,328 | 8,062 | 8,062 |
| 00010 | Hydrocracker 4 | 100% | 7,000,000 | 7,000,000 | 7,650 | 7,230 | 5,643 | 5,643 |
| 00011 | Olefin | 100% | 30,000,000 | 30,000,000 | 32,787 | 30,985 | 24,185 | 24,185 |
| 00012 | Hydrogen | 100% | 50,000,000 | 50,000,000 | 54,645 | 51,642 | 40,309 | 40,309 |
| 00013 | Boiler 1 | 100% | 20,000,000 | 20,000,000 | 21,858 | 20,657 | 16,124 | 16,124 |
| 00014 | Boiler 2 | 100% | 20,000,000 | 20,000,000 | 21,858 | 20,657 | 16,124 | 16,124 |
| 00015 | Boiler 3 | 100% | 20,000,000 | 20,000,000 | 21,858 | 20,657 | 16,124 | 16,124 |
| 00016 | Flare | 100% | 10,000,000 | 10,000,000 | 10,929 | 10,328 | 500 | 500 |
| 00017 | S Recovery Tail Gas | | | | | | | |
| 00018 | Vacuum Crude Heater | 100% | 15,000,000 | 15,000,000 | 16,393 | 15,493 | 12,093 | 12,093 |
| 00019 | Decant Oil Tank Heater 1 | 100% | 1,000,000 | 1,000,000 | 1,093 | 1,033 | 806 | 806 |
| 00020 | Decant Oil Tank Heater 2 | 100% | 1,000,000 | 1,000,000 | 1,093 | 1,033 | 806 | 806 |

## MHA Refinery Process and Exhaust Data and Calculations

| Furnace | Duty | Exhaust Flow Wet (lbmol/hr) | Exhaust Flow Dry (lbmol/hr) | Exhaust Flow Dry @0%O2 (lbmol/hr) | Exhaust Flow Dry @3%O2 (lbmol/hr) | Exhaust Flow (scfm) | Exhaust Temp (F) | Calc Exhaust Flow (acfm) |
|---|---|---|---|---|---|---|---|---|
| Atmospheric Crude Heater | 100% | 1,019 | 833 | 714 | 833 | 6,096 | 410 | 11,662 |
| Reformer Heater 1 | 100% | 87 | 71 | 61 | 71 | 523 | 410 | 1,000 |
| Reformer Heater 2 | 100% | 87 | 71 | 61 | 71 | 523 | 410 | 1,000 |
| Reformer Heater 3 | 100% | 233 | 190 | 163 | 190 | 1,393 | 410 | 2,666 |
| Reformer Heater 4 | 100% | 175 | 143 | 122 | 143 | 1,045 | 410 | 1,999 |
| Reformer Heater 5 | 100% | 44 | 36 | 31 | 36 | 261 | 410 | 500 |
| Hydrocracker 1 | 100% | 175 | 143 | 122 | 143 | 1,045 | 410 | 1,999 |
| Hydrocracker 2 | 100% | 204 | 167 | 143 | 167 | 1,219 | 410 | 2,332 |
| Hydrocracker 3 | 100% | 291 | 238 | 204 | 238 | 1,742 | 410 | 3,332 |
| Hydrocracker 4 | 100% | 204 | 167 | 143 | 167 | 1,219 | 410 | 2,332 |
| Olefin | 100% | 873 | 714 | 612 | 714 | 5,225 | 410 | 9,996 |
| Hydrogen | 100% | 1,456 | 1,189 | 1,019 | 1,189 | 8,708 | 410 | 16,660 |
| Boiler 1 | 100% | 582 | 476 | 408 | 476 | 3,483 | 410 | 6,664 |
| Boiler 2 | 100% | 582 | 476 | 408 | 476 | 3,483 | 410 | 6,664 |
| Boiler 3 | 100% | 582 | 476 | 408 | 476 | 3,483 | 410 | 6,664 |
| Flare | 100% | 18 | 15 | 13 | 15 | 108 | 410 | 207 |
| S Recovery Tail Gas | | 55 | 44 | 17 | 19 | 0 | 100 | 0 |
| Vacuum Crude Heater | 100% | 437 | 357 | 306 | 357 | 2,613 | 410 | 4,998 |
| Decant Oil Tank Heater 1 | 100% | 29 | 24 | 20 | 24 | 174 | 410 | 333 |
| Decant Oil Tank Heater 2 | 100% | 29 | 24 | 20 | 24 | 174 | 410 | 333 |

# MHA Refinery Process and Exhaust Data and Calculations

| | | | Molecular Weights (lb/lbmol) | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 39.92 | 28.01 | 32.00 | 44.01 | 18.02 | | |
| | | Wet Exhaust Analysis (% Volume) | | | | | Total | Total |
| **Furnace** | **Duty** | **Ar** | **N2** | **O2** | **CO2** | **H2O** | **Wet** | **Dry** |
| Atmospheric Crude Heater | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Reformer Heater 1 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Reformer Heater 2 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Reformer Heater 3 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Reformer Heater 4 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Reformer Heater 5 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Hydrocracker 1 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Hydrocracker 2 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Hydrocracker 3 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Hydrocracker 4 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Olefin | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Hydrogen | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Boiler 1 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Boiler 2 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Boiler 3 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Flare | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| S Recovery Tail Gas | | 0.72% | 0.58% | 2.88% | 17.86% | 20.05% | 0.42 | 0.22 |
| Vacuum Crude Heater | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Decant Oil Tank Heater 1 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |
| Decant Oil Tank Heater 2 | 100% | 0.84% | 70.21% | 2.45% | 8.19% | 18.30% | 1.00 | 0.82 |

### MHA Refinery Process and Exhaust Data and Calculations

| Furnace | Duty | Total Mol Wt Wet (lb/lbmol) | Total Mol Wt Dry (lb/lbmol) | Dry Exhaust Analysis (% Volume) Ar | N2 | O2 | CO2 |
|---|---|---|---|---|---|---|---|
| Atmospheric Crude Heater | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Reformer Heater 1 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Reformer Heater 2 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Reformer Heater 3 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Reformer Heater 4 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Reformer Heater 5 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Hydrocracker 1 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Hydrocracker 2 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Hydrocracker 3 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Hydrocracker 4 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Olefin | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Hydrogen | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Boiler 1 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Boiler 2 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Boiler 3 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Flare | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| S Recovery Tail Gas |  | 30.52 | 41.89 | 3.28% | 2.62% | 13.06% | 81.04% |
| Vacuum Crude Heater | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Decant Oil Tank Heater 1 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |
| Decant Oil Tank Heater 2 | 100% | 27.69 | 29.86 | 1.03% | 85.95% | 3.00% | 10.03% |

## MHA Refinery Potential Air Pollutant Emission Calculations - Normal Operations

| Source ID | Engine | Load | Normal NOx Conc(1) (ppmvd@0%O2) | Normal NOx as NO2 (lb/hr) | Normal Calc NOx (lb/MMBTU) | Normal CO Conc (ppmvd@3%O2) | Normal Calc CO (lb/hr) | Normal Calc CO (lb/MMBTU) |
|---|---|---|---|---|---|---|---|---|
| 00001 | Atmospheric Crude | 100% | 40 | 1.4 | 0.041 | 50 | 1.3 | 0.037 |
| 00002 | Reformer Heater 1 | 100% | 40 | 0.1 | 0.041 | 50 | 0.1 | 0.037 |
| 00003 | Reformer Heater 2 | 100% | 40 | 0.1 | 0.041 | 50 | 0.1 | 0.037 |
| 00004 | Reformer Heater 3 | 100% | 40 | 0.3 | 0.041 | 50 | 0.3 | 0.037 |
| 00005 | Reformer Heater 4 | 100% | 40 | 0.2 | 0.041 | 50 | 0.2 | 0.037 |
| 00006 | Reformer Heater 5 | 100% | 40 | 0.1 | 0.041 | 50 | 0.1 | 0.037 |
| 00007 | Hydrocracker 1 | 100% | 40 | 0.2 | 0.041 | 50 | 0.2 | 0.037 |
| 00008 | Hydrocracker 2 | 100% | 40 | 0.3 | 0.041 | 50 | 0.3 | 0.037 |
| 00009 | Hydrocracker 3 | 100% | 40 | 0.4 | 0.041 | 50 | 0.4 | 0.037 |
| 00010 | Hydrocracker 4 | 100% | 40 | 0.3 | 0.041 | 50 | 0.3 | 0.037 |
| 00011 | Olefin | 100% | 40 | 1.2 | 0.041 | 50 | 1.1 | 0.037 |
| 00012 | Hydrogen | 100% | 40 | 2.1 | 0.041 | 50 | 1.8 | 0.037 |
| 00013 | Boiler 1 | 100% | 30 | 0.7 | 0.036 | 50 | 0.7 | 0.037 |
| 00014 | Boiler 2 | 100% | 30 | 0.7 | 0.036 | 50 | 0.7 | 0.037 |
| 00015 | Boiler 3 | 100% | 30 | 0.7 | 0.036 | 50 | 0.7 | 0.037 |
| 00016 | Flare | 100% |  | 0.7 | 0.068 |  | 3.7 | 0.370 |
| 00017 | S Recovery Tail Ga | 0% |  |  |  |  | 4.8 |  |
| 00018 | Vacuum Crude Hea | 100% | 40 | 0.6 | 0.041 | 50 | 0.5 | 0.037 |
| 00019 | Decant Oil Tank He | 100% | 40 | 0.04 | 0.041 | 50 | 0.04 | 0.037 |
| 00020 | Decant Oil Tank He | 100% | 40 | 0.04 | 0.041 | 50 | 0.04 | 0.037 |

(1) - Boiler NOx units are ppmvd@3%O2

## MHA Refinery Potential Air Pollutant Emission Calculations - Normal Operations

| Engine | Load | Normal Fuel S Conc (lb S/MMscf) | Normal Calc SO2 (lb/hr) | Normal Calc SO2 (lb/MMBTU) | Normal VOC Factor (lb/MMscf) | Normal Calc VOC (lb/hr) | Normal Calc VOC lb/MMBTU | Normal PM Factor (lb/MMscf) | Normal Calc PM (lb/hr) | Normal Calc PM lb/MMBTU |
|---|---|---|---|---|---|---|---|---|---|---|
| Atmospheric Crude | 100% | 5.36 | 0.45 | 0.0129 | 5.5 | 0.23 | 0.0066 | 7.6 | 0.32 | 0.0091 |
| Reformer Heater 1 | 100% | 5.36 | 0.04 | 0.0129 | 5.5 | 0.02 | 0.0066 | 7.6 | 0.03 | 0.0091 |
| Reformer Heater 2 | 100% | 5.36 | 0.04 | 0.0129 | 5.5 | 0.02 | 0.0066 | 7.6 | 0.03 | 0.0091 |
| Reformer Heater 3 | 100% | 5.36 | 0.10 | 0.0129 | 5.5 | 0.05 | 0.0066 | 7.6 | 0.07 | 0.0091 |
| Reformer Heater 4 | 100% | 5.36 | 0.08 | 0.0129 | 5.5 | 0.04 | 0.0066 | 7.6 | 0.05 | 0.0091 |
| Reformer Heater 5 | 100% | 5.36 | 0.02 | 0.0129 | 5.5 | 0.01 | 0.0066 | 7.6 | 0.01 | 0.0091 |
| Hydrocracker 1 | 100% | 5.36 | 0.08 | 0.0129 | 5.5 | 0.04 | 0.0066 | 7.6 | 0.05 | 0.0091 |
| Hydrocracker 2 | 100% | 5.36 | 0.09 | 0.0129 | 5.5 | 0.05 | 0.0066 | 7.6 | 0.06 | 0.0091 |
| Hydrocracker 3 | 100% | 5.36 | 0.13 | 0.0129 | 5.5 | 0.07 | 0.0066 | 7.6 | 0.09 | 0.0091 |
| Hydrocracker 4 | 100% | 5.36 | 0.09 | 0.0129 | 5.5 | 0.05 | 0.0066 | 7.6 | 0.06 | 0.0091 |
| Olefin | 100% | 5.36 | 0.39 | 0.0129 | 5.5 | 0.20 | 0.0066 | 7.6 | 0.27 | 0.0091 |
| Hydrogen | 100% | 5.36 | 0.64 | 0.0129 | 5.5 | 0.33 | 0.0066 | 7.6 | 0.46 | 0.0091 |
| Boiler 1 | 100% | 5.36 | 0.26 | 0.0129 | 5.5 | 0.13 | 0.0066 | 7.6 | 0.18 | 0.0091 |
| Boiler 2 | 100% | 5.36 | 0.26 | 0.0129 | 5.5 | 0.13 | 0.0066 | 7.6 | 0.18 | 0.0091 |
| Boiler 3 | 100% | 5.36 | 0.26 | 0.0129 | 5.5 | 0.13 | 0.0066 | 7.6 | 0.18 | 0.0091 |
| Flare | 100% | 5.36 | 0.13 | 0.0258 |  | 1.5 | 0.1540 | 7.6 | 0.09 | 0.0091 |
| S Recovery Tail Ga | 0% |  | 8.49 |  |  |  |  |  |  |  |
| Vacuum Crude Hea | 100% | 5.36 | 0.19 | 0.0129 | 5.5 | 0.10 | 0.0066 | 7.6 | 0.14 | 0.0091 |
| Decant Oil Tank He | 100% | 5.36 | 0.01 | 0.0129 | 5.5 | 0.01 | 0.0066 | 7.6 | 0.01 | 0.0091 |
| Decant Oil Tank He | 100% | 5.36 | 0.01 | 0.0129 | 5.5 | 0.01 | 0.0066 | 7.6 | 0.01 | 0.0091 |

## MHA Refinery Potential Air Pollutant Emission Calculations - Startup Operations

| Source ID | Engine | Load | Startup Factor NOx (lb/MMscf) | Startup NOx as NO2 (lb/hr) | Startup Calc NOx (lb/MMBTU) | Startup Factor CO (ppmvd@3%O2) | Startup Calc CO (lb/hr) | Startup Calc CO (lb/MMBTU) |
|---|---|---|---|---|---|---|---|---|
| 00001 | Atmospheric Crude | 100% | 100 | 3.8 | 0.109 | 200 | 5.1 | 0.147 |
| 00002 | Reformer Heater 1 | 100% | 100 | 0.3 | 0.109 | 200 | 0.4 | 0.147 |
| 00003 | Reformer Heater 2 | 100% | 100 | 0.3 | 0.109 | 200 | 0.4 | 0.147 |
| 00004 | Reformer Heater 3 | 100% | 100 | 0.9 | 0.109 | 200 | 1.2 | 0.147 |
| 00005 | Reformer Heater 4 | 100% | 100 | 0.7 | 0.109 | 200 | 0.9 | 0.147 |
| 00006 | Reformer Heater 5 | 100% | 100 | 0.2 | 0.109 | 200 | 0.2 | 0.147 |
| 00007 | Hydrocracker 1 | 100% | 100 | 0.7 | 0.109 | 200 | 0.9 | 0.147 |
| 00008 | Hydrocracker 2 | 100% | 100 | 0.8 | 0.109 | 200 | 1.0 | 0.147 |
| 00009 | Hydrocracker 3 | 100% | 100 | 1.1 | 0.109 | 200 | 1.5 | 0.147 |
| 00010 | Hydrocracker 4 | 100% | 100 | 0.8 | 0.109 | 200 | 1.0 | 0.147 |
| 00011 | Olefin | 100% | 100 | 3.3 | 0.109 | 200 | 4.4 | 0.147 |
| 00012 | Hydrogen | 100% | 100 | 5.5 | 0.109 | 200 | 7.3 | 0.147 |
| 00013 | Boiler 1 | 100% | 100 | 2.2 | 0.109 | 200 | 2.9 | 0.147 |
| 00014 | Boiler 2 | 100% | 100 | 2.2 | 0.109 | 200 | 2.9 | 0.147 |
| 00015 | Boiler 3 | 100% | 100 | 2.2 | 0.109 | 200 | 2.9 | 0.147 |
| 00016 | Flare | 100% | | 0.7 | 0.068 | | 3.7 | 0.370 |
| 00017 | S Recovery Tail Ga | 0% | | | | | | |
| 00018 | Vacuum Crude Hea | 100% | 100 | 1.6 | 0.109 | 200 | 2.2 | 0.147 |
| 00019 | Decant Oil Tank He | 100% | 100 | 0.1 | 0.109 | 200 | 0.1 | 0.147 |
| 00020 | Decant Oil Tank He | 100% | 100 | 0.1 | 0.109 | 200 | 0.1 | 0.147 |

NOx startup emissions are based on uncontrolled emissions for Small Boilers in Table 1.4-1. Emission Factors for Nitrogen Oxides (NOx). CO startup concentrations provided by vendor.

## MHA Refinery Potential Air Pollutant Emission Calculations - Startup Operations

| Engine | Load | Startup Fuel S Conc (lb S/MMscf) | Startup Calc SO2 (lb/hr) | Startup Calc SO2 (lb/MMBTU) | Startup VOC Factor (lb/MMscf) | Startup Calc VOC (lb/hr) | Startup Calc VOC lb/MMBTU | Startup PM Factor (lb/MMscf) | Startup Calc PM (lb/hr) | Startup Calc PM lb/MMBTU |
|---|---|---|---|---|---|---|---|---|---|---|
| Atmospheric Crude | 100% | 14.47 | 1.11 | 0.0316 | 5.5 | 0.21 | 0.0060 | 7.6 | 0.29 | 0.0083 |
| Reformer Heater 1 | 100% | 14.47 | 0.09 | 0.0316 | 5.5 | 0.02 | 0.0060 | 7.6 | 0.02 | 0.0083 |
| Reformer Heater 2 | 100% | 14.47 | 0.09 | 0.0316 | 5.5 | 0.02 | 0.0060 | 7.6 | 0.02 | 0.0083 |
| Reformer Heater 3 | 100% | 14.47 | 0.25 | 0.0316 | 5.5 | 0.05 | 0.0060 | 7.6 | 0.07 | 0.0083 |
| Reformer Heater 4 | 100% | 14.47 | 0.19 | 0.0316 | 5.5 | 0.04 | 0.0060 | 7.6 | 0.05 | 0.0083 |
| Reformer Heater 5 | 100% | 14.47 | 0.05 | 0.0316 | 5.5 | 0.01 | 0.0060 | 7.6 | 0.01 | 0.0083 |
| Hydrocracker 1 | 100% | 14.47 | 0.19 | 0.0316 | 5.5 | 0.04 | 0.0060 | 7.6 | 0.05 | 0.0083 |
| Hydrocracker 2 | 100% | 14.47 | 0.22 | 0.0316 | 5.5 | 0.04 | 0.0060 | 7.6 | 0.06 | 0.0083 |
| Hydrocracker 3 | 100% | 14.47 | 0.32 | 0.0316 | 5.5 | 0.06 | 0.0060 | 7.6 | 0.08 | 0.0083 |
| Hydrocracker 4 | 100% | 14.47 | 0.22 | 0.0316 | 5.5 | 0.04 | 0.0060 | 7.6 | 0.06 | 0.0083 |
| Olefin | 100% | 14.47 | 0.95 | 0.0316 | 5.5 | 0.18 | 0.0060 | 7.6 | 0.25 | 0.0083 |
| Hydrogen | 100% | 14.47 | 1.58 | 0.0316 | 5.5 | 0.30 | 0.0060 | 7.6 | 0.42 | 0.0083 |
| Boiler 1 | 100% | 14.47 | 0.63 | 0.0316 | 5.5 | 0.12 | 0.0060 | 7.6 | 0.17 | 0.0083 |
| Boiler 2 | 100% | 14.47 | 0.63 | 0.0316 | 5.5 | 0.12 | 0.0060 | 7.6 | 0.17 | 0.0083 |
| Boiler 3 | 100% | 14.47 | 0.63 | 0.0316 | 5.5 | 0.12 | 0.0060 | 7.6 | 0.17 | 0.0083 |
| Flare | 100% | 14.47 | 560.00 | 56.0000 |  | 1.4 |  | 7.6 | 0.08 | 0.0083 |
| S Recovery Tail Ga | 0% |  |  |  |  |  |  |  |  |  |
| Vacuum Crude Hea | 100% | 14.47 | 0.47 | 0.0316 | 5.5 | 0.09 | 0.0060 | 7.6 | 0.12 | 0.0083 |
| Decant Oil Tank He | 100% | 14.47 | 0.03 | 0.0316 | 5.5 | 0.01 | 0.0060 | 7.6 | 0.01 | 0.0083 |
| Decant Oil Tank He | 100% | 14.47 | 0.03 | 0.0316 | 5.5 | 0.01 | 0.0060 | 7.6 | 0.01 | 0.0083 |

**MHA Refinery Potential Air Pollutant Emission Calculations**

**Sample Normal NOx Exhaust Flow and Mass Emission Rate Calculation**

**Boiler**
Atmospheric Crude Heater

| | | | |
|---|---|---|---|
| Annual Hours | 8284 | hours | |
| Exhaust Flow | 28,216 | lb/hr | Engineering Data |
| Exhaust Mol Weight Wet | 27.69 | lb/lbmol | Engineering Data |
| Exhaust Mol Weight Dry | 29.86 | lb/lbmol | Engineering Data |
| Exhaust H2O | 18.30% | | Engineering Data |
| Exhaust O2 Wet | 2.45% | | Engineering Data |
| Ehaust O2 Dry | 3.00% | | Engineering Data |
| Ideal Gas Density | 358.9337 | scf/lbmol | |
| NOx Mol Weight | 46.005 | lb/lbmol | |
| Exhaust Temp | 410 | deg F | |
| Base Temperature | 460 | deg F | |
| Standard Temperature | 32 | deg F | |
| Ambient Pressure | 13.59 | psi | |
| Standard Pressure | 14.70 | psi | |

**Exhaust Flow**

$$\frac{28{,}216}{1}\ \frac{\text{lb}}{\text{hr}} * \frac{1}{27.69}\ \frac{\text{lbmol}}{\text{lb}} = 1{,}019\ \frac{\text{lbmol wet}}{\text{hr}}$$

$$1{,}019\ \frac{\text{lbmol wet}}{\text{hr}} * 359\ \frac{\text{scf}}{\text{lbmol}} = 365{,}822\ \frac{\text{scf}}{\text{hr}}$$

$$365{,}822\ \frac{\text{scf}}{\text{hr}} * \frac{(460 + 410)}{(460 + 32)} * \frac{14.70}{13.59} = 699{,}843\ \frac{\text{acf}}{\text{hr}}$$

$$699{,}843\ \frac{\text{acf}}{\text{hr}} * \frac{1\ \text{hr}}{60\ \text{min}} = 11{,}664\ \frac{\text{acf}}{\text{min}}$$

**Mass Emission Calculation**

Remove H2O from Exhaust

H2O Volume

$$1{,}019\ \text{lbmol} * 18.30\% = 186\ \frac{\text{lbmol H2O}}{\text{hr}}$$

$$1{,}019\ \text{lbmol} - 186 = 833\ \frac{\text{lbmol exhaust dry}}{\text{hr}}$$

Correct to 0 percent O2

$$21.00\% - 3.00\% = 18.00\%$$

$$21.00\% - 0.00\% = 21.00\%$$

$$833 * \left(\frac{18.00\%}{21.00\%}\right) = 714\ \frac{\text{lbmol exhaust dry corrected to}}{\text{hr}}\ 0\ \text{percent O2}$$

NOx Emissions = 40 ppmvd @ 0 percent O2

$$714 * \frac{40}{1.00E{+}06} = 0.03\ \frac{\text{lbmol NOx}}{\text{hr}}$$

$$\frac{0.03}{1}\ \frac{\text{lbmol NOx}}{\text{hr}} * \frac{46.005}{1}\ \frac{\text{lb}}{\text{lbmol}} = 1.31\ \frac{\text{lb NOx}}{\text{hr}}$$

10% Contingency

$$1.3 * (1 + 0.10) = 1.44\ \frac{\text{lb NOx}}{\text{hr}}$$

Annual Emissions

$$1.44\ \frac{\text{lb}}{\text{hr}} * \frac{8284\ \text{hr}}{1\ \text{yr}} * \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 5.98\ \frac{\text{ton}}{\text{yr}}$$

## MHA Refinery Potential Air Pollutant Emission Calculations

## Sample Startup NOx Mass Emission Rate Calculation

### Boiler

Atmospheric Crude Heater

| | | |
|---|---|---|
| Annual Hours | 500 | hours |
| Power Rating | 35 | MMBTU/hr |
| Fuel Heat Content | 915 | BTU/scf |

NOx emissions = 100 lb/MMscf AP-42 Table 1.4-1

$$100\ \frac{\text{lb}}{\text{MMscf}} * \frac{1\ \text{MMscf}}{915\ \text{MMBTU}} = 0.109\ \text{lb/MMBtu}$$

$$0.109\ \frac{\text{lb}}{\text{MMBTU}} * 35\ \frac{\text{MMBtu}}{\text{hr}} = 3.83\ \frac{\text{lb}}{\text{hr}}$$

Annual Emissions

$$3.83\ \frac{\text{lb}}{\text{hr}} * \frac{500\ \text{hr}}{1\ \text{yr}} * \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 0.96\ \frac{\text{ton}}{\text{yr}}$$

**MHA Refinery Potential Air Pollutant Emission Calculations**

**Sample Normal CO Exhaust Flow and Mass Emission Rate Calculation**

**Boiler**
Atmospheric Crude Heater

| | | | |
|---|---|---|---|
| Annual Hours | 8284 | hours | |
| Exhaust Flow | 28,216 | lb/hr | Engineering Data |
| Exhaust Mol Weight Wet | 27.69 | lb/lbmol | Engineering Data |
| Exhaust Mol Weight Dry | 29.86 | lb/lbmol | Engineering Data |
| Exhaust H2O | 18.30% | | Engineering Data |
| Exhaust O2 Wet | 2.45% | | Engineering Data |
| Ehaust O2 Dry | 3.00% | | Engineering Data |
| Ideal Gas Density | 358.9337 | scf/lbmol | |
| CO Mol Weight | 28.01 | lb/lbmol | |
| Exhaust Temp | 410 | deg F | |
| Base Temperature | 460 | deg F | |
| Standard Temperature | 32 | deg F | |
| Ambient Pressure | 13.59 | psi | |
| Standard Pressure | 14.70 | psi | |

**Exhaust Flow**

$$\frac{28{,}216}{1}\ \frac{\text{lb}}{\text{hr}} * \frac{1}{27.69}\ \frac{\text{lbmol}}{\text{lb}} = 1{,}019\ \frac{\text{lbmol wet}}{\text{hr}}$$

$$1{,}019\ \frac{\text{lbmol wet}}{\text{hr}} * 359\ \frac{\text{scf}}{\text{lbmol}} = 365{,}822\ \frac{\text{scf}}{\text{hr}}$$

$$365{,}822\ \frac{\text{scf}}{\text{hr}} * \frac{(460 + 410)}{(460 + 32)} * \frac{14.70}{13.59} = 699{,}843\ \frac{\text{acf}}{\text{hr}}$$

$$699{,}843\ \frac{\text{acf}}{\text{hr}} * \frac{1\ \text{hr}}{60\ \text{min}} = 11{,}664\ \frac{\text{acf}}{\text{min}}$$

**Mass Emission Calculation**

Remove H2O from Exhaust

H2O Volume

$$1{,}019\ \text{lbmol} * 18.30\% = 186\ \frac{\text{lbmol H2O}}{\text{hr}}$$

$$1{,}019\ \text{lbmol} - 186 = 833\ \frac{\text{lbmol exhaust dry}}{\text{hr}}$$

Correct to 3 percent O2

21.00% - 3.00% = 18.00%

21.00% - 3.00% = 18.00%

$$833 * \left(\frac{18.00\%}{18.00\%}\right) = 833\ \frac{\text{lbmol exhaust dry corrected to 3 percent O2}}{\text{hr}}$$

CO Emissions = 50 ppmvd @ 3 percent O2

$$833 * \frac{50}{1.00\text{E}+06} = 0.04\ \frac{\text{lbmol CO}}{\text{hr}}$$

$$\frac{0.04}{1}\ \frac{\text{lbmol CO}}{\text{hr}} * \frac{28.01}{1}\ \frac{\text{lb}}{\text{lbmol}} = 1.2\ \frac{\text{lb CO}}{\text{hr}}$$

$$10\%\ \text{Contingency}\quad 1.2 * (1 + 0.10) = 1.28\ \frac{\text{lb CO}}{\text{hr}}$$

Annual Emissions

$$1.28\ \frac{\text{lb}}{\text{hr}} * \frac{8284\ \text{hr}}{1\ \text{yr}} * \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 5.31\ \frac{\text{ton}}{\text{yr}}$$

**MHA Refinery Potential Air Pollutant Emission Calculations**

**Sample Startup CO Exhaust Flow and Mass Emission Rate Calculation**

**Boiler**

Atmospheric Crude Heater

| | | | |
|---|---|---|---|
| Annual Hours | 500 | hours | |
| Exhaust Flow | 28,216 | lb/hr | Engineering Data |
| Exhaust Mol Weight Wet | 27.69 | lb/lbmol | Engineering Data |
| Exhaust Mol Weight Dry | 29.86 | lb/lbmol | Engineering Data |
| Exhaust H2O | 18.30% | | Engineering Data |
| Exhaust O2 Wet | 2.45% | | Engineering Data |
| Ehaust O2 Dry | 3.00% | | Engineering Data |
| Ideal Gas Density | 358.9337 | scf/lbmol | |
| CO Mol Weight | 28.01 | lb/lbmol | |
| Exhaust Temp | 410 | deg F | |
| Base Temperature | 460 | deg F | |
| Standard Temperature | 32 | deg F | |
| Ambient Pressure | 13.59 | psi | |
| Standard Pressure | 14.70 | psi | |

**Exhaust Flow**

$$\frac{28{,}216}{1}\ \frac{\text{lb}}{\text{hr}} * \frac{1}{27.69}\ \frac{\text{lbmol}}{\text{lb}} = 1{,}019\ \frac{\text{lbmol wet}}{\text{hr}}$$

$$1{,}019\ \frac{\text{lbmol wet}}{\text{hr}} * 359\ \frac{\text{scf}}{\text{lbmol}} = 365{,}822\ \frac{\text{scf}}{\text{hr}}$$

$$365{,}822\ \frac{\text{scf}}{\text{hr}} * \left(\frac{460 + 410}{460 + 32}\right) * \frac{14.70}{13.59} = 699{,}843\ \frac{\text{acf}}{\text{hr}}$$

$$699{,}843\ \frac{\text{acf}}{\text{hr}} * \frac{1\ \text{hr}}{60\ \text{min}} = 11{,}664\ \frac{\text{acf}}{\text{min}}$$

**Mass Emission Calculation**

Remove H2O from Exhaust

H2O Volume $1{,}019\ \text{lbmol} * 18.30\% = 186\ \frac{\text{lbmol H2O}}{\text{hr}}$

$$1{,}019\ \text{lbmol} - 186 = 833\ \frac{\text{lbmol exhaust dry}}{\text{hr}}$$

Correct to 0 percent O2

$$21.00\% - 3.00\% = 18.00\%$$

$$21.00\% - 0.00\% = 21.00\%$$

$$833 * \left(\frac{18.00\%}{21.00\%}\right) = 714\ \frac{\text{lbmol exhaust dry corrected to}}{\text{hr}}\ 0\ \text{percent O2}$$

CO Emissions = 200 ppmvd @ 0 percent O2

$$714 * \frac{200}{1.00\text{E}+06} = 0.14\ \frac{\text{lbmol CO}}{\text{hr}}$$

$$\frac{0.14}{1}\ \frac{\text{lbmol CO}}{\text{hr}} * \frac{28.01}{1}\ \frac{\text{lb}}{\text{lbmol}} = 4.0\ \frac{\text{lb CO}}{\text{hr}}$$

10% Contingency $4.0 * (1 + 0.10) = 4.40\ \frac{\text{lb CO}}{\text{hr}}$

Annual Emissions

$$4.40\ \frac{\text{lb}}{\text{hr}} * \frac{500}{1}\ \frac{\text{hr}}{\text{yr}} * \frac{1}{2{,}000}\ \frac{\text{ton}}{\text{lbs}} = 1.10\ \frac{\text{ton}}{\text{yr}}$$

# MHA Refinery Potential Air Pollutant Emission Calculations

## Sample Normal Boiler SO2 Calculation

**Boiler**
Atmospheric Crude Heater

| | | |
|---|---|---|
| Annual Hours | 8284 | hours |
| Fuel Heat Content (LHV) = | 915.0 | BTU/scf |
| Heat Input = | 35 | MMBTU/hr |
| Ideal Gas Density | 358.9 | scf/lbmol |
| S Mol Weight | 32.065 | lb |
| SO2 Mol Weight | 64.063 | lb |
| | | |
| Fuel S Concentration | 60 | ppmvd |

Calculate Fuel Flow

$$35{,}000{,}000\ \frac{\text{BTU}}{\text{hr}} * \frac{1\ \text{scf}}{915\ \text{BTU}} = 38{,}251\ \frac{\text{scf}}{\text{hr}}$$

Calculate Sulfur Emissions

$$\frac{60\ \text{lb-mol S}}{1000000\ \text{lb-mol CH4}} * 32.065\ \frac{\text{lb S}}{\text{lb-mol S}} * \frac{1\ \text{lb-mol CH4}}{358.9\ \text{scf}} = 5.36\text{E-}06\ \frac{\text{lb S}}{\text{scf}}$$

$$5.36\text{E-}06\ \frac{\text{lb S}}{\text{scf}} * 38{,}251\ \frac{\text{scf}}{\text{hr}} = 0.205\ \frac{\text{lb S}}{\text{hr}}$$

$$0.2050\ \frac{\text{lb S}}{\text{hr}} * \frac{64\ \text{lb SO2}}{32\ \text{lb S}} = 0.41\ \frac{\text{lb SO2}}{\text{hr}}$$

$$\text{10\% Contingency} \quad 0.41 * (1 + 0.10) = 0.45\ \frac{\text{lb SO2}}{\text{hr}}$$

Annual Emissions

$$0.45\ \frac{\text{lb}}{\text{hr}} * \frac{8284\ \text{hr}}{1\ \text{yr}} * \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 1.87\ \frac{\text{ton}}{\text{yr}}$$

**MHA Refinery Potential Air Pollutant Emission Calculations**

**Sample Startup Boiler SO2 Calculation**

**Boiler**
Atmospheric Crude Heater

| | | |
|---|---|---|
| Annual Hours | 500 | hours |
| Fuel Heat Content (LHV) = | 915.0 | BTU/scf |
| Heat Input = | 35 | MMBTU/hr |
| Ideal Gas Density | 358.9 | scf/lbmol |
| S Mol Weight | 32.065 | lb |
| SO2 Mol Weight | 64.063 | lb |
| | | |
| Fuel S Concentration | 162 | ppmvd |

Calculate Fuel Flow

$$35{,}000{,}000\ \frac{\text{BTU}}{\text{hr}} * \frac{1\ \text{scf}}{915\ \text{BTU}} = 38{,}251\ \frac{\text{scf}}{\text{hr}}$$

Calculate Sulfur Emissions

$$\frac{162\ \text{lb-mol S}}{1000000\ \text{lb-mol CH4}} * 32.065\ \frac{\text{lb S}}{\text{lb-mol S}} * \frac{1\ \text{lb-mol CH4}}{358.9\ \text{scf}} = 1.45\text{E-05}\ \frac{\text{lb S}}{\text{scf}}$$

$$1.45\text{E-05}\ \frac{\text{lb S}}{\text{scf}} * 38{,}251\ \frac{\text{scf}}{\text{hr}} = 0.554\ \frac{\text{lb S}}{\text{hr}}$$

$$0.5536\ \frac{\text{lb S}}{\text{hr}} * \frac{64\ \text{lb SO2}}{32\ \text{lb S}} = 1.11\ \frac{\text{lb SO2}}{\text{hr}}$$

Annual Emissions

$$1.11\ \frac{\text{lb}}{\text{hr}} * \frac{500\ \text{hr}}{1\ \text{yr}} * \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 0.28\ \frac{\text{ton}}{\text{yr}}$$

**MHA Refinery Potential Air Pollutant Emission Calculations**

**Normal and Startup Startup VOC Mass Emission Rate Calculation**

**Boiler**

Atmospheric Crude Heater

| | | |
|---|---|---|
| Annual Normal Hours | 8284 | hours |
| Annual Startup Hours | 500 | hours |
| Power Rating | 35 | MMBTU/hr |
| Fuel Heat Content | 915 | BTU/scf |

VOC emissions = 5.5 lb/MMscf AP-42 Table 1.4-2

$$6\ \frac{\text{lb}}{\text{MMscf}} * \frac{1\ \text{MMscf}}{915\ \text{MMBTU}} = 0.006\ \text{lb/MMBtu}$$

$$0.006\ \frac{\text{lb}}{\text{MMBTU}} * 35\ \frac{\text{MMBtu}}{\text{hr}} = 0.21\ \frac{\text{lb}}{\text{hr}}$$

Annual Normal Emissions

$$0.21\ \frac{\text{lb}}{\text{hr}} * \frac{8284\ \text{hr}}{1\ \text{yr}} * \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 0.87\ \frac{\text{ton}}{\text{yr}}$$

Annual Startup Emissions

$$0.21\ \frac{\text{lb}}{\text{hr}} * \frac{500\ \text{hr}}{1\ \text{yr}} * \frac{1\ \text{ton}}{2{,}000\ \text{lbs}} = 0.05\ \frac{\text{ton}}{\text{yr}}$$

**MHA Refinery Potential Air Pollutant Emission Calculations**

## Normal and Startup Startup PM Mass Emission Rate Calculation

### Boiler

Atmospheric Crude Heater

| | | |
|---|---|---|
| Annual Normal Hours | 8284 | hours |
| Annual Startup Hours | 500 | hours |
| Power Rating | 35 | MMBTU/hr |
| Fuel Heat Content | 915 | BTU/scf |

PM emissions = 7.6 lb/MMscf AP-42 Table 1.4-2

$$8 \frac{\text{lb}}{\text{MMscf}} * \frac{1 \text{ MMscf}}{915 \text{ MMBTU}} = 0.008 \text{ lb/MMBtu}$$

$$0.008 \frac{\text{lb}}{\text{MMBTU}} * 35 \frac{\text{MMBtu}}{\text{hr}} = 0.29 \frac{\text{lb}}{\text{hr}}$$

Annual Normal Emissions

$$0.29 \frac{\text{lb}}{\text{hr}} * \frac{8284 \text{ hr}}{1 \text{ yr}} * \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 1.20 \frac{\text{ton}}{\text{yr}}$$

Annual Startup Emissions

$$0.29 \frac{\text{lb}}{\text{hr}} * \frac{500 \text{ hr}}{1 \text{ yr}} * \frac{1 \text{ ton}}{2{,}000 \text{ lbs}} = 0.07 \frac{\text{ton}}{\text{yr}}$$

# MHA Refinery

**MHA Refinery Potential Air Pollutant Emission Calculations**

**Tail Gas Exhaust Calculations**

**Annual Hours** 8584

**Engineering Estimate of Tail Gas Composition**

| Species | Exhaust Flow (lb-mol/hr) | Molecular Weight (lb/lb-mol) | Emission Rate (lb/hr) | (ton/yr) |
|---|---|---|---|---|
| Ar | 0.40 | 39.948 | 16.0 | 68.6 |
| CO | 0.17 | 28.010 | 4.8 | 20.4 |
| CO2 | 9.87 | 44.009 | 434.4 | 1864.3 |
| H2 | 0.17 | 2.016 | 0.3 | 1.5 |
| H2O | 11.08 | 18.015 | 199.6 | 856.7 |
| N2 | 31.87 | 28.014 | 892.8 | 3831.9 |
| O2 | 1.59 | 31.998 | 50.9 | 218.4 |
| SO2 | 0.11 | 64.063 | 7.0 | 30.2 |
| | | | | |
| Total Wet | 55.26 | | | |
| Total Dry | 44.18 | | | |
| SO2 Concentration | 2,490 | ppmvd | | |
| | | | | |
| Recalculate SO2 at | 3,000 | ppmvd | | |
| | | | | |
| SO2 | 0.13 | 64.063 | 8.5 | 36.4 |

**MHA Refinery Potential Air Pollutant Emission Calculations**

**Flare Normal Emissions**

AP-42 Table 13.5-1 (English Units). Emission Factors for Flare Operations

| | | |
|---|---|---|
| NOx | 0.068 | lb/MMBTU |
| CO | 0.37 | lb/MMBTU |

| | | | |
|---|---|---|---|
| Normal Hours | 8684 | hours | |
| Fuel S Concentration | 5.36E-06 | lb S/scf | See worksheet "Normal-Boiler-SO2" |
| Fuel Heat Content | 915 | BTU/scf | |
| Fuel Heat Input | 10 | MMBTU/hr | |
| Fuel Rate | 0.011 | MMscf/hr | |

Normal Emissions

NOx

$$0.068\,\frac{\text{lb}}{\text{MMBTU}} * 10\,\frac{\text{MMBTU}}{\text{hr}} = 0.68\,\frac{\text{lb}}{\text{hr}}$$

$$0.68\,\frac{\text{lb}}{\text{hr}} * 8684\,\frac{\text{hr}}{\text{yr}} * \frac{1\text{ ton}}{2000\text{ lb}} = 2.95\,\frac{\text{ton}}{\text{yr}}$$

CO

$$0.37\,\frac{\text{lb}}{\text{MMBTU}} * 10\,\frac{\text{MMBTU}}{\text{hr}} = 3.7\,\frac{\text{lb}}{\text{hr}}$$

$$3.7\,\frac{\text{lb}}{\text{hr}} * 8684\,\frac{\text{hr}}{\text{yr}} * \frac{1\text{ ton}}{2000\text{ lb}} = 16.07\,\frac{\text{ton}}{\text{yr}}$$

SO2

$$5.36\text{E-06}\,\frac{\text{lb S}}{\text{scf}} * 1.00\text{E+06}\,\frac{\text{scf}}{\text{MMscf}} * 0.011\,\frac{\text{MMscf}}{\text{hr}} * 2\,\frac{\text{lb SO2}}{\text{lb S}} = 0.12\,\frac{\text{lb}}{\text{hr}}$$

$$0.12\,\frac{\text{lb}}{\text{hr}} * 8684\,\frac{\text{hr}}{\text{yr}} * \frac{1\text{ ton}}{2000\text{ lb}} = 0.51\,\frac{\text{ton}}{\text{yr}}$$

## MHA Refinery Potential Air Pollutant Emission Calculations

### Flare Startup Emissions

AP-42 Table 13.5-1 (English Units). Emission Factors for Flare Operations

| | | |
|---|---|---|
| NOx | 0.068 | lb/MMBTU |
| CO | 0.37 | lb/MMBTU |

| | | |
|---|---|---|
| Startup Hours | 100 | hours |
| Fuel Heat Input | 10 | MMBTU/hr |
| SRU Capacity | 3 | long-tons/day |

Startup Emissions

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| NOx | 0.068 lb | * | 10 MMBTU | = | 0.68 lb | | |
| | MMBTU | | hr | | hr | | |
| | 0.68 lb | * | 100 hr | * | 1 ton | = | 0.03 ton |
| | hr | | yr | | 2000 lb | | yr |
| CO | 0.37 lb | * | 10 MMBTU | = | 3.7 lb | | |
| | MMBTU | | hr | | hr | | |
| | 3.7 lb | * | 100 hr | * | 1 ton | = | 0.19 ton |
| | hr | | yr | | 2000 lb | | yr |
| SO2 | 3 long-tons S | * | 2,240 lb S | = | 6,720 lb S | = | 280 lb S |
| | day | | long-tons | | day | | hr |
| | 280.0 lb S | * | 2 Mol SO2 | = | 560.0 lb | | |
| | hr | | Mol S | | hr | | |
| | 560.0 lb | * | 100 hr | * | 1 ton | = | 28.0 ton |
| | hr | | yr | | 2000 lb | | yr |

## Updated Fugitive VOC Calculations

| | | |
|---|---|---|
| Original Storage Tank Total | 26.7 | ton/yr |
| 2 Decant Oil Tanks | 12.56 | lb/yr |
| | 0.00628 | ton/yr |
| **New Storage Tank Total** | **26.7** | |
| | | |
| Original Area Fugitives | 38.02 | |
| Assume 20% Increase from New Vacuum Unit | 7.604 | |
| **New Area Fugitive Total** | **45.6** | |

## Updated Fugitive PM Calculations

| | |
|---|---|
| Original Fugitive Vehicle Traffic PM10 | 16.74 |
| Assume 20% Increase from New Vacuum Unit | 3.348 |
| **New Fugitive Vehicle Traffic PM10 Total** | **20.088** |

# TANKS 4.0.9d
# Emissions Report - Summary Format
# Tank Indentification and Physical Characteristics

**Identification**

| | |
|---|---|
| User Identification: | Decant Oil Tank 1 |
| City: | Bismarck |
| State: | North Dakota |
| Company: | |
| Type of Tank: | Vertical Fixed Roof Tank |
| Description: | Decant Oil Tank |

**Tank Dimensions**

| | | |
|---|---|---|
| Shell Height (ft): | | 40.00 |
| Diameter (ft): | | 40.00 |
| Liquid Height (ft) : | | 35.00 |
| Avg. Liquid Height (ft): | | 25.00 |
| Volume (gallons): | | 329,011.52 |
| Turnovers: | | 50.00 |
| Net Throughput(gal/yr): | | 16,450,576.00 |
| Is Tank Heated (y/n): | Y | |

**Paint Characteristics**

| | |
|---|---|
| Shell Color/Shade: | White/White |
| Shell Condition | Good |
| Roof Color/Shade: | White/White |
| Roof Condition: | Good |

**Roof Characteristics**

| | | |
|---|---|---|
| Type: | Dome | |
| Height (ft) | | 5.00 |
| Radius (ft) (Dome Roof) | | 40.00 |

**Breather Vent Settings**

| | |
|---|---|
| Vacuum Settings (psig): | -0.03 |
| Pressure Settings (psig) | 0.03 |

Meterological Data used in Emissions Calculations: Fargo, North Dakota (Avg Atmospheric Pressure = 14.25 psia)

# TANKS 4.0.9d
# Emissions Report - Summary Format
# Liquid Contents of Storage Tank

## Decant Oil Tank 1 - Vertical Fixed Roof Tank
## Bismarck, North Dakota

| Mixture/Component | Month | Daily Liquid Surf. Temperature (deg F) Avg. | Min. | Max. | Liquid Bulk Temp (deg F) | Vapor Pressure (psia) Avg. | Min. | Max. | Vapor Mol. Weight. | Liquid Mass Fract. | Vapor Mass Fract. | Mol. Weight | Basis for Vapor Pressure Calculations |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residual oil no. 6 | All | 85.00 | 85.00 | 85.00 | 85.00 | 0.0001 | 0.0001 | 0.0001 | 190.0000 | | | 387.00 | Option 1: VP70 = .00006 VP80 = .00009 |

# TANKS 4.0.9d
# Emissions Report - Summary Format
# Individual Tank Emission Totals

## Emissions Report for: Annual

**Decant Oil Tank 1 - Vertical Fixed Roof Tank**
**Bismarck, North Dakota**

| | Losses(lbs) | | |
|---|---|---|---|
| Components | Working Loss | Breathing Loss | Total Emissions |
| Residual oil no. 6 | 6.28 | 0.00 | 6.28 |

**Exhibit 8**:

Air Quality Modeling Analysis, Air Quality Modeling Update for the FEIS (June 6, 2011)

# Air Quality Modeling Analysis

# Air Quality Modeling Update for the Final Environmental Impact Statement for the Mandan, Hidatsa, and Arikara Nation’s Proposed Clean Fuels Refinery Project

June 6, 2011

## Table of Contents

## List of Tables

## List of Figures

## List of Appendices

## Chapter 1 - Introduction

The purpose of this report is to update the air quality air quality impacts associated with the proposed Mandan, Hidatsa, and Arikara Nation's Proposed Clean Fuels Refinery Project (MHA Refinery). The proposed refinery will be located on the Fort Berthold Indian Reservation in western North Dakota. The original Air Quality Technical Report for this proposed refinery was submitted to EPA Region 8 in December, 2007.

This evaluation was done using existing monitoring data available for the MHA Refinery proposed location and surrounding areas, projections of criteria air pollutants from the proposed refinery, and air quality modeling. The report also identifies the federal air regulatory requirements for air emissions from the proposed refinery.

A Vacuum Crude Heater and two Decant Oil Tank Heaters have been added to this analysis since the December 2007 Air Quality Technical Report.

The air quality modeling conducted was compared concentrations of criteria air pollutants to the National Ambient Air Quality Standards (NAAQS). This addresses air quality impacts from emissions of oxides of nitrogen ($NO_x$), carbon monoxide (CO), sulfur dioxide ($SO_2$), and particulate matter with nominal aerodynamic diameters of 10 microns and 2.5 microns ($PM_{10}$ and $PM_{2.5}$ respectively) from the sources at the MHA Refinery.

## Chapter 2 - Air Quality Standards

EPA has established NAAQS for $NO_2$, CO, $SO_2$, $PM_{10}$, and $PM_{2.5}$ have been developed to protect public health and welfare with an adequate margin of safety. The NAAQS for these pollutants are presented in Table 2 as well as the State of North Dakota's ambient air quality standards. These are the regulatory limits that concentrations of pollutants must not exceed during the specific averaging period for an area to be considered in attainment for air quality.

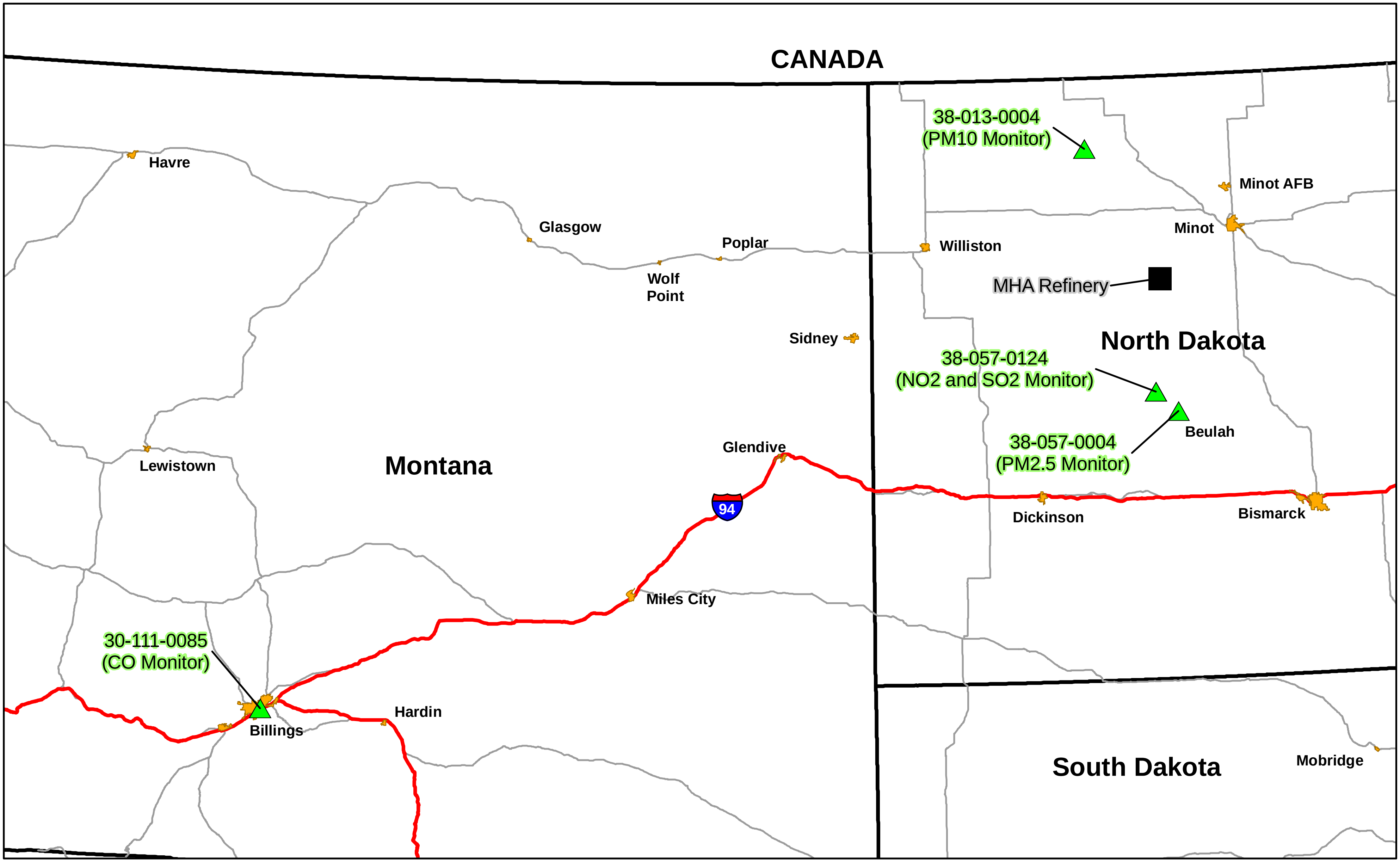
**Table 1 Summary of Regulatory Ambient Air Quality Concentrations (µg/m3)[1]**

| Pollutant | Averaging Time | NAAQS[2] (µg/m³) | Increment Class II (µg/m³) |
|---|---|---|---|
| $NO_2$ | 1-Hour | 188[3] | NS |
| | Annual | 100 | 100 |
| CO | 1-Hour | 40,000 | 40,000 |
| | 8-Hour | 10,000 | 10,000 |
| $PM_{10}$ | 24-Hour | 150 | 150 |
| $PM_{2.5}$ | 24-Hour | 35[3] | NS |
| | Annual | 15 | NS |
| $SO_2$ | 1-hour | 196[4] | 715 |
| | 24-Hour | 365 | 260 |
| | Annual | 80 | 60 |

1. µg/m³ = micrograms per cubic meter
2. National Ambient Air Quality Standards (40 CFR 50)
3. 98th Percentile
4. 99th Percentile

## Existing Ambient Air Quality

Ambient air quality data were selected from EPA ambient air monitoring stations that would be considered representative of the air quality at the project site. Figure 2-1 Ambient Air Quality Monitoring Stations shows the locations of the selected monitoring stations.



**FORT BERTHOLD REFINERY EIS**

*FIGURE 2-1*
*AMBIENT AIR QUALITY*
*MONITORING STATIONS*

| | |
|---|---|
| ANALYSIS AREA: MOUNTRAIL AND WARD COUNTIES, N. DAKOTA | |
| Date: 05/17/2011 | File: I:/1600/Figure 2-1.mxd |
| Drawn By: MSH | |

Table 2 summarizes the data for these monitoring sites. These data represent maximums and averages for the years 2005 through 2009.

**Table 2 Monitoring Data Summary**

| Pollutant | Averaging Period | EPA Station ID | Location | Calculated Ambient Concentration ($\mu g/m^3$) | Calculation Method[1] |
|---|---|---|---|---|---|
| NO2 | 1-hour | 38-057-0124 | Beulah, ND | 41 | 8H Average |
| | Annual | 38-057-0124 | Beulah, ND | 4 | Maximum |
| CO | 1-hour | 30-111-0085 | Billings, MT | 7,980 | 1H Average |
| | 8-hour | 30-111-0085 | Billings, MT | 3,124 | 1H Average |
| PM10 | 24-hour | 38-013-0004 | Kenmare, ND | 45 | 1H Average |
| PM2.5 | 24-hour | 38-057-0004 | Mercer Co., ND | 16 | 2H Average |
| | Annual | 38-057-0004 | Mercer Co., ND | 6 | Maximum |
| SO2 | 1-hour | 38-057-0124 | Beulah, ND | 96 | 4H Average |
| | 24-hour | 38-057-0124 | Beulah, ND | 21 | 1H Average |
| | Annual | 38-057-0124 | Beulah, ND | 3 | Max Average |

1. NH represents the Nth High (ex. 8H is the Eighth High for that averaging period)

Table 3 presents the monitoring data summary for each year.

**Table 3 Monitoring Data Summary by Year ($\mu g/m^3$) for the Stations Listed in Table 2**

| | $NO_2$ | | CO | | $PM_{10}$ | $PM_{2.5}$ | | $SO_2$ | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **8th High 1-Hour** | **Annual** | **Max 1-Hour** | **Max 8-Hour** | **Max 24-Hour** | **2nd High 24-Hour** | **Annual** | **4th High 1-Hour** | **Max 24-Hour** | **Annual** |
| 2005 | 43 | 4 | 15,276 | 4,218 | 34 | 19 | 6 | 99 | 21 | 2 |
| 2006 | 47 | 4 | 6,726 | 3,078 | 52 | 19 | 6 | 94 | 26 | 2 |
| 2007 | 39 | 3 | 5,130 | 2,736 | 76 | 14 | 6 | 99 | 21 | 3 |
| 2008 | 36 | 4 | 5,472 | 2,622 | 32 | 13 | 6 | 112 | 21 | 2 |
| 2009 | 41 | 4 | 7,296 | 2,964 | 30 | 14 | 5 | 73 | 16 | 2 |

## Chapter 3 — Air Quality Impact Analysis

The air quality modeling analysis used the same plant, source, and receptor configurations that were used in the 2007 modeling analysis. Since the previous modeling was conducted using the ISCST3 dispersion model, the analysis was updated using the AERMOD dispersion modeling system which is now the EPA preferred model for this application.

## Air Quality Modeling Methodology

### Model Selection

The EPA recommended AERMOD dispersion modeling system was used to evaluate Class II air quality impacts. The AERMOD model (Version 11103) is the latest generation of the EPA's AERMOD model, which is recommended for predicting impacts from industrial point sources as well as area and volume sources. The model combines simple and complex terrain algorithms, and includes the PRIME algorithms to account for building downwash and cavity zone impacts.

The complete AERMOD modeling system is comprised of three parts—the AERMET pre-processor, the AERMAP pre-processor, and the AERMOD model. The AERMET (Version 11059) pre-processor compiles the surface and upper-air meteorological data and formats the data for AERMOD input. The AERMAP (Version 11103) pre-processor is used to obtain elevation and controlling hill heights for AERMOD input.

BEEST for Windows (Version 9.83) was used to compile and generate the AERMOD model runs.

### AERMET Meteorological Data Processing

#### Land Use Analysis

Land use analysis for use by AERMET was processed using the AERSURFACE processor. National Land Cover Data for North Dakota were downloaded from the U.S. Geological Survey (USGS) webpage (http://edcftp.cr.usgs.gov/pub/data/landcover/states). Precipitation data for each of the modeling years (2005 through 2009) were compared against a normal precipitation summary for Minot, ND to determine whether precipitation for each year was dry (below the 30th percentile), average (30th to 70th percentile), or wet (above the 70th percentile).

#### Selection of the Meteorological Database

Surface data collected at Minot Airport (WBAN 24013) and upper air data collected at Bismarck, ND (WBAN 24011) for the years 2005 through 2009 were used in this analysis.

#### Meteorological Data Processing

The surface and upper air data were processed with AERMET along with the output from the AERSURFACE processing.

The preparation of the meteorological data files using AERMET was a two-step process. The first step was the extraction of raw hourly surface observations and upper air soundings. The extracted files were checked by AERMET module for consistency and any missing or calm hours were identified.

The second step was to read the meteorological data and estimate the boundary layer parameters required by AERMOD using land use surface parameters unique to the area surrounding the project site.

## AERMOD Processing

The AERMOD model was used with regulatory default options as recommended in the EPA Guideline on Air Quality Models as listed as follows:

- Use stack-tip downwash
- Model accounts for elevated terrain effects
- Use calms processing
- Use sequential meteorological date checking
- Use of the PRIME algorithm for sources influenced by building downwash
- Use Missing Data Processing routine
- No exponential decay calculated

### Building Downwash

Building wake effects were assessed with the Building Profile Input Program with Plume Rise Enhancements (BPIP-PRIME, dated 04274). BPIP-PRIME was also be used to analyze Good Engineering Practice (GEP) stack heights for the point sources. Table 4 presents the dimensions of the buildings to be used in this analysis.

**Table 4 Dimensions of Buildings at the MHA Nation's Proposed Clean Fuels Refinery**

| Building/Structure | Length 1 (m)[1] | Length 2 (m) | Height (m) |
|---|---|---|---|
| Office Building | 71 | 55 | 12.2 |
| Utility Building | 28 | 33 | 12.2 |
| Control Building | 49 | 15 | 12.2 |

1. m = meter

### Treatment of Chemical Transformations (for example, NO to NO2, parameterizations)

100 percent of the NOx emissions were assumed to be $NO_2$. No other chemical transformations were used.

### Pollutant Averaging Periods

The following air pollutants were modeled for the corresponding averaging periods:

- $NO_x$ – 1-hour and annual
- CO – 1-hour and 8-hour
- $SO_2$ – 1-hour, 24-hour, and annual
- $PM_{10}$ – 24-hour
- $PM_{2.5}$ – 24-hour and annual

### MHA Refinery Modeled Emission Rates

Estimated emissions for refinery sources included $NO_x$, CO, $PM_{10}$, and $SO_2$ were presented in air quality technical report presented to EPA on March 9, 2011 (MHA 2011). Except for the soybean and soybean meal handling, $PM_{2.5}$ emissions were assumed to be equivalent to $PM_{10}$.

For the soybean and soybean meal handling $PM_{2.5}$ emission rates were assumed to be 17% of $PM_{10}$ emission rates based on information provided in EPA's AP-24 on Table 9.9.1-1. Particulate Emission Factors for Grain Elevators (USEPA 2011a). These sources include:

- Soybean Loadout
- Meal Loadout 1
- Meal Loadout 2

For all other sources $PM_{2.5}$ emission rates were assumed to be equivalent to $PM_{10}$ emission rates.

For the 1-hour $NO_2$ modeling, the emergency generator and fire pump engine were excluded from the modeling analysis. This is recommended in recent EPA guidance for modeling 1-hour $NO_2$ with intermittent sources (USEPA 2011b).

For the 1-hour and 24-hour $SO_2$ modeling, annual average emissions (that include elevated emission events) were used. Although higher short-term $SO_2$ emissions were estimated for this source, these would be intermittent emissions associated with the shutdown of both Sulfur Recovery Units (SRUs), therefore the recommendations from EPA's 1-hour $NO_2$ modeling guidance should be appropriate for $SO_2$ modeling.

According to the EPA 1-hour $NO_2$ guidance (USEPA 2011b, page 8):

> "...the intermittent nature of the actual emissions associated with emergency generators and startup/shutdown in many cases, when coupled with the probabilistic form of the standard, could result in modeled impacts being significantly higher than actual impacts would realistically be expected to be for these emission scenarios."

Elevated flaring emissions would be similar to startup/shutdown events since these are based on the low probability of a shutdown of both SRUs. One SRU will normally be shutdown and will be used as a backup should a shutdown be required for the other SRU. This design has been developed to create an extremely low probability for the elevated flaring events. Therefore the elevated flare emissions would not likely coincide with worst-case meteorological conditions and maximum background concentrations.

Although the potential elevated $SO_2$ emissions from the flare have been estimated to occur 100 hours per year, this is an extremely conservative assumption. The SRU units will be monitored and maintained with a goal of having far fewer - if any - events over the period of a year.

Summaries of the modeled emission rates and source exhaust parameters are presented in Appendix A.

### Receptor Network

The same receptor grid as was used in the original ISCST3 modeling analysis was used in this analysis. The elevations for these receptors were revised using current data and the AERMAP receptor elevation processor.

### Receptor Elevations

The AERMOD pre-processor AERMAP was used to generate receptor elevations and controlling terrain elevations.

The elevation data used to generate receptor elevations and controlling terrain elevations were obtained from the United States Geological Survey (USGS) in a National Elevation Data (NED) GEOTIFF format. These data were obtained from the USGS Seamless Data Warehouse (http://seamless.usgs.gov/index.php).

### Background Concentrations

Ambient air quality monitoring data for the various criteria pollutants were used to establish background concentrations in the refinery project area. The data presented above on Table 2 were used to represent ambient background for the modeling analysis. The monitored values reflect the impacts from existing regional sources such as power plants and mobile sources as well as transported pollutants from neighboring states.

## Class II NAAQS Analysis Results

The refinery project and surrounding area is classified as a Class II area. The total cumulative air quality impacts are shown in Table 5. The maximum ambient cumulative impacts associated with the proposed refinery are below all NAAQS.

**Table 5 Results of Class II Modeling Analysis**

| Pollutant | Averaging Period | Modeled Impact (µg/m³) | Background (µg/m³) | Total (µg/m³) | NAAQS (µg/m³) | Percent of NAAQS |
|---|---|---|---|---|---|---|
| $NO_2$ | 1-Hour[1] | 33 | 41 | 74 | 188 | 39.5% |
| | Annual[2] | 1 | 4 | 5 | 100 | 5.0% |
| CO | 1-Hour[2] | 56 | 7,980 | 8,036 | 40000 | 20.1% |
| | 8-Hour[2] | 38 | 3,124 | 3,162 | 10000 | 31.6% |
| $PM_{10}$ | 24-Hour[2] | 51 | 45 | 96 | 150 | 63.9% |
| $PM_{2.5}$ | 24-Hour[1] | 8 | 16 | 24 | 35 | 68.4% |
| | Annual[2] | 1 | 6 | 7 | 15 | 49.6% |
| $SO_2$ | 1-Hour[1] | 63 | 96 | 159 | 196 | 81.0% |
| | 24-Hour[2] | 16 | 21 | 37 | 365 | 10.1% |
| | Annual[2] | 1 | 3 | 4 | 78 | 4.8% |

1. Modeled impact is High 1st High, 5 year average
2. Modeled impact is 5 year maximum

## Chapter 6 — References

MHA 2011. Addendum, Air Quality Technical Report for the Final Environmental Impact Statement for the Mandan, Hidatsa, and Arikara Nation's Proposed Clean Fuels Refinery Project. March 9, 2011

U.S. EPA 2011a. Compilation of Air Pollutant Emission Factors, Fifth Edition, Volume I: Stationary Point and Area Sources. AP42, Volume I, Supplements A, B, C, D, E, F, Updates 2001, 2002, 2003, and 2004 [Web Page] Located at: hhtp://epa.gov/ttn/chief/ap42/index.html. Accessed: May 15, 2011.

U.S. EPA 2011b. Memorandum, Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour $NO_2$ National Ambient Air Quality Standard.

U.S. EPA 2007. Air Quality Technical Report for the Final Environmental Impact Statement for the Mandan, Hidatsa, and Arikara Nation's Proposed Clean Fuels Refinery Project.

# Appendix A - Source Emission Rates and Exhaust Parameters

**Table A-1 Source Parameters for MHA Nation's Proposed Clean Fuels Refinery**

| Model ID | Source Description | UTM X (m) | UTM-Y (m) | Elev (m) | Stack Height (m) | Exhaust Temp (K) | Exhaust Velocity (m/s) | Stack Diameter (m) |
|---|---|---|---|---|---|---|---|---|
| 00001 | Crude Heater | 286096.00 | 5317510.00 | 632 | 30.50 | 483 | 0.75 | 3.050 |
| 00002 | Reformer Heater 1 | 286268.00 | 5317440.00 | 636 | 30.50 | 483 | 0.72 | 0.910 |
| 00003 | Reformer Heater 2 | 286268.00 | 5317450.00 | 636 | 30.50 | 483 | 0.72 | 0.910 |
| 00004 | Reformer Heater 3 | 286268.00 | 5317460.00 | 636 | 30.50 | 483 | 1.92 | 0.910 |
| 00005 | Reformer Heater 4 | 286239.00 | 5317440.00 | 635 | 30.50 | 483 | 1.44 | 0.910 |
| 00006 | Reformer Heater 5 | 286239.00 | 5317450.00 | 635 | 30.50 | 483 | 0.36 | 0.910 |
| 00007 | Hydrocracker 1 | 286212.00 | 5317300.00 | 632 | 30.50 | 483 | 1.44 | 0.910 |
| 00008 | Hydrocracker 2 | 286212.00 | 5317310.00 | 632 | 30.50 | 483 | 1.68 | 0.910 |
| 00009 | Hydrocracker 3 | 286212.00 | 5317320.00 | 633 | 30.50 | 483 | 2.40 | 0.910 |
| 00010 | Hydrocracker 4 | 286212.00 | 5317330.00 | 633 | 30.50 | 483 | 1.68 | 0.910 |
| 00011 | Olefin | 286088.00 | 5317440.00 | 631 | 30.50 | 483 | 7.19 | 0.910 |
| 00012 | Hydrogen | 286272.00 | 5317500.00 | 636 | 30.50 | 483 | 11.98 | 0.910 |
| 00013 | Boiler 1 | 286018.00 | 5317470.00 | 631 | 30.50 | 483 | 4.79 | 0.910 |
| 00014 | Boiler 2 | 286018.00 | 5317460.00 | 631 | 30.50 | 483 | 4.79 | 0.910 |
| 00015 | Boiler 3 | 286018.00 | 5317450.00 | 631 | 30.50 | 483 | 4.79 | 0.910 |
| 00016 | Flare | 286186.00 | 5317070.00 | 631 | 54.90 | 1273 | 40.30 | 0.840 |
| 00017 | Sulfur Incinerator | 286090.00 | 5317380.00 | 631 | 36.60 | 311 | 0.03 | 3.050 |
| 00018 | Standby Generator | 286021.28 | 5317373.97 | 631 | 6.10 | 797 | 50.29 | 0.300 |
| 00019 | Fire Pump | 285913.66 | 5317224.77 | 631 | 6.10 | 730 | 9.74 | 0.300 |
| 00020 | Soybean Loadout | 286295.23 | 5317621.01 | 637 | 11.60 | 294 | 6.47 | 0.300 |
| 00021 | Meal Loadout 1 | 286295.23 | 5317596.55 | 637 | 11.60 | 294 | 6.47 | 0.300 |
| 00022 | Meal Loadout 2 | 286327.03 | 5317596.55 | 637 | 11.60 | 294 | 6.47 | 0.300 |
| 00023 | Vacuum Crude Heater | 286096.00 | 5317510.00 | 632 | 30.50 | 483 | 0.75 | 3.050 |
| 00024 | Decant Oil Tank Heater 1 | 286096.00 | 5317510.00 | 632 | 30.50 | 483 | 4.79 | 0.910 |
| 00025 | Decant Oil Tank Heater 2 | 286096.00 | 5317510.00 | 632 | 30.50 | 483 | 4.79 | 0.910 |

**Table A-2 Source Emission Rates (gm/s) for MHA Nation's Proposed Clean Fuels Refinery**

| | | NOx | | CO | | PM10 | PM2.5 | | SO2 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Model ID** | **Source Description** | **1-hour** | **Annual** | **1-hour** | **8-hour** | **24-hour** | **24-hour** | **Annual** | **1-hour** | **24-hour** | **Annual** |
| 00001 | Crude Heater | 0.4820 | 0.1991 | 0.6464 | 0.6464 | 0.0403 | 0.0403 | 0.0401 | 0.1395 | 0.1395 | 0.0615 |
| 00002 | Reformer Heater 1 | 0.0413 | 0.0171 | 0.0554 | 0.0554 | 0.0035 | 0.0035 | 0.0034 | 0.0120 | 0.0120 | 0.0053 |
| 00003 | Reformer Heater 2 | 0.0413 | 0.0171 | 0.0554 | 0.0554 | 0.0035 | 0.0035 | 0.0034 | 0.0120 | 0.0120 | 0.0053 |
| 00004 | Reformer Heater 3 | 0.1102 | 0.0455 | 0.1478 | 0.1478 | 0.0092 | 0.0092 | 0.0092 | 0.0319 | 0.0319 | 0.0141 |
| 00005 | Reformer Heater 4 | 0.0826 | 0.0341 | 0.1108 | 0.1108 | 0.0069 | 0.0069 | 0.0069 | 0.0239 | 0.0239 | 0.0105 |
| 00006 | Reformer Heater 5 | 0.0207 | 0.0085 | 0.0277 | 0.0277 | 0.0017 | 0.0017 | 0.0017 | 0.0060 | 0.0060 | 0.0026 |
| 00007 | Hydrocracker 1 | 0.0826 | 0.0341 | 0.1108 | 0.1108 | 0.0069 | 0.0069 | 0.0069 | 0.0239 | 0.0239 | 0.0105 |
| 00008 | Hydrocracker 2 | 0.0964 | 0.0398 | 0.1293 | 0.1293 | 0.0081 | 0.0081 | 0.0080 | 0.0279 | 0.0279 | 0.0123 |
| 00009 | Hydrocracker 3 | 0.1377 | 0.0569 | 0.1847 | 0.1847 | 0.0115 | 0.0115 | 0.0115 | 0.0399 | 0.0399 | 0.0176 |
| 00010 | Hydrocracker 4 | 0.0964 | 0.0398 | 0.1293 | 0.1293 | 0.0081 | 0.0081 | 0.0080 | 0.0279 | 0.0279 | 0.0123 |
| 00011 | Olefin | 0.4131 | 0.1706 | 0.5541 | 0.5541 | 0.0345 | 0.0345 | 0.0344 | 0.1196 | 0.1196 | 0.0527 |
| 00012 | Hydrogen | 0.6885 | 0.2844 | 0.9235 | 0.9235 | 0.0576 | 0.0576 | 0.0573 | 0.1993 | 0.1993 | 0.0879 |
| 00013 | Boiler 1 | 0.2754 | 0.1015 | 0.3694 | 0.3694 | 0.0230 | 0.0230 | 0.0229 | 0.0797 | 0.0797 | 0.0352 |
| 00014 | Boiler 2 | 0.2754 | 0.1015 | 0.3694 | 0.3694 | 0.0230 | 0.0230 | 0.0229 | 0.0797 | 0.0797 | 0.0352 |
| 00015 | Boiler 3 | 0.2754 | 0.1015 | 0.3694 | 0.3694 | 0.0230 | 0.0230 | 0.0229 | 0.0797 | 0.0797 | 0.0352 |
| 00016 | Flare | 0.0857 | 0.0857 | 0.4662 | 0.4662 | 0.0115 | 0.0115 | 0.0115 | 0.8193 | 0.8193 | 0.8193 |
| 00017 | Sulfur Incinerator | 0.0000 | 0.0000 | 0.6000 | 0.6000 | 0.0000 | 0.0000 | 0.0000 | 1.0698 | 1.0698 | 1.0577 |
| 00018 | Standby Generator | 2.4809 | 0.1412 | 0.1814 | 0.1814 | 0.0202 | 0.0202 | 0.0011 | 0.0617 | 0.0617 | 0.0035 |
| 00019 | Fire Pump | 0.4586 | 0.0261 | 0.0202 | 0.0202 | 0.0050 | 0.0050 | 0.0003 | 0.0126 | 0.0126 | 0.0007 |
| 00020 | Soybean Loadout | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.1184 | 0.0201 | 0.0201 | 0.0000 | 0.0000 | 0.0000 |
| 00021 | Meal Loadout 1 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0680 | 0.0116 | 0.0115 | 0.0000 | 0.0000 | 0.0000 |
| 00022 | Meal Loadout 2 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0580 | 0.0099 | 0.0098 | 0.0000 | 0.0000 | 0.0000 |
| 00023 | Vacuum Crude Heater | 0.2066 | 0.0853 | 0.2770 | 0.2770 | 0.0173 | 0.0173 | 0.0172 | 0.0598 | 0.0598 | 0.0264 |
| 00024 | Decant Oil Tank Heater 1 | 0.0138 | 0.0057 | 0.0185 | 0.0185 | 0.0012 | 0.0012 | 0.0011 | 0.0040 | 0.0040 | 0.0018 |
| 00025 | Decant Oil Tank Heater 2 | 0.0138 | 0.0057 | 0.0185 | 0.0185 | 0.0012 | 0.0012 | 0.0011 | 0.0040 | 0.0040 | 0.0018 |

**Exhibit 9**:

Letter from Stephen S. Tuber, Assistant Regional Administrator, Region 8 to Tex G. Hall, Chairman, Three Affiliated Tribes (May 9, 2011)

**UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**
**REGION 8**
**1595 Wynkoop Street**
**DENVER, CO 80202-1129**
**Phone 800-227-8917**
http://www.epa.gov/region08

MAY 09 2011

Ref: 8P-AR

Tex G. Hall, Chairman
Three Affiliated Tribes
404 Frontage Road
New Town, North Dakota 58763

Re: Proposed MHA Nation Clean Fuels Refinery

Dear Chairman Hall:

This letter provides the United States Environmental Protection Agency (EPA) Region 8's evaluation of information submitted by the Mandan, Hidatsa and Arikara Nation (MHA or Tribes) in response to EPA's March 24, 2010, information request. EPA's request was made to obtain further information necessary to assist in finalizing the NEPA process and to determine the applicable Clean Air Act requirements for MHA's proposed petroleum refinery on the Fort Berthold Reservation.

EPA reviewed the March 9, 2011 Air Quality Technical Report Addendum for the proposed refinery submitted by the MHA's consultant as well as the October 20, 2010 North Dakota Department of Mineral Resources Bakken and Three Forks Crude Oil Database Analysis submitted by the MHA on March 8, 2011.

While the information submitted by the Tribes suggests that the proposed refinery would have potential emissions less than the Prevention of Significant Deterioration (PSD) permitting thresholds, due to the uncertainty of the design that the emission estimates are based on, EPA cannot concur with the Tribes' analysis. As discussed in the examples below, uncertainty remains in the "potential to emit" (PTE) calculations that are needed to make a PSD applicability determination for the proposed refinery. Three instances where the lack of design details and specifications leads to uncertainty regarding emissions are flaring, sulfur recovery, and the variability inherent in the Bakken crude feedstock.

The flaring discussion in the March 9, 2011 Addendum does not discuss any additional sources of flaring, but does give some basis for the assumption of a 500 lb/hr flare gas loading rate. However, without further details on design data or additional justification for this assumption, EPA cannot confirm the validity of the 500 lb/hr flare gas loading assumption.

The March 9, 2011 Addendum also discusses an additional three long tons per day sulfur recovery system with associated amine treating unit and tail gas unit. In the absence of federally enforceable permit conditions requiring only one unit to operate at a time, and due to the regulatory provisions for calculating potential to emit, the emissions from this second unit would have to be included in the refinery PTE calculations. If this additional emission source were part of the actual refinery design, the proposed refinery would have a PTE greater than 100 tons per year for sulfur dioxide emissions and be a major source for PSD purposes, requiring the Tribe to obtain a PSD permit prior to commencing construction.

Finally, the information presented in the Crude Oil Database Analysis consists of the crude characteristics of over 150 wells producing in the Bakken formation in North Dakota. Looking at the broader Bakken field data, it appears that the proposed refinery design can only accommodate a portion of the available Bakken crudes. A significant portion of Bakken crudes could contain more sulfur than the refinery design appears to be able to process. In order to process any Bakken crude, the existing refinery design may need to be modified to handle the incoming feedstock sulfur content.

The design details, equipment specifications and other information that EPA would need to determine whether the proposed refinery needs to obtain a PSD permit would be included in a PSD permit application. Consequently, EPA recommends that the Tribes prepare a PSD permit application at this time. Please note that if the Tribes commence construction of the proposed refinery without receiving a PSD permit from EPA, they do so at their own risk of non-compliance with the Clean Air Act if emissions exceed the PSD permit thresholds.[1]

If you have any questions about this letter, please contact me at 303-312-6241 or Alfreda Mitre, Director of Region 8's Tribal Assistance Program, at 303-312-6343. If your staff or contractors have questions regarding the air technical issues, please have them contact Carl Daly at 303-312-6416.

Sincerely,

Stephen S. Tuber

Stephen S. Tuber
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

cc: Frank Whitecalfe, Vice Chairman, Three Affiliated Tribes Business Council
V. Judy Brugh, Secretary, Three Affiliated Tribes Business Council
Mervin Packineau, Treasurer, Three Affiliated Tribes Business Council
Scott Eagle, Councilman, Three Affiliated Tribes Business Council
Arnold Strahs, Councilman, Three Affiliated Tribes Business Council
Barry Benson, Councilman, Three Affiliated Tribes Business Council
Damon Williams, Attorney, Three Affiliated Tribes
David Williams, Three Affiliated Tribes Energy Office

---

[1] EPA's interpretation of "constructed" as it applies to activities undertaken prior to issuance of a PSD permit is discussed in EPA's Memorandum on this issue, available at http://www.epa.gov/NSR/ttnnsr01/psd1/p14_4.html.

**Exhibit 10**:
Expert Report by Julia May (Sept. 12, 2011)

# Expert Report
# Regarding the MHA Nation Proposed and Redesigned Oil Refinery NPDES Permit and Environmental Impact Statement process

## Appeal to
## U.S. EPA Environmental Assessment Board

September 12, 2011

Prepared for:

MHA Nation Tribal Members
Jodie White, Loren White Jr., Kandi Mossett, Theodora BirdBear,
the Environmental Awareness Committee, North Dakota
and the Environmental Integrity Project (EIP), Washington, D.C.

Review Prepared by Julia May,
Environmental Consultant, jmay@sbcglobal.net

## Table of Contents

## I. Introduction

The proposed new MHA Nation oil refinery (Mandan, Hidatsa, and Arikara Nation) in North Dakota has been through a number of permitting processes for many years. The original Draft Environmental Impact Statement (EIS) was missing many necessary evaluations and data, and took some time to proceed to the Final EIS stage, which was carried out in 2009. The FEIS also had deficiencies which received public comment. Recently the project has been drastically changed. Despite this, EPA filed a notice in the federal register (August 12, 2011) proposing to finalize the NPDES permit unless appealed by September 12, with the permit becoming final on October 1, 2011 if not appealed.

The project proponents have now made public, major changes to the project design. This has occurred without any new Environmental Impact Statement (EIS). The proponents proposed changing the crude oil feedstock for the refinery from Canadian Syncrude (a partially pre-refined material), to local Bakken crude oil. As a result many new process units have been added to the oil refinery design. The new crude oil is a natural crude that unlike the Canadian Syncrude has not been pre-refined, so it has the potential for much higher levels of contaminants in the crude compared to Canadian Syncrude. The changed feedstock will impact the local environment and add to regional and global impacts. The project proponents have written a report on air quality impacts of the changes, and EPA has written a short Supplemental Information Report to decide whether to carry out an EIS. EPA so far has decided not to do a new EIS, but should re-evaluate this decision based on much missing data and project information for the newly defined project.

The changes to the project as a result of the crude oil switch are major and far reaching with many potential significant impacts, requiring an EIS to provide an analysis of these changes. Since the project proponents have provided almost no detail regarding new process unit sizes, integration with the rest of the refinery, control equipment, discharge and emissions volumes and character, the scientific basis for project approval is entirely lacking. A new EIS is necessary to evaluate this major change.

Furthermore, local conditions have changed drastically since the 2009 FEIS process, and have changed even more since the DEIS process, such that the cumulative impacts of the project in the context of the local Bakken oil boom and other major heavy industry expansions needs a new assessment in an EIS.

It appears from a call to EPA that EPA is handling the NPDES and EIS issues altogether in one process. Earlier the NPDES water permit and entire EIS process were combined into one public comment and hearing process that included water, air, and all the impacts handled together. The current proceeding appears to do the same. Although EPA's nominal action is a finalization of the NPDES water permit, EPA has stated that its decision to go ahead with the final NPDES permit is based on the previous FEIS plus a new supplemental report. This new report evaluates changes to the project including water, air, solid waste, and other issues. Since the new refinery redesign proposal will impact all these areas and more, since EPA is proposing its NPDES action as a final approval, and since EPA's public process combined the EIS process with the NPDES permitting, the discussion below includes many issues in addition to the NPDES permit.

It also seems that the project proponents and perhaps additional oil industry sources are pressing for premature finalization of this entirely new project with no EIS, which is impacting the scientific and engineering assessment. These are not completed and so should not be used as a basis for a final action by EPA. Most key data which would form the basis for identifying the number of potentially significant environmental impacts due to the re-designed project are not present, and the information that *is* present shows a very high likelihood that the project *will* cause environmental impacts. The conclusion reached by EPA in the Supplemental Information Report, that no new EIS is necessary, is not factually based and should be reversed, so that EPA begins a new EIS process.

## II. The Crude Oil Feedstock Change is substantial, was not previously considered, and wasn't adequately evaluated in the Supplemental Information Report

### a) Overview

When the U.S. Environmental Protection Agency (EPA) recently issued the final NPDES permit, EPA stated on its website:[1]

> *The decision to issue the permit is based on the Environmental Impact Statement (EIS) prepared by the EPA and the Bureau of Indian Affairs (BIA). The final EIS was issued in August 2009. Since that time, the MHA Nation decided to change crude feedstocks to the local Bakken formation crude. The EPA prepared a Supplemental Information Report (SIR) to assess the potential changes in impact resulting from the change in feedstock.* [2011]

I confirmed with EPA staff that this supplemental report is not considered by EPA as an EIS, but as a report to help EPA decide whether to do an EIS. EPA has proposed not to do a new EIS based on this informational report. Unfortunately there are several fatal flaws in the Supplemental Information Report's reasoning, data, and conclusions, as summarized below and detailed later. I respectfully submit that these flaws require that EPA withdraw its finding that the changes to the project don't have the potential to cause significant environmental impacts. In summary:

- **No factual basis was publicly provided regarding the crude slate change, and the conclusion that this would not affect the permit or cause new environmental impacts has no merit:** No data was provided to the public documenting the details of the Bakken crude oil slate, and comparing it to the Canadian synthetic crude oil in the Supplemental Information Report,[2] such as the API gravity, sulfur content, metals content, benzene content, and other specific and standard crude oil characteristics normally used, nor any quantification of the range of variation of these measurements. Any data that EPA evaluated that was not provided to the public should not be used as a basis of EPA's decision to finalize the permit, especially on such a major project change. Using secret data is unscientific. If this data was provided by project proponents, it especially needs to

---

[1] http://www.epa.gov/region8/compliance/nepa/mharefinery.html#appeal

[2] *MHA Nation Refinery Environmental Impact Statement Supplemental Impact Report*, July 29, 2011, http://www.epa.gov/region8/compliance/nepa/SIRMHA.pdf

be subject to public review for potential bias in the choice of data points and any missing data. The supplemental report conclusions cannot be taken simply on faith.

- **The supplemental report concludes that the NPDES permit can be finalized simply by stating that "the environmental analysis is similar."** p. 4
- **In fact the information that was provided in the supplemental report contradicts itself, but it still provides many pieces of evidence showing there will be significant impacts:** Although the supplemental report starts out to say that the original Canadian crude slate and new Bakken slate are both "light and sweet" (implying that both crudes are basically the same), it goes on to provide information showing that the Bakken crude will in fact be substantially different from the originally planned Canadian synthetic crude oil, and that as a result, the project will have to be redesigned to include several major new process units. These are being added to the refinery design, compared to the project described in the 2009 Final EIS. These new process units include among several others additional sulfur processing units. The necessity of adding new sulfur processing proves that the Bakken crude will have a higher sulfur content in the crude compared to the Canadian crude. The supplemental report does acknowledge that crude with higher sulfur (called sour crude) has additional environmental impacts compared to sweet (low sulfur) crude. But despite this acknowledgement, the supplemental report still incorrectly concludes, in contradiction of these facts, that the new crude use and new project design is substantially the same.
- **EPA previously told the public there would be no switch to Bakken crude without completely re-evaluating the project, because the refinery redesign associated with such a switch would require it.** During a public informational meeting on the FEIS in 2009, a tribal elder asked EPA why they couldn't refine their local Bakken crude oil at the refinery instead of using Canadian oil, according to Jodie White. (A transcript of video footage of this meeting is discussed further below and attached.) EPA responded that there would have to be an entire re-evaluation of emissions if the crude feedstock was changed from Canadian syncrude to local Bakken crude. EPA staffmembers identified by Jodie White as Steve Wharton, Dana Allen, and BIA staffmember Diane Mann-Klager agreed. Now this evaluation is being reversed without the crude oil data being provided, and without any new EIS process. There is an abundance of evidence showing that such a crude switch will cause significant impacts that the EPA staff have previously publicly acknowledged.
- **The Bakken crude oil and other data that is available to the public online (but not available on the EPA's website for this project) show there will be significant impacts from the new project that aren't addressed by the NPDES Permit and which require a new EIS.** The new crude slate and new process units and related practices will cause significant new environmental impacts, water impacts, air impacts, and other impacts that need a full EIS assessment to be carried out. The crude change and project redesign form a new project that wasn't considered during the previous EIS process. There has been no assessment of alternatives and cumulative impacts for the new project, and the assessments that were done in the supplemental information report are scant (the whole report is 16 pages including the cover page, references, and pictures).

- **There has been no support data or quantitative information provided as part of a clear and complete project description, such as sizing of the new process units.** The public has to use assumptions written into appendices and included in a few calculations in the proponent's Addendum air report as the only specifics for the project description, except for a paragraph bullet list in EPA's Supplemental Information Report. These are not set as firm limits on sizes; EPA has also stated that the project design is not finalized. In addition to lack of information on unit sizes, the amounts of hazardous waste and water discharge by the units, and the range of variation in the new crude oil, is missing (how much can sulfur content vary? new metals? gravity? etc.). Only very generalized, qualitative information is provided to the public in the supplementary report, not sufficient to determine the outcomes. This report is also at odds with outside data.
- **The permit finalization and use of a supplemental report instead of a new EIS is in conflict with public policy including EPA's Environmental Justice principles and a recent directive to EPA employees from EPA Administrator Lisa Jackson:** Administrator Jackson recently sent a memo to all EPA employees, which stated that EPA should "include environmental justice principles in all of [EPA's] decisions . . .," noting that **protecting vulnerable populations was "a top priority**."[3] The NPDES permit has been suddenly proposed as final despite the major crude slate change and new process units, without warning, two years after the last public process, with only a short public comment period (1 month), and no additional EIS. This does not provide a public process that includes environmental justice principles or "meaningful participation" required by these principles, as described on EPA's website.[4] Ms. Jackson also stated: *"Strong partnerships and accountability are more important than ever. . . . EPA must do its part to support state and tribal capacity and, through strengthened oversight, ensure that programs are consistently delivered nationwide."* The supplemental report failure to publish any facts measuring the crude slate quality changes and associated impacts fails to provide the accountability and oversight needed by the public.

The Supplemental Information Report (p. 3) states:

> *Agencies shall prepare supplements to either draft or final EIS's if:*
>
> *1. The agency makes substantial changes in the proposed action that are relevant to environmental concerns; or*
>
> *2. There are significant new circumstances or information relevant to environmental concerns and bearing on the proposed action or its impacts.*

All these conditions are met – there are substantial changes in the proposed action (the whole refinery design has changed to accommodate the new crude slate), these are highly relevant to

---

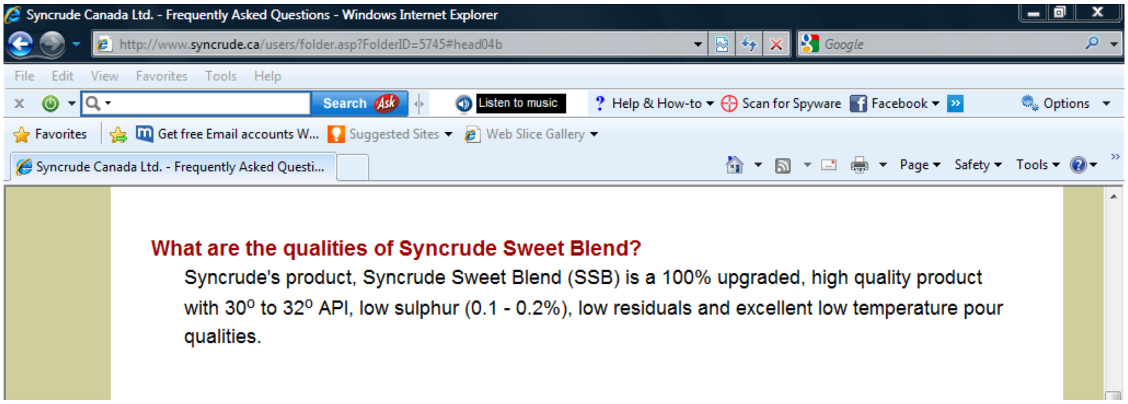
[3] Memorandum from Lisa P. Jackson, Administrator to All Employees, dated January 12, 2010, attached as JMay MHA report Exhibit 1 Jackson EJ

[4] EPA's website defines environmental justice principles as follows: *"Environmental Justice is the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. EPA has this goal for all communities and persons across this Nation. It will be achieved when everyone enjoys the same degree of protection from environmental and health hazards and equal access to the decision-making process to have a healthy environment in which to live, learn, and work."* http://www.epa.gov/environmentaljustice/

environmental concerns (since the changes involve processing substantial amounts of hazardous materials with the potential for significant water, air, and other impacts). There are also new circumstances relevant to environmental concerns that have occurred since the 2009 FEIS process. These are all substantial and require a new draft EIS. EPA should reassess these major problems and begin work on a full new Draft EIS for the new project. This is extremely important for the protection of the environment and public health, when considering building an entirely new refinery which is inherently hazardous, and where none existed before. **The following are some additional details on these issues.**

### b. Contrary to the supplemental report, some Bakken crude is high sulfur, known by EPA to cause increased environmental impacts

According to Syncrude Canada Ltd's website, the sulfur content of Canadian syncrude is 0.1 to 0.2%:[5]



**What are the qualities of Syncrude Sweet Blend?**

Syncrude's product, Syncrude Sweet Blend (SSB) is a 100% upgraded, high quality product with 30° to 32° API, low sulphur (0.1 - 0.2%), low residuals and excellent low temperature pour qualities.

Regarding the proposed change in the crude oil feedstock for the refinery from Canadian Syncrude to local Bakken crude oil, the EPA's supplemental report states:

> ***III. Feedstock Change***
>
> *In 2010, the Tribes informed EPA of their intent to change the feedstock for their proposed refinery from synthetic crude to the local Bakken crude oil. In comparing the two feedstocks, EPA notes that* ***both the synthetic and Bakken crudes are light, sweet crudes. Refineries with heavier or sour crude feedstocks have more refinery process units and additional waste streams increasing potential environmental impacts. The Bakken crude has a higher salt content, has a bottoms (residual oil) component, and has more variability of composition than the synthetic crude, since the latter would be partially refined in Canada.*** *The Tribes have not changed the site location or the proposed capacity of the refinery from what is described in the FEIS.   p. 3   . . .*

---

[5] Excerpt of the webpage inserted above directly into this report, and available at: http://www.syncrude.ca/users/folder.asp?FolderID=5745#head04b

In contradiction to the statement in the supplemental report that the Bakken crude is always a sweet crude (low sulfur), other data (a publication of Platts[6] finds that Bakken crude sulfur content can go high enough to meet the definition of sour crude oil (high sulfur) that was used in the FEIS (0.5% or higher):[7]

> ***FEIS Glossary:***
>
> ***Sour crude** – Crude oil with a comparatively high sulfur content, **0.5 percent** by weight and higher.*

The Supplemental Information Report concedes that the Bakken crude oil characteristics can vary much more than the Canadian crude, but doesn't state how much it can vary. No data was provided to the public in the supplemental report on the crude oil quality. Data available online from the attached report by the publication Platts and also Downstream Today, on Bakken crude oil, shows that crude oil from two different Bakken sites had sulfur content varying at least 2 ½ times– from 0.2 percent to 0.5 percent sulfur content:

> The *Bakken Blend ex-Clearbrook* assessment reflects an American Petroleum Institute (API) gravity ranging from 38-40 degrees and **0.5% sulfur**[8]
>
> The *Bakken Blend ex-Guernsey* assessment represents an API gravity of 38-40 degrees and 0.2% sulfur

**Thus the Bakken Blend ex-Clearbrook crude is <u>sour</u> (high sulfur) according to the definition used in the FEIS that formed the basis of EPA's decision (since it contains 0.5% sulfur).** Thus the supplemental report facts forming the basis of its conclusions are incorrect, in stating that the Bakken crude is essentially solely a sweet crude.

---

[6] *"Platts has more than 100 years' experience assessing physical commodity prices and bringing transparency to the markets through our price assessment processes," said David Ernsberger, global director of oil. "We have been in the forefront of oil price discovery in the U.S. since 1909, and our decision to begin publishing an open-market value of this significant new source of high-quality North American crude is another example of our contributions to the industry and the marketplace." "Platts' Bakken Blend assessments will be developed using its Market-on-Close (MOC) methodology, a structured, highly transparent price assessment process based on the principle that price is a function of time. The MOC process in oil identifies bid, offer and transaction data by company of origin and results in a time-sensitive end-of-trading-day daily price assessment. For more information on the methodology and quality-control guidelines, visit the methodology and specifications page of the Platts website."*

[7] *Proposed Clean Fuels Refinery FEIS, August 2009, p. 8-3, http://www.epa.gov/region8/compliance/nepa/tatdeis/TAT_FEIS_Chap5-9.pdf*

[8] Platts publication: http://www.printthis.clickability.com/pt/cpt?expire=&title=Platts+Plans+World%27s+First-Ever+Price+Assessments+of+Crude+Oil+From+Bakken+Shale+Fields...+--+NEW+YORK%2C+April+5+%2FPRNewswire%2F+--&urlID=424138248&action=cpt&partnerID=506122&cid=89929412&fb=Y&url=http%3A%2F%2Fwww.prnewswire.com%2Fnews-releases%2Fplatts-plans-worlds-first-ever-price-assessments-of-crude-oil-from-bakken-shale-fields-in-central-united-states-89929412.html, Also at DownstreamToday.com, Monday, May 3, 2010, http://www.downstreamtoday.com/News/ArticlePrint.aspx?aid=22531, attached as JMay MHA report Exhibit 2 Bakken crude variation

This means that this particular Bakken crude falls into the category that the Supplemental Information Report concedes causes increased environmental impacts: (*"Refineries with heavier or* ***sour crude feedstocks have more refinery process units and additional waste streams increasing potential environmental impacts****.")* This is entirely consistent with the fact that new sulfur processing units are being added to the project to process the additional sulfur that will be brought into the refinery with the new crude. This is also consistent with the fact that Canadian synthetic crude oil that is partially refined can be processed to remove the sulfur ahead of time, so the original project design evaluated in the FEIS did not need the additional sulfur recovery units. Now the new MHA Nation refinery redesign will need to remove the extra sulfur due to the new crude slate at the refinery site. This is a major environmental issue. The reason the use of sour crude is so important is that even at 0.5% of the crude oil, this continuously generates very large volumes of corrosive and acutely hazardous gases within the refinery including hydrogen sulfide (H2S) and many others. Refineries designed for sour crude are designed quite differently from refineries with sweet crude oil.

As part of the 2009 EIS process, EPA and the BIA held an informational meeting on the MHA Nation refinery project, which was recorded on videotape by Loren White, Jr. (He has posted an excerpt from this video on YouTube at http://www.youtube.com/watch?v=2h16cEjCBvw , and I have attached a transcript of this excerpt.[9]) During this meeting, EPA and BIA staff told the public (when asked why the project didn't use local Bakken crude oil instead of Canadian syncrude) that Bakken crude oil is quite different from Canadian Syncrude which didn't require the more aggressive process units, and that a switch to using local Bakken crude would mean different emissions. These officials stated that the whole project would have to be "totally re-examined" if there was a switch to Bakken crude:

> **EPA (Steve Wharton)**
> *The question was why is the feedstock for the refinery oil from Canada when there is active production here locally. . . .*
>
> *The second point is, we talked about air emissions requirements. Part of those are contingent upon sulfur, the sulfur that's coming out, well that's a function of how much sulfur is going in.*
>
> *And the feedstock, the, it's called syncrude this pre-refined material coming out of Canada has kind of, quite a bit of that removed from it already. So it makes it easier in a way to take that feedstock, convert it into, say, low sulfur diesel and other fuels, without having more aggressive process units within the refinery. . . .*
>
> **BIA (Diane Mann-Klager):** *And the emission production would be totally different.*
>
> **EPA (Steve Wharton)** *right – Different feedstock-in means different emissions-out, so yes, that would all have to be totally re-examined.*

---

[9] Attached as JMay MHA report Exhibit 3 EPA 2009 info hearing transcript excerpt

In addition to the higher sulfur content of Bakken crude compared to Canadian syncrude, the EPA supplemental report excerpt above also indicates that the Bakken crude is heavier (higher carbon) than the Canadian crude, since the report states it *"has a bottoms (residual oil) component, and has more variability of composition than the synthetic crude, since the latter would be partially refined in Canada."* The bottom fraction of crude oil is the heaviest portion, clearly indicating that the conclusion EPA made that it is the same kind of light crude as the Canadian crude, is not correct. This crude is heavier than the Canadian crude, another reason the additional new process units are being added. Heavier crude inherently requires burning more fuel to refine it, which causes increased greenhouse gas and other air emissions. Heavier crude oil is also generally associated with higher metals content, which was not assessed. Impacts of increased toxic metals on water impacts were not assessed.

A new EIR is needed which provides full disclosure of the crude oil data that is available, with additional crude oil assays carried out if necessary, in order to determine the full range of variability of the Bakken crude oil.

### c. The many new units needed for the re-designed refinery mean increased environmental impacts

The supplemental report itself again provides evidence that an actual EIS is needed, because of the new processing units for the newly defined project, which cause environmental impacts. These are as follows:

> *The preliminary refinery design and site plans used to determine the environmental impacts of the proposed projects in the FEIS are the same for both the synthetic and the Bakken crudes with* ***the following process units added for the Bakken crude:***
>
> - *Vacuum crude heater*
> - *Two decant oil tank heaters*
> - *Desalter*
> - *Desalter brine disposal facilities*
> - *Additional air pollution control units: second sulfur recovery, tail gas treating, and amine treating. Supplemental Information Report p. 4*

It is on its face not credible that so many new units can be built without requiring a new EIS. While I can't replicate all the environmental assessments that should be done in an EIS for this redesigned and new refinery project, I included some specific examples below of environmental impacts caused by these changes.

### d. New sources of Solid and Hazardous Waste will be significant

Regarding the added desalter unit the supplemental report states:

> ***The refinery would generate an additional hazardous waste stream through the refining of Bakken crude.*** *A desalter unit would produce desalter sludge and additional*

> *wastes would be produced from cleaning the desalter during turnaround.* ***These desalter wastes are EPA listed hazardous wastes -- F037****. The FEIS identified other F037 wastes that would be generated at the refinery, and these desalter wastes would be managed in the same manner as the previously identified wastes as discussed in the FEIS. As described in FEIS, other process units would generate waste and or wastewater exhibiting characteristics of hazardous waste. All hazardous wastes generated by the refinery are required to be transported offsite within 90 days and disposed of at a Treatment, Storage and Disposal Facility in compliance with RCRA.* (p. 11)

Characterization of such waste was not provided in the supplemental report (it only contained a paragraph on the entire subject of solid and hazardous waste). A handy summary of EPA hazardous waste codes (Hazardous Waste from non-specific sources) provided by the University of Maryland identifies EPA's code F037 as very generalized petroleum sludge that can come from many processes:[10]

| | |
|---|---|
| F037 | Petroleum refinery primary oil/water/solids separation sludge--Any sludge generated from the gravitational separation of oil/water/solids during the storage or treatment of process wastewaters and oily cooling wastewaters from petroleum refineries. Such sludge include, but are not limited to, those generated in: oil/ water/solids separators; tanks and impoundments; ditches and other conveyances; sumps; and stormwater units receiving dry weather flow. Sludge generated in stormwater units that do not receive dry weather flow, sludge generated from non-contact once-through cooling waters segregated for treatment from other process or oily cooling waters, sludge generated in aggressive biological treatment units as defined in § 261.31(b)(2) (including sludge generated in one or more additional units after wastewaters have been treated in aggressive biological treatment units) and K051 wastes are not included in this listing. |

It is inadequate for the supplemental report to find that there is an additional new source of hazardous waste and then to dismiss this lightly by stating that these wastes will be handled the same way as other hazardous wastes. There is a need for an EIS to evaluate the actual <u>quantities</u> of the new wastes and possible different chemicals within this category depending on the individual process units (such as benzene content, which is very toxic material and which can be present in this waste stream). The potential ways that the increased volume of hazardous waste due to the new project will impact the environment needs to be assessed. For example, the additional transportation of the waste offsite, (with added diesel trucking emissions and their substantial associated toxic air pollution), as well as the onsite and offsite impacts of these quantity increases, including evaporation of the potentially high benzene content. These impacts were not evaluated. No quantities of the waste or details were provided.

---

[10] http://www.des.umd.edu/hw/rest/manual/codes.html

There is evidence that such waste is generated in substantial quantities, that it can contain highly toxic chemicals, and that alternative methods are available to generate less waste. According to the *California Petroleum Refinery Hazardous Waste Source Reduction 1998 Report*[11] there are alternatives to simply disposing of such refinery sludge, such as recycling the waste (p. 6-7). This report showed how large such waste streams are (**many millions of pounds per year** from sludge-related waste streams at the Chevron refinery). While the Chevron Richmond refinery is more than ten times larger than the nominal MHA Nation refinery is planned to be sized at first (although there are plans to expand the MHA refinery later), even a tenth or a hundred of the Chevron volume means at least tens of thousands of pounds per year of waste. This report does identify benzene as one major component of such hazardous waste. Benzene is known to cause leukemia.

It is interesting to note that a refinery that is smaller than the Chevron refinery (the Martinez refinery discussed in the same California report), had much higher levels of waste than the Chevron refinery, so the specific quantities of waste generated are not always directly proportional to the refinery size – a smaller refinery can generate more waste if there isn't a careful evaluation of Best Available Control Technology and Lowest Achievable Emissions Rates in the project design. In either case above, the quantities are huge. Because of these variations, this is another reason that the actual quantities of waste need to be provided and evaluated in an EIS.

It must be conceded that adding a whole new processing unit that is known to generate hazardous waste in large amounts represents the potential to cause a significant impact, even in a "small" refinery. This must be evaluated, mitigated, and reviewed for potential alternatives.

In addition, the increased trucking of new sources of hazardous materials in the redesigned project needs to be evaluated in the context of an updated Cumulative Impacts assessment. The cumulative truck traffic impacts have grown drastically since the MHA Project 2009 FEIS, and even more since the original DEIS, years before. The whole Bakken oil boom has had a major impact on truck traffic, with associated air, water and soil impacts (including runoff and other impacts). The supplemental report concedes the traffic increase due to the oil boom.

In addition to the direct air quality impacts of diesel trucking (long lines of trucks are now common), hazardous materials are being spilled and illegally dumped by oil industry trucks. Theodora BirdBear, MHA Nation tribal member, photographed illegal water dumping on roadways from spigots left partially open while tanker trucks transporting fracking wastewater were driving with water spewing from them, shown below.

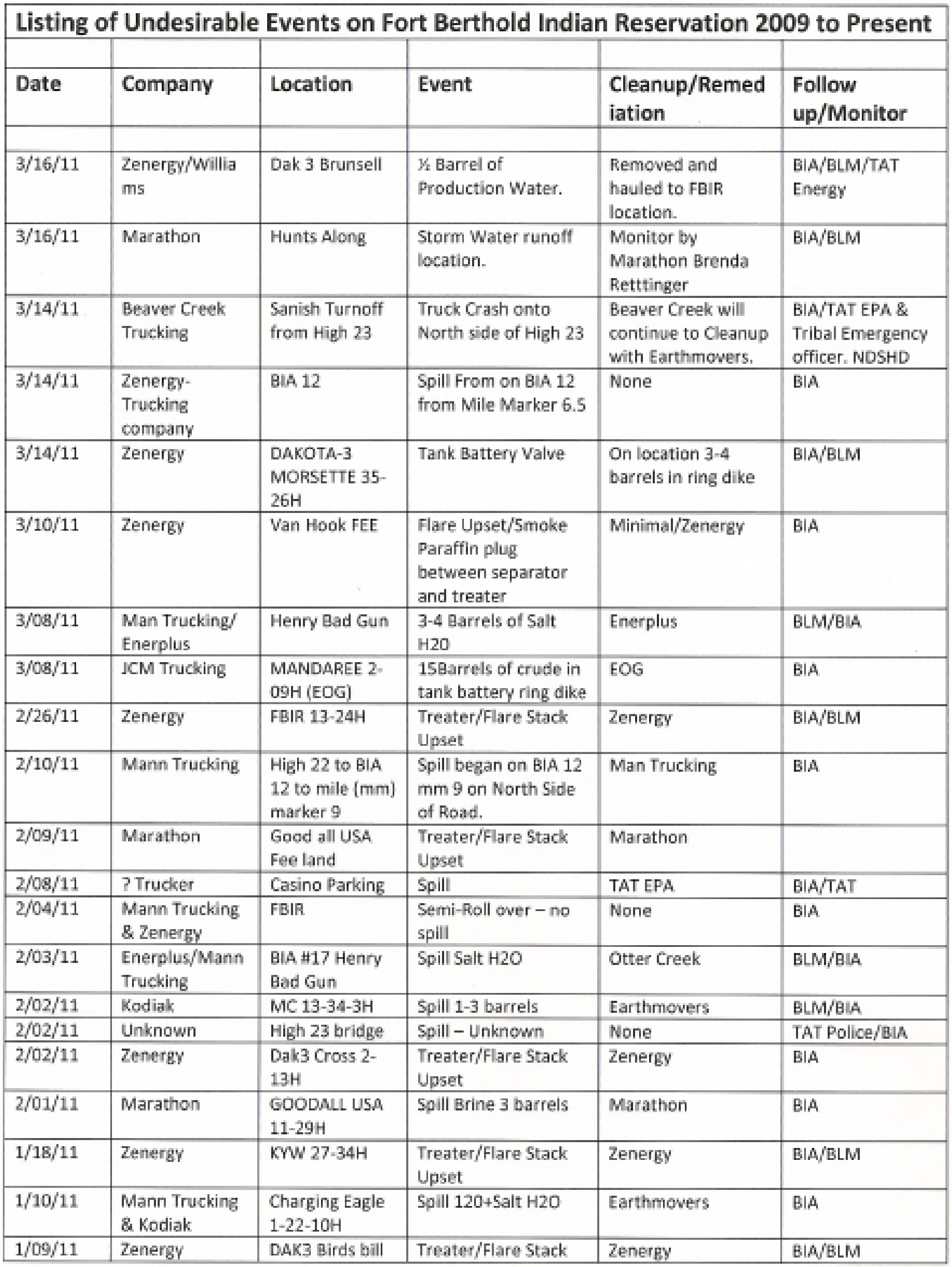
---

[11] http://www.dtsc.ca.gov/pollutionprevention/upload/P2_REP_Petroleum_Assessment-2.pdf , attached as JMay MHA report Exhibit 4 Refinery Haz Was reduction

Theodora BirdBear stated regarding this picture of spills by oil trucks in Mandaree: *The photo clearly shows the oil truck spilling unknown fluid on the highway. It may not have the sharpness in details - since I was driving at the time I took the photo! –Theodora"*

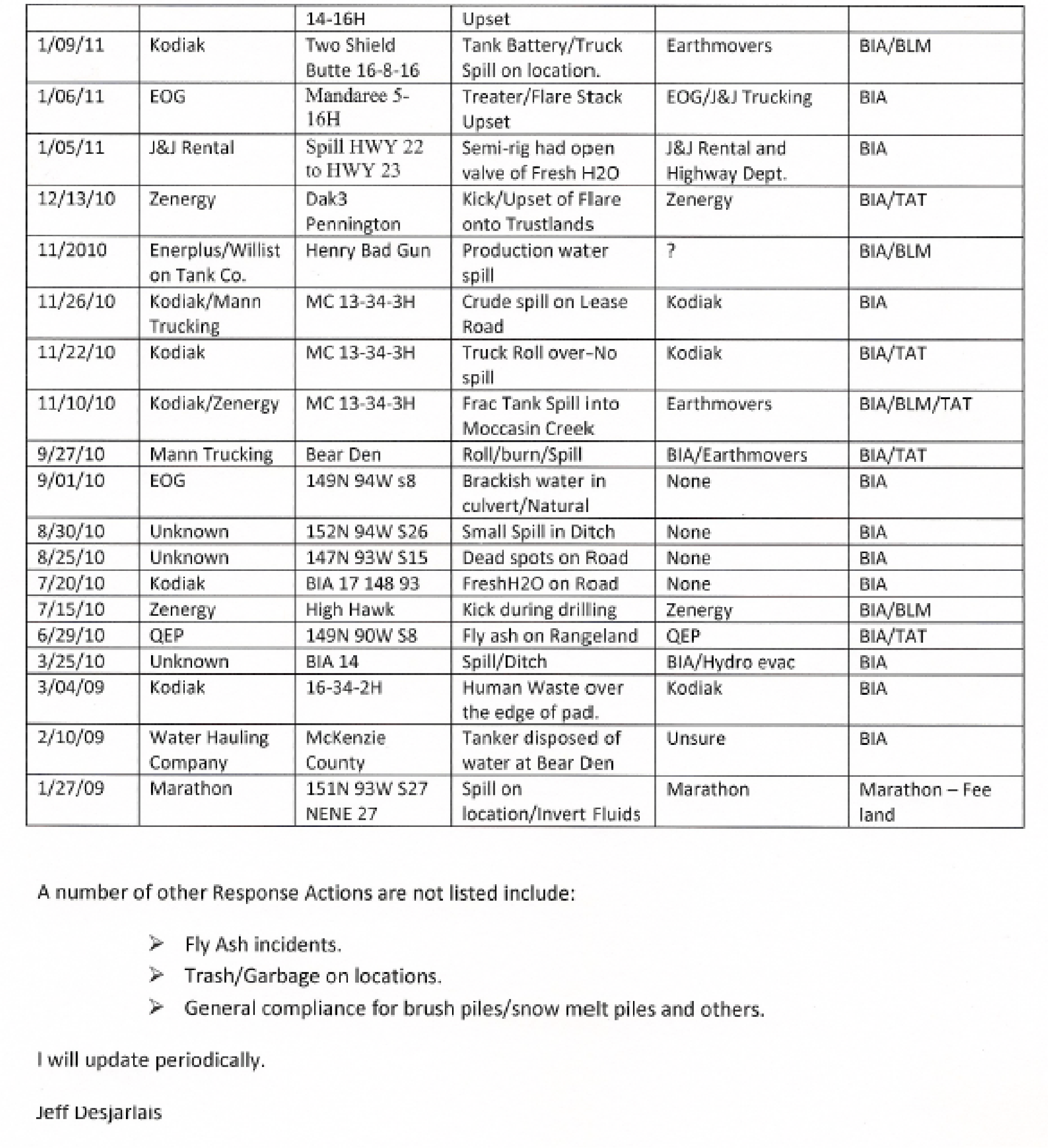
Tribal members have stated that many other reports of illegal dumping have been made relating to the booming oil industry in the area, including those identified by an employee of an oil company who was aware of illegal dumping of fracking wastewater in the area.

The following is a "Listing of Undesirable Events" pages 1 and 2, from Fort Berthold Indian Reservation, which shows dozens of the hazardous materials spills and flaring that were actually reported and recorded.



## Listing of Undesirable Events on Fort Berthold Indian Reservation 2009 to Present

| Date | Company | Location | Event | Cleanup/Remediation | Follow up/Monitor |
|---|---|---|---|---|---|
| | | | | | |
| 3/16/11 | Zenergy/Williams | Dak 3 Brunsell | ½ Barrel of Production Water. | Removed and hauled to FBIR location. | BIA/BLM/TAT Energy |
| 3/16/11 | Marathon | Hunts Along | Storm Water runoff location. | Monitor by Marathon Brenda Retttinger | BIA/BLM |
| 3/14/11 | Beaver Creek Trucking | Sanish Turnoff from High 23 | Truck Crash onto North side of High 23 | Beaver Creek will continue to Cleanup with Earthmovers. | BIA/TAT EPA & Tribal Emergency officer. NDSHD |
| 3/14/11 | Zenergy-Trucking company | BIA 12 | Spill From on BIA 12 from Mile Marker 6.5 | None | BIA |
| 3/14/11 | Zenergy | DAKOTA-3 MORSETTE 35-26H | Tank Battery Valve | On location 3-4 barrels in ring dike | BIA/BLM |
| 3/10/11 | Zenergy | Van Hook FEE | Flare Upset/Smoke Paraffin plug between separator and treater | Minimal/Zenergy | BIA |
| 3/08/11 | Man Trucking/ Enerplus | Henry Bad Gun | 3-4 Barrels of Salt H20 | Enerplus | BLM/BIA |
| 3/08/11 | JCM Trucking | MANDAREE 2-09H (EOG) | 15Barrels of crude in tank battery ring dike | EOG | BIA |
| 2/26/11 | Zenergy | FBIR 13-24H | Treater/Flare Stack Upset | Zenergy | BIA/BLM |
| 2/10/11 | Mann Trucking | High 22 to BIA 12 to mile (mm) marker 9 | Spill began on BIA 12 mm 9 on North Side of Road. | Man Trucking | BIA |
| 2/09/11 | Marathon | Good all USA Fee land | Treater/Flare Stack Upset | Marathon | |
| 2/08/11 | ? Trucker | Casino Parking | Spill | TAT EPA | BIA/TAT |
| 2/04/11 | Mann Trucking & Zenergy | FBIR | Semi-Roll over – no spill | None | BIA |
| 2/03/11 | Enerplus/Mann Trucking | BIA #17 Henry Bad Gun | Spill Salt H2O | Otter Creek | BLM/BIA |
| 2/02/11 | Kodiak | MC 13-34-3H | Spill 1-3 barrels | Earthmovers | BLM/BIA |
| 2/02/11 | Unknown | High 23 bridge | Spill – Unknown | None | TAT Police/BIA |
| 2/02/11 | Zenergy | Dak3 Cross 2-13H | Treater/Flare Stack Upset | Zenergy | BIA |
| 2/01/11 | Marathon | GOODALL USA 11-29H | Spill Brine 3 barrels | Marathon | BIA |
| 1/18/11 | Zenergy | KYW 27-34H | Treater/Flare Stack Upset | Zenergy | BIA/BLM |
| 1/10/11 | Mann Trucking & Kodiak | Charging Eagle 1-22-10H | Spill 120+Salt H2O | Earthmovers | BIA |
| 1/09/11 | Zenergy | DAK3 Birds bill | Treater/Flare Stack | Zenergy | BIA/BLM |



| | | | | | |
|---|---|---|---|---|---|
| | | 14-16H | Upset | | |
| 1/09/11 | Kodiak | Two Shield Butte 16-8-16 | Tank Battery/Truck Spill on location. | Earthmovers | BIA/BLM |
| 1/06/11 | EOG | Mandaree 5-16H | Treater/Flare Stack Upset | EOG/J&J Trucking | BIA |
| 1/05/11 | J&J Rental | Spill HWY 22 to HWY 23 | Semi-rig had open valve of Fresh H2O | J&J Rental and Highway Dept. | BIA |
| 12/13/10 | Zenergy | Dak3 Pennington | Kick/Upset of Flare onto Trustlands | Zenergy | BIA/TAT |
| 11/2010 | Enerplus/Willist on Tank Co. | Henry Bad Gun | Production water spill | ? | BIA/BLM |
| 11/26/10 | Kodiak/Mann Trucking | MC 13-34-3H | Crude spill on Lease Road | Kodiak | BIA |
| 11/22/10 | Kodiak | MC 13-34-3H | Truck Roll over-No spill | Kodiak | BIA/TAT |
| 11/10/10 | Kodiak/Zenergy | MC 13-34-3H | Frac Tank Spill into Moccasin Creek | Earthmovers | BIA/BLM/TAT |
| 9/27/10 | Mann Trucking | Bear Den | Roll/burn/Spill | BIA/Earthmovers | BIA/TAT |
| 9/01/10 | EOG | 149N 94W s8 | Brackish water in culvert/Natural | None | BIA |
| 8/30/10 | Unknown | 152N 94W S26 | Small Spill in Ditch | None | BIA |
| 8/25/10 | Unknown | 147N 93W S15 | Dead spots on Road | None | BIA |
| 7/20/10 | Kodiak | BIA 17 148 93 | FreshH2O on Road | None | BIA |
| 7/15/10 | Zenergy | High Hawk | Kick during drilling | Zenergy | BIA/BLM |
| 6/29/10 | QEP | 149N 90W S8 | Fly ash on Rangeland | QEP | BIA/TAT |
| 3/25/10 | Unknown | BIA 14 | Spill/Ditch | BIA/Hydro evac | BIA |
| 3/04/09 | Kodiak | 16-34-2H | Human Waste over the edge of pad. | Kodiak | BIA |
| 2/10/09 | Water Hauling Company | McKenzie County | Tanker disposed of water at Bear Den | Unsure | BIA |
| 1/27/09 | Marathon | 151N 93W S27 NENE 27 | Spill on location/Invert Fluids | Marathon | Marathon – Fee land |

A number of other Response Actions are not listed include:

- Fly Ash incidents.
- Trash/Garbage on locations.
- General compliance for brush piles/snow melt piles and others.

I will update periodically.

Jeff Desjarlais

This is an indication of the cumulative environmental degradation that has occurred during the last few years, that was not present during the formation of the original project. Conditions have changed drastically and need to be reevaluated. The supplemental information report acknowledges some of this,[12] but an evaluation of the Cumulative Impacts would need to be carried out in an EIS if the extent of potential significant impacts are to be determined. While the supplemental report does identify increases in traffic in the region as part of the oil boom, and implies that this is cumulatively significant, **it only recommends that a traffic study be carried out in the future after the project is approved**, rather than as part of an EIS where the facts and impacts can be assessed before project approval. It doesn't include an upfront

---

[12] ***"As shown below in Table 5, traffic has increased along US 23 by about 50% as a result of the Bakken oil development."*** **p. 6**

evaluation of the specific or cumulative impacts of and quantities of new major hazardous waste streams transported. In fact, the refinery is being required to truck the waste offsite within 90 days, but alternatives to generating the waste have not been assessed as they should be. Some alternatives are identified in the California refinery report attached to this report, but a broader evaluation of methods that have been used since the 1998 California report for minimizing such hazardous waste needs to be assessed so that the project will comply with NEPA.

### e. Surface water quality and other water quality issues

The supplemental report states:

> *As noted above, the requirement for EPA to prepare an FEIS for the proposed MHA Nation refinery was triggered by the Tribes' application for an NPDES discharge permit for the proposed refinery. The draft NPDES permit was included in both the DEIS and FEIS. The draft NPDES permit contains both technology based effluent limits and water quality based effluent limits. Neither of the permit limits are based on the feedstock, but rather on the quantity and type of production at the facility for the technology limits and the water quality standards for the water quality based limits. The discharge limits, monitoring requirements and authorized outfalls would remain unchanged from the original public noticed permit.* ***The water quality impacts of the facility discharging under permit conditions would be the same for either feedstock scenario as the limits remain unchanged.***

This argument states that despite new process units being added to the project, the discharge limits will be the same in the NPDES permit. Since the new project units will definitely result in additional wastewater sources (for example, the new desalter unit produces significant additional contaminated water), this means that the existing permit limits are too lax, if they can accommodate all these new process units without change. The project must still comply with NEPA, so if the permit conditions don't address a significant increase in contaminated wastewater, then there is a significant environmental impact that is not being identified or mitigated.

The lack of an EIS means that we don't know how much water will be discharged from the new units into surface waters, and how this will impact surface waters. The supplemental study only provides an estimate of quantities of water that will be injected into underground wells. This is based on an uncited source (*"Triad (2010) estimated 700 bpsd (barrels per stream day) of briny water from the desalter would be injected into the well."*) This is apparently a report (not identified in the supplemental report endnotes or identified on the EPA website for the MHA Nation relevant documents). It is unclear how or whether this estimate relates to any NPDES permit limit, but it is the only quantitative assessment of water discharges identified for the new project units in the Supplemental report.

Online information about desalter units shows that these units can be a large source of contaminated refinery wastewater, and contain highly toxic BTEX compounds (Benzene, Toluene, Ethelbenzene, Xylene). No discussion or quantities of increases from this unit was provided. A paper called *Control VOC's in Refinery Wastewater*[13] describes this.

> *Petroleum refineries do not like salts in their feedstock since these corrode and foul process equipment. The first refining step is desalting where a hot water wash extracts the salts. If feedstock contains aromatics then some will be in the desalter effluent and this is a major source of refinery wastewater containing VOCs.*
>
> ***Usually the desalter is the major source of contaminated process wastewater and typically also has the highest BTEX content. At several refineries the desalter effluent flow has been as high as 50% of the total wastewater flow and over 70% of total BTEX discharge.***

This means a very large new source of toxic BTEX compounds, which represent both a water pollution source, and an air pollution source due to evaporation. Unfortunately the supplemental report identifies only general problems without specifically evaluating the BTEX sources, and states these problems will be handled later (e.g - local water under the refinery grounds may be drinkable aquafers, the water may be hazardous and the tribes would need to submit additional analysis and no-migration petitions in the future, page 10). Without a full EIS with a specific new project description and evaluation of these new added impacts, it is impossible for EPA and the public to determine the extent of these very likely highly significant impacts.

There is no opportunity to evaluate alternatives to the proposed new units or practices without an EIS. Information is available on best technologies for reducing impacts from wastewater that could be used in an EIS to minimize such waste streams. For example, a newer publication *Petroleum Refining Water/wastewater Use and Management Operations, Best Practice Series, 2010*[14] discusses best practices for water issues. Such an analysis with a survey of available best practices needs to be carried out for the new equipment proposed for the refinery, which are a major source of new, contaminated wastewater.

### f. Climate Change impacts are significant

On this issue, the supplemental report makes quite an illogical argument. It states that because the FEIS greenhouse gas assessment wasn't based on an actual emissions assessment, but instead on a similarly sized refinery in Canada, and since the overall similar "size" (apparently meaning barrels per day of crude processing) hasn't changed, then the greenhouse gas emissions estimates

---

[13] Mike Worrall and Irl Zuber Paper presented at the Process Optimization Conference Houston, TX - March 1998, http://www.amcec.com/case3.html, attached as JMay MHA report Exhibit 5 Refin Wastewater VOC controls

[14] IPIECA is the global oil and gas industry association for environmental and social issues. IPIECA was formed in 1974 following the launch of the United Nations Environment Programme (UNEP). IPIECA is the only global association involving both the upstream and downstream oil and gas industry on environmental and social issues. IPIECA's membership covers over half of the world's oil production. IPIECA is the industry's principal channel of communication with the United Nations. http://www.ipieca.org/about-us

using this same method would be the same even with new process units added. However, again in a contradictory fashion, it concedes that the new units <u>will</u> increase greenhouse gases:

> ***The addition of several new refinery units to accommodate refining of Bakken crude will increase greenhouse gas emissions.*** *However, the greenhouse gas emissions estimate in the FEIS was not based on actual modeled emissions from the refinery, given the uncertainties associated with the refinery design. The FEIS estimate was based on a similarly sized petroleum refinery operating in Canada. Since the estimate is not specific to the design of the refinery, but rather size, and* ***since the size has not changed, the estimated emissions would be similar to those estimated in the FEIS****.* p. 11

This argument is nonsensical. The fact that the FEIS didn't provide a good assessment originally doesn't mean that when the project is re-designed to add new units, it's also ok to do an inaccurate assessment and leave out the emissions from the new units. It is instead a clear fact, acknowledged by the supplemental report, that if you add new units to a refinery, those new units will definitely burn more fuel, and these will cause more greenhouse gas emissions. It is necessary to evaluate what the increase in emissions will be from these new units.

It is a relatively straightforward matter to estimate the CO2 emissions based on the size of the units and the type and approximate amount of fuel that will be burned in these units, and there are standard methods for doing this. We have come quite a long way in greenhouse gas emissions assessment since the original EIS process for this project, so the approach proposed in the supplemental report is entirely unnecessary. When you burn hydrocarbons, most of it produces CO2. Calculating this is a simple matter of well-known chemistry, but the size of the units and specific fuel use must be identified in a reliable project description.

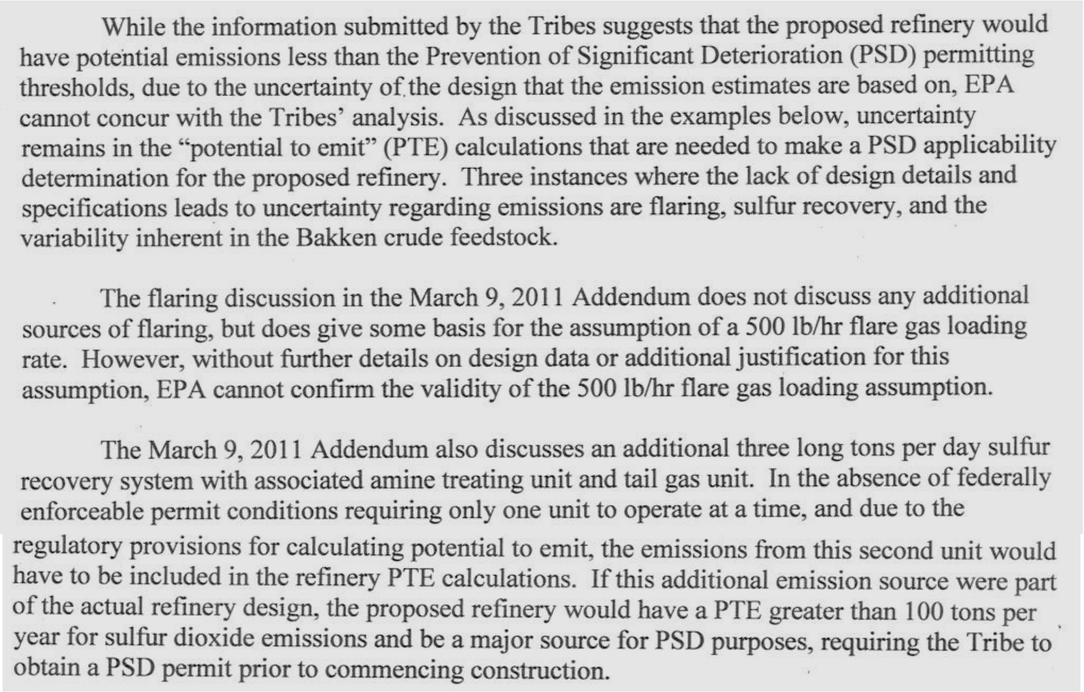
### g. Air Quality evaluations have not been completed

The supplemental report states the following:

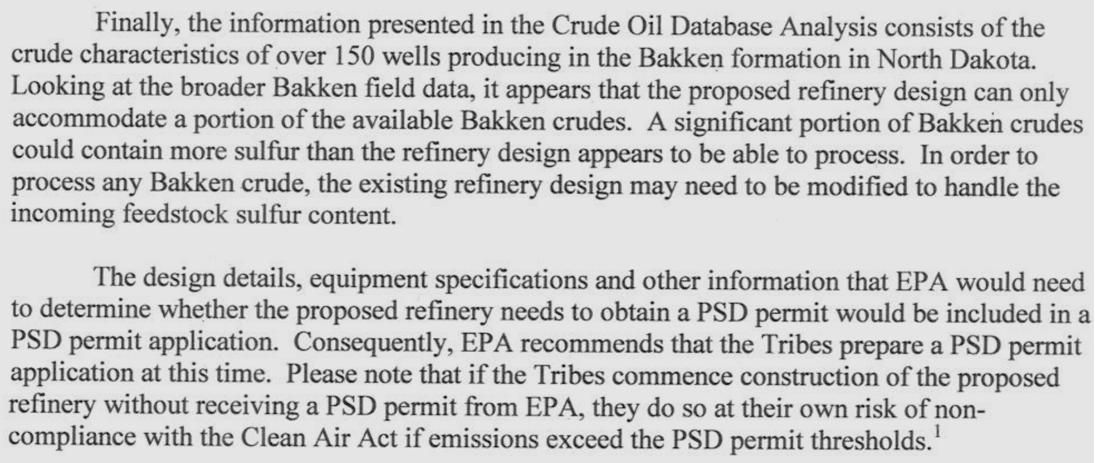
> *In a May 5, 2011 letter (in Appendix A), EPA notified the Tribes that the March 9, 2011 Addendum to the Air Quality Technical Report for the FEIS for the MHA Nation Proposed Clean Fuels Refinery Project did not have the information needed for EPA to concur with the Tribes assessment that the facility would be a minor source for air emissions. Due to the preliminary nature of design, EPA was not able at that time to make a determination of PSD applicability. EPA recommended that the Tribes apply for a PSD permit. Final design is not anticipated until many months after the conclusion of the NEPA process.*

EPA should require that the project proponents provide at least the minimal design information necessary to evaluate the applicability of key requirements, such as PSD applicability.

The supplemental report and EPA letter of May[15] identified above and available on EPA's website clearly indicate that after completion of the March air quality technical addendum report, EPA still did not have sufficient information from the project to make key determinations.  The EPA letter itself specifically identifies problems with the new proposal as follows:



> While the information submitted by the Tribes suggests that the proposed refinery would have potential emissions less than the Prevention of Significant Deterioration (PSD) permitting thresholds, due to the uncertainty of the design that the emission estimates are based on, EPA cannot concur with the Tribes' analysis.  As discussed in the examples below, uncertainty remains in the "potential to emit" (PTE) calculations that are needed to make a PSD applicability determination for the proposed refinery.  Three instances where the lack of design details and specifications leads to uncertainty regarding emissions are flaring, sulfur recovery, and the variability inherent in the Bakken crude feedstock.
>
> The flaring discussion in the March 9, 2011 Addendum does not discuss any additional sources of flaring, but does give some basis for the assumption of a 500 lb/hr flare gas loading rate.  However, without further details on design data or additional justification for this assumption, EPA cannot confirm the validity of the 500 lb/hr flare gas loading assumption.
>
> The March 9, 2011 Addendum also discusses an additional three long tons per day sulfur recovery system with associated amine treating unit and tail gas unit.  In the absence of federally enforceable permit conditions requiring only one unit to operate at a time, and due to the regulatory provisions for calculating potential to emit, the emissions from this second unit would have to be included in the refinery PTE calculations.  If this additional emission source were part of the actual refinery design, the proposed refinery would have a PTE greater than 100 tons per year for sulfur dioxide emissions and be a major source for PSD purposes, requiring the Tribe to obtain a PSD permit prior to commencing construction.



> Finally, the information presented in the Crude Oil Database Analysis consists of the crude characteristics of over 150 wells producing in the Bakken formation in North Dakota.  Looking at the broader Bakken field data, it appears that the proposed refinery design can only accommodate a portion of the available Bakken crudes.  A significant portion of Bakken crudes could contain more sulfur than the refinery design appears to be able to process.  In order to process any Bakken crude, the existing refinery design may need to be modified to handle the incoming feedstock sulfur content.
>
> The design details, equipment specifications and other information that EPA would need to determine whether the proposed refinery needs to obtain a PSD permit would be included in a PSD permit application.  Consequently, EPA recommends that the Tribes prepare a PSD permit application at this time.  Please note that if the Tribes commence construction of the proposed refinery without receiving a PSD permit from EPA, they do so at their own risk of non-compliance with the Clean Air Act if emissions exceed the PSD permit thresholds.[1]

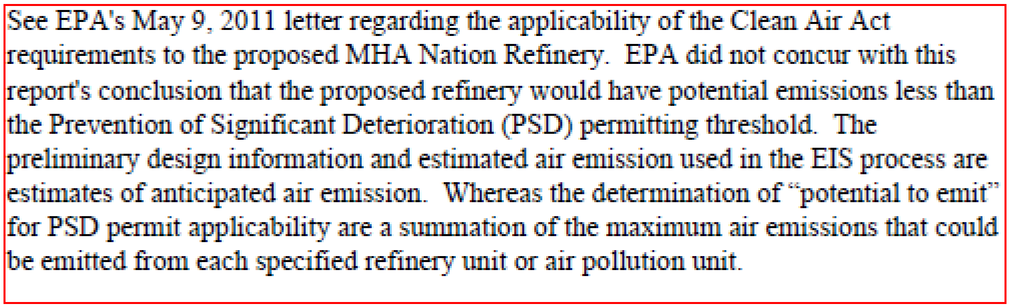
Clearly EPA staff did not find that the March 9th report was sufficient to answer the questions about significance of emissions, and no further evaluation was provided in the final supplemental report that would clear up these questions.  EPA found in the letter above that the project as it stands, without additional limits, does exceed the PSD threshold for SO2. ("*If this additional*

---

[15] Note that it appears that the supplemental report has an type or error regarding the date of the letter.  On the MHA Nation website, (http://www.epa.gov/region8/compliance/nepa/PSDMHA.pdf) the letter is identified as May 9, 2011, not May 5, 2011.

*emission source were part of the actual refinery design, the proposed refinery would have a PTE greater than 100 tons per year for sulfur dioxide emissions and would be a major source for PSD purposes, requiring the Tribe to obtain a PSD permit* ***prior to commencing construction****.")* **Since this second sulfur recovery unit is indeed part of the new refinery design, the refinery PTE for SO2 must be considered to trigger the PSD thresholds requiring BACT according to EPA's own staff.**

The *Addendum Air Quality Technical Report for the Final Environmental Impact Statement for the Mandan, Hidatsa, and Arikara Nation's Proposed Clean Fuels Refinery Project*, (March 9, 2011) is available on EPA's website[16] which calculates air emissions from the new units added to the proposed redesign of the MHA Nation refinery. No authors of the report are identified. The public was not made aware of this new report previous to the notice of the proposed finalizing of the NPDES permit in August, where the link to EPA's website including documents associated with the proposed decision, was made available. **A label is added to the front of the report showing that EPA did not agree with the report's conclusion:**



See EPA's May 9, 2011 letter regarding the applicability of the Clean Air Act requirements to the proposed MHA Nation Refinery. EPA did not concur with this report's conclusion that the proposed refinery would have potential emissions less than the Prevention of Significant Deterioration (PSD) permitting threshold. The preliminary design information and estimated air emission used in the EIS process are estimates of anticipated air emission. Whereas the determination of "potential to emit" for PSD permit applicability are a summation of the maximum air emissions that could be emitted from each specified refinery unit or air pollution unit.

It is very much counter to normal public review processes to make major project changes without a public comment period except for an appeals process, especially when EPA staff found they did not concur with major environmental assessments of the project proponents. This is another clear reason why a whole new EIS process is necessary.

However, even within this flawed process and with scant project data provided to the public, we can carry out additional calculations that show the high likelihood that confirm that the project PTE (Potential to Emit) exceeds PSD (Prevention of Significant Deterioration) permitting thresholds below. The Supplementary Information Report table 3 (page 7) summarized the results of the FEIS emissions and added the new emissions for the redesign as calculated by the project proponents:

---

[16] http://www.epa.gov/region8/compliance/nepa/addendumMHA.pdf

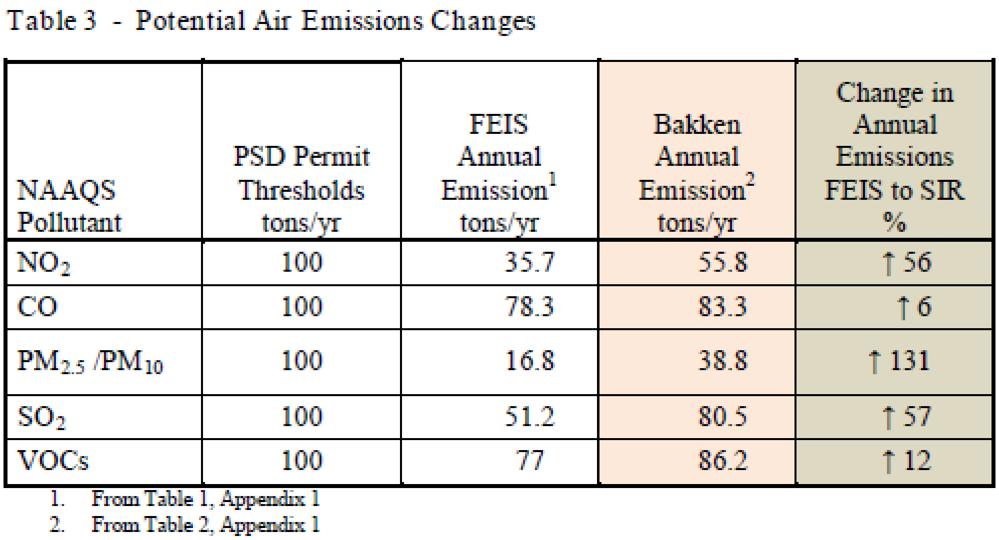


Table 3 - Potential Air Emissions Changes

| NAAQS Pollutant | PSD Permit Thresholds tons/yr | FEIS Annual Emission[1] tons/yr | Bakken Annual Emission[2] tons/yr | Change in Annual Emissions FEIS to SIR % |
|---|---|---|---|---|
| $NO_2$ | 100 | 35.7 | 55.8 | ↑ 56 |
| CO | 100 | 78.3 | 83.3 | ↑ 6 |
| $PM_{2.5}$ /$PM_{10}$ | 100 | 16.8 | 38.8 | ↑ 131 |
| $SO_2$ | 100 | 51.2 | 80.5 | ↑ 57 |
| VOCs | 100 | 77 | 86.2 | ↑ 12 |

1. From Table 1, Appendix 1
2. From Table 2, Appendix 1

This table includes the emissions from the original project under the FEIS, plus the additional equipment due to use of the Bakken crude oil.

### h. SO2 emissions are higher than calculated from additional flaring and tail gas unit emissions

The Addendum Air Quality Technical report[17] performed calculations of SO2 emissions, including the largest sources which are flaring (calculated as startup emissions of the new Sulfur Recovery Unit (SRU), when gases from the new SRU would be sent to the flare), and ongoing emissions of the tail gas unit (which burns the remaining hydrogen sulfide that is not recovered in the SRU as elemental sulfur). These are two major sources of SO2 emissions. The Addendum report also calculated a few smaller sources. However, these calculations only included one of the Sulfur Recovery Units, and now with the redesign, the project has <u>two</u>, and it also has a second tail gas unit (which is really part of the SRU,). However, only one tail gas unit was included in the SO2 calculations for normal operations.

After the project proponents carried out these calculations in the Addendum in March, EPA informed them in its May letter discussed above that without having an additional limit requiring that the refinery only use one SRU at a time, the refinery PTE would need to include emissions from both SRUs. In that case the refinery PTE would exceed the PSD threshold for SO2 of 100 tons per year that determines whether the refinery is a major source under the Clean Air Act, requiring added public health protections such as Best Available Control Technology. But in allowing the finalization of the NPDES permit without a new EIS and new PSD evaluation of these added emissions, EPA is accepting the calculations done by the proponent, counter to EPA's own findings.

---

[17] 40th page of the pdf (page numbers are not numbered throughout the report)

These calculations in the Addendum report resulted in 36 tpy from one tail gas unit (18th page of Addendum pdf), and 28 tpy from flaring emissions during startup of the SRU (same page). The calculation assumed 3 long tons of sulfur produced per day in one SRU. Along with a few other SO2 sources,[18] these calculations resulted in 80 tons per year SO2 total. In addition, the flare calculations included no shutdown emissions at all, either planned or unplanned. It is impossible that the refinery will never shut down. Refineries shut down for maintenance operations, and refineries shut down or partially flare during upsets even without entirely shutting down. It is possible to minimize flaring through very rigorous Flare Mnimization Plans, but only a couple refineries in the country have carried this out in a very rigorous way (Shell Martinez, CA and Flint Hills Texas). Virtually all the other refineries flare frequently. Without rigorous controls that are not present as part of this project, shutdown flaring emissions (and perhaps also routine flaring emissions) will be almost certain.

Furthermore, given the change from Canadian Syncrude to Bakken crude, the increased sulfur content in the crude is consistent with the need to operate both SRUs and tail gas units, which must be assessed as part of the project. We can calculate the sulfur content in the crude change to evaluate this.

The FEIS states that the refinery is a 13,000 barrel per day (bpd) refinery. Bakken crude oil at about 39 API gravity converts to one metric ton per 7.64 barrels of crude oil.[19] We can calculate the increased sulfur emissions in tons due to the switch from Canadian Syncrude (which is about 0.1 - 0.2% sulfur by weight, discussed earlier) to Bakken crude (which can include 0.5% sulfur by weight, also cited earlier). **Thus the potential increase in sulfur content by weight due to the crude slate switch is potentially 0.3% to 0.4% higher,** or it may be greater since we don't know the full range of fluctuation of Bakken crude oil sulfur content. For a 13,000 barrels /day refinery, we can do the following calculation:

13,000 barrels/day (of 39API crude) x 1metric ton / 7.64 barrels
= 1701 metric tons of crude oil refined per day

### Flare startup emissions recalculation:

1701 metric tons /day of crude oil **x 0.3% increased sulfur** by weight = **5.1 metric tons/day sulfur** (or 5.2 long tons/day sulfur,[20] which is **1.73 times higher** than the 3 long tons assumption used in the Addendum)

1.73 x (28 U.S. tons/year SO2 flare emissions from startup estimated in the Addendum)
**= 48.4 tons per year that should have been added to the FEIS**

1701 metric tons/day x **0.4% increased sulfur** by weight = **6.8 metric tons/day sulfur**

---

[18] The flare emissions calculation also included some small emissions it called "Normal" operation, which apparently calculated flare emissions from burning fuel in the pilot light.

[19] Oil Industry Conversions, http://www.eppo.go.th/ref/UNIT-OIL.html

[20] A U.S. ton is 2000 lbs, a metric ton is 2200 lbs, a long ton is 2240 lbs.

(or 6.9 long tons/day which is **2.3 times higher** than the 3 long tons assumption in the Addendum)

2.3 x (28 U.S. tons/year SO2 flare emissions from startup estimated in the Addendum)
**= 64.4 tons per year that should have been added to the FEIS**

This is consistent with the adding of a second SRU that processes 3 additional long tons of sulfur per day, to the existing 3 long ton SRU, effectively doubling the capacity of the refinery to handle sulfur content in the crude in the range of 6 long tons/day. So it appears that the refinery proponents will need to use both SRUs together, and the emissions of both need to be included in the project totals due to the added sulfur due to the crude oil switch.

Another way to estimate the SO2 with the new design using both SRUs and both tail gas units is to use the 80 tons of SO2 emissions calculated by the project proponents, and to add emissions from one more SRU and tail gas unit at the same emission level (36 tpy (extra tail gas unit) + 28 tpy (extra SRU startup flaring)), which equals an extra 64 tpy added to the 80 tpy result of the Addendum calculation. **This results in 144 tpy of SO2 emissions, without even including necessary shutdown or maintenance flaring.**

**Flare shutdown and maintenance emissions calculations are also missing:**

The Addendum didn't include any emissions for flaring from refinery shutdowns at all. All Startup, Shutdown, and Maintenance emissions are required to be included in PTE calculations. SO2 shutdown emissions from flaring during either emergency or planned maintenance shutdown of the SRU or other units have the same Potential to Emit as the calculations above for startup (48.4 to 64.4 additional tons per year), during a complete refinery shutdown. Even a small portion of these emissions from a partial shutdown or upset conditions would cause the flare emissions to exceed PSD.

**Routine flare emissions calculation:**

There has been no mention of the needed increase in refinery gas recovery capacity to accommodate the new units and new crude oil feedstock. Additional vapors generated as a result of the switch to the Bakken crude oil plus the new units added will mean that the refinery can routinely generate additional gases that would be routinely flared unless this capacity is added. No discussion of additional compressor capacity and backup capacity has been provided.

Routine flaring from failure to design and install refinery gas recovery capacity can cause massive, continual emissions. For a 100+ barrel /day refinery in the San Francisco Bay Area that did not have sufficient flare gas recovery capacity, flaring routinely emitted an average of 8.5 tons of SO2 every day for the three months when data was available, and routinely emitted 13 tons per day of VOC emissions for the year. (Data is attached in a spreadsheet provided by the Bay Area Air Quality Management District.)[21] This is just one example of a refinery with problems with routine flaring – many other examples abound that could have been evaluated in a

---

[21] Attached as JMay MHA report Exhibit 6 Tesoro BAAQMD refinery flaring

new EIS taking into consideration the new redesigned refinery for comparison. Without a preconstruction permit, requiring sufficient gas recovery capacity, monitoring of flare gases to identify the flow and constituency of gases to the flare, and without a Flare Minimization Plan and oversight by an inspecting agency, there is almost no chance that the flare emissions for this facility will be minimized.

If the MHA refinery, at about 1/10th the size of this refinery, routinely emitted a proportional amount (1/10th these emissions), it would emit another 1.3 tons/day of VOCs throughout the year (1.3tpd x 365 days = **475 ton/year of additional VOC emissions**), and 0.85 tons/day of SO2 emissions routinely (0.85 x 365 days = **310 tons per year additional SO2 emissions**). SO2 is especially bad for people with asthma. Clearly such design characteristics absolutely must be identified, or no PSD and PTE determination can be made. The environmental impacts of the project will vary drastically depending on these key issues. A new EIS is necessary to evaluate these.

There are any number of scenarios given the lack of constraint on the current project design, where the project PTE would exceed PSD for SO2 and VOCs. If the project is allowed to wait until after it is approved and constructed to evaluate public health and environmental impacts, it greatly lowers the chances of compliance with environmental protections and emission minimization. An updated EIS and PSD evaluation with the details of the range of crude oil sulfur content, all SSM emissions, and calculating the maximum potential total sulfur handling capacity of the facility needs to be publicly carried out, with the necessary data made public, since this facility clearly is almost certain to exceed the SO2 PSD. There are many methods for reducing sulfur emissions that need to be evaluated in a full BACT analysis for this facility.

### i. NOx emissions are higher than calculated

The NOx emissions assumptions for heaters in the Addendum document assumed compliance with a 40 ppm limit, that the refinery may not be held to meet later. The Addendum states:

> *The normal heater emission estimates are based on the following concentrations:*
> - *$NO_x$ emissions = 40 parts per million (ppm) corrected to 0 percent oxygen ($O_2$).*

The use of the 40 ppm figure is justified in this report on the following basis:

> *John Zink has also provided an estimate of 20 ppm corrected to 3 percent $O_2$ for $NO_x$ emissions. Therefore the $NO_x$ emission concentration used in the calculations is approximately twice the anticipated concentration. The John Zink $NO_x$ emission concentration is based on the following assumptions:*
> - *Ultra LoNox burners,*
> - *No air preheat (APH), and*
> - *Natural gas and fuel gas combust at similar temperatures.*
>
> (p. 1-1)

However, an email from the manufacturer John Zink included in the Addendum report (Appendix A) contradicts this, identifying three options for NOx emissions depending on whether it is a standard burner (100 ppm), LoNOx burner (40 ppm), or Ultra LoNOx burner (20 ppm), and states that there is no guarantee on NOx limits for standard burners: [22]

> Email from John Zink Co.:
>
> **Standard Burner**
> 100 ppm predicted - Note; We do not make NOx guarantees on standard burners as there is no means to make design adjustments to meet emissions guarantees.
>
> **Staged Fuel LoNOx Burner**
> 30 ppm predicted / 35 ppm guaranteed
>
> **Ultra LoNOx Burner**
> 17 ppm predicted / 20 ppm guaranteed

Furthermore the FEIS states:

> Process heaters > 20 MMBtu/hr must meet NOx limit of 80 ppm on 24-hr rolling average. [40 CFR 60.100a – 60.108a]

(Although many of the heaters are listed in the Addendum report as less than 20 MMBtu/hr)

A summary of 40 CFR federal Subpart Ja regulations provided by Spirit Environmental states:[23]

> *The Subpart Ja regulations add short-term NOX limits for process heaters only. The new short-term (24-hour rolling average) NOX limit is 40 ppm and* ***applies to only process heaters with a rated capacity of 40 million BTU per hour ("MMBTU/hr") or higher.***

Unfortunately additionally, the Subpart Ja regulations have been stayed. This is a condition that has been changed since EPA's 2007 technical report on air for the EIS, which assumed that low NOx burners would be used pursuant to Subpart Ja. Furthermore, the Addendum report lists all these units at less than 40 MMBtu/hr except for the hydrogen unit.

The calculations in the Addendum does list sizes used in the calculations for the heaters, but it sets all the heaters to 40 ppm including the new ones added, and those that were previously included in the FEIS, despite the FEIS assumption that they would only meet an 80 ppm limit and only if they were larger than 20 MMBTU. Since the new project has had no EIS, and since EPA has stated that the design is preliminary, we don't know that the sizes used in the Appendix calculations are actually what will be designed.

Since there is no preconstruction permit, no EIS, a stay of Subpart Ja, and no clear project description for these new project components, there is no guarantee regarding the size of the heaters, nor the control technologies that will be used. These inconsistencies are troubling and indicate that the maximum Potential to Emit (PTE) for NOx is much higher than calculated in the Addendum report since the size and type of the burner isn't set or limited.

---

[22] From: Clayton, Jim [jim.clayton@johnzink.com],Sent: Wednesday, November 03, 2010 4:05 PM, To: Frisbie, Gordon/DEN, Subject: RE: Refinery Heater Specs, 11th page of the pdf

[23] *How the New Subpart Ja Regulations will Affect Your Refinery*, Joseph F. Guida - Guida, Slavich & Flores P.C. Jess McAngus, P.E. – Spirit Environmental, LLC http://www.spiritenvironmental.com/documents/HowtheNewSubpartJaRegulationswillAffectYourRefinery.pdf

Carrying out a calculation replacing the 40 ppm value used for heaters in the Addendum with 100 ppm during normal operation, the following emissions results in an increase 2 ½ times higher for those heaters. (Also see the sample calculation performed on the 30th page of the Addendum report pdf document, which is replaced with 100 ppm, so all the NOx emissions for the heaters sized less than 40 MMBtu would increase to 100 ppm. I have inserted a table below showing the resulting changes for all the heaters except for the hydrogen unit, boilers, flare, and tail gas unit calculated at 100 ppm. The table below only includes the NOx startup emissions (not all NOx emissions).

The same problems apply to the boilers. The Addendum assumed a 30 ppm, based on the following Addendum statement (p. 2-2):

> *The normal boiler emission estimates are based on the following concentrations:*
>
> - *$NO_x$ emissions = 30 ppm (Webster Engineering burners can achieve 9 ppm).*

Again, the Subpart Ja requirements are stayed, and without upfront limits aside from an estimation in an appendix, there is no guarantee that the facility will be required to meet 30 ppm. The recalculation below also inserts 100 ppm for boilers as a PTE calculation.

**Recalculating Heater & Boiler Normal NOx Emissions at 100 ppm (doesn't include startup)**

| | | **Addendum report Assumptions** | | **Replacing with100 ppm** | |
|---|---|---|---|---|---|
| **Source ID** | **Engine** | **Normal Nox concentration (ppmvd@ 0% O2)** | **(lb/hr)** | **Normal Nox concentration (ppmvd@ 0% O2)** | **(lb/hr) except where tpy listed** |
| 00001 | Atmosph Crude | 40 | 1.4 | 100 | 3.5 |
| 00002 | Reformer Heater | 40 | 0.1 | 100 | 0.25 |
| 00003 | Reformer Heater | 40 | 0.1 | 100 | 0.25 |
| 00004 | Reformer Heater | 40 | 0.3 | 100 | 0.75 |
| 00005 | Reformer Heater | 40 | 0.2 | 100 | 0.5 |
| 00006 | Reformer Heater | 40 | 0.1 | 100 | 0.25 |
| 00007 | Hydrocracker 1 | 40 | 0.2 | 100 | 0.5 |
| 00008 | Hydrocracker 2 | 40 | 0.3 | 100 | 0.75 |
| 00009 | Hydrocracker 3 | 40 | 0.4 | 100 | 1 |
| 00010 | Hydrocracker 4 | 40 | 0.3 | 100 | 0.75 |
| 00011 | Olefin | 40 | 1.2 | 100 | 3 |
| 00012 | Hydrogen | 40 | 2.1 | 40 | 2.1 |
| 00013 | Boiler 1 | 30 | 0.7 | 30 | 1.75 |
| 00014 | Boiler 2 | 30 | 0.7 | 30 | 1.75 |
| 00015 | Boiler 3 | 30 | 0.7 | 30 | 1.75 |
| 00016 | Flare | | 0.7 | | 0.7 |

| | | | | | |
|---|---|---|---|---|---|
| 00017 | S Recov Tail Gas | | | | |
| 00018 | Vac Crude Heater | 40 | 0.6 | 100 | 1.5 |
| 00019 | Dcnt Oil Tank Hter | 40 | 0.04 | 100 | 0.1 |
| 00020 | Dcnt Oil Tank Hter | 40 | 0.04 | 100 | 0.1 |
| | Total (lbs/hr) | | 10.18 | | 21.2 lbs/hr |
| | **Total (tpy)** | | 44.6 tpy | | 93.1 tpy |
| **Additional normal NOx emissions above the Addendum calculation** | | | | | 48.5 tpy |
| **Plus total NOx in Addendum of 55.8 tpy including all NOx emissions** | | | | | **104.3 tpy** |

The recalculation above finds that about 48.5 additional tons per year of NOx would be added if the heaters (except for one) and boilers listed were recalculated at 100 ppm NOx during normal operations. When added to the 55.8 tpy NOx total of the Addendum, this equals about over 104 tpy. This is a large increase compared to the 35.7 tpy of the FEIS NOx total of the FEIS, and it exceeds the PSD threshold of 100 tpy. It may not reflect the total maximum Potential to Emit, since so few details are available on the new project changes. With the added equipment and crude oil switch, there may be a debottlenecking of other parts of the refinery that cannot be evaluated until a full project description, with process interconnections and sizes identified, that would further increase the NOx totals above 100 tpy. It is very important that a detailed, fully public assessment be carried out, since failure to do so could result in construction of a refinery that is not up to modern standards, and that will emit much more than necessary.

### j. Hydrogen sulfide emissions weren’t assessed

The supplemental report in combination with the air modeling failed to assess the increased hydrogen sulfide that will be present and potentially emitted at the refinery due to the increased sulfur content of the crude oil. An EIS is needed for assessment of this acutely hazardous compound that can increase by a factor of 5 (due to the potential increased sulfur content from 0.1% up to 0.5%).

### k. The new units might debottleneck other parts of the refinery

The added units can’t be treated as operating separately from the new refinery – oil refineries are inherently integrated operations. No analysis has been provided regarding the potential that the new units could debottleneck existing units, so that those units may also operate at higher rates than planned during the FEIS process. This analysis needs to be included in a new EIS.

## III. Conditions have drastically changed since the FEIS and earlier DEIS proceedings

Many conditions have changed drastically since the 2009 FEIS, and even more since the earlier DEIS, for example:

- The area has had major, record flooding, bringing the water table up much higher, increasing the potential for contamination of the water table due to spills
- The Bakken oil boom has drastically increased oil industry traffic, and trucking accidents including deaths, hazardous materials spills, and air emissions from trucking.
- Emissions from oil drilling have drastically increased
- Major coal fired plants in the area are adding to a major air pollution increase that has occurred in the last few years.

These issues make a new EIS, with a Cumulative Impacts assessment, and an assessment of new conditions in general essential for determining the impacts of this project.

# Julia E. May

Senior Scientist / Environmental Consultant

510/658-2591

jmay@sbcglobal.net

## *Experience*

**1989-present** **Industrial Air Pollution & Pollution Prevention Technical Evaluation / Science team manager** Identification and quantification of industrial air pollution sources including criteria pollutants, toxics, and greenhouse gases. Identification of pollution prevention methods and engineering solutions for communities facing continuous and episodic chemical releases. Research of best and worst industrial practices, and chemical phase-out methods. Compiling available health and environmental impacts data, and analyzing air monitoring and permitting data. Evaluation of technical basis of regulatory compliance with environmental laws. Working through practical technical issues of regulation, negotiating with industry and government agencies to craft most health-protective policy and regulatory language. Translating inaccessible technical information into lay language and educational materials. Technical assistance for communities of color facing severe pollution burdens with cumulative impacts analysis, and industrial workers and neighbors proposing environmental health protection regulation, permitting, and policy. Managed four-person science department for statewide environmental organization. Hired by regulatory agency as technical advisor to community members to identify feasible air pollution control methods not previously adopted, and assisting communities submitting comments during regulatory proceedings.

Project examples:

- **Evaluation of air emission and other impacts from proposed permits for individual U.S. fossil fuel industry expansions including refineries, oil drilling, pipelines, and coal gasification:** Evaluation of refinery emissions and solutions regarding permitting of feedstock switches to Canadian tar sands crude oil at ConocoPhilips Wood River, BP Whiting, Detroit Marathon, and proposed new MHA Nation, North Dakota, refineries, as well as dozens of refinery expansions in Northern and Southern California. Evaluation of oil drilling operations, air impacts, public safety hazards, earthquake and subsidence hazards, public nuisance hazards and solutions in residential neighborhood in Southern California. Evaluation of pipeline transport impacts of crude oil, hydrogen, and other oil industry feedstocks in California and the Midwest. Evaluation of coal gasification plant air emissions. (1990s to present)
- **Development of model California oil industry criteria pollutant regulation, proposed greenhouse gas regulation and alternatives analysis:** Developed multiple proposals ultimately adopted for addition to ozone attainment plans in Northern and Southern California of model oil refinery regulations for flares, pressure relief devices, tanks, leakless fugitives standards, petroleum product marine loading, and others. Technical working group member in State of California regulation of greenhouse gas and co-pollutants (smog precursors and toxics). Developed recommendations for regulation of oil industry greenhouse emissions, sources, alternatives, and reporting; the State found

these recommendations feasible and recommended regulation. (1990s to present)

- **Evaluation of emissions and phaseout opportunities for smaller industrial sources including metal finishing, foam manufacturing, wood finishing, electronics, consumer products, etc**.: Evaluation of air emissions and unnecessary use of ozone depletors, carcinogens, and reproductive toxins, direct negotiation with individual companies to identify specific chemical elimination options in lieu of penalties for environmental violations. For example, metal degreasing was replaced with benign alternatives (soap and water) or grease use eliminated, by talking through use with manufacturers. Phaseout of chemicals was over a million pounds of various substances from many sources. (1990s)

### *Education*

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

Engineering principles, mathematics, thermodynamics, physics, materials science, chemistry, electronic circuit design, solid-state physics, and others; majored in electrical engineering.

### *Positions*

2004- present **Independent Environmental Consultant (2004 - ongoing) and Senior Scientist, Communities for Better Environment (2006 – present) --** Industrial pollution quantification, analysis of impacts and solutions to environmental problems including trends in oil industry crude feedstocks, associated equipment changes, emissions of criteria pollutants, toxic emissions, and greenhouse gases. Technical consultant and strategist in community campaigns on industrial regulation and pollution prevention. Geographic areas include Southern California, Northern California, and multiple U.S. states.

2001-2003 **Statewide CBE Lead Scientist, CBE,** Oakland, CA

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

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

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

1987-1990 **Research Associate, CBE**

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

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

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

1981-1985 **Integrated Circuits Design Engineer, National Semiconductor Corp., Santa Clara, CA**

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

***A few special activities***

2002-2003 **Roundtable on Bay Area Ozone Attainment Progress**

Invited member of problem-solving group of decision makers including BAAQMD board members, City Council members, industry CEOs and trade group directors, California Air Resources Board (CARB) and US EPA officials, and others, for reviewing progress and proposing action to control San Francisco Bay Area regional smog.

1995-2003 **Negotiator for Optical Sensing Air Pollution Monitoring Equipment on oil refinery fenceline**

CBE signatory to enforceable Good Neighbor Agreement with Rodeo, California oil refinery, providing technical analysis for community negotiators, resulting in permanent installation of a state-of-the art air pollution monitoring system on the refinery fenceline, using optical sensing to continuously measure air pollution and broadcast data to a community computer screen. Reviewed manufacturer specifications, developed Land Use Permit language, and worked with refinery and manufacturer for better Quality Assurance/Quality Control. Worked with US EPA, Contra Costa County, and community groups evaluating the system and publishing a report.

1998-2002 **Program Administrator for Bucket Brigade air pollution monitoring**. Coordinated community groups of Contra Costa County Bucket Brigade project (funded by US EPA) who carried out training events in several communities surrounding major Bay Area refineries and chemical plants. The Bucket Brigade used low-tech air pollution monitors community members can build and operate, based on a standard air pollution sampling tedlar bags analyzed at certified laboratories. Provided community information on laboratory results, administered complex federal grant including quality assurance plan.

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

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

***Publications and written comments (examples)***

1. ***California statewide Oil Refinery Sector GHG emissions and recommendations,*** technical comments submitted to the State of California on refinery greenhouse gases statewide, entitled: *Recommendations on AB 32 Scoping Plan on Corn Ethanol Refineries, Electricity Generation, and Oil Refineries from Environmental Justice Organizations,* by Communities for a Better Environment (CBE), the Environmental Health Coalition (EHC), the Association of Irritated Residents (AIR), and the Center on Race Poverty and the Environment (CRPE), May, 2008
2. ***Evaluations of major oil refinery expansions and crude switch modifications at various U.S. refineries****: Comments on ConocoPhillips Wood River CORE Project (Coker and Refinery Expansion), New Source Review Permit Application,* Comments on BP Whiting *Significant Source Modification No.: 089-25484-00453 and Significant Permit Modification No.: 089-25488-00453, Comments on DEIS for Mandan, Hidatsa and Arikara Nation's Proposed Clean Fuels Refinery Project,* providing detailed evaluation of a new refinery proposed to be sited without air permits on MHA Nation reservation, among others. *CBE's Comments on Chevron Refinery Draft Title V Permit*, September 27, 2002, Julia May and Will Rostov, (documenting extensive inadequacies in voluminous Chevron operating permits under Title V of the Clean Air Act).
3. ***Reports on California refinery sources:*** *The Increasing Burden of Oil Refineries and Fossil Fuels in Wilmington, California and How to Clean them Up,* a report including information on oil industry concentration in Southern California, trends in heavy crude oil use, and local oil drilling issues, April 2009. *Refinery Flaring in the Neighborhood,* Report on Refinery flaring in the San Francisco Bay Area, the need for new regulation and better law enforcement, and the community campaign to get there, CBE, Julia May, February 2004
4. ***Optical Open Path Monitors at the Tosco San Francisco Refinery at the Rodeo Fenceline***, May 2001, coauthors Julia May (CBE), Elinor Blake, Jim Gallagher, Randy Sawyer (Contra Costa County Health Services), Andy Mechling, Kasha Kessler, and Sandra Dare, (Shoreline Environmental Alliance, SEA), with assistance from US EPA Region IX, and advisory committee made up of the BAAQMD, Cal/EPA, California Dept. of Health Services, Occupational Health and Environmental Health Branches, and the Tosco Rodeo Refinery (now Phillips)
5. ***Evaluation of Ozone Attainment Plans:*** *For example: These Readily-Available Stationary Control Measures should be included in the Bay Area Clean Air Plan,* 5/14/2001, to Celia Bloomfield, Planning Office, [AIR-2], Air Division, U.S. Environmental Protection Agency, Region IX, CBE, Julia May, and *CBE Comments on the BAAQMD/ MTC/ABAG Proposed Final 2001 Ozone Attainment Plan (June 2001 version,* July 16, 2001, to Chairperson Randy Attaway and Members of the Board, Bay Area Air Quality Management District (BAAQMD), Richard Toshiyuki Drury, Julia May

ttp://yosemite.epa.gov/opa/admpress.nsf/3ee0a48cce87f7ca85257359003f533d/bb39e443097b5df5852576a9006a5a86!OpenDocument

---

Memorandum From Lisa P. Jackson, Administrator to All EPA Employees

Release date: 01/12/2010

Contact Information: Adora Andy, press@epa.gov, 202-564-6794; En español: Betsaida Alcántara, press@epa.gov 202-564-1692

Colleagues:

Almost one year ago, I began my work as Administrator. It has been a deeply fulfilling 12 months and a wonderful homecoming for me. As our first year together draws to a close, we must now look to the tasks ahead.

In my First Day Memo, I outlined five priorities for my time as Administrator. We have made enormous strides on all five, and our achievements reflect your hard work and dedication. By working with our senior policy team, listening to your input and learning from the experiences of the last 12 months, we have strengthened our focus and expanded the list of priorities. Listed below are seven key themes to focus the work of our agency.

***Taking Action on Climate Change:*** 2009 saw historic progress in the fight against climate change, with a range of greenhouse gas reduction initiatives. We must continue this critical effort and ensure compliance with the law. We will continue to support the President and Congress in enacting clean energy and climate legislation. Using the Clean Air Act, we will finalize our mobile source rules and provide a framework for continued improvements in that sector. We will build on the success of Energy Star to expand cost-saving energy conservation and efficiency programs. And, we will continue to develop common-sense solutions for reducing GHG emissions from large stationary sources like power plants. In all of this, we must also recognize that climate change will affect other parts of our core mission, such as protecting air and water quality, and we must include those considerations in our future plans.

***Improving Air Quality:*** American communities face serious health and environmental challenges from air pollution. We have already proposed stronger ambient air quality standards for ozone, which will help millions of American breathe easier and live healthier. Building on that, EPA will develop a comprehensive strategy for a cleaner and more efficient power sector, with strong but achievable emission reduction goals for $SO_2$, $NO_x$, mercury and other air toxics. We will strengthen our ambient air quality standards for pollutants such as PM, $SO_2$ and $NO_2$ and will achieve additional reductions in air toxics from a range of industrial facilities. Improved monitoring, permitting and enforcement will be critical building blocks for air quality improvement.

***Assuring the Safety of Chemicals:*** One of my highest priorities is to make significant and long overdue progress in assuring the safety of chemicals in our products, our environment and our bodies. Last year I announced principles for modernizing the Toxic Substances Control Act. Separately, we are shifting EPA’s focus to address high-concern chemicals and filling data gaps on widely produced chemicals in commerce. At the end of 2009, we released our first-ever chemical management plans for four groups of substances, and more plans are in the pipeline for 2010. Using our streamlined Integrated Risk Information System, we will continue strong progress toward rigorous, peer-reviewed health assessments on dioxins, arsenic, formaldehyde, TCE and other substances of concern.

***Cleaning Up Our Communities:*** In 2009 EPA made strong cleanup progress by accelerating our Superfund program and confronting significant local environmental challenges like the asbestos Public Health Emergency in Libby, Montana and the coal ash spill in Kingston, Tennessee. Using all the tools at our disposal, including enforcement and compliance efforts, we will continue to focus on making safer, healthier communities. I am committed to maximizing the potential of our brownfields program, particularly to spur environmental cleanup and job creation in disadvantaged communities. We are also developing enhanced strategies for risk reduction in our Superfund program, with stronger partnerships with stakeholders affected by our cleanups.

***Protecting America's Waters:*** America's waterbodies are imperiled as never before. Water quality and enforcement programs face complex challenges, from nutrient loadings and stormwater runoff, to invasive species and drinking water contaminants. These challenges demand both traditional and innovative strategies. We will continue comprehensive watershed protection programs for the Chesapeake Bay and Great Lakes. We will initiate measures to address post-construction runoff, water quality impairment from surface mining, and stronger drinking water protection. Recovery Act funding will expand construction of water infrastructure, and we will work with states to develop nutrient limits and launch an Urban Waters initiative. We will also revamp enforcement strategies to achieve greater compliance across the board.

***Expanding the Conversation on Environmentalism and Working for Environmental Justice:*** We have begun a new era of outreach and protection for communities historically underrepresented in EPA decision-making. We are building strong working relationships with tribes, communities of color, economically distressed cities and towns, young people and others, but this is just a start. We must include environmental justice principles in all of our decisions. This is an area that calls for innovation and bold thinking, and I am challenging all of our employees to bring vision and creativity to our programs. The protection of vulnerable subpopulations is a top priority, especially with regard to children. Our revitalized Children's Health Office is bringing a new energy to safeguarding children through all of our enforcement efforts. We will ensure that children's health protection continues to guide the path forward.

***Building Strong State and Tribal Partnerships:*** States and tribal nations bear important responsibilities for the day-to-day mission of environmental protection, but declining tax revenues and fiscal challenges are pressuring state agencies and tribal governments to do more with fewer resources. Strong partnerships and accountability are more important than ever. EPA must do its part to support state and tribal capacity and, through strengthened oversight, ensure that programs are consistently delivered nationwide. Where appropriate, we will use our own expertise and capacity to bolster state and tribal efforts.

We will also focus on improving EPA's internal operations, from performance measures to agency processes. We have a complex organization -- which is both an asset and a challenge. We will strive to ensure that EPA is a workplace worthy of our top notch workforce. Our success will depend on supporting innovation and creativity in both what we do and how we do it, and I encourage everyone to be part of constructively improving our agency.

These priorities will guide our work in 2010 and the years ahead. They are built around the challenges and opportunities inherent in our mission to protect human health and the environment for all Americans. We will carry out our mission by respecting our core values of science, transparency and the rule of law. I have unlimited confidence in the talent and spirit of our workforce, and I will look to your energy, ideas and passion in the days ahead. I know we will meet these challenges head on, as one EPA.

Sincerely,
Lisa P. Jackson

DOWNSTREAMTODAY.COM
Your Refining, Petrochem, Pipeline and LNG Destination

# Platts Launches Bakken Crude Assessment

Platts
Monday, May 03, 2010

Beginning Monday, U.S. Midwest and Canadian oil producers, refiners, traders and other market observers can benefit from the launch of the first open-market spot price assessments of crude oil from the Bakken Shale formation stretching across central United States and parts of Canada. The Bakken formation is part of the Williston Basin of underground petroleum reserves and one of the most significant new sources of regional crude oil supply for refiners in the United States and Canada.

Platts, a leading global energy information provider, on Monday published spot-market price assessments reflecting the end-of-trading day value of Bakken Blend crude oil injected into pipelines at Clearbrook, Minnesota and Guernsey, Wyoming. Platts' assessments, known as *Bakken Blend ex-Clearbrook* and *Bakken Blend ex-Guernsey*, are reported both as a spot price and a differential to West Texas Intermediate (WTI), a similar quality light sweet crude. They are being reported in two fashions in order to provide consumers, producers and the trading community with a fixed price value and a means to compare with a competitive crude oil with similar properties.

"We're excited to play what we believe is a helpful role in the evolution of this new crude oil," said Dave Ernsberger, Platts global director of oil, "and we are pleased to address the industry's call for daily price information derived from an independent, transparent price discovery process."

As of 3:15 p.m. ET Monday, Platts assessed the spot prices of Bakken Blend ex-Clearbrook and Bakken Blend ex-Guernsey at $85.41 per barrel (/b) and $84.76/b, respectively. Expressed as a differential to the calendar month average of WTI futures, as listed by the New York Mercantile Exchange, the prices for *Bakken Blend ex-Clearbrook* and for *Bakken Blend ex-Guernsey* were minus $4.15/b and minus $4.80/b, respectively.

The *Bakken Blend ex-Clearbrook* assessment reflects an American Petroleum Institute (API) gravity ranging from 38-40 degrees and 0.5% sulfur, similar to the characteristics of North Dakota Sweet. API gravity is a measure of how heavy or light a grade of crude oil is compared to water. The *Bakken Blend ex-Guernsey* assessment represents an API gravity of 38-40 degrees and 0.2% sulfur, similar to the nature of North Dakota Light Sweet.

The Bakken formation spans North and South Dakota, Montana, Saskatchewan, Manitoba and Alberta. Initial government and private estimates put the Bakken formation recoverable reserves at nearly 5.5 billion barrels, with current Bakken crude output about 200,000 barrels per day and rising.

"Many in the industry expect that this high-quality crude will play an increasingly vital role in addressing not only U.S. Midwest and Canadian refining demands, but possibly that of U.S. Gulf Coast refiners, assuming south-bound pipelines come to fruition," said Esa Ramasamy, director of Americas market reporting at Platts.

Platts' Bakken Blend assessments are developed using its Market-on-Close (MOC) methodology, a structured, highly-transparent price assessment process based on the principle that price is a function of time. The MOC process in oil identifies bid, offer and transaction data by company of origin and results in a time-sensitive end-of-trading-day daily price assessment

The assessments are published in numerous Platts publications including Platts Global Alert, a real-time news service; Platts Dispatch, a data delivery service, and the publications Platts Crude Oil Marketwire, North American Crude Wire, and Platts Oilgram Price Report.

Platts, a division of The McGraw-Hill Companies, is a leading global provider of energy and commodities information. With a century of business experience, Platts serves customers across more than 150 countries. An independent provider, Platts serves the oil, natural gas, electricity, emissions, nuclear power, coal, petrochemical, shipping, and metals markets from 17 offices worldwide. Platts' real-time news, pricing, analytical services and conferences help markets operate with transparency and efficiency. Traders, risk managers, analysts, and industry leaders depend upon Platts to help them make better trading and investment decisions.

**EPA MHA Nation 2009 excerpt of informational hearing,**

**Transcription of video recording by Loren White Jr**., video available for viewing on Youtube: http://www.youtube.com/watch?v=2h16cEjCBvw

(Begins finishing another question . . .)

**EPA (Steve Wharton repeating a question): The question was why is the feedstock for the refinery oil from Canada when there is active production here locally.** Uh, you may want to go back to ask the tribe about that directly as to how that got started, but prior to that there are two reasons I could mention to you. One is the pipeline from Canada that cuts down and goes very close to the northeast corner of the reservation makes that feedstock available unlike other parts of the country where that's not the case . . . So one, availability. And the transportation process associated with getting that feedstock which is a liquid in a pipe to the refinery, through a pipeline, no train, no truck – a pipe. So there's a pretty good advantage there.

The second point is, we talked about air emissions requirements. Part of those are contingent upon sulfur, the sulfur that's coming out, well that's a function of how much sulfur is going in.

And the feedstock, the, it's called syncrude this pre-refined material coming out of Canada has kind of, quite a bit of that removed from it already. So it makes it easier in a way to take that feedstock, convert it into, say, low sulfur diesel and other fuels, without having more aggressive process units within the refinery.

**EPA (Dana Allen):** And also, this refinery was proposed in 2003, before the majority of the well development that started in the last three years. So it kind of, it came before a lot of this well development.

**EPA (Steve Wharton):** So part of the answer from the tribe might be that they had no concept of what might happen at that point.

**Audience:** I made that question about six years ago when they started this, and they said that if they were to go with North Dakota crude, that they would have to start this EPA process all over again like you were talking about earlier. And maybe sometimes the proponents would rather see them go to North Dakota crude but then it would take another 10 years to get the project going.

**EPA (Steve Wharton) right**

**BIA (Diane Mann-Klager):** And the emission production would be totally different.

**EPA (Steve Wharton) right –** Different feedstock in means different emissions out, so yes, that would all have to be totally re-examined.

IPIECA

# Petroleum refining water/wastewater use and management

**Operations Best Practice Series**
2010

www.ipieca.org






IPIECA

The global oil and gas industry association for environmental and social issues

5th Floor, 209–215 Blackfriars Road, London SE1 8NL, United Kingdom
Telephone: +44 (0)20 7633 2388     Facsimile: +44 (0)20 7633 2389
E-mail: info@ipieca.org  Internet: www.ipieca.org

This publication is printed on paper manufactured from fibre obtained from sustainably grown softwood forests and bleached without any damage to the environment.

# Petroleum refining water/wastewater use and management

IPIECA Operations Best Practice Series

This document was prepared by AECOM, Inc. on behalf of the IPIECA Refinery Water Management Task Force.
The assistance of M. Venkatesh of ENSR–AECOM is gratefully acknowledged.

Cover photographs reproduced courtesy of the following (clockwise from top left): ExxonMobil; Nexen; Photodisc Inc.; iStockphoto; Corbis; Shutterstock.com.

# Contents

## List of Tables

## List of Figures

# Introduction

This manual describes typical 'best practices' and strategies used in petroleum refineries to manage water, including ways to reduce water usage. Improved water management in a petroleum refinery can potentially reduce the volume and cost of raw water used in refinery operations. Furthermore, improved water management may result in reductions in wastewater flow or contaminant load or both. Lower flow and contaminant load may result in lower wastewater treatment operating and maintenance costs. Optimized water management may also reduce the mass of contaminants in the treated effluent, thus improving the quality of a wastewater discharge and ultimately the environmental impact of a refinery's discharge.

These practices are a collection of operational, equipment and procedural actions related to water management in a refinery. Since each refinery is uniquely configured, some of these practices may or may not be applicable based on the complexity of the refining operations, type of wastewater treatment operations available at a particular site, availability of raw water sources, discharge configuration and type of receiving water body. This manual will enable a refiner to compare their operations with typical industry practices and develop a plan for optimizing water management in the refinery.

The manual is organized as follows:

- Introduction
- Refinery water overview
- Wastewater
- Stormwater and sewerage
- Effluent treatment
- Recycle and reuse issues

# Refinery water overview

Petroleum refineries are complex systems of multiple operations that depend on the type of crude refined and the desired products. For these reasons, no two refineries are alike. Depending on the size, crude, products and complexity of operations, a petroleum refinery can be a large consumer of water, relative to other industries and users in a given region. Within a refinery, the water network is as unique to the refinery as its processes. This section describes the typical sources of water supplied to a refinery and the typical discharges of water from a refinery. It also provides an overview of the types of contaminants contained in the raw water and the methods used to remove these contaminants.

## Overall refinery water balance

Many of the processes in a petroleum refinery use water, however, not each process needs raw or treated water, and water can be cascaded or reused in many places. A large portion of the water used in a petroleum refinery can be continually recycled with in a refinery. There are losses to the atmosphere, including steam losses and cooling tower evaporation and drift. A smaller amount of water can also leave with the products. Certain processes require a continuous make-up of water to the operation such as steam generating systems or cooling water systems. Understanding water balance for a refinery is a key step towards optimizing water usage, recycle and reuse as well as optimizing performance of water and wastewater treatment systems.

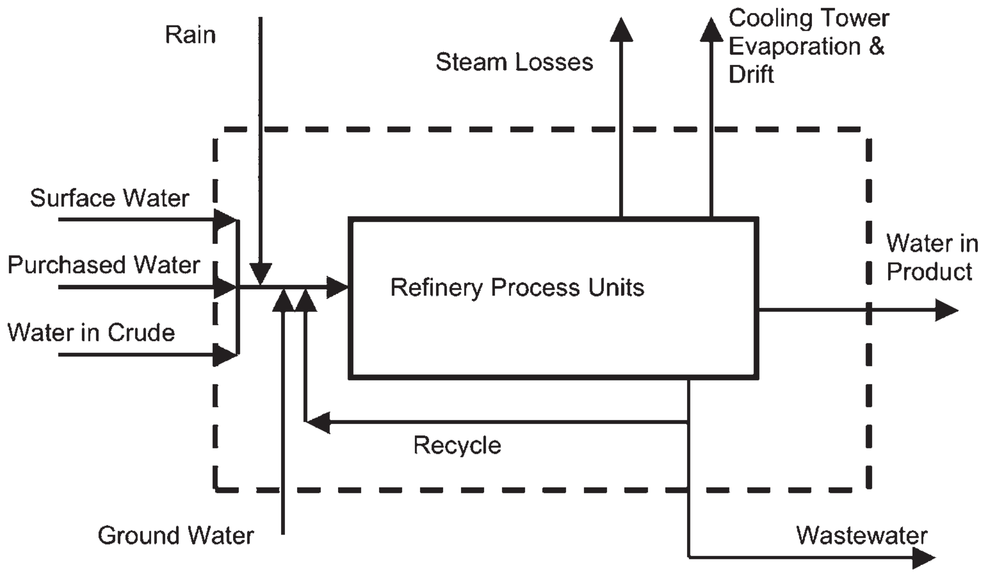
Figure 1 shows a typical example of the water balance in a refinery.

## Sources of water

### *Surface water*

Water to the refinery can be supplied from various surface-water sources such as rivers or lakes. In some cases it may also be supplied from the sea or from other brackish water sources. Additional supply of water can come from groundwater located in aquifers, if the subsurface water is available and accessible. Typical characteristics of raw water can include varying amounts of solids and/or salts, also referred to as total suspended solids (TSS), total dissolved solids (TDS) and turbidity. Each water body

**Figure 1** *Refinery water balance*



*A schematic example of the typical water balance in a refinery*

**Table 1** *Typical sources of water*

| Source | Typical characteristics |
|---|---|
| Lake | Suspended solids, dissolved solids (metals), turbidity |
| River | Suspended solids (with seasonal variation), dissolved solids (metals), turbidity |
| Groundwater (wells) | Suspended solids, dissolved solids (metals), dissolved organics |
| Sea water | Suspended solids, dissolved solids (metals, chlorides) |

and aquifer has a unique quality associated with it and may require treatment before use in a refinery. The level of pretreatment required for source water before it is used in the refinery is dependent on the uses of the water in the refinery and what level of solids and salts is compatible with the process.

Table 1 shows the types of water sources and typical characteristics of the water from each source.

### *Purchased water*

Water can also be supplied from a municipality. Municipalities generally can offer potable water (drinking water) but may also be able to offer a treated effluent for industrial use or reuse. Potable water (drinking water and sanitary water) required by a refinery is frequently purchased from a local municipality. If available, potable water may also come from groundwater aquifers or alternative sources.

### *Water in crude*

When crude arrives at a refinery, it often carries entrained water that remains from the oil well extraction process and/or pickup during transshipment. The water is typically removed as storage tank bottom sediment and water (BS&W) or in the desalter which is part of the crude unit in the refinery, and is typically sent to wastewater treatment.

### *Rain*

Another source of water for a refinery is rain. Rain that falls within the refinery battery limits is typically treated before discharge. Rain that falls in non-industrial areas of a refinery, e.g. parking lots, green areas or administrative housing, may be discharged without treatment depending on local regulations. Stormwater harvesting can be a technique that is employed to capture uncontaminated stormwater. With proper storage and or treatment (if needed) this stormwater can be used for certain processes such as equipment washing.

## Water leaving the refinery

The water that leaves refineries is indicated in Figure 1 and described briefly below.

### *Wastewater*

Refineries can generate a significant amount of wastewater that has been in contact with hydrocarbons. Wastewater can also include water rejected from boiler feedwater pretreatment processes (or generated during regenerations). Wastewater can also refer to cooling tower blowdown stream, or even once-through cooling water that leaves the refinery. Once-through cooling water typically does not receive any treatment before discharge. Cooling tower blowdown water and wastewater from raw water treating may or may not receive treatment at the wastewater treatment plant (WWTP) before discharge. Contaminated wastewater is typically sent to either a wastewater treatment plant that is located at the facility, or it can be pretreated and sent to the local publicly owned treatment works or third-party treatment facility for further treatment. Water that has not been in direct contact with hydrocarbons or which has only minimal contamination can be a source for reuse and is discussed in the section on '*Recycle and reuse* *issues*', beginning on page 42 of this document. Wastewater can sometimes also be reused after passing through the wastewater treatment plant, sometimes requiring additional treatment to remove suspended solids and other contaminants.

### *Steam losses*

Low pressure steam that is produced in the refinery is vented to the atmosphere when it is in excess. Other sources include tracing steam that is vented at some locations in the refinery. Proper monitoring of the steam system in the refinery will help minimize the production of excess steam and minimize/ eliminate the need for venting. Any expected losses should be considered when reviewing the water balance in a refinery.

### *Cooling tower losses*

As water is cooled in the tower by evaporation, this results in a loss of water in the refinery. Some of the water in the cooling tower is entrained by the large quantities of air passing through the tower and are lost to the atmosphere. These entrainment losses are also referred to as cooling tower drift. Any expected losses from cooling towers should be considered when reviewing the water balance in a refinery. In some cases once-through cooling water is used in the refinery (see overleaf, and page 17).

### *Water in product*

There is some water that leaves with some of the products in the refinery although this is a very small amount because it is limited by product quality specifications.

## Raw water treatment

Source water for a refinery typically needs to be treated before being used in different processes. The type of treatment depends on the quality of the source water and its ultimate use in the refinery. Turbidity, sediments and hardness are examples of source water constituents that may require treatment. Water having a high mineral content is generally referred to as 'hard water' and has a tendency to form scale. Calcium salts are deposited as scale when water is heated causing a decrease in heat transfer rates in heat exchangers (heaters and coolers). Both calcium and magnesium salts form scale upon evaporation of water in steam-generating equipment. These deposits not only reduce heat transfer rates but also restrict fluid flow. Removal of calcium and magnesium from water is referred to as softening, and the treatments commonly used include lime-soda, phosphates, ion exchange and reverse osmosis. Other contaminants that could be present in raw water and their removal methods are shown in Table 2.

### Use of raw water in refineries

The required degree of water purity depends on the particular use. Preliminary treatment of all raw water entering a plant may include screening and sedimentation to remove suspended solids, but subsequent treatment will depend on the ultimate use for each water system. A typical plant water supply might be separated into process, boiler feed, cooling, potable, fire water and utility water systems.

Brief descriptions of the different water uses in refineries are given below.

### *Process water*

In refineries, water is typically used for various purposes where the water is closely contacted with the hydrocarbons. Softened water is usually used for these purposes.

### *Boiler feedwater*

The boiler feedwater (BFW) required for the generation of steam in a refinery needs to be treated prior to use. The higher the steam pressure being generated, the higher the purity of the BFW required. Ordinarily water is treated by the lime-soda process and further purified by ion exchange or by hot phosphate treatment in order to produce boiler feedwater. Reverse osmosis can also be used to soften the water.

Typically, a purge stream is removed from the water purification systems in order to prevent the buildup of contaminants. This purge stream is sent to wastewater treatment and is replaced by fresh makeup water.

### *Cooling water*

Water-cooled condensers, product coolers (heat exchangers) and other heat exchangers can use a large amount of water in a refinery. Some refineries use air coolers, where the process stream is exchanged with air prior the being sent to a cooling water heat exchanger. This will minimize the use of cooling water in the refinery.

Some refineries use a once-through system where the incoming water is exchanged against the process fluid and the warmer cooling water is then returned to the source of the water. However, if water is a scarce commodity at a particular location it may be preferable to recirculate the water through a cooling tower and then back to the process. In these circulating systems water is supplied at about 90° F and returned to the cooling tower at a maximum of about 120°F.

Some water treatment is necessary even for once-through cooling systems to prevent scale formation, corrosion, and slime and algae formation. The extent of treatment required for circulating systems is much greater since impurities are concentrated in the system as evaporation losses occur.

In cooling tower systems, a build-up of salt concentration is unavoidable since water is evaporated in the cooling tower. Make-up water is required to replace these and other losses.

Sea water has been used successfully as cooling water especially in coastal areas with fresh water shortages. Cathodic protection systems employing magnesium anodes located in the floating head and channel of exchangers prevent excessive corrosion. Deposits are minimized by restricting cooling water temperature increase below the point where the calcium salts begin to precipitate.

### *Potable water*

Potable water is required for use in kitchens, wash areas and bathrooms in refineries as well as in safety showers/eyewash stations. City water or treated groundwater can be used for this purpose. In remote locations or in small towns a portion of the treated water from the plant softening unit may be diverted for potable water use. The treated water must be chlorinated to destroy bacteria, and then pumped in an independent system to prevent potential cross-contamination. Potable quality water may also be required in some specialist chemical operations (e.g. as a diluent).

### *Fire water*

The requirements for fire water in refineries are intermittent, but can constitute a very large flow. Often, refineries collect stormwater from non-process areas and store it in a reservoir dedicated to the fire water system in the plant.

Provisions are typically made for a connection (for use in emergency situations) of the fire water system into the largest available reservoir of water. Usually this is the raw water supply since fire water requires no treatment. Sea water or brackish water is often used as fire water by plants located along coastal areas.

### *Utility water*

Utility water is used for miscellaneous washing operations, such as cleaning an operating area. It should be free from sediment but does not require any other treatment.

Table 2 shows the typical impurities in various types of water and the processes generally used to remove them.

**Table 2** *Contaminants in raw water*

| Contaminant | Problem | Removal methods |
|---|---|---|
| Turbidity | Makes water cloudy and deposits in water lines and process equipment | Coagulation, settling and filtration |
| Hardness | Primary source of scale formation in heat exchangers and pipe lines | Softening, distillation, surfactants |
| Alkalinity | Causes foaming in steam systems and attacks boiler steel. Bicarbonate and carbonate produce carbon dioxide in steam which is highly corrosive | Lime and lime-soda softening, Zeolite softening, Dealkalization by anion exchange |
| Sulphate | Adds to the solids content of water and combines with calcium to form calcium sulfate scale | Demineralization, distillation |
| Chloride | Adds to solids content and increases the corrosive properties of water | Demineralization, distillation, desalination (if sea water is being used) |
| Silica | Scaling on heating and cooling equipment and pipelines | Anion exchange resins, distillation |
| Iron and magnesium | Discolors the water and precipitates in water lines and process equipment | Aeration, coagulation and filtration, lime softening, cation exchange |
| Oil | Source of scale, sludge and foaming in boilers. Impedes heat exchange. Undesirable in most processes | Oil/water separators strainers. coagulation and filtration. Diatomaceous earth filtration |
| Oxygen | Corrosion of water lines heat exchange equipment, boilers, return lines, etc. | Deaeration, sodium sulphite, corrosion inhibitors |
| Hydrogen sulphide | Cause of 'rotten egg' odor. Corrosion, toxicity | Aeration, chlorination, highly basic anion exchange |
| Conductivity | Conductivity is the result of ionizable solids in solution. High conductivity can increase the corrosive characteristics of a water | Processes which decrease dissolved solids content will decrease conductivity. Examples are demineralization, lime softening |
| Dissolved solids | 'Dissolved solids' is the measure of total amount of dissolved material. High concentrations of dissolved solids are objectionable because of process interference and as a cause of foaming in boilers | Various softening process, such as lime softening and cation exchange by zeolite, will reduce dissolved solids. Demineralization, distillation |
| Suspended solids | 'Suspended solids' is the measure of undissolved matter. Suspended solid plug lines, cause deposits in heat exchange equipment, boilers, etc. | Sedimentation. Filtration, usually preceded by coagulation and settling |

# Wastewater

This section describes the various sources of process water in refineries and discusses best practices with respect to how they are managed. Also included is a discussion of the wastewater generated from the different utility systems in the refinery and how these systems are managed. Finally, concepts for pretreatment of wastewater generated in the process units are discussed.

## Process water

Process water is defined as water that has been in intimate contact with hydrocarbons in the refinery. Water that is generated in the process units is represented by the following categories:

- desalter effluent;
- sour water;
- tank bottom draws; and
- spent caustic.

### Desalter effluent

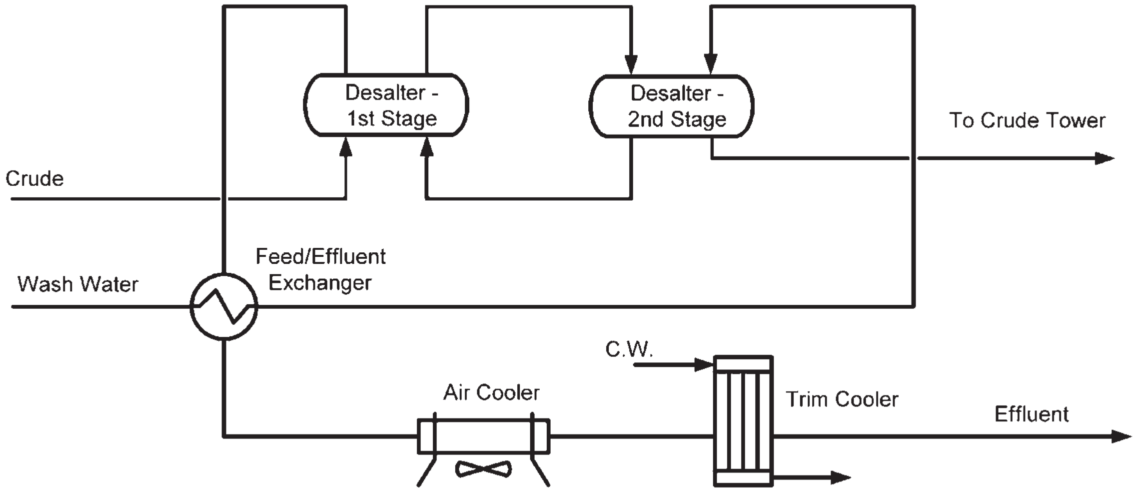
Inorganic salts are present in crude oil as an emulsified solution of salt (predominantly sodium chloride). The source of the aqueous phase is the naturally occurring brine that is associated with the oil field from where the crude is extracted. The amount of water received at the refinery with the crude varies widely but an approximate range would be 0.1–2.0% volume.

The salts contained in the aqueous phase are variable and range from 10 to 250 pounds per thousand barrels (p.t.b.) of crude. The salts are present mostly in the form of chlorides of sodium, magnesium and calcium. Typically, the first operation in a refinery crude unit is desalting, which is used to wash out the salt present in the crude. The most important reasons for removing the salts from the crude are to:

- prevent plugging and fouling of process equipment by salt deposition; and
- reduce corrosion caused by the formation of HCl from the chloride salts during the processing of the crude.

There are two basic types of desalters: chemical and electrical. Refineries that use two-stage electrical desalters can achieve a desalted crude specification of 0.1 p.t.b. of salt in the crude. The wash water that is used in the desalter is discharged from the unit. Figure 2 shows the typical configuration of a two-stage desalter.

**Figure 2** *Typical desalter configuration*



The wash water is usually injected into the second stage of the desalter after being heated by exchange with the hot effluent. The water from the second stage is sent to the first stage where it is contacted with the incoming crude. The hot (about 300°F) brine is then discharged to the wastewater treatment plant after being cooled. The optimum operating pH in the desalter is 6 to 7 because the emulsion formation is minimized and the oil/water separation is most effective at this pH. The pH is significantly impacted by source of the wash water that is used as well as corrosion considerations in the crude tower system.

**Table 3** *Sources of wash water*

| Source | Advantages | Disadvantages |
|---|---|---|
| Fresh water | 1. The water requires no or minimal pretreatment | 1. Increases overall water usage in the refinery<br>2. Increases generation of wastewater in the refinery<br>3. Increases capital and operating costs for wastewater treatment |
| Recycled crude tower overhead | 1. Results in lower sour water stripping requirements<br>2. Avoids the piping required to send the crude tower overhead to the sour water strippers<br>3. Minimizes fresh water use in the refinery | 1. More challenging to control the pH in the desalters due to the ammonia content of the crude tower overhead<br>2. Results in more emulsion formation in the desalters leading to the inadvertent discharge of hydrocarbons to wastewater treatment<br>3. Results in the discharge of $H_2S$ from the desalter effluent to the atmosphere in the sewers as well as wastewater treatment if effluent does not go for pretreatment before discharge to sewers or wastewater treatment |
| Recycled vacuum tower overhead supplemented by sources of water | 1. Results in lower sour water stripping requirements<br>2. Avoids the piping required to send the crude tower overhead to the sour water strippers<br>3. Minimizes fresh water use in the refinery | 1. More challenging to control the pH in the desalters due to potential ammonia content of the vacuum tower overhead<br>2. Results in more emulsion formation in the desalters leading to the inadvertent discharge of hydrocarbons to wastewater treatment<br>3. Results in the discharge of $H_2S$ from the desalter effluent to the atmosphere in the sewers as well as wastewater treatment if effluent does not go for pretreatment before discharge to sewers or wastewater treatment |
| Recycled stripped sour water | 1. The phenol contained in the stripped sour water is extracted into the crude resulting in significantly lowering the phenol content of the effluent.<br>2. The lower phenol content results in lower capital and operating costs for wastewater treatment.<br>3. Allows better pH control in the desalter | 1. Routing all sour water generated in the plant results in requiring a large sour water stripper<br>2. Increase the piping required to convey the crude and vacuum tower overhead to the sour water stripper |

Some of the drilling muds that come in with the crude tend to accumulate in the desalter and need to be removed. This can be done either continuously or periodically. Some desalters have a continuous mud washing system in which the muds are not allowed to accumulate in the vessel. Most refineries do the mud washing on an intermittent basis (typically once a shift) by temporarily increasing the wash water flow to the mud washing nozzles located at the bottom of the desalter. However, when this operation is carried out it can result in increased discharges of hydrocarbons to the wastewater treatment system.

Oil/water interface control is an important aspect of the design and operation of desalters. There are a number of interface controllers that are available in the marketplace and one such system uses high frequency electromagnetic measurement to detect the interface. Control of the oil/water interface will help minimize/eliminate the inadvertent discharges of hydrocarbons to the wastewater treatment systems.

The wash water used in desalters is typically 5 to 8% of the crude throughput. The source of wash water that is used in the desalters varies widely in different refineries. Table 3 describes the various sources that are used and discusses the advantages and disadvantages of each source.

The level of contaminants contained in the desalter is highly variable depending on factors such as:

- operating pH of the desalter (higher pH results in more emulsions);
- effectiveness of the interface control device in the desalter; and
- frequency and effectiveness of the mudwash.

Table 4 shows the expected concentration of containments in desalter effluent.

***Desalter—summary of best practices***

- Avoid using fresh water as wash water in the desalter.
- Preferentially use stripped phenolic sour water as wash water.
- Operating pH in the desalter should be optimized to about 6–7.
- Use proper interface probes in the desalter for effective oil/water separation.
- Consider diverting desalter brine to a separate tank where solids can drop out during mud washing operations.

**Table 4** *Desalter effluent contaminants*

| Contaminant | Expected concentration (mg/l) |
|---|---|
| Chemical oxygen demand (COD) | 400 to 1000 |
| Free hydrocarbons | Up to 1000 |
| Suspended solids | Up to 500 |
| Phenol | 10 to 100 |
| Benzene | 5 to 15 |
| Sulphides | Up to 100 |
| Ammonia | Up to 100 |

## Sour water

Steam is used in many processes in refineries as a stripping medium in distillation and as a diluent to reduce the hydrocarbon partial pressure in catalytic cracking and other applications. The steam is condensed as an aqueous phase and is removed as sour water. Since this steam condenses in the presence of hydrocarbons, which contain hydrogen sulphide ($H_2S$) and ammonia ($NH_3$), these compounds are absorbed into the water at levels that typically require treatment.

The typical treatment for sour water is to send it to a stripper for removal of $H_2S$ and $NH_3$. Steam is used to inject heat into the strippers. High performance strippers are able to achieve < 1 ppm $H_2S$ and < 30 ppm $NH_3$ in the stripped sour water. With these levels, the stripped sour water is an ideal candidate for recycle/reuse in the refinery. Strippers that use direct steam injection as the stripping medium create more wastewater in the refinery compared to strippers that use reboilers to inject heat into the strippers. Figure 3 shows the configuration of a typical sour water stripper.

In this system, all the sour water produced in the refinery is flashed in a drum and any separated oil is sent to refinery slops. The vapours from this drum are sent to the flare. The sour water from the drum is then sent to a storage tank which provides the required surge in the system. The sour water is then passed through a feed/bottoms exchanger where it is heated up and then sent to the stripper. Steam is used in the reboiler to heat up the bottoms and provide the vapour traffic in the tower. The separated vapors containing $H_2S$ and $NH_3$ are typically sent to a sulphur plant. The stripped water is routed via the feed/bottoms exchanger and a trim cooler for reuse in the refinery. Any excess water that cannot be reused would be sent to a wastewater treatment plant.

Refineries that include process units such as catalytic crackers and delayed cokers produce more sour water than a less complex refinery. The sour water from these sources also contains phenols and cyanides, and should be segregated from the remaining sour water produced in the refinery. Dedicated sour water strippers may be used to process this water, and the stripped sour water from this stripper should be preferentially reused as wash water for the desalters. This will result in the extraction of a substantial portion (up to 90%) of the phenol contained in this sour water and result in a lowering of the load of phenol to the wastewater treatment system.

**Figure 3** *Sour water stripper configuration*

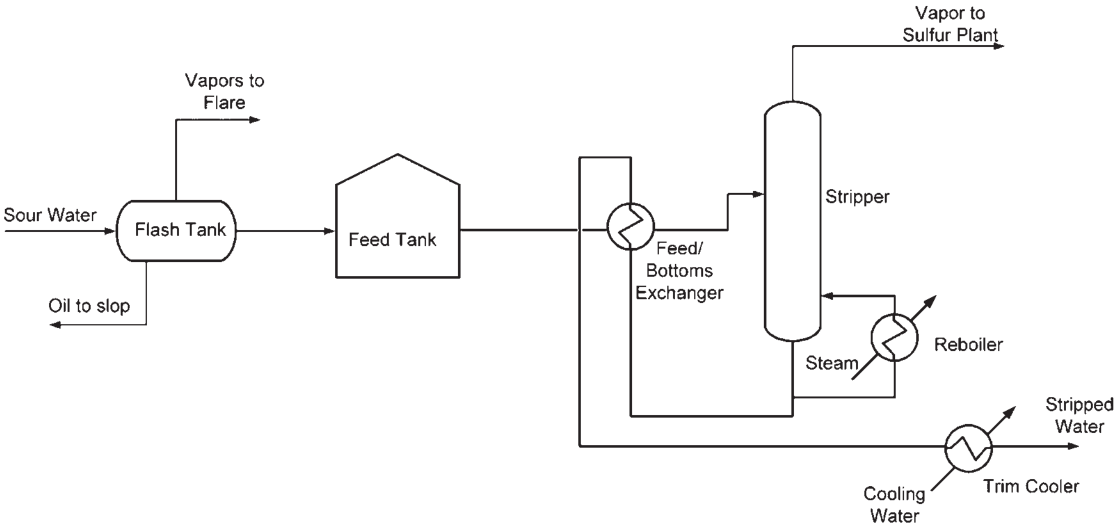


**Table 5** *Sour water producers*

| Unit | Producer | Typical destination | Comments |
|---|---|---|---|
| Crude | Atmospheric tower overhead drum | Sour water stripper or desalter | Some refineries use this stream as desalter wash water without stripping. This practice can lead to emulsion formation resulting in reduced oil/water separation in the desalter |
| Vacuum | Tower hotwell | Sour water stripper or desalter | Some refineries use this stream as desalter wash water without stripping. This practice can lead to emulsion formation resulting in reduced oil/water separation in the desalter |
| Catalytic cracker | Fractionator overhead drum | Sour water stripper | This sour water contains elevated levels of phenol and cyanides which do not get removed in the sour water strippers |
| Delayed coker | Fractionator overhead drum and blowdown drum | Sour water stripper | This sour water contains elevated levels of phenol and cyanides which do not get removed in the sour water strippers |
| Visbreaker | Fractionator overhead drum and blowdown drum | Sour water stripper | This sour water contains elevated levels of phenol and cyanides which do not get removed in the sour water strippers |
| Hydrotreaters | Wash water separator | Sour water stripper | Stripped water is generally used as wash water and therefore hydrotreaters are typically not net producers of sour water |
| Hydrocracker | Wash water separator | Dedicated sour water stripper | Hydrocrackers generally require very clean wash water and one strategy is to send sour water to a dedicated sour water strippers to avoid impurities that might be present in sour water produced in other units in the refinery |
| Sulphur plant | Tail gas treater | Sour water stripper | none |

**Table 6** *Stripped sour water contaminants*

| Contaminant | Expected concentration (mg/l) |
|---|---|
| Chemical oxygen demand (COD) | 600 to 1200 |
| Free hydrocarbons | < 10 |
| Suspended solids | < 10 |
| Phenol | Up to 200 |
| Benzene | 0 |
| Sulphides | < 10 |
| Ammonia | < 100 |

Table 5 (above) shows the various process units that produce sour water and best practices with respect to reuse of stripped sour water.

The composition of the stripped sour water is highly dependent on the design and operation of the sour water stripper. Table 6 (left) shows the expected level of contaminants in stripped sour water.

***Sour water stripper—summary of best practices***

- Route sour water produced in the refinery to the sour water stripper except where it can be used directly, e.g. as desalter wash water (see below).
- If the refinery has a catalytic cracker or a coker, the sour water produced in these units should be segregated and processed in a dedicated phenolic sour water stripper.
- The stripped water from the phenolic stripper should be preferentially used as wash water in the desalter.
- Where necessary, the stripped sour water should be cooled prior to discharge to wastewater treatment, to avoid subjecting the biological treatment system to excessive temperatures.

## Tank bottom draws

Typically, the categories of tanks that may require water draws in refineries include:

- crude tanks;
- gasoline tanks; and
- slop tanks.

The incoming crude to refineries normally contains water and sediments (mud) that are picked up when the oil is extracted from the wells—this is referred to as bottom sediment and water (BS&W). When the crude is stored in large tanks, the BS&W settles to the bottom and must be periodically removed to prevent a buildup of this material which would otherwise result in a loss of storage capacity. Water draws are normally sent to either the wastewater treatment or to a separate tank where the solids are separated from the oil and water. Figure 4 shows a typical arrangement of a crude tank draw.

In this system, the crude tank, which is located inside a berm for secondary containment, is equipped with a valved drain line that is sent to a sump located outside the berm. The operator uses the valve to drain the BS&W periodically using the interface level indicator to ensure that hydrocarbons do not get inadvertently drained out. Many refineries make it an operating practice that the operator be present to monitor the draining operation during the entire draining period to ensure that free hydrocarbons are not inadvertently drained. There can be many variations of the system shown in this example but the principle of operation would be similar. The type of interface indicator used is also an important consideration. Some crude tanks use probes, which use high frequency electromagnetic measurement to detect the interface.

Tanks that store gasoline also tend to collect water. These tanks should be equipped with drainage systems similar to that of crude tanks to ensure that the hydrocarbon product is not inadvertently drained from the tanks. It should be noted that the amount of water that is drained from gasoline tanks is relatively small compared to the amount of water from crude tanks.

**Figure 4** *Crude tank water draw*

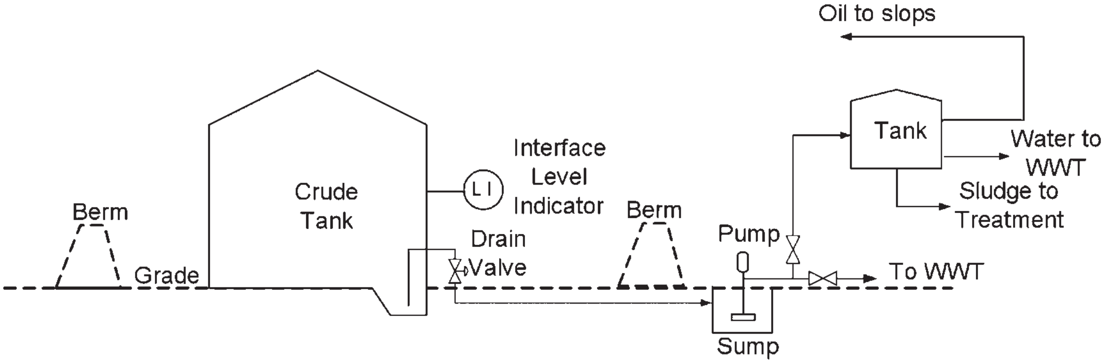


**Table 7** *Crude tank bottom sediment and water contaminants*

| Contaminant | Expected concentration (mg/l) |
|---|---|
| Chemical oxygen demand (COD) | 400 to 1000 |
| Free hydrocarbons | Up to 1000 |
| Suspended solids | Up to 500 |
| Sulphides | Up to 100 |

Table 7 shows the expected level of contaminants in typical crude tank BS&W.

***Tank bottom draws—summary of best practices***

- Adequate piping and valves should be provided to allow proper draining of the tank.
- Proper instrumentation should be provided so that the oil/water interface in the tank can be monitored properly.
- Operating procedures that require the presence of an operator at the tank during the entire draining period should be implemented if practices and automation still results in excessive oil to the sewer.

## Spent caustic

Spent caustic is formed due to the extraction of acidic components from hydrocarbon streams. This includes residual $H_2S$, phenols, organic acids, hydrogen cyanide and carbon dioxide. These acidic compounds are absorbed into the reagent, and the resulting spent caustic solution cannot be regenerated. As a result, these absorbed acidic compounds contained in the caustic solution must be purged intermittently or continuously from the caustic treating system, and replaced by fresh caustic. The caustic solution will drop out as separate aqueous phase in intermediate or product storage tanks. Subsequent drawdown and discharge from the tanks will be required. This discharge usually occurs to the sewer, frequently on a batch basis and can cause problems in the wastewater treatment plant.

The intermediate/product streams most frequently treated with caustic in a refinery are shown in Table 8.

If a refinery is running a particularly corrosive crude, e.g. one with a high TAN (total acid number), the naphthenic acid that is contained in such a crude tends to concentrate in the kerosene/jet fuel cut in the refinery. When this stream is caustic treated the acids are converted to naphthenates which are especially refractory to biological treatment.

Traditionally, spent caustic has been disposed of in a number of different ways. Discharge to the sewer system is common but not necessarily the best practice. An alternative option is off-site disposal of

**Table 8** *Intermediate product stream—caustic treated*

| Intermediate product | Usual contaminants/impurities | | | | |
|---|---|---|---|---|---|
| | $H_2S$ | RSH | Phenol | HCN | Other |
| Straight run LPG | X | X | | | X |
| Light straight-run naphtha | | X | | | X |
| FCC* C3 + C4 LPG (produces phenolic spent caustic) | X | X | X | X | X |
| FCC* gasoline (produces phenolic spent caustic) | | X | X | X | |
| Coker C3 + C4 LPG (produces phenolic spent caustic | X | X | X | X | X |
| Kerosene/jet fuel) | X | | X | | X |

* Fluid catalytic cracker

phenolic spent caustics where recovery of contained organic components can occur. Off-site disposal of sulphidic spent caustics (often the largest portion of refinery spent caustic) is more difficult because there are few reprocessing options for this stream.

There are two strategies for dealing with spent caustic in refineries: in-process abatement and end-of-pipe treatment.

### *In-process abatement/minimization—best practices*

The following in-process options have the common objective of minimizing quantities of spent caustic requiring disposal.

- As discussed above, there are two types of spent caustic that are generated in refineries depending on the types of process units present. Some refineries are able to treat the sulphidic spent caustic in the refinery wastewater treatment plant. Phenolic spent caustic is very odorous and therefore cannot be treated in the wastewater treatment plant. Phenolic spent caustic (from catalytic cracker, coker and kerosene/jet fuel treater) should be segregated from the sulphidic spent caustic and stored separately. This will allow the refinery to properly evaluate appropriate strategies for spent caustic disposal.
- The amount of spent caustic generated is dependent on operating procedures in the treating units. These procedures often call for the caustic to be purged when the sodium hydroxide concentration in the solution reaches a certain value. The production of spent caustic can be minimized by exercising tighter control of caustic treating operations by ensuring that the caustic solution is not purged prematurely.
- Hydrocarbons are normally treated in an amine system to absorb the hydrogen sulphide prior to being sent to a caustic treater. The operation of the absorber should be reviewed to maximize its efficiency of absorption so that the amount of hydrogen sulphide reaching the caustic treating system is minimized.
- Consider prewashing (absorbing) hydrocarbons with stripped sour water to reduce the quantity of acidic compounds in these streams prior to them being sent to the caustic treater. This will minimize the amount of acidic compounds requiring removal in the caustic treater, and thus minimize the discharge of spent caustic.
- The strength, purity and composition of caustic required for a given treatment, or generated by a treatment process, vary widely. The quality of caustic will depend on both the product being treated and the type of treatment system being employed. An effective strategy to reduce the use of fresh caustic and minimize the generation of ‘end-of-pipe’ spent caustics is to carefully match caustic treatment needs with available spent caustics being generated.

### *End-of-pipe treatment—best practices*

The following treatment systems are used in refineries for treating spent caustic.

- Sulphidic spent caustic can be treated in the wastewater treatment plant as long as it is added in a controlled manner. This will prevent shocking the system and will minimize the generation of odours from the system.
- Off-site disposal of phenolic caustic is practiced in many refineries. The cost of disposal together with transportation and potential liability costs need to be taken into account before choosing this option.

### *End-of-pipe treatment—other options*

Other options available for the treatment/disposal of spent caustic are listed below:

- Deep neutralization (lowering the pH to less than 4) which results in the stripping of the $H_2S$ and the separation of phenols is an option for treating phenolic spent caustics. This option requires relatively high capital and operating costs.
- If the spent caustic includes a significant amount of naphthenates (such as spent caustic from kerosene/jet fuel treaters), wet air oxidation of the spent caustic should be considered. In this

system, the spent caustic is oxidized with air at very high temperature and pressure (~700 psi, ~500°F). This type of system is also very high in capital and operating costs.

- The potential for sale of spent caustic to an adjacent industry such as a pulp and paper mill or cement plant should also be explored.

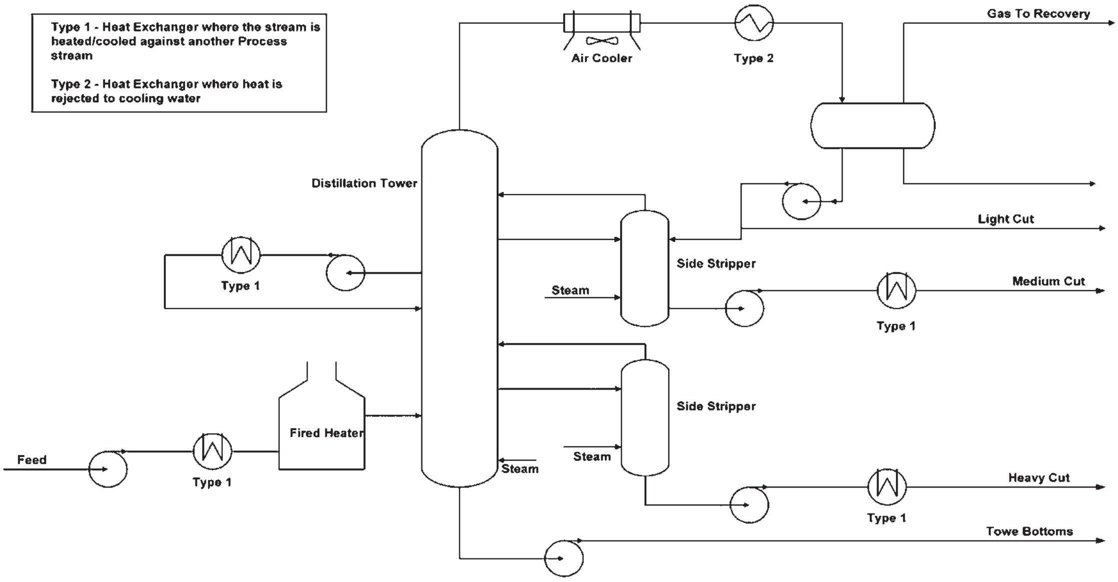
## Cooling water

In refineries, crude oil is separated in various fractions based on boiling point. This is accomplished by fractional distillation of the crude oil. The distillation is carried out in distillation columns where the crude is heated up and vapourized in a fuel (fuel oil, natural gas or refinery fuel gas) fired heater. Various fractions are separated by condensing and cooling products that are withdrawn from the tower. From an overall heat balance point of view, the heat that is put into the system by burning fuel and/or the introduction of steam has to be removed or 'rejected'. This is accomplished in various ways, including:

- heat exchange with boiler feedwater to generate steam;
- heat exchange with other process streams;
- rejection of heat using air coolers; and
- rejection of heat to cooling water.

Figure 5 shows a typical distillation system in a refinery. In this system, three types of heat rejection systems are shown. The crude oil is preheated by exchanging with another process stream and fed to a fired heater. The partially vapourized products are sent to the distillation tower where different side streams are withdrawn based on the boiling point range of the product. The side streams are sent to strippers which are also distillation columns where the boiling point range of the product is adjusted further by the addition of steam. The bottoms product from these strippers is cooled and sent to storage. The vapours from these side strippers are sent back to the main tower. The overhead vapours from the main tower are condensed using an air-cooled exchanger, and then further cooled using a cooling water heat exchanger. Three types of heat exchangers are shown in this system:

**Figure 5** *Typical distillation system*



- Type 1 heat exchangers such as steam generators and process stream heat exchangers;
- Type 2 heat exchangers which use cooling water;
- air coolers.

There are three types of cooling water systems:

**1. Once-through cooling water system:** In this type of system the cooling capacity of the water is used only once without contacting the fluid or vapour being cooled. These systems use water withdrawn from a surface water source such as a lake, river or estuary and typically return the water to the same source. Figure 6 shows a typical once-through cooling water system.

**2. Closed-loop cooling water system:** In this system water is circulated in a closed-loop piping system and is subject to cooling and heating without evaporation or air contact. Heat that is absorbed by the water in a closed-loop system is normally rejected using a heat exchanger to a once-through cooling system. Figure 7 shows and example of a closed-loop system.

**3. Evaporative cooling water system:** In this type of system, the heat that is picked up by the recirculating cooling water is rejected in a cooling tower by evaporation. In the cooling tower the hot water is sprayed against a rising stream of atmospheric air. The heat in the cooling water is removed by heating the air as well as evaporation of the cooling water. An example of an evaporative recirculating cooling tower system is shown in Figure 8.

**Figure 6** *Once-through cooling water system*

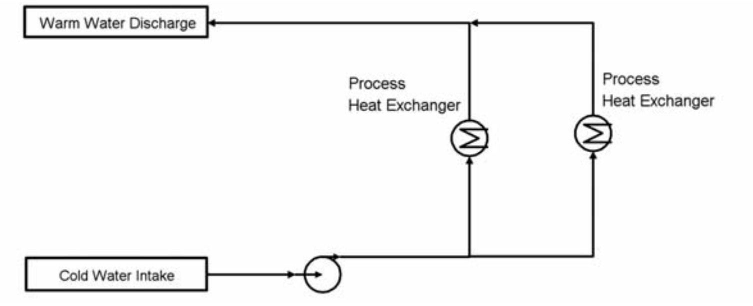


**Figure 7** *Closed-loop cooling system*

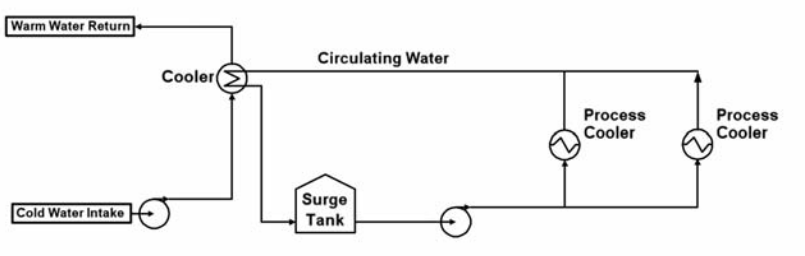
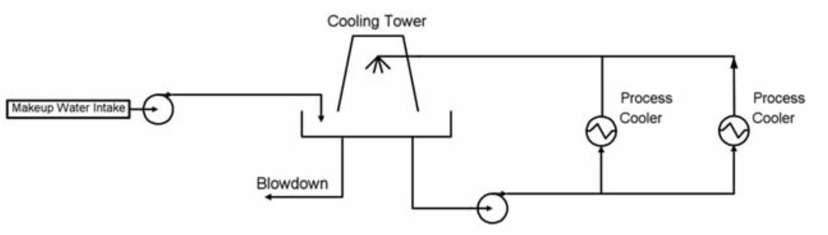


**Figure 8** *Evaporative cooling water system*



In a cooling tower system, part of the circulating water is removed as blowdown to prevent the build-up of dissolved solids in the system. The quantity of blowdown required depends on the quality of the make-up water, and the number of cycles of concentration that the cooling tower is operated at (typically 4 to 7).

Cooling tower blowdown is typically sent to wastewater treatment in refineries via the sewer. This is because in many cases the pressure on the process side of heat exchangers is higher than the cooling water pressure, and any leaks in a heat exchanger would result in the contamination of the cooling water with hydrocarbons. This practice imposes a hydraulic load on the wastewater treatment system. The full impact on wastewater treatment needs to be evaluated on a case-by-case basis.

**Table 9** *Cooling tower blowdown—contaminants*

| Contaminant | Expected concentration (mg/l) |
|---|---|
| Chemical oxygen demand (COD) | 150 |
| Free hydrocarbons | < 5 |
| Suspended solids | Up to 200 |
| Dissolved solids | Up to 700 |

Table 9 shows the expected level of contaminants in the cooling tower blowdown stream.

***Cooling tower blowdown—best practices***

- Monitor the cooling tower circulation loop for hydrocarbons.
- If hydrocarbon is detected the source of the leak needs to be determined and isolated quickly.
- Route the cooling tower blowdown to the wastewater treatment plant by a separate line and not through the sewer. This will prevent the blowdown from getting further contaminated with hydrocarbons that may be present in the sewers. However, this is costly, and may not be practicable in all cases. Reduction of oil to the sewer should be regarded as a primary strategy and can accomplish similar results.
- The cooling tower blowdown can be routed directly to the secondary oil/water separation equipment in wastewater treatment (bypassing the primary oil/water separation system).

## Condensate blowdown

In a refinery condensate losses are from:

- blowdown from the plant boiler system;
- blowdown from the various steam generators that are located in the process units; and
- unrecovered condensate from steam traps, steam tracing etc.

### Boiler blowdown

A portion (usually up to 5%) of the boiler feedwater (BFW) and condensate that is fed to the boilers in the refinery is purged from the system to maintain the dissolved solids level in the system at an acceptable level. This level could be different depending on the pressure level of the steam being produced (150 psi, 600 psi or 1500 psi). Figure 9 shows a typical system.

### Steam generator blowdown

A steam generator system is similar to the system shown above but the heat source is a process heat exchanger that needs to reject heat. Figure 10 shows the typical configuration of this system.

### Unrecovered condensate

The drivers for condensate recovery in refineries include:

- more energy savings if more condensate is recovered;
- quantity of boiler feedwater makeup required is directly proportional to the quantity of condensate lost; this results in increased operating costs for treating the BFW; and
- any condensate lost to the sewer increases the temperature of the wastewater and thus imposes a heat load at wastewater treatment.

The percentage of condensate recovered can be low in some refineries depending on design and layout of the refinery. Additionally, some of the condensate from steam traps and heat tracing is also lost to the atmosphere and/or sewer. Often these traps are discharged directly to the sewer and the hot discharge can ultimately cause deterioration of the sewers.

**Figure 9** *Boiler blowdown—typical*

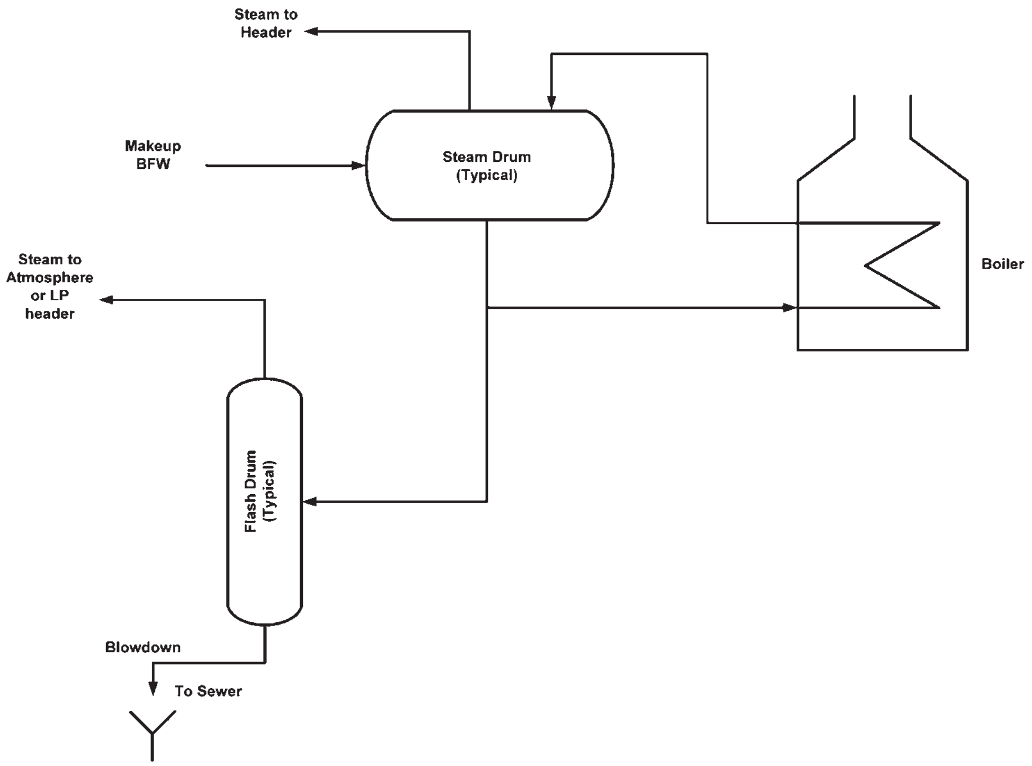
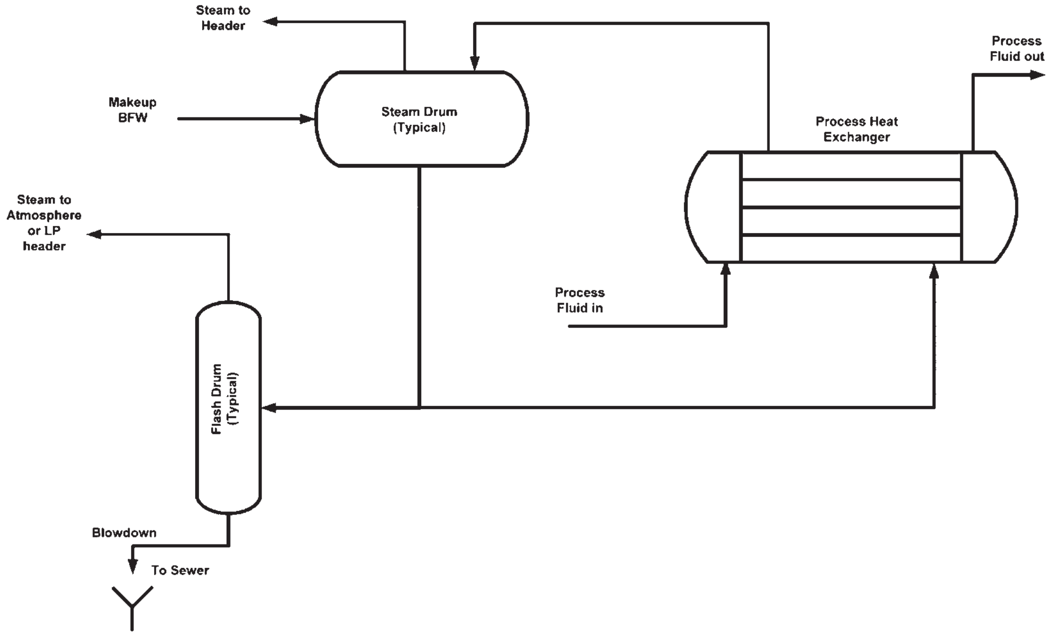


**Figure 10** *Steam generator blowdown—typical*



### Condensate blowdown—best practices

- The refinery should monitor the condensate balance in the refinery on an ongoing basis and efforts should be made to maximize recovery.
- The total volume of condensate blowdown (boiler, steam generator blowdown and others) should be less than 10% of the total flow of wastewater from the refinery.
- The quantity of blowdown taken at each boiler or steam generator in the refinery should be monitored and minimized.
- The blowdown from each location or a group of locations should be collected and sent to a flash drum (as shown in Figure 10) where the pressure is let down to atmospheric pressure before being discharged. The flashed blowdown should then be cooled with a heat exchanger. This will prevent deterioration of the sewers and also avoid heating and vaporizing of any hydrocarbons that might be present in the sewer. The discharge should not be cooled by directly adding water (such as utility water) because this could require the addition of a substantial quantity of water to adequately cool the stream. This will also result in an increase of the total flow of wastewater to the treatment plant.

## Raw water treatment

The raw water treatment in a refinery creates wastewater and sludges that require disposal. The following section describes the best practices with respect to these discharges.

### Raw water treatment—best practices

- When lime softening is used for raw water treatment, the sludge generated in this process should be thickened, and optionally dewatered. The thickener overflow water can be discharged directly without any further treatment, when local regulations allow. The sludge that is generated should be disposed off-site. Not discharging it to the sewer in the refinery will prevent the introduction of inert solids into the sewer in the refinery which in turn will avoid creation of more oil sludge that requires disposal.
- The use of ion exchange for treatment of raw water creates an alkaline wastewater stream and an acidic wastewater stream as a result of the regeneration of the ion exchange beds. These streams should be collected in a tank and the pH neutralized prior to being discharged directly to an outfall (bypassing wastewater treatment) if allowed by local regulation.
- The use of reverse osmosis for raw water treatment results in the creation of a reject stream that is very high in dissolved solids. This reject stream should be discharged directly to an outfall (bypassing wastewater treatment) if allowed by local regulation.

## Miscellaneous discharges—best practices

There are a variety of additional activities that, if implemented routinely at a facility, could reduce water use. Some of these activities include the following:

- **Housekeeping and washdowns:** If facilities use utility water hoses to washdown the process area and small inadvertent spills of hydrocarbons and other materials, operating procedures and training must be implemented to ensure that hoses are turned off after their use, and that other non-water means (for example, adsorbent pads or booms, brooms) be used to clean up area as appropriate.
- **Closed-loop sample systems:** For sampling hydrocarbons, closed-loop samplers should be installed and used. This will prevent the discharge of hydrocarbons to the sewer during the purging of sample lines.
- **Leak identification programme:** Firewater, or other water leaks in raw water piping or cooling-water piping can add to WWTP flows. These

systems should be periodically monitored for leaks.

### Miscellaneous discharges—minimization

Some additional ideas that can contribute to minimization of wastewater discharges to the sewer:

- **External cooling of heat exchangers:** At some locations due to the lack of adequate heat exchanger area or the high cooling water inlet temperature during the summer months, utility water hoses are used to cool these exchangers externally. This results in the discharge of substantial quantities of clean water to the sewer. This practice should be discontinued and the lack of adequate heat exchanger area should be addressed as soon as practical.
- **Fire water system:** Some refineries use treated wastewater in their firewater system. Implementation of this practice should be explored since it will not only minimize the discharge to the sewer but also result in savings of raw water.

## Laboratory wastewater

Typical refinery laboratories analyse both hydrocarbon and water samples. The wastewater that is generated in these laboratories can be categorized as follows:

- spent/unused hydrocarbon samples;
- spent/unused wastewater samples;
- discharges from sinks in the laboratory; and
- discharges from bottle washing systems in the laboratory.

### Spent/unused hydrocarbons samples—best practices

The spent/unused hydrocarbon samples should be disposed of in segregated drums located at convenient locations inside the laboratory. These drums should drain to a slop drum located outside the laboratory building where it will be collected and picked up periodically by a vacuum truck in the refinery and sent to the refinery slop system.

### Spent/unused wastewater samples—best practices

The wastewater samples should be discharged to a local sewer and, if necessary, routed through a local oil/water separator, prior to discharge to the wastewater treatment plant.

### Discharges from laboratory sinks—best practices

Discharges from the sinks in the laboratory should be routed to the wastewater treatment plant via a local oil/water separator, in cases where practices to ensure the discharges are oil free are unsuccessful. Care must be taken not to discharge various chemicals or reagents (such as nitro benzene) that could cause problems in the wastewater treatment plant. Chemicals or reagents that could upset a wastewater treatment plant should be managed separately, for example, disposed of in a separate drum and sent off-site for disposal.

### Discharges from bottle washing systems—best practices

It must be ensured that sample bottles are emptied to their respective systems (hydrocarbons to slops and wastewater to the sewer) prior to being washed in the bottle washing machines. This will minimize the formation of emulsions in the discharges from these machines. The discharges from the machines should be sent to the local sewer.

# Stormwater and sewerage

In this document, stormwater refers to precipitation from rainfall or snowfall. Stormwater from within the refinery process areas is potentially contaminated and typically needs to be treated prior to discharge. Non-process area stormwater may be discharged without prior treatment if allowed by local regulation.

Sewerage refers to wastewater that is discharged from kitchens, employee locker rooms and washrooms.

## Stormwater segregation and management

A variety of stormwater management practices are employed at refineries across the world. The particular approach a refinery adopts towards stormwater management is influenced by the age and condition of the sewer system, the frequency and intensity of precipitation, the water quality of process area runoff, the area contained within the process zones and local regulations and requirements.

Segregating non-process area stormwater from process area stormwater allows a refinery to potentially discharge the stormwater from non-process areas without treatment provided it is allowed by local regulation. Effective segregation can be achieved by means of curbing, grading, and proper selection of collection points. Non-process area stormwater is generally clean, and can be reused if it is segregated. A separate sewer or drainage system must be in place to implement this option. Contaminated stormwater must be collected separately and stored until it can be treated in the wastewater treatment plant.

### Contaminated stormwater

Process area runoff (contaminated stormwater) can be collected in storage tanks or impoundment basins and discharged for wastewater treatment at a controlled rate. This lowers the hydraulic loading on the treatment plant, and consequently decreases the sizing requirements for individual units in the treatment plant. Equipment sizing of many wastewater treatment units depends on hydraulic load. Biological treatment systems in particular do not respond effectively to sudden changes in flow or contaminant loadings.

The quantity of precipitation depends on rainfall intensity and the drainage area (process area). The drainage area can be directly measured through topological surveys or satellite imagery of the refinery property, taking into consideration the location of drainage points. Rainfall intensity data can be obtained from the local weather service or airport. The required storage volume required for stormwater is governed by local regulations.

***Contaminated stormwater—best practices***

Techniques that can be used to minimize the quantity of contaminated stormwater include:

- **Minimize process collection area:** Stormwater runoff from process units where they wash out hydrocarbons that have been inadvertently spilled on the pads should be directed to the contaminated stormwater collection system. Process areas where the stormwater cannot potentially come into contact with hydrocarbons or other chemicals can be routed to the non-contaminated stormwater collection system, or discharge it directly if it is allowed by regulation. Curbing or other modifications can be made to reduce the area draining to the contaminated stormwater sewer.
- **Treatment of 'first flush':** 'first flush' of stormwater refers to the stormwater that initially runs off the process area. First flush treatment is based on the assumption that the initial runoff is more contaminated because the hydrocarbons and other pollutants deposited on process areas get washed off by the first flush. The first flush will also contain any oil or solids that were trapped in a catchment area or sewer system. After the first flush is captured, subsequent runoff can then be diverted to the non-contaminated

stormwater system if allowed by local regulation. Even if the stormwater is allowed to be diverted to the non-contaminated system, local regulations typically require that the diverted stormwater be subjected to one stage of oil/water separation just as a precaution. The amount of first flush stormwater collected is the first inch or the first two inches of rain, and is usually governed by local regulations. The first flush is collected in a tank or basin and discharged to wastewater treatment at a controlled rate to avoid overloading the system hydraulically.

- **Minimize solids in stormwater:** Any sand or grit that collects in the process areas gets washed into the sewer with stormwater. These solids will mix with any hydrocarbons present in the sewer and create oily sludge. Typically, one pound of dry solids creates ten pounds of oily sludge and increases the load on the API separator[1] and the sludge treatment system. One of the sources of solids could be the erosion from unpaved areas that make their way into the process units. Paving adjacent areas or covering them with gravel will minimize the migration of sand and grit. Plant areas should be periodically swept and the solids should be collected and disposed of in an appropriate manner. Vegetation can be planted in strategic areas to minimize soil erosion during storm events.
- **Cover process areas:** Covering process equipment (where feasible) reduces the amount of stormwater that comes into contact with potentially contaminated areas. Water flows over the covers and can be directed to the non-contaminated stormwater collection system. Some examples of process areas where covers would be beneficial and practical are pump stations, heat exchangers and separation drums. Areas adjacent to non-contaminated drainage areas are the most logical candidates for covers, as the stormwater from these locations can be diverted directly into the non-contaminated drainage area. This technique would not be practical for large process units, where elevations of various pieces of equipment can vary significantly. A larger area of low-lying process equipment, however, could be covered by a single roof sloped towards a non-contaminated drainage area. In climates where significant snowfalls can be expected, covering for process areas must be designed to account for snow loads and/or must be equipped with measures to prevent freezing of drain lines.

## Non-contaminated stormwater

Segregating non-process area stormwater from process area stormwater requires a separate drainage system. This may consist of a buried drainage system, or a system based on grading, trenches and culverts. Curbing may also be necessary to separate process area stormwater from non-process area stormwater. Non-contaminated stormwater can be sent to a pond or lagoon for use as raw water for the refinery.

### *Non-contaminated stormwater—best practices*

- **Re-use:** There are several potential re-use opportunities for non-contaminated stormwater including fire water, cooling tower makeup, utility water and boiler feedwater makeup. These issues are discussed in more detail in the section on *'Re-use of non-contaminated stormwater'* on page 43 of this document.
- **Retention:** Local regulation will dictate the type and frequency of testing that will be required prior to the discharge of non-contaminated stormwater. Many refineries choose to hold the stormwater in a pond or basin prior to discharge. This will also allow time for the refinery to evaluate whether to reuse this water or not.

---

[1] See page 28 for more information on API separators.

## Sewerage management

Sewerage refers to wastewater that is generated in kitchens, locker rooms and washrooms in the refinery. At many locations the sewerage is combined with the wastewater generated in the refinery and sent to the wastewater treatment plant. Other refineries segregate the sewerage and treat it separately from the refinery wastewater.

The strategy for treatment should be dictated by the requirements of the local regulation. Typically the flow of sewerage in a refinery is relatively small when compared to the other wastewater generated in the refinery. If local regulations require that the combined treated wastewater needs to be chlorinated prior to discharge then segregation and separate treatment will result in substantial savings in chlorination costs. Local regulations may dictate additional certification and training for refinery WWTP operators when sanitary waste is comingled with refinery wastewater.

Treatment of sewerage can be effectively carried out in small self-contained packaged treatment systems at relatively small capital and operating costs.

# Effluent treatment

This section discusses the various types of treatment that are usually practiced by refineries for treating wastewater. It should be noted that best practices for the various types of treatment are not included in this section. This is because the technology used for refinery wastewater systems is site-specific and depends largely on influent conditions and the level of treatment required which is governed by local regulations.

Typical refinery wastewater treatment plants consist of primary and secondary oil/water separation, followed by biological treatment, and tertiary treatment (if necessary).

A typical refinery wastewater treatment system is shown in Figure 11.

In a refinery wastewater treatment system, two steps of oil removal are typically required to achieve the necessary removal of free oil from the collected wastewater prior to feeding it to a biological system. This oil removal is achieved by using an API separator followed by a dissolved air flotation (DAF) or induced air flotation (IAF) unit.

The wastewater from the secondary oil/water separation unit is sent to the equalization system (the choices for location of the equalization system are discussed on page 31) that is used to dampen out variations in flow and concentration in the refinery wastewater. The wastewater is then routed to the aeration tank/clarifier which constitutes the biological system. The effluent from the clarifier is then sent to tertiary treatment (if necessary) prior to discharge.

## Process wastewater pretreatment

In some refineries the wastewater generated from some of the units can be pretreated prior to discharge to wastewater treatment. Some of the practices that are used in refineries are summarised below.

### Desalter effluent treatment

The effluent from the desalter can be the cause of operating problems in wastewater treatment. Often, this is the result of changes to crude slates or other desalter upsets that affect the operation of the desalter resulting in inadvertent discharges of oil, emulsion and solids to wastewater treatment. The desalter effluent can also contain significant concentrations of benzene and other volatile organic compounds (VOCs) that tend to vapourize in the sewers leading to excessive emissions as well as odour problems in the refinery if the desalter effluent is not managed properly.

***Desalter oil/water separation***
Some refineries choose to subject the desalter effluent to an oil/water separation step (possibly using a separation tank) prior to discharge to the

**Figure 11** *Typical refinery wastewater treatment*

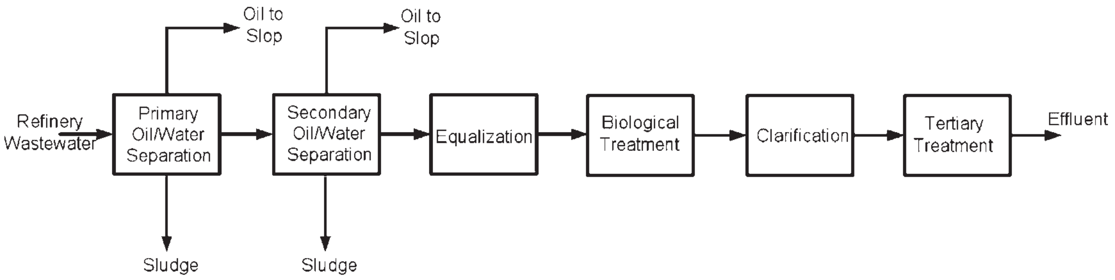
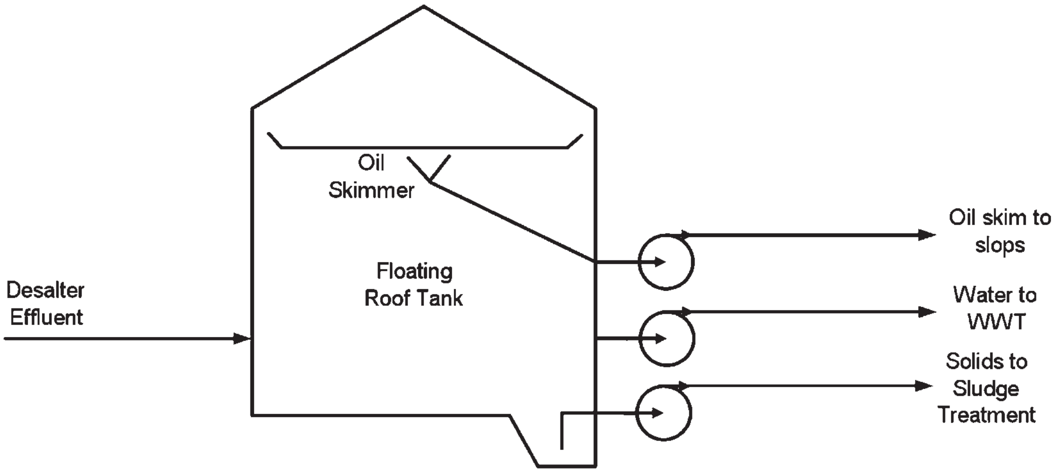


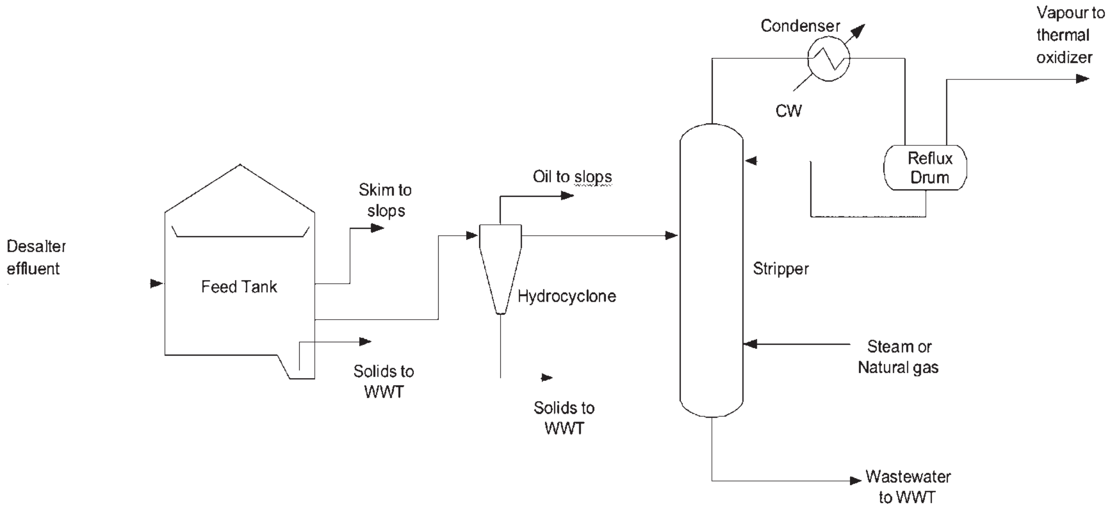
**Figure 12** *Desalter oil/water separation*



wastewater treatment plant. This approach is used especially when the capacity of a primary oil/water separator in the wastewater treatment is limited, and an analysis indicates that it is more cost-effective to install a separation step on the desalter stream rather than change or upgrade the existing wastewater treatment plant configuration. This is also a way of handling the increased load of solids that get discharged during mud washing of the desalter. Some refineries also use such a tank to divert the brine during upsets in the desalter. Figure 12 shows the configuration of a typical desalter effluent pretreatment system.

The desalter effluent is sent to a floating roof tank (floating roof in order to control VOC emissions) which typically has a residence time of a day or so in order to provide equalization, upset buffering etc. The brine is allowed to settle and separate. The oil is skimmed off and sent to refinery slops and the water

**Figure 13** *Desalter effluent stripper*



phase is sent to the wastewater plant. The bottom solids from the tank is sent to the sludge treatment plant or the coker unit if the refinery has such a suit.

### *Desalter effluent VOC control*

In some countries emissions of benzene and other volatiles are required to be controlled, by regulation. Since the desalter effluent can contain significant concentrations of these compounds, attempts have been made to control the emissions using strippers (steam/natural gas). The oil and solids content of the desalter effluent are high and this can foul/plug the internals of the stripper if proper pretreatment and equalization are not utilized. Figure 13 shows the configuration of a desalter effluent stripper.

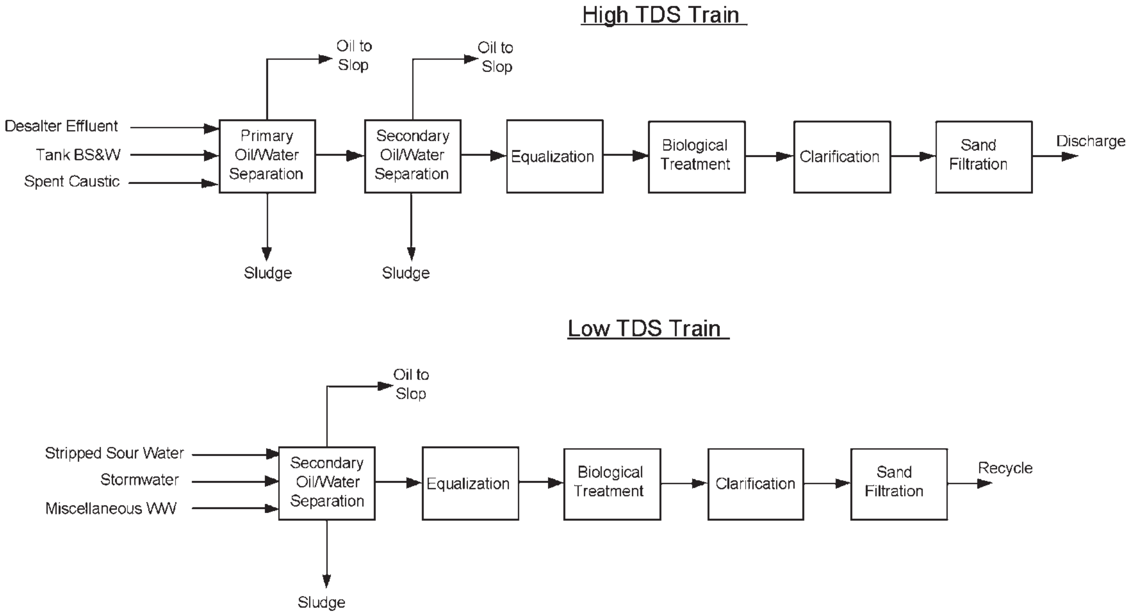
## Wastewater segregation

Given that there is a shortage of available raw water in many locations, and the fact that a typical refinery produces anywhere from 10 to 50 gallons of wastewater per barrel of crude processed, the reuse of treated refinery wastewater is increasingly coming into focus. An effective strategy for segregation of refinery wastewater is by the TDS content of the wastewater. As previously discussed the sources of wastewater in a refinery can be categorized as follows:

- desalter effluent (high TDS);
- tank BS&W (high TDS);
- spent caustic (high TDS);
- stripped sour water (low TDS);
- stormwater (low TDS); and
- miscellaneous wastewater (low TDS).

In a segregated system the refinery wastewater system would consist of two parallel trains with the same unit operations, except that the low TDS train would not include an API separator because the suspended solids loading of the inlet wastewater tends to be quite low. Figure 14 describes the two parallel trains.

**Figure 14** *Segregated wastewater treatment*



It should be noted that this level of segregation and treatment is not common practice in refineries but is sometimes considered in water-scarce areas. The issues associated with recycle and reuse of treated wastewater are discussed in greater detail in the section on '*Recycle and reuse issues*', beginning on page 42 of this document.

## Primary treatment

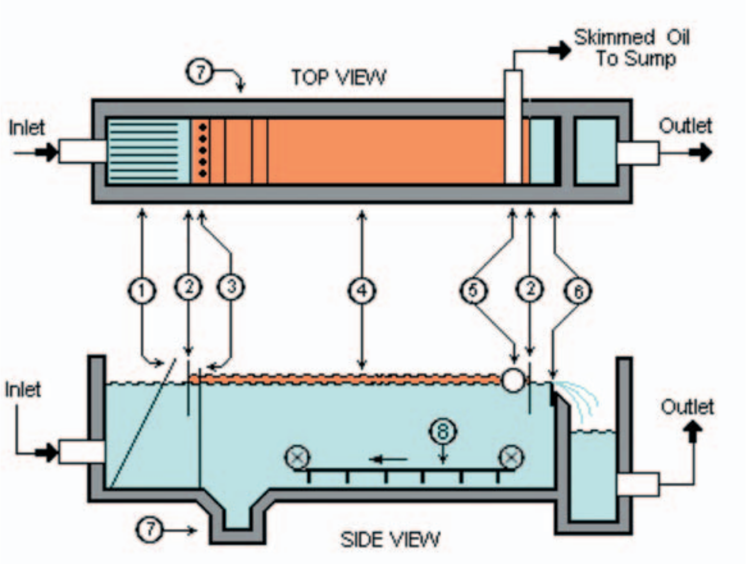
The primary treatment for refinery wastewater is a physical operation, usually gravity separation, to remove the floating and the settleable materials in the wastewater. In a typical refinery wastewater treatment system, the primary treatment step consists of an oil/water separator where oil, water and solids are separated. This is followed by a secondary oil/water/solids separation step in which a DAF or an IAF unit is used. The primary treatment steps are discussed in detail below.

### First stage: separation (oil/water separators, API separators)

API separators are frequently used in the treatment of refinery wastewater which usually contains oil and oil-bearing sludge. Separators use the difference in specific gravity to allow heavier material to settle below lighter liquids. Hydrocarbons that float on the surface are skimmed off, while the sludge that settles to the bottom is removed periodically.

In a typical API separator, wastewater is first collected in a pretreatment section that allows sludge removal. A diffusion barrier slowly allows the wastewater to flow down the separator towards the outlet while the lighter oil fractions can be skimmed off. Flights and scrapers are sometimes used to remove heavier solids. Underflow baffle plates are usually used to prevent oil from escaping into the outlet section. Figure 15 shows a typical API separator.

**Figure 15** *API separator*



1. Trash trap (inclined rods)
2. Oil retention baffles
3. Flow distributors (vertical rods)
4. Oil layer
5. Slotted pipe skimmer
6. Adjustable overflow weir
7. Sludge sump
8. Chain and flight scraper

(Reproduced courtesy of PSENCO)

Some of the performance-limiting factors relating to the API separators are listed and discussed below:

- Emulsified or dissolved oil that is usually present cannot be removed by an API Separator.
- High pH at the API separators can stabilize emulsions. Spent caustic streams should be either neutralized or routed directly to equalization in order to reduce pH at the API separators.

An API separator is an effective device for separating three phases (oil, solids and water) that are usually present in refinery wastewater. There are some refineries that use corrugated plate interceptors (CPI) or parallel plate separators (PPI). Both CPI and PPI separators tend to be smaller than a comparable API and require less plot space. However, while these devices are very effective as two-phase separators (oil and water), they are less effective when a third phase (solids) are present. The solids that are present in refinery wastewater tend to foul and plug the parallel plates resulting in the need for frequent maintenance.

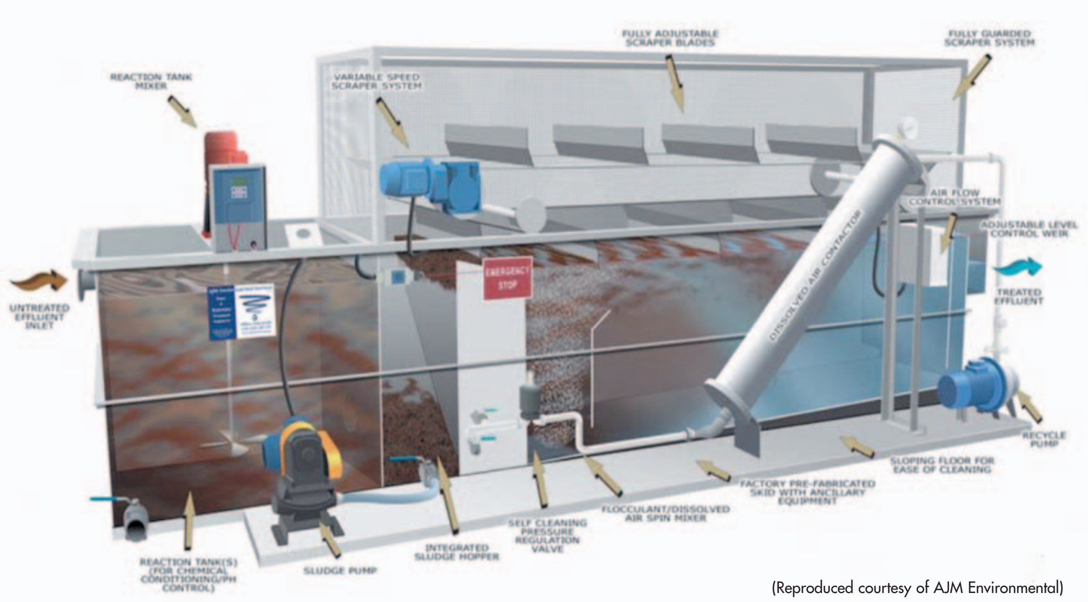
## Secondary oil/water separation

The effluent from the primary oil/water separation step is sent for further oil and fine solids removal to either a DAF unit or an IAF unit. The choice of whether to use a DAF versus an IAF unit is refinery-specific, and needs to be evaluated based on the influent conditions and the required outlet conditions.

### *Dissolved air flotation (DAF)*

The first step in a DAF system is coagulation/flocculation. Dispersed particles (oil/solids) are stabilized by negative electric charges on their surfaces, causing them to repel each other. Since this prevents these charged particles from colliding to form larger masses, called flocs, they do not settle. To assist in the removal of colloidal particles from suspension, chemical coagulation and flocculation are required. These processes, usually done in sequence, are a combination of physical and chemical procedures. Chemicals are mixed with wastewater to promote the aggregation of the suspended solids into particles large enough to settle or be removed.

**Figure 16** *Dissolved air flotation—a typical DAF unit*



(Reproduced courtesy of AJM Environmental)

In a DAF system, part of the effluent is recycled, pressurized, saturated with air and mixed with the incoming feed. When the recycle stream is depressurized it releases the air bubbles which attach themselves to any free oil/solids contained in the feed and float them to the surface of the vessel. The floated material is skimmed off and sent to refinery slops after further dewatering. Some solids also settle to the bottom of the DAF where they are scraped off and removed periodically. Figure 16 shows a picture of a typical DAF unit.

### *Induced air flotation (IAF)*

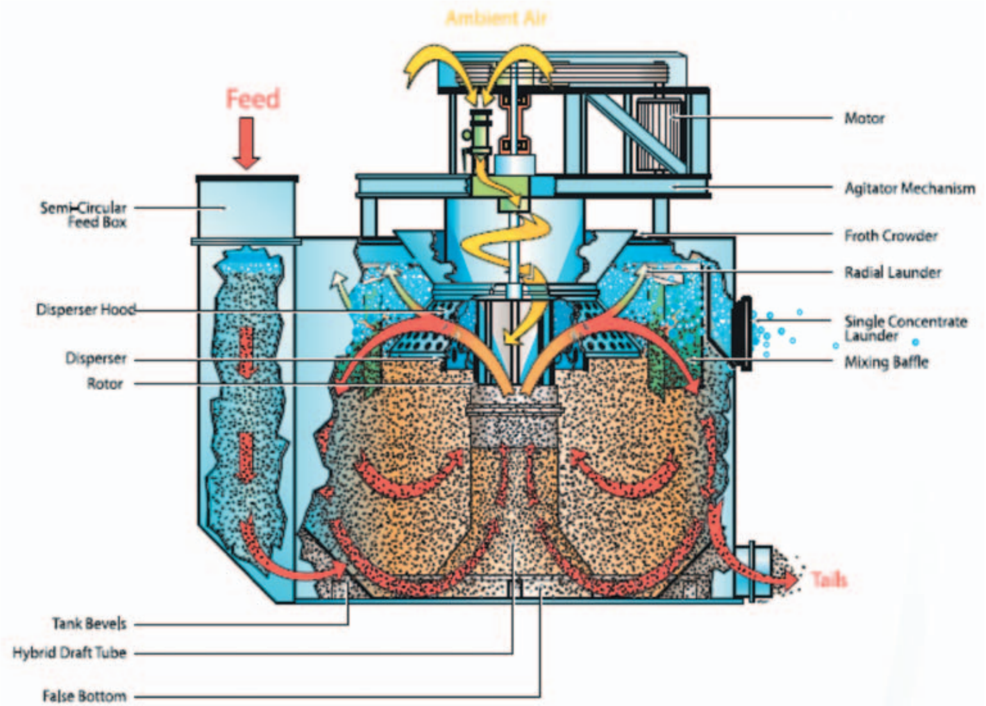
In an IAF unit, air is induced by a rotor-disperser mechanism, the spinning rotor acts as a pump and forces the fluid through the disperser openings and creates a vacuum in the stand pipe. The vacuum in the standpipe pulls the air and mixes it with the liquid. The liquid moves through a series of cells before leaving the unit and the float passes over the weir on one or both sides of the unit. The advantages of the IAF technique are compact size, low capital cost and the effective removal of free oil and suspended materials. The configuration of a typical IAF unit is shown in the Figure 17.

Other types of dispersed gas flotation units exist, such as the hydraulic type, where effluent is pumped and educts vapour from the top, before being distributed to each cell via a striker plate to create smaller bubbles which again attract and pull oil out of suspension.

## Equalization system

The objective of the equalization system is to minimize or reduce the fluctuations caused due to either sudden change of flow or composition in the wastewater treatment plant.

**Figure 17** *Induced air flotation (IAF) unit*



(Reproduced courtesy of WEMCO)

- **Flow equalization:** Flow equalization provides dampening of the flow variations, thereby reducing potential spikes in flow and loads to the downstream units; it also reduces the size of the downstream units and the cost of the overall refinery wastewater system.
- **Concentration equalization:** This system provides dampening of contaminants, thereby preventing the shock loading of the downstream units such as biological systems. In a biologically-based system, performance is limited by the capacity of the microorganisms to adapt to the changing conditions of variation in flow and composition.

### Location of the equalization system

In Figure 11, the equalization system is shown *after* the secondary oil/water separation step. Other potential locations for the equalization system are discussed below.

#### *Upstream of the API separator*

Some refineries choose to locate the equalization tank upstream of the API separator in order to dampen the variations in flow to the separator. If this location is chosen, it must be recognized that all the oil and solids contained in the refinery wastewater will pass through this tank and some of them will separate. Hardware (piping/pumps and controls) must be provided to allow removal of free oil and solids from the tank in order to avoid accumulation of these materials. Frequent cleaning of this tank (once or twice a year) may also be required depending on the loading of solids and oil that are contained in the refinery wastewater.

#### *Upstream of the DAF/IAF*

The equalization tank is installed at this location in order to dampen the flow variations to the DAF/IAF and downstream equipment. While this will tend to make all the downstream equipment smaller, any oil that is present in the effluent from the API separator will accumulate in this tank if it is not removed periodically.

#### *Downstream of the DAF/IAF*

The primary goal of installing the equalization tank at this location is to protect the downstream equipment (biological system) from wide variations in flow and concentration.

## Secondary treatment

Biological treatment is the most widely used wastewater treatment technology for removal of dissolved organic compounds in the oil refining industry.

In general, biological treatment can be classified into two categories:

- suspended growth processes; and
- attached growth processes.

### Suspended growth processes

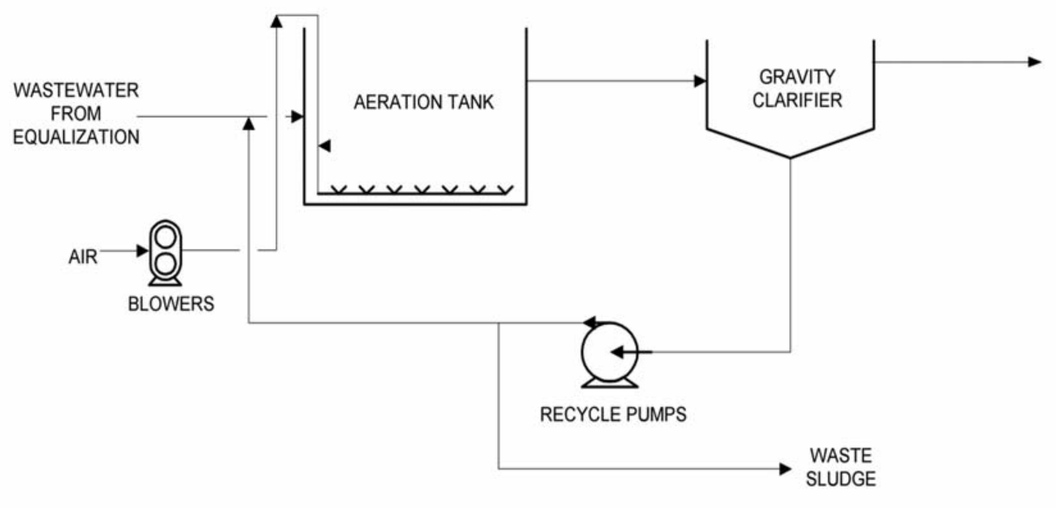
Suspended growth processes are biological treatment processes in which the microorganisms are thoroughly mixed with the organics in the liquid, and maintained as a suspension in the liquid. Microorganisms use organic constituents as food for their growth and clump together to form the active biomass. The most commonly practiced suspended growth process used in the treatment of refinery wastewater is the 'activated sludge process' (discussed below).

#### *Activated sludge*

An activated sludge process is the most effective of all the biological systems available. It is used in many refineries around the world and offers a reliable method of biological treatment.

Activated sludge is a continuous suspension of aerobic biological growths in a wastewater containing entrapped suspended colloidal, dissolved organic and inorganic materials. The microorganisms use the organic material as a carbon source and energy for the microbial growth, and convert the food into cell tissue, water and oxidized products (mainly $CO_2$).

**Figure 18** *Activated sludge system*



In an activated sludge process, the wastewater enters an aeration tank where the microorganisms are brought in contact with organic contaminants of the wastewater. Air is continuously injected into the system to keep the sludge aerobic and to maintain the solids in suspension. The mixture of wastewater and sludge in the aeration basin/tank is referred to as the 'mixed liquor', and the biomass in the mixed liquor is referred to as 'mixed liquor suspended solids' (MLSS). The organic portion of the biomass is generally referred to as the 'mixed liquor volatile suspended solids' (MLVSS). In a typical refinery wastewater treatment system, the MLSS are composed of 70–90% active MLVSS and 10–30% inert solids.

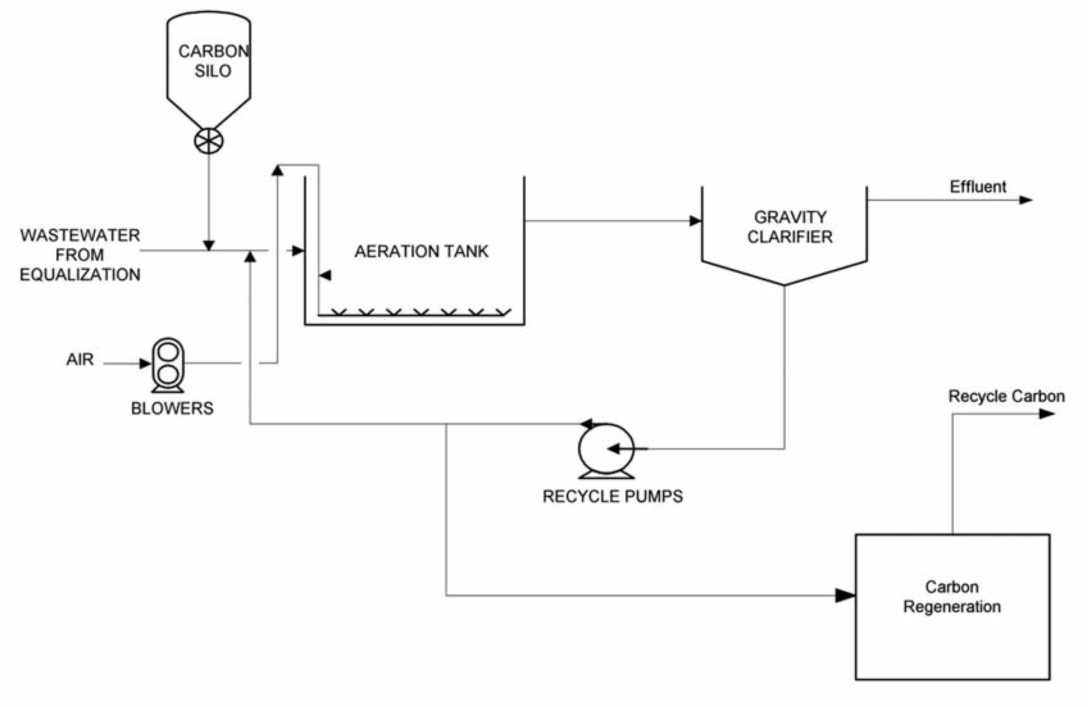
A schematic of a typical activated sludge system is shown in Figure 18. The incoming wastewater enters the aeration tank where it is contacted with microorganisms and air. The effluent from the aeration tank is sent to the clarifier. The organic contaminant in the wastewater gets converted into the biomass and gets separated later in the clarifier. A portion of the concentrated sludge, referred to as 'return activated sludge' (RAS), from the clarifier is recycled back and mixed with incoming wastewater, and the remainder of the sludge is discharged as 'waste activated sludge' (WAS).

### *Activated sludge treatment with powdered activated carbon (PACT®)*

The PACT® (Powdered Activated Carbon Treatment) system is similar to the conventional activated sludge system described above. In this treatment system both biological oxidation and carbon absorption occur simultaneously, thus enhancing the removal of contaminants in the wastewater. Most of the powdered activated carbon is recycled with the activated sludge, but the system requires a continuous makeup of fresh carbon. PACT® systems are generally used for refinery wastewater in those cases where stringent standards need to be met for certain contaminants.

A schematic of a typical PACT® system is shown in Figure 19.

**Figure 19** *The PACT® (Powdered Activated Carbon Treatment) system*



***Sequencing batch reactor***

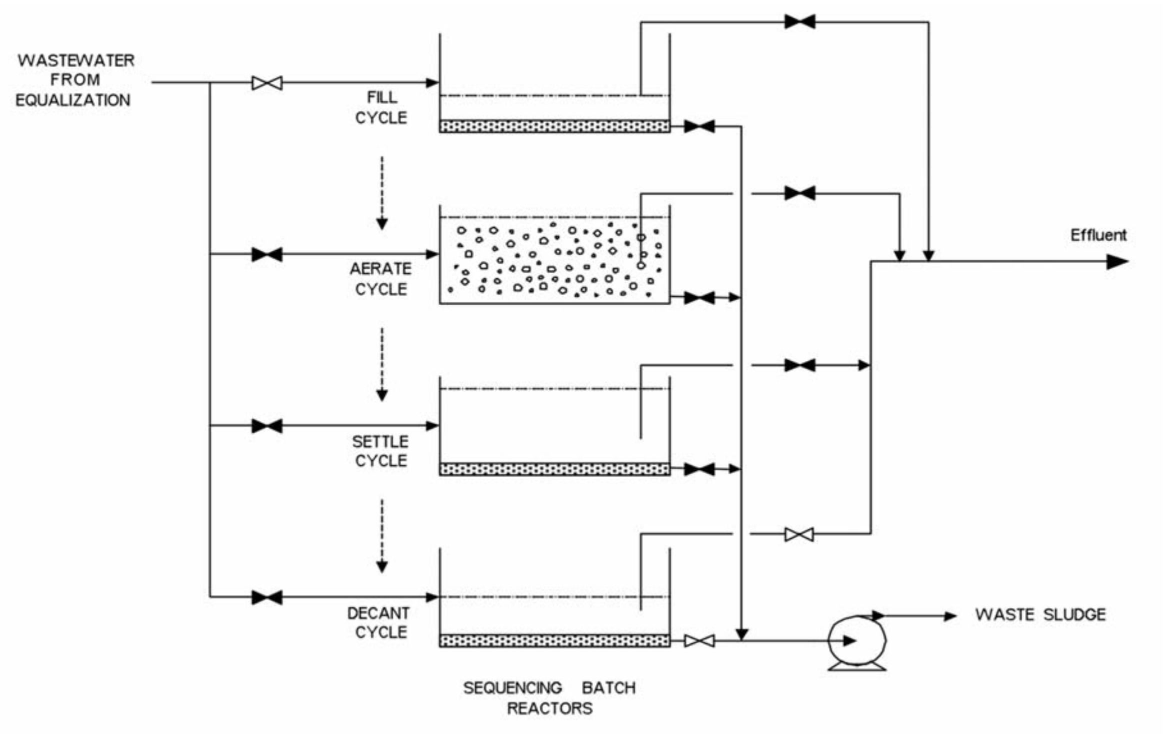
A sequencing batch reactor (SBR) is a fill-and-draw semi-batch biological treatment alternative that employs aeration, sedimentation and clarification in a single reactor. The unit processes of aeration and sedimentation are common to both the SBR and activated sludge systems. In activated sludge systems the unit operations take place in different basins, while in the SBR the operations take place in a sequential order in a common basin.

Although still practiced in some refineries, SBR technology is increasingly uncommon and has limited application in refinery wastewater treatment. Figure 20 (overleaf) shows a typical SBR system.

The various steps of operation are described below:

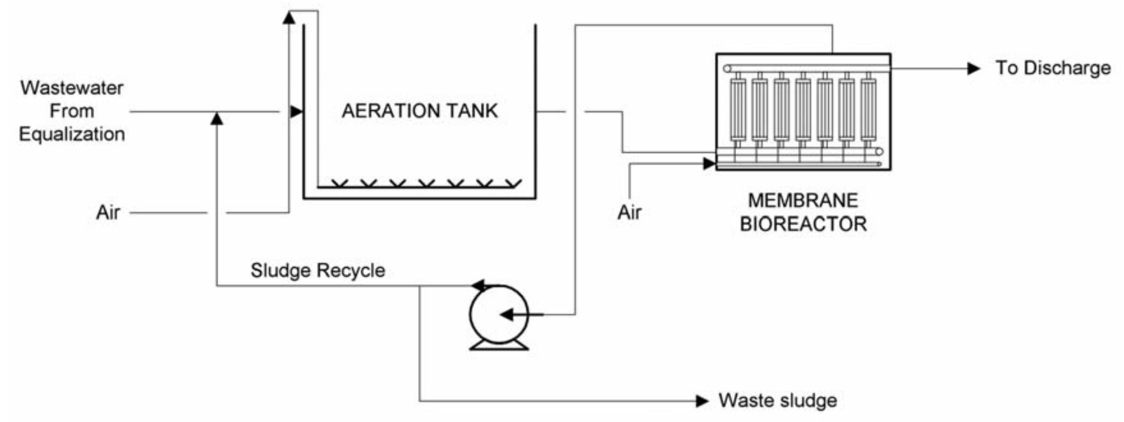
- **Fill:** During the fill operation, wastewater with the substrate is added to the reactor. The aeration system is not operated as the reactor is charged with wastewater from the equalization tank.
- **React:** During this step, wastewater is aerated in the same way as in the activated sludge system. Biological activity is initiated in this cycle of operation.
- **Settle:** In this step, aeration is terminated and MLSS is allowed to settle. The settling is accomplished under quiescent conditions; no flow enters, or is withdrawn from the reactor during the settle period.
- **Decant:** During the decant period, clarified or treated supernatant effluent is withdrawn from the upper portion of the reactor. The sludge blanket at the bottom of the reactor is maintained so that it is available as seed sludge for the next cycle.
- **Idle:** This is not a necessary step and is usually omitted for the refinery wastewater treatment system. The idle period is the time between the draw and the fill; it could be zero or could be days. Generally, it is used in multi-tank systems, thereby providing time to one reactor to complete its fill phase before switching to another unit.

**Figure 20** *Sequencing batch reactor system*



***Membrane bioreactor technology***
Membrane bioreactors (MBRs) are suspended-growth biological treatment processes and are a variation on the activated sludge system. A membrane bioreactor combines a membrane process (e.g. microfiltration) with a suspended growth bioreactor, thereby eliminating the secondary clarification used in an activated sludge system. A schematic of a typical MBR system is shown in Figure 21.

**Figure 21** *Membrane bioreactor system*



The micro-filtration membranes are located in a steel membrane tank and are subjected to a low-pressure vacuum that pulls water through the membranes and pumps the filtered water to the next process step while retaining solids in the reactor. Compressed air is injected into the system to scour the exterior of the membranes. The MBR system usually operates at higher MLSS concentrations (15,000–20,000 mg/l) than conventional activated sludge systems. MBR systems are not used in refining due to increased cost compared to conventional activated sludge, however for activated sludge systems that require tertiary filtration, MBR is more cost competitive, since it is equivalent to having an effluent filter. For applications where further tertiary treatment such as reverse osmosis will be used, MBR can be attractive versus the alternative option of using media filtration and microfiltration after biological treatment (see page 47).

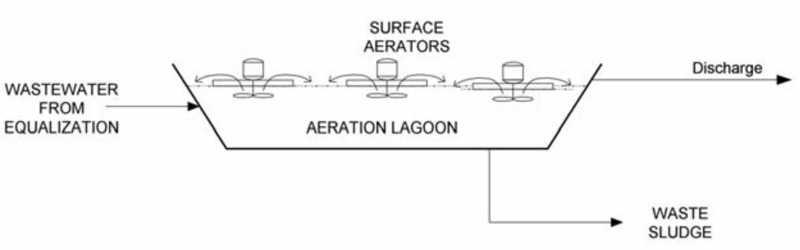
### *Aerated lagoons*

In this type of system, wastewater is treated in an earthen in-ground basin that is used for both the aeration and the settling functions. Air is injected through mechanical or diffused aeration units into the lagoon to promote biological treatment. There are usually two types of aerated lagoons:

- **Aerobic lagoons:** In aerobic lagoons, dissolved oxygen is maintained throughout the basins. For this type of a system, settling can take place at a part of the pond separated by baffles or separate sludge settling and disposal facilities might be required. The settled sludge is removed periodically.
- **Aerobic-anaerobic/facultative lagoons:** In these types of lagoons, oxygen is maintained in the upper layer of the liquid in the basin and the rest of the lagoon remains anaerobic. A portion of suspended solids moves to the downstream part of the lagoon where settling takes place and undergoes anaerobic decomposition.

Figure 22 shows a typical lagoon treatment system.

**Figure 22** *Aerated lagoon system*



Aerated lagoons usually require much larger plot areas than other treatment methods, and are commonly employed where land area is not expensive or when discharge standards are not overly restrictive. With the current stringent effluent standards faced by the petroleum industry, aerated lagoons are used less frequently for wastewater treatment in refineries because they cannot produce comparable effluent quality to activated sludge systems.

## Attached growth processes

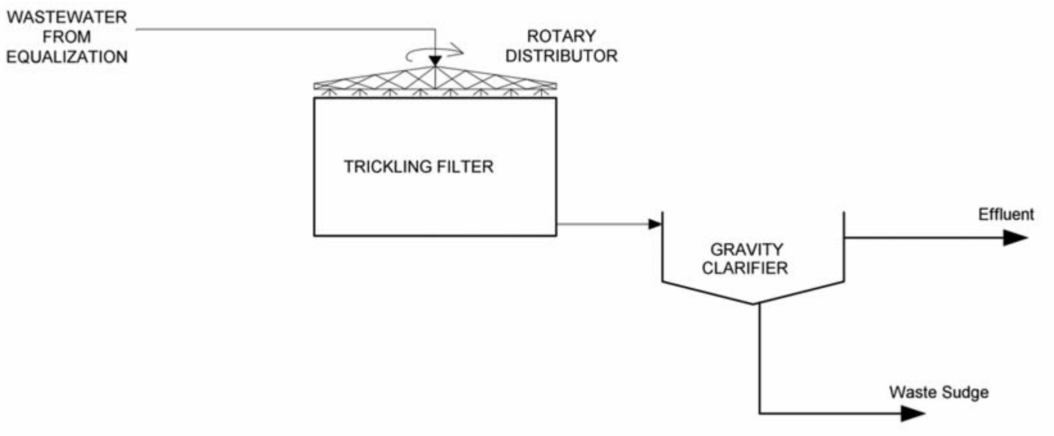
In attached growth processes, microorganisms are attached to an inert packing material instead of being suspended in the liquid as in suspended growth processes. The packing used in the attached growth processes can be rocks, gravel, plastic material and various synthetic materials. The wastewater comes in contact with the microorganisms that are attached to the media and are converted to more biomass and $CO_2$. The film of biomass on the media keeps growing and ultimately sloughs off when it reaches a certain thickness.

### *Trickling filters*

The trickling filter system consists of:

- a bed of packing material such as rock or plastic packing on which the wastewater is distributed continuously;
- an underdrain system to carry the treated water to other units; and
- distributors for distributing the influent wastewater to the surface of the filter bed.

**Figure 23** *Trickling filters*



A slime layer (microorganisms) develops on the packing in the trickling filter. As wastewater passes through the trickling filter bed, the microorganisms biodegrade the organics to be removed from the liquid flowing over the packing. A final clarifier, located immediately downstream of the filter, serves to remove microbial growths that periodically slough off from the filter media.

A schematic of a typical trickling filter system is shown in Figure 23.

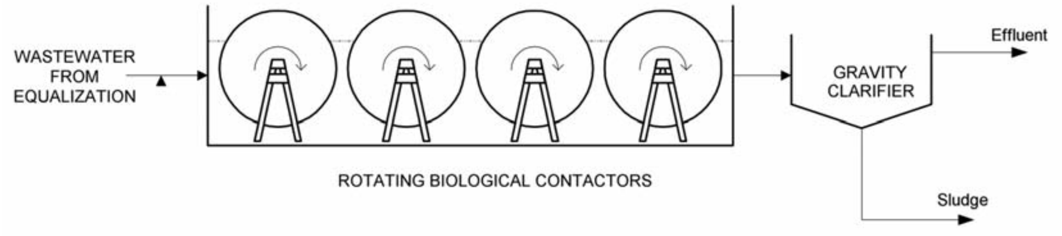
***Rotating biological contactor***

The basic element of the rotating biological contactor (RBC) consists of closely spaced plastic discs mounted on a horizontal shaft. The disc material is usually of polystyrene or polyvinyl chloride. These plastic discs are submerged in wastewater and are continuously rotated by the horizontal shaft through an air driven motor. Microorganisms adhere to the plastic surface and form a layer of biological mass (slime) on the discs. Over time, excess sludge is sloughed off the discs.

As the discs are rotating, the attached microorganisms react with the contaminants in the wastewater and convert them to biomass and $CO_2$.

A schematic of a typical RBC system is shown in Figure 24.

**Figure 24** *Rotating biological contactor system*



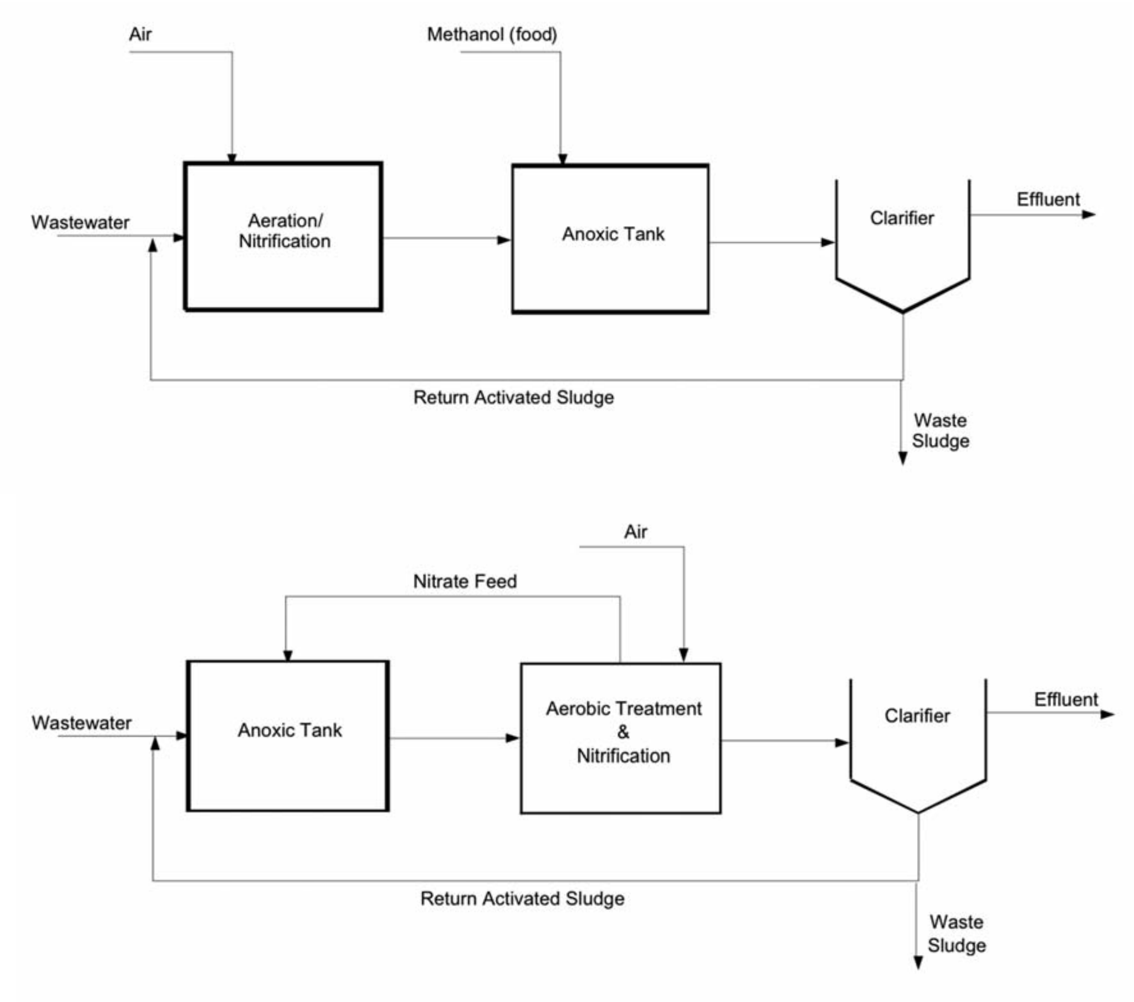
***Nitrification, or nitrification with denitrification***

In some cases when a refinery site is required to meet tight ammonia or nitrogen limits, the biological treatment system could include either a nitrification (by the use of nitrifying bacteria) or a combined nitrification/denitrification step. The level of nitrogen compounds in refinery wastewater can be controlled by avoiding discharges of spent amines and proper removal of ammonia in the sour water stripper. If the concentration of nitrogen compounds is still too high to meet regulatory limits, then nitrification or nitrification/denitrification should be included in the biological treatment system.

Nitrification is the term used to describe the two-step biological process in which ammonia ($NH_4$-N) is oxidized to nitrite ($NO_2$-N) and the nitrite is oxidized to nitrate ($NO_3$-N). In denitrification, the nitrate is reduced to nitric oxide, nitrous oxide and nitrogen gas. Figure 25 shows the two arrangements that are used in these systems.

In the first system, the aeration/nitrification tank is followed by an anoxic tank where denitrification occurs. A food source (typically methanol) is added to this tank to aid in the process. In the second system, the anoxic tank is followed by the aeration/nitrification tank. In this case, the food source for the anoxic tank is the BOD in the

**Figure 25** *Nitrification/denitrification systems*



incoming wastewater. A portion of the treated wastewater from the aeration tank is recycled so that the reduction of nitrates in the effluent can occur.

## Tertiary treatment

Tertiary treatment needs to be considered if the refinery needs to meet stringent limits for different contaminants such as:

- total suspended solids (TSS);
- chemical oxygen demand (COD);
- dissolved and suspended metals; and
- trace organics such polyaromatic hydrocarbons (PAHs)

### Sand filtration

Effluent from the biological treatment system typically contains about 25 to 80 mg/l of suspended solids depending on the operating conditions in the clarifier. Refineries at many locations need to meet limits as low as 15 mg/l on a consistent basis. In these instances, one option is for the effluent from the clarifier to be filtered using sand filters. This process involves passing the wastewater through a filter bed comprised of a filter media. Dual media filters comprise a layer of anthracite over sand. The larger particles are trapped by the anthracite and the finer solids are held up in the sand. Periodically, the forward flow is stopped and the filter is backwashed to remove the trapped solids. Figure 26 shows the typical configuration of a sand filtration system.

### Activated carbon

Removal of dissolved organic constituents from the refinery wastewater can be done by carbon adsorption. In general, activated carbon is usually applied as an effluent 'polishing' step (removal of residual organics) for wastewater that has been processed in a biological treatment system. This is because the carbon usage will be prohibitively high if it applied to the refinery wastewater.

In this process the wastewater is passed though a bed of granular activated carbon (GAC) where the organics in the wastewater are adsorbed by the carbon. The carbon bed is periodically regenerated to remove the organics from the exhausted carbon. Figure 27 shows the configuration of a typical carbon adsorption system.

**Figure 26** *Sand filtration*

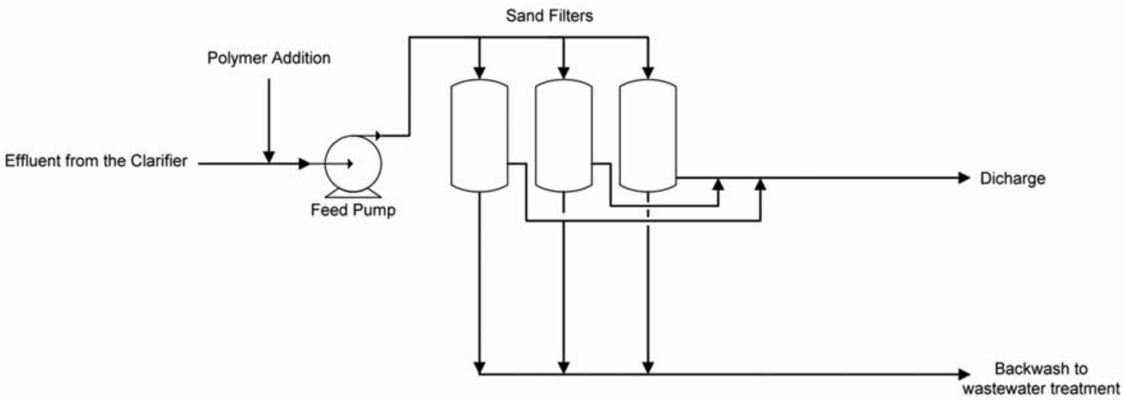
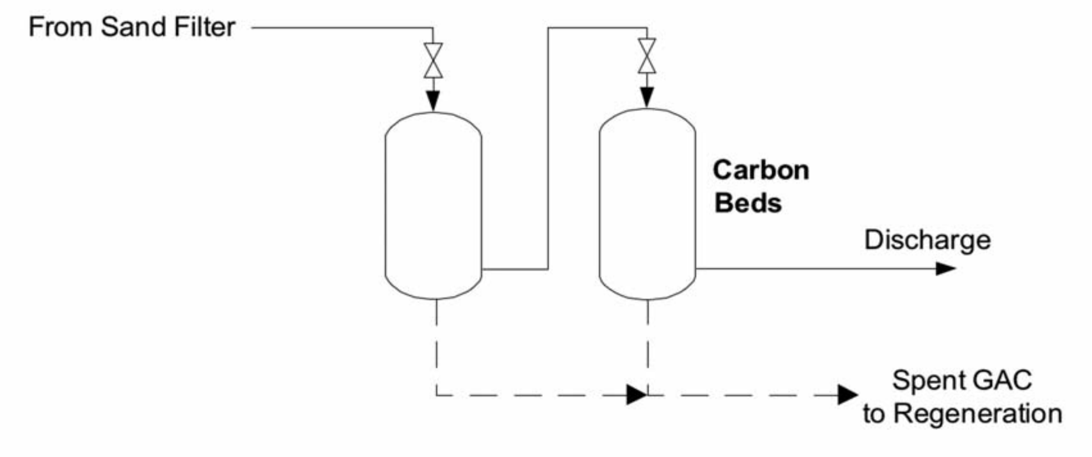


**Figure 27** *Activated carbon system*



## Chemical oxidation

Chemical oxidation in a refinery is generally used for reduction of residual COD, non-biodegradable compounds, and trace organic compounds. It is not common to have a chemical oxidation system in a refinery wastewater treatment plant; details of this approach are included in this document for information purposes.

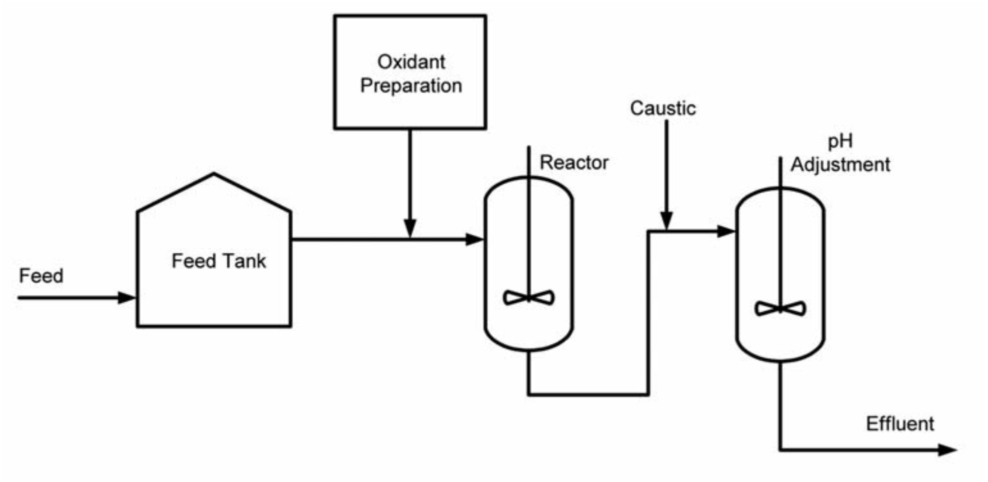
The following oxidation reagents are generally used in a chemical oxidation system:

- hydrogen peroxide;
- chlorine dioxide; and
- ozone.

Chemical oxidation can be enhanced in some cases by the use of UV light as a catalyst, but this needs to be evaluated on a case-by-case basis.

Figure 28 shows the configuration of a typical chemical oxidation system.

**Figure 28** *Chemical oxidation system*



The feed is sent to the oxidation reactor via a feed tank which provides any surge capacity that is required. Chemical oxidant (hydrogen peroxide, ozone or chlorine dioxide) is prepared fresh to maintain reactivity and fed to the reactor. The effluent from the reactor is then sent to another vessel for adjustment of pH if necessary.

## Treatment of sludges

In a refinery wastewater treatment plant, sludge is typically produced from the following unit operations:

- API separator—bottom sludge;
- dissolved gas flotation (DGF) and induced gas flotation (IGF) systems—float and bottom sludge;
- biological treatment—waste biological sludge

### API separator—bottom sludge

The need for treatment of sludge that is removed from the bottom of the API separator depends on refinery configuration as well as local environmental regulations. This sludge, after further dewatering and de-oiling, can be sent either to off-site disposal or to the coker unit in the refinery (if the refinery has such a process unit). A typical sludge treatment system is shown in Figure 29.

The API sludge is sent to a decanter tank where water and free oil are removed. If the refinery has a coker unit, the sludge from the tank can be sent to this unit if possible. An alternative is to send it to a centrifuge for further separation. The centrate from a centrifuge is sent to refinery slops and the sludge sent to off-site disposal.

### DGF/IGF float and sludge

The float from the DGF/IAF typically contains emulsions the chemicals (flocculants and coagulants) that are added to aid the separation and therefore require to be handled separately. Figure 30 (opposite) shows the typical treatment of DGF/IGF float.

The float is sent to a tank where emulsion-breaker chemicals are added (if necessary) and the fluid is recirculated and heated up to break the emulsions. The material in the tank is then sent to disposal.

The sludge from the DGF is normally sent to the same system that treats the API sludge (shown in Figure 29).

**Figure 29** *API sludge treatment system*

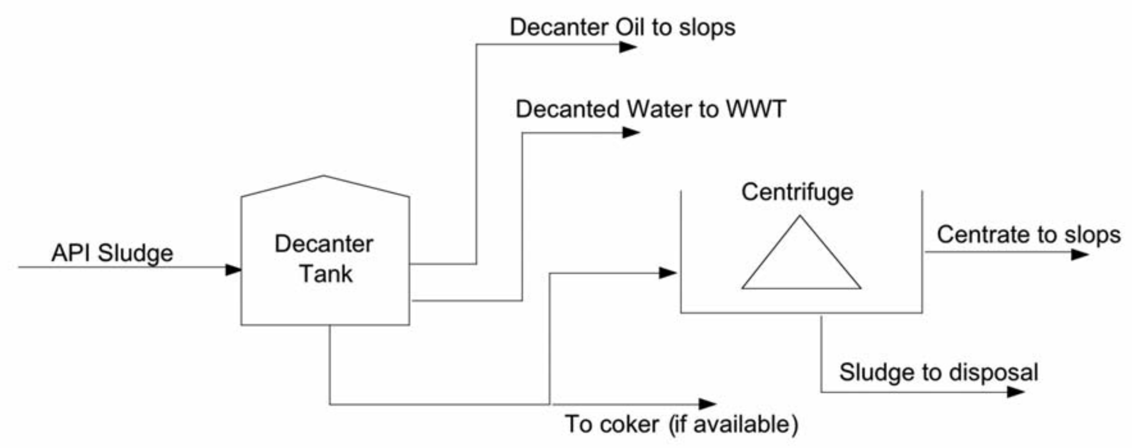
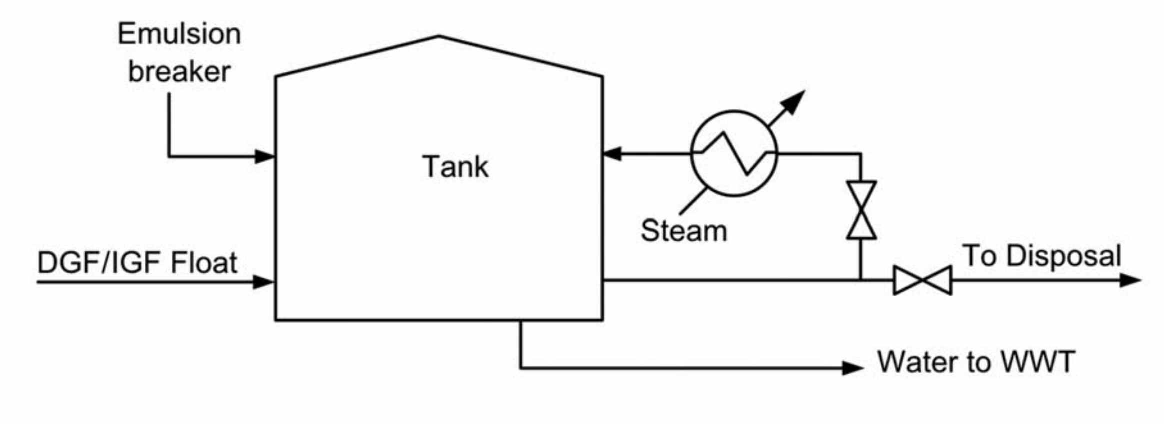


**Figure 30** *DGF/IGF float treatment*



## Waste biological sludge

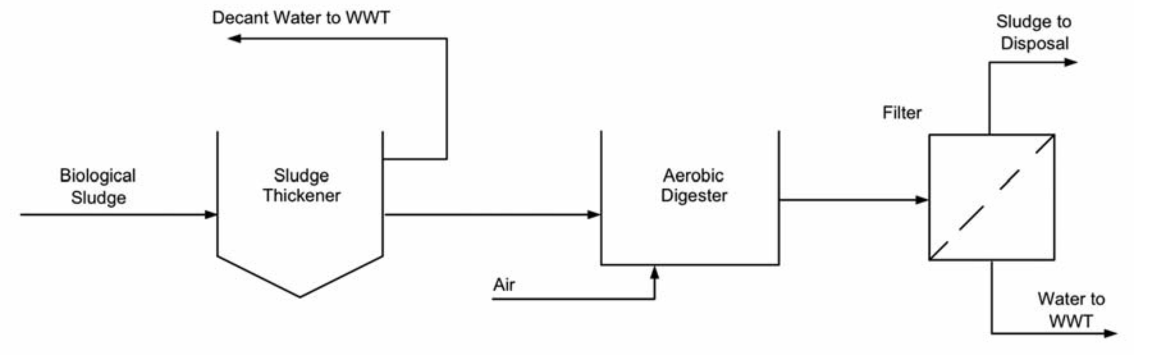
Excess sludge that is produced in a biological system can be disposed of (after pretreatment) in several ways, depending on local regulations, including:

- land farming;
- land fills; and
- off-site disposal.

Typical pretreatment of biological sludge is shown in Figure 31.

The biological sludge is sent to a thickener, which could be a gravity or DAF thickener, where water is separated from the sludge and returned to WWT, The sludge from the Thickener is sent to an aerobic digester where air is added to digest the sludge. This step is essentially a volume reduction step to lessen the load on the downstream filter. In some cases the sludge from the Thickener is sent to the Filter. Several types of filters such as belt filter presses, plate and frame filters etc can be used. The type of filter that is most appropriate will need to be evaluated on a case-by-case basis.

**Figure 31** *Biological sludge treatment*



## Recycle and reuse issues

With the shortage of fresh water in most areas of the world, and the requirements for relatively high volumes of raw water in a refinery, the pressure to recycle and/or reuse of water is increasing. In evaluating recycle/reuse issues in a refinery, the potential uses of water should be evaluated along with recycle/reuse of refinery wastewater as well as external sources of wastewater (such as municipalities).

The water uses in the refinery can be broken down as follows:

- process water:
  - desalter makeup;
  - coker quench water;
  - coker cutting water;
  - flare seal drum;
  - FCC scrubbers;
  - hydrotreaters;
- boiler feedwater makeup;
- cooling water makeup;
- potable water;
- fire water; and
- utility water.

**Table 10** *Contaminant specification for reuse water*

| Water category | Contaminant specification | Potential source of re-use water |
|---|---|---|
| Desalter makeup | • Sulphide: < 10 mg/l<br>• Ammonia: < 50 mg/l<br>• Total dissolved solids (TDS): < 200 mg/l | • Stripped sour water<br>• Vacuum tower overhead<br>• Crude tower overhead |
| Coker quench water | • Total suspended solids: < 100 mg/l<br>• Biological solids: none<br>• $H_2S$ and other odorous compounds: none | • Stripped sour water |
| Coke cutting water | • Total suspended solids: < 100 mg/l<br>• Biological solids: none<br>• $H_2S$ and other odorous compounds: none | • Stripped sour water |
| Boiler feedwater makeup (quality required is highly dependent on the pressure of steam being produced) | • Conductivity: < 1 µS/cm<br>• Hardness: < 0.3 mg/l<br>• Chlorides: < 0.05 mg/l<br>• Sulphates: < 0.05 mg/l<br>• Total silica: < 0.01 mg/l<br>• Sodium: < 0.05 mg/l<br>• Dissolved oxygen: < 0.007 mg/l | • Treated and upgraded refinery wastewater |
| Cooling tower makeup | • Conductivity: < 6,000 µS/cm<br>• Alkalinity: < 3,000 mg/l<br>• Chlorides: < 1,500 mg/l<br>• Suspended solids: < 150 mg/l | • Treated and upgraded refinery wastewater |

From the list of water uses on the previous page, the process water, boiler feedwater makeup and cooling tower makeup represent the largest users and are ideal candidates for use of recycled water. Table 10 shows the typical specification of contaminant levels required for these waters.

These values should be used for general informational purposes only. A detailed evaluation of the refinery specific application in question is required before initiating any water re-use.

## Re-use of non-contaminated stormwater

Many opportunities exist for reuse of non-contaminated stormwater. Some examples of applications for collected non-contaminated stormwater runoff are described below.

### Fire water

Fire drills and actual fire events at refineries require large volumes of fire water. During emergencies, firewater is usually drawn from an on-site storage and supplemented by an outside source such as rivers, lakes etc. Non-contaminated stormwater can be directed to the fire pond in the refinery for storage and reused in the fire water system as required.

### Cooling tower makeup water

Cooling tower systems require a constant source of water for makeup due to losses from drift, evaporation and blowdown. Non-contaminated stormwater may be used for this purpose, though it will require some treatment to remove particulates before entering the cooling tower system. Water softening may also be required if calcium and magnesium is picked up from the impoundment used to store the non-contaminated stormwater.

### Utility water

Refinery utility water systems use non-potable, non-contaminated water. Utility water may be used for any purpose in the refinery where water is needed, such as paved area wash-down and wash water for spill clean-ups. Stormwater may be collected and pumped from storage into the plant utility water supply header. As with any water reuse system, the source of the water, its quality and potential contaminants must be monitored and deemed acceptable for all designated uses.

### Boiler feedwater makeup

Demineralization systems are required for boiler makeup water to avoid boiler scaling. Non-contaminated stormwater can be used as makeup to the BFW makeup system. It will need pretreatment for solids removal and additional treatment to remove hardness prior to use as BFW makeup.

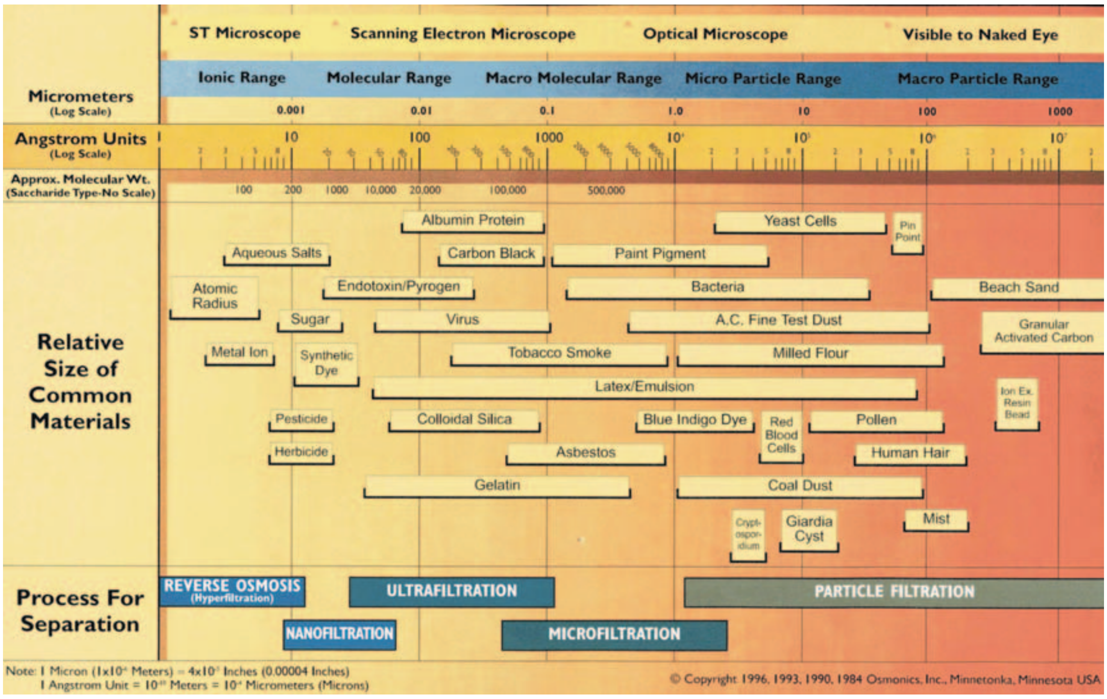
## Technologies for upgrade of refinery wastewater

All the options available for upgrade of refinery wastewater utilize one or more filtration processes for treatment, including some membrane treatment options. Membrane treatment technologies have become increasingly popular (although they have their limitations due to cost) in the water and wastewater treatment industry over the past 20 years, and offer significant advantages over more traditional treatment options. Figure 32 shows the size of contaminants that can be removed through different types of filtration, and provides sizes for some common particles for reference.

The following options are considered potentially suitable for treating refinery effluent:

- basic media/sand filtration;
- microfiltration or ultrafiltration;
- microfiltration or ultrafiltration, with reverse osmosis;

**Figure 32** *Contaminant removal for different types of filtration processes*



(Reproduced courtesy of Osmonics)

- microfiltration or ultrafiltration with nanofiltration; and
- ion exchange softening.

The suitability of application of a particular technology is often site-specific and should be evaluated on a case-by-case basis. The following is a set of suggested criteria for evaluation:

- extent of prior application in refineries for wastewater reuse;
- ability to consistently achieve the required product water specification;
- operability and flexibility;
- capital and operating cost; and
- plot space requirements.

The following sections discuss the various technologies mentioned above.

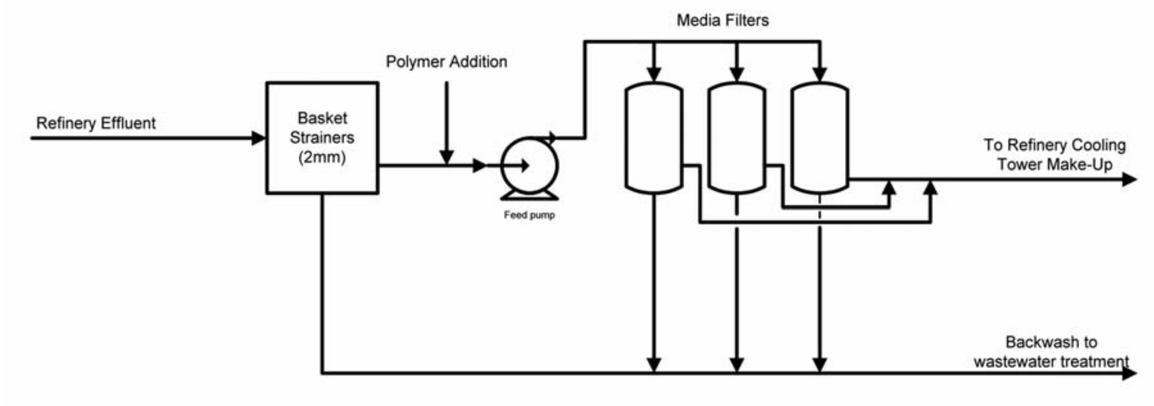
It should be noted that none of these technologies are widely practiced in refineries. The refining industry is starting to look at these options as water costs increase but they are not yet commonplace. The technologies described below are options that should be considered by refineries based on regulatory and cost pressures in a local region.

## Basic media/sand filtration

Sand or media filtration can be used to remove the gross solids and suspended solids found in the refinery effluent. Media filtration systems work by pushing the water through a vessel packed with a filter media such as sand or anthracite. Anionic or cationic polymers are often added to the feedwater to improve particle removal efficiency. This type of treatment generally removes contaminant particles greater than approx 5 μm in size.

Media filtration systems need to be backwashed periodically through reversal of the flow through the system. Backwashes are initiated when the differential pressure across the filter reaches a pre-determined set point. Backwashing produces an

**Figure 33** *Media filtration*



intermittent wastewater stream averaging approximately 5% of the feed flow. Media filtration systems have a relatively small footprint and energy demand. Filter backwashes can be sent back to the head of the refinery WWTP.

Figure 33 shows a process schematic of a typical media filtration system.

The key disadvantage for this type of system is that it will offer no removal of dissolved inorganic compounds (salts) or metals, and thus media filtration alone will not improve the quality of the refinery effluent sufficiently for it to be used as either cooling tower make-up water or feedwater to the demineralized water production system.

Media filtration as a standalone technology is not considered to be a viable option for the treatment of the refinery effluent, either for reuse as BFW makeup or cooling tower make-up, but could be used for other purposes such as utility water or emergency fire water.

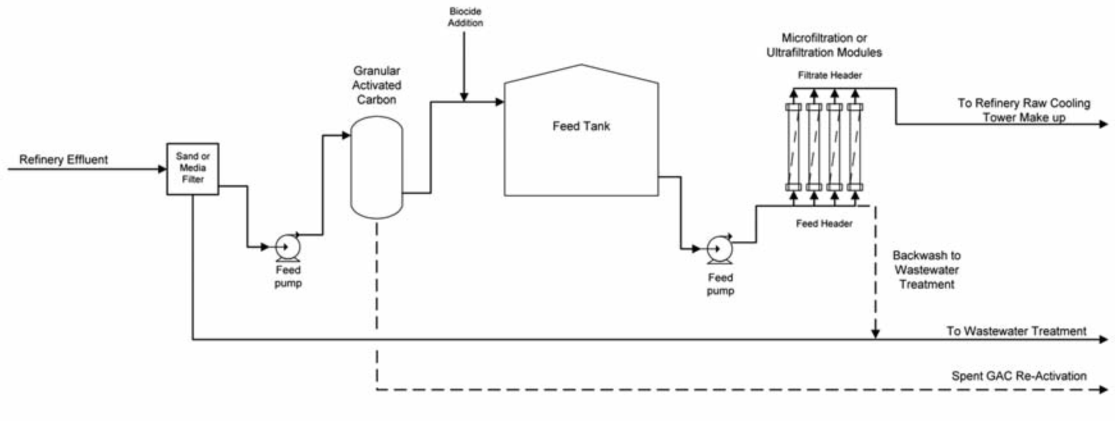
## Microfiltration or ultrafiltration

Microfiltration (MF) or ultrafiltration (UF), like media filtration, can be used to remove fine suspended solids found in the refinery effluent. As shown in Figure 32, there is a significant overlap between these processes in terms of the size of particles they will remove. Microfiltration can remove particles greater than approximately 0.1 μm while ultrafiltration will remove particles down to approximately 0.01 μm.

Both MF and UF are pressure driven membrane separation processes that separate particulate matter from soluble components in the carrier fluid (water). Using a hollow fibre outside in membrane configuration is the most suitable, as this tends to give fewer problems with suspended solids fouling, and also tends to be more robust in its ability to deal with feedwater quality aberrations.

Most materials that are used in MF and UF membrane manufacture are polymeric and are naturally hydrophobic. Common materials used include: polysulphone, polyethersulphone, polypropylene or polyvinylidene fluoride. Because of the hydrophobic nature of the membrane materials, they are highly susceptible to organic fouling by oil and grease. For this reason most MF and UF manufacturers have a typical specification of <1 mg/l oil and grease. In order to remove dissolved and emulsified oil and grease, granular activated carbon (GAC) pretreatment is typically used.

Figure 34 *Microfiltration or ultrafiltration*



New generation ceramic microfiltration membranes are under development by a number of membrane manufacturers, and have been developed specifically for dealing with oily wastewaters, such as refinery effluents, and produced water from exploration and production activities. Figure 34 shows a system using microfiltration or ultrafiltration with GAC pretreatment.

The first unit operation employed is a sand filter or media filter, for the removal of gross solids, such as sand and plastic debris which may have passed through the refinery WWTP, or blown into the open treatment ponds, and the majority of the biological solids which have escaped the treatment ponds. Any oil bound to solids will also be removed in this step, thus lowering the oil and grease content of the feedwater and reducing the loading on the next process. Note that while the addition of polymers or flocculants will improve the performance of the filter, this is not recommended, as they can rapidly foul membrane surfaces.

The next step is granular activated carbon for the removal of oil, grease and trace amounts of hydrocarbons still present in the effluent, which could potentially foul or damage the MF/UF membranes. Spent GAC will need to be periodically regenerated, at a rate dependent on the oil content of the refinery effluent. This can be performed on-site if infrastructure is installed, or more commonly taken off-site for regeneration by the GAC vendor.

The feed tank serves to balance flows to filtration system when the GAC, or MF/ UF units need to backwash. A biocide such as chlorine or chloramines is also added to prevent biological growth in the system and biofouling of the membranes.

The water is then forced through a set of membranes either by pressure or vacuum (pressure, in this schematic), leaving particulates and colloidal matter on the feed side of the membrane. The transmembrane pressure (TMP) will slowly increase over time as the solids accumulate, requiring the system to be backwashed to remove the fouling layer. Periodic cleaning using disinfectants such as sodium hypochlorite, or acid and caustic, are required to remove accumulated contaminants not removed by backwashing.

Microfiltration and ultrafiltration will both produce a very clear filtrate with <1 mg/L suspended solids. However, like media filtration, both processes will not be able to achieve any significant reduction in the presence of dissolved salts and metals present in the refinery effluent, in order to make the water suitable for supplementing the cooling tower or demineralized water supplies to either refinery.

Microfiltration, as a stand alone technology, is not considered to be a viable option for the treatment of refinery effluent for either BFW makeup or cooling tower make-up, but the treated effluent can be used for other purposes such as utility water or emergency fire water.

## Microfiltration or ultrafiltration, with reverse osmosis

Unlike the media filtration and the MF/UF options, reverse osmosis (RO) can remove the dissolved salts and metals found in the refinery effluent, potentially producing a product water suitable for reuse at the refinery. Reverse osmosis membranes have an extremely fine pore size of less than 0.001 μm which is smaller than most contaminants found in water. RO membranes will selectively allow the passage of pure water with the exclusion of salts at 99% rejection rates or higher.

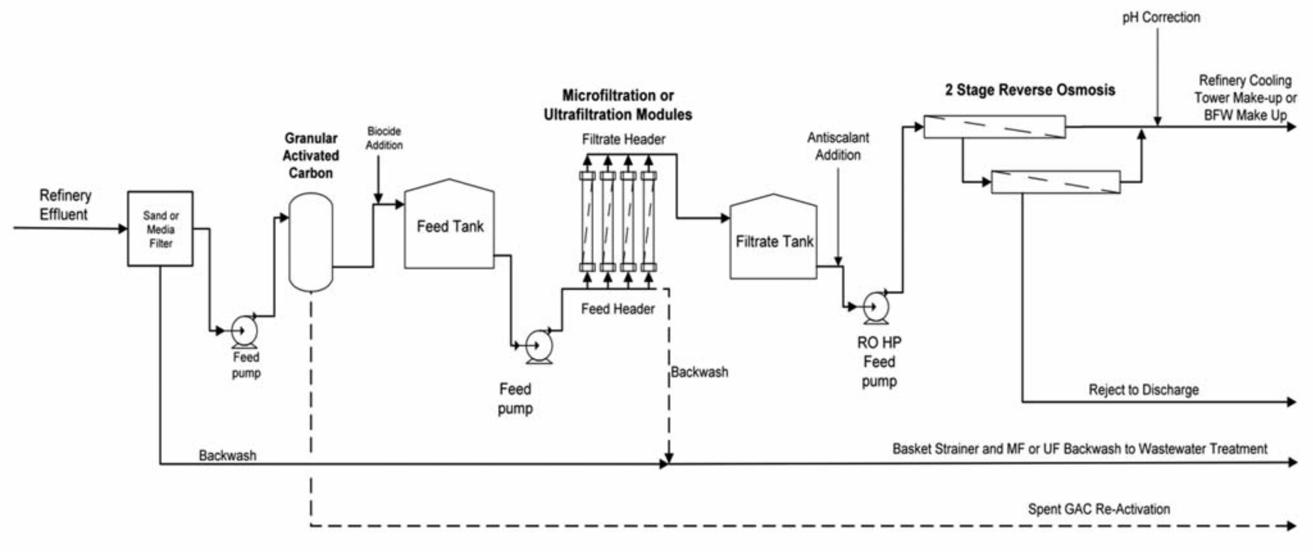
Due to the small pore size and polyamide membrane composition, RO membranes are even more susceptible to fouling by oil and hydrocarbons than MF or UF membranes. Most membrane manufacturers recommend <0.1 mg/l oil and grease in the RO feedwater, and cases have been documented where as little as 0.001 mg/l of a hydrocarbon in the feedwater has irreversibly fouled RO systems. This further emphasizes the need for effective oil and grease removal pretreatment.

Figure 35 is a schematic flow diagram for a suitable reverse osmosis system, incorporating GAC pretreatment for oil removal.

Like the previous MF/UF options, the first process is gross solids removal using a sand or media filter to reduce the loading and prevent blocking of the GAC column. The next step in the process is GAC removal of dissolved organics, oil and grease. Spent GAC will need to be periodically regenerated either on-site or off-site.

Following the GAC, biocide addition and a small balance tank are shown. The most common biocide used in these applications is monochloramine, as chloramines are less likely to oxidize the RO membranes than free chlorine. Due to the very fine pore size of RO membranes, they are susceptible to blockage/plugging by suspended solids, which can include broken GAC granules and fines shed from the GAC pretreatment. Therefore, microfiltration or ultrafiltration pretreatment should be installed

**Figure 35** *Microfiltration or ultrafiltration, and reverse osmosis*



upstream of the reverse osmosis system. The use of this technology will allow the reuse of the refinery effluent for all purposes in the refinery; note however that discharge of ultrafiltration reject water can become a significant issue because inorganic contaminants such as metals will increase in concentration and may not meet concentration-based discharge limits, leading to additional treatment costs.

## Microfiltration or ultrafiltration, with nanofiltration

Nanofiltration (NF) is a moderate pressure membrane process commonly used for removal of select dissolved organic compounds and water softening. Nanofiltration and reverse osmosis systems share many common features in terms of their design and operation. Standard NF membrane elements share the same physical dimensions as standard RO membrane elements and are loaded into standard RO membrane pressure housings. For these reasons, nanofiltration systems look much the same as reverse osmosis systems. The key difference between the two processes is that salt rejection of reverse osmosis systems is much higher, and consequently so are the operating pressures. Nanofiltration can be thought of as essentially like a low pressure, low stringency RO system. NF generally has a low rejection for metals. NF membranes offered by the major manufacturers are somewhat tailored to different applications and are available with varying levels of efficiency in removal of salts and/or organics, depending on the application. One major application of NF is water softening before further treatment such as reverse osmosis or ion exchange.

A process description is not included for this option as it is essentially the same as for reverse osmosis, however a schematic flow diagram is given in Figure 36.

## Ion exchange

Ion exchange softening is another viable option for the removal of the dissolved inorganic compounds found in the refinery effluent. Unlike the previous options discussed, ion exchange is not strictly a filtration process, although some filtration will occur as the feedwater passes through the packed resin bed. Some suspended solids loading on the resins may be acceptable, depending on the system design.

Ion exchange works by passing the feedwater through a packed bed of anion or cation exchange resins which exchange the undesirable ions present in the feedwater, such as calcium and magnesium, with more desirable ions such as the hydronium

**Figure 36** *Microfiltration or ultrafiltration, with nanofiltration*

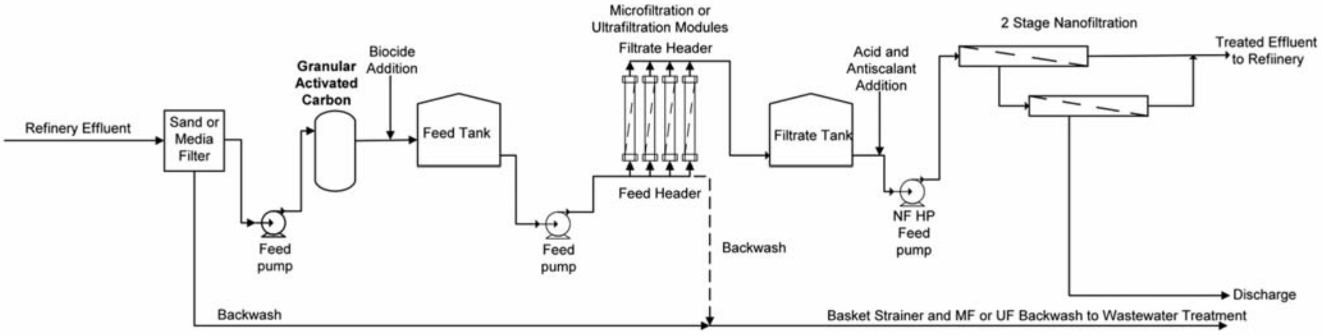
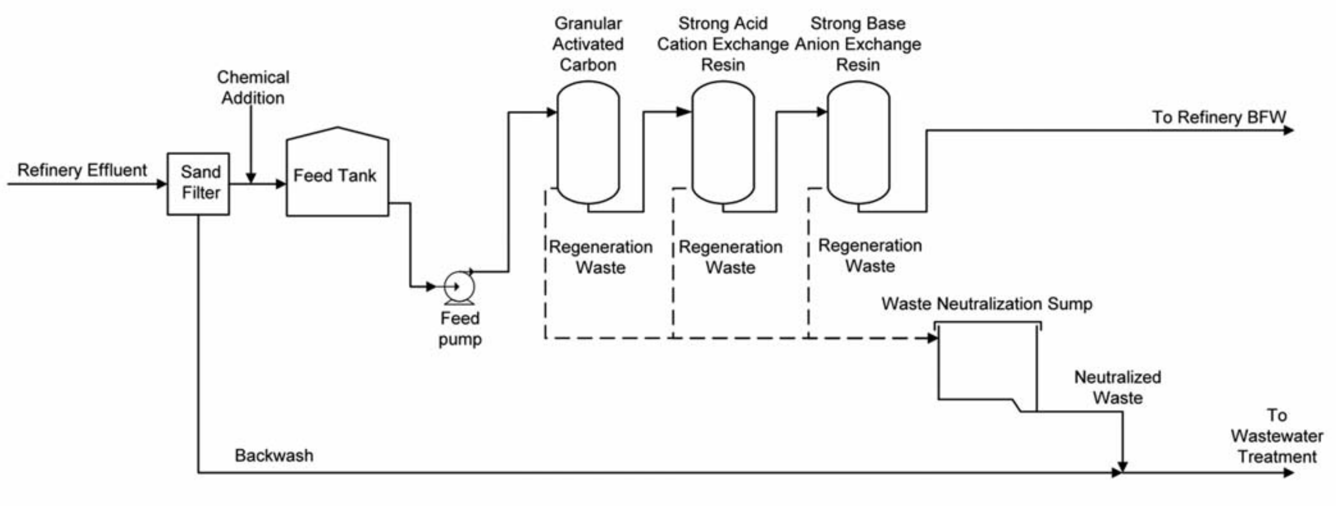


**Figure 37** *Ion exchange treatment*



(H+). Ion exchange is a reversible process and the ion exchanger can be regenerated or loaded with desirable ions by washing with an excess of these ions. Eventually the resins need to be replaced due to gradual breakdown and irreversible fouling.

Ion exchange could be used to treat the refinery effluent to a suitable standard for supplementing the raw feedwater to the refinery using weak acid and base resins, or alternately stronger resins could be used to treat the effluent all the way to boiler feedwater quality. Complete treatment to boiler feedwater quality is probably the most cost-effective option if this technology were to be employed.

A schematic flow diagram of an ion exchange system suitable for treating the refinery effluent is shown in Figure 37.

Treated refinery effluent enters the sand filters for removal of large particulates. Again, a small balance tank is required to balance flows to the ion exchange system when the strainers need to backwash.

The organics scavenger is a selective media such as GAC, or similar, which can remove dissolved organics in the feedwater. Organics removal should be considered since dissolved organic material in the refinery effluent can rapidly and irreversibly foul ion exchange resins.

Post organics removal, the wastewater is then fed through a multiple bed ion exchange process. A recovery rate of around 70% should be achievable and depends on the feedwater TDS, which makes this option comparable to the RO and NF options in this regard. Ion exchange systems produce an intermittent waste stream (that requires disposal) which require neutralization, and are normally very high in salts and contaminants.

Various studies have been conducted in the past to determine whether ion exchange alone or reverse osmosis followed by ion exchange is the most cost-effective option for high purity water production. While the cost-effectiveness of these options tends to vary with plant size, feedwater TDS and the relative costs of power and chemicals, the so called 'salinity break even' point for a moderate-sized system is approximately 350–400 mg/l (as $CaCO_3$ equivalent). Reverse osmosis systems tend to be more cost-effective over this threshold value, due to their relative insensitivity with feedwater TDS. At higher TDS values, regeneration chemicals for ion exchange are prohibitively expensive. Ion exchange is more cost-effective for lower salinities.

### Technology summary—refinery wastewater reuse

Table 11 summarizes the technologies available for refinery wastewater reuse.

As mentioned before, none of these technologies are widely practiced in refineries. The refining industry is starting to look at these options as water costs increase, but they are not yet commonplace. The technologies summarized below are options that should be considered by refineries based on regulatory and cost pressures in a local region.

## Reuse of municipal wastewater

In this section municipal wastewater refers to water from external municipalities and not municipal wastewater that is generated within the refinery. Municipal wastewater generally consists of :

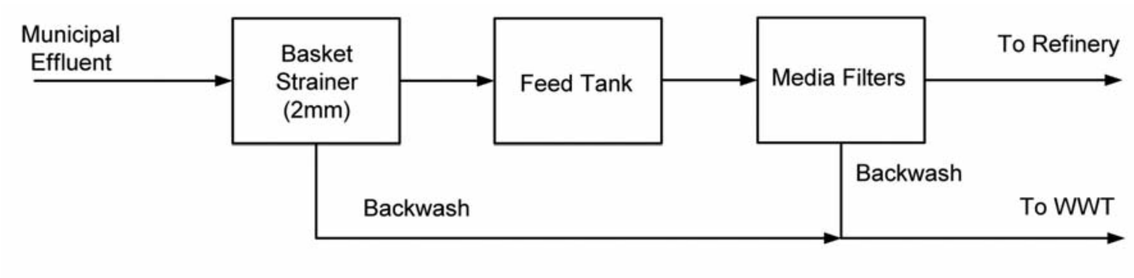
- grey water, e.g. water from bathing, hand washing and clothes washing; and
- black water, e.g. water from kitchen sinks and toilets.

Typically these waters, together with stormwater, are treated in a common wastewater treatment plant by the local municipality which consists of primary treatment (sand and grit removal) followed by biological treatment. The effluent from these plants can be upgraded such that they could be used in the refinery for either cooling tower makeup or BFW

**Table 11** *Refinery wastewater reuse—summary*

| Technology | Suitability |
|---|---|
| Media filtration | Removes suspended solids but not dissolved solids. Treated water not suitable for cooling water or boiler feedwater makeup but can be used for other uses such as utility water or fire water. |
| Ultrafiltration or microfiltration | Removes suspended solids (to a greater extent than media filtration) but not dissolved solids. Treated water not suitable for cooling water or boiler feedwater makeup but can be used for other uses such as utility water or fire water. |
| Ultrafiltration or microfiltration, with reverse osmosis | Removes both suspended and dissolved solids. Treated water suitable for all uses in the refinery including cooling tower and boiler feedwater makeup |
| Ultrafiltration or microfiltration, with nanofiltration | Removes both suspended and dissolved solids. Treated water suitable for all uses in the refinery including cooling tower and boiler feedwater makeup. Salt rejection is lower than reverse osmosis but this system can be operated at a lower pressure than RO systems |
| Ion exchange | Removes both suspended and dissolved solids. Treated water suitable for all uses in the refinery including cooling tower and boiler feedwater makeup. Usually applicable when the dissolved solids concentration is less than 400 mg/l. |

**Figure 38** *Media filtration*



makeup. The following considerations need to be taken into account when considering the reuse of municipal wastewater:

- Cost of conveyance of the wastewater from the municipal wastewater treatment plant to the refinery (includes piping and other infrastructure).
- Capital and operating costs for pumping the wastewater to the refinery.
- The quality of the available effluent: this will dictate the level of treatment required to enable reuse in the refinery.
- The discharge of the effluents (such as backwashes and RO reject) from the system is also an important consideration. The ideal scenario would be to be able to return these streams back to the municipal wastewater treatment plant, but this might not be feasible due to the capital and operating costs involved. If they need to be discharged by the refinery then the potential impacts of the contaminants contained in them could be problematic.

The situation sometimes arises where groups of industries are clustered close to a municipal treatment plant. When this happens, joint approaches—where municipalities are willing to make investments to improve the water quality by installing reverse osmosis streams, manage the reject themselves and send a much better quality water stream to the industrial users—make better economic sense than each industrial user installing its own RO stream.

The technologies available for upgrading municipal wastewater are similar to those discussed in the sections above, except that some pretreatment and post treatment is typically required. The technologies that can be used to upgrade municipal wastewater for reuse in the refinery are discussed below. To avoid repetition, detailed descriptions of each technology are not included, but any differences between those discussed in the sections above are highlighted.

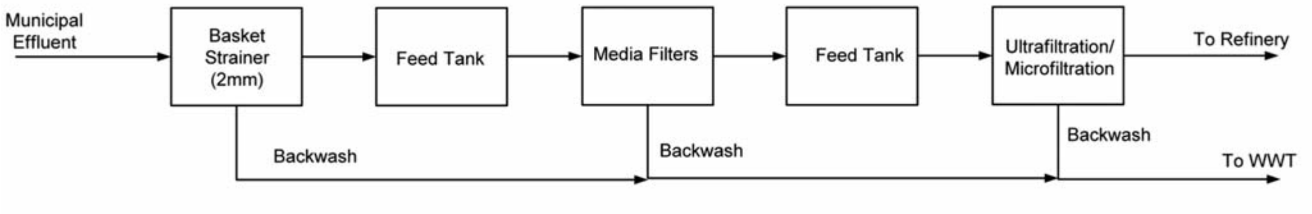
### Media filtration

Figure 38 shows a block flow diagram of a media filtration system The system is the same as that described on pages 44–45, except that the municipal effluent is first sent to basket strainers to remove any large solids prior to being sent to the feed tank, and then sent to the media filters. The effluent from the media filters will not be suitable for use as BFW makeup or cooling tower makeup but can be used for other purposes such as utility water or emergency fire water.

### Microfiltration or ultrafiltration

Figure 39 shows a block flow diagram of a microfiltration/ultrafiltration system. The system is the same as that described on pages 45–46, except that the municipal effluent is first sent to basket strainers to remove any large solids prior to being sent to the feed tank, and then sent to the media filters. The water from the media filter is then sent to

**Figure 39** *Microfiltration/ultrafiltration*



the UF/MF modules for filtration of finer particles. The effluent from the MF/UF will not be suitable for us as BFW makeup or cooling tower makeup, but can be used for other purposes such as utility water or emergency fire water.

## Microfiltration or ultrafiltration, plus reverse osmosis

Figure 40 shows a block flow diagram of this system. The system is similar to the one described on page 47, with the addition of the reverse osmosis system downstream of the MF/UF filters. Due to the fact that $CO_2$ (present as a dissolved gas in the wastewater) is a small uncharged molecule, dissolved $CO_2$ tends to be poorly rejected by RO membranes, and ends up in the permeate stream. This has the effect of lowering the pH of the RO permeate and raising the pH of the RO reject from that of the initial feedwater. pH adjustment of the RO permeate through acid or caustic addition is feasible, but tends to be difficult to control due to the limited concentration of bicarbonate to buffer the pH. For these reasons, a degasser tower is the most commonly employed method of pH correction downstream of the RO. A forced draft degasifier works by contacting forced air coming in with the RO permeate in a packed column to strip the dissolved $CO_2$ from the RO permeate. A vacuum degasifier would also be suitable.

The dissolved $CO_2$ concentration is also dependent on pH. Typical operating pH for a reverse osmosis system treating municipal effluent is in the range of 6.0–6.5. Operating at a slightly acidic pH helps to control inorganic scale formation, lower chemical dosing and maximize recovery. It also tends to convert dissolved bicarbonate to dissolved carbon dioxide gas.

**Figure 40** *Microfiltration/ultrafiltration plus reverse osmosis*

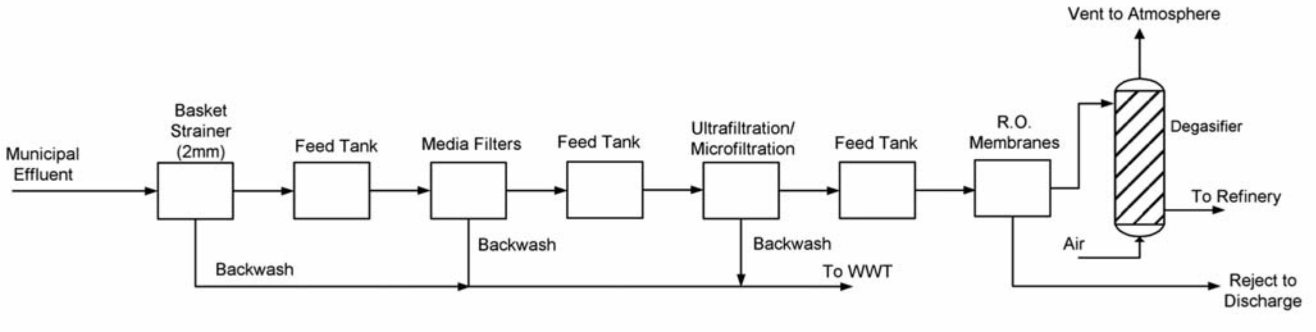
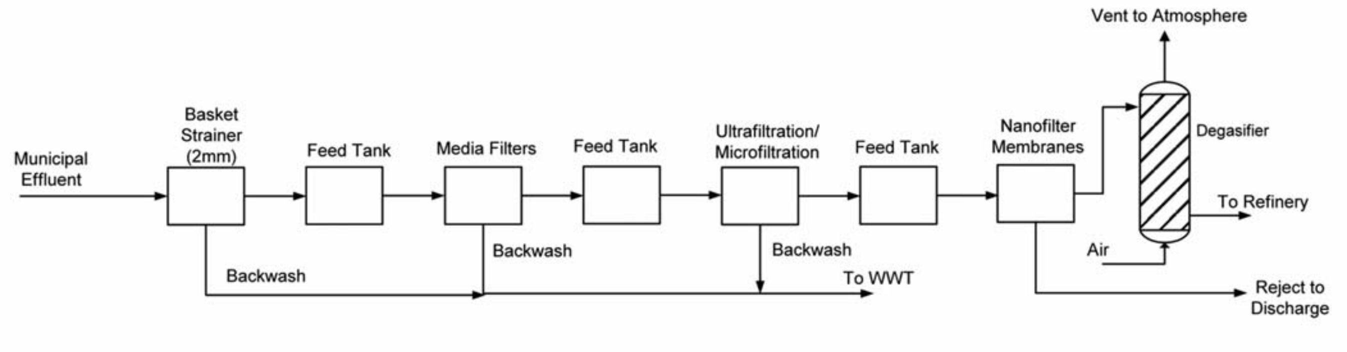


**Figure 41** *Microfiltration/ultrafiltration plus nanofiltration*



### Microfiltration or ultrafiltration, plus nanofiltration

Figure 41 shows a block flow diagram of this system. The system above is the same as that shown on page 48, except that the reverse osmosis membranes are replaced by nanofiltration membranes.

### Ion exchange

The system for ion exchange is the same as that shown on pages 48–49 and is not repeated here.

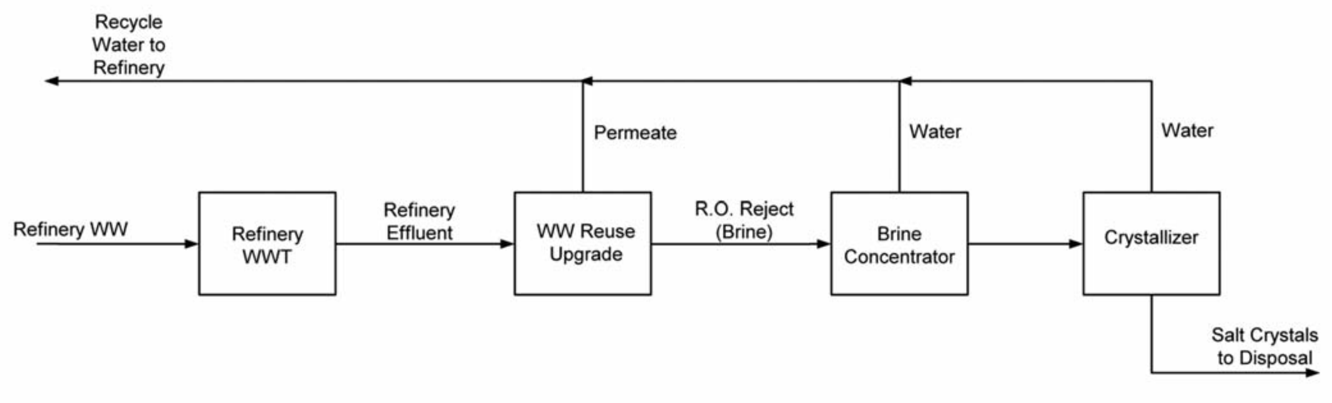
## Zero liquid discharge

The recycling/reuse options and technologies discussed in the sections above result in the need to discharge a concentrated brine stream that comes from the reverse osmosis/nanofiltration reject. At some refineries, depending on the location and local conditions, it might be problematic to dispose of this stream off-site. The reasons for this could include:

- high cost due to the fees that might be imposed in discharging a concentrated brine stream;
- only option being discharge to a fresh water stream (due to location of refinery); regulatory authorities usually do not allow discharges of brine into fresh water streams;
- aquatic toxicity restrictions on the discharge stream (the concentration of contaminants, primarily metals, in the brine could prevent the passing of a toxicity test); and
- concentration of metals in the brine could exceed concentration-based discharge limits.

In such cases zero liquid discharge (ZLD) needs to be considered. In a ZLD system the brine that is

**Figure 42** *ZLD block flow diagram*



usually discharged from a wastewater reuse system is further treated to extract more water and separate the dissolved solids that are left as solid crystals for disposal. The water that is removed is sent back to the refinery for recycle.

Figure 42 shows a block flow diagram of a typical ZLD system.

It should be noted that application of ZLD in refineries is very rare, in part because the energy requirements are very high. The possible use of this approach needs to be evaluated on a site-specific basis. It is included in this document for information purposes.

# References

Rase, Howard F., and Barrow, M.H., *Project Engineering for Process Plants*, John Wiley and Sons Inc.

Beychok, Milton R., *Aqueous Wastes from Petroleum and Petrochemical Plants*, John Wiley and Sons Inc.

Evans, Frank L. Jr., *Equipment Design Handbook for Refineries and Chemical Plants*, Volumes 1 and 2, Gulf Publishing

Metcalf and Eddy, *Wastewater Engineering – Treatment and Reuse,* 4th Edition, McGraw Hill

American Petroleum Institute, *A Guide to Leak Detection for Above-Ground Storage Tanks*, Publication 334, First Edition, March 1996

American Petroleum Institute, *Welded Tanks for Oil Storage*, Downstream Segment, API Standard 650, Eleventh Edition June 2007, Addendum 1 June 2008.

US DOE, *Energy and Environmental Profile of the U.S. Petroleum Refining Industry*, December 1998.

Environmental Protection Agency, *Profile of the Petroleum Industry*, EPA/310-R-95-013, 1995.

**IPIECA**

IPIECA is the global oil and gas industry association for environmental and social issues. It develops, shares and promotes good practices and knowledge to help the industry improve its environmental and social performance; and is the industry's principal channel of communication with the United Nations.

Through its member led working groups and executive leadership, IPIECA brings together the collective expertise of oil and gas companies and associations. Its unique position within the industry enables its members to respond effectively to key environmental and social issues.

**Company members**

BG Group
BP
Chevron
CNOOC
ConocoPhillips
Eni
ExxonMobil
Hess
Hunt Oil
KPC
Mærsk
Marathon
Nexen
NOC Libya
Occidental
OMV
Petrobras
Petronas
Petrotrin
PTT EP
Qatargas
RasGas
Repsol YPF
Saudi Aramco
Shell
SNH
StatoilHydro
Talisman
Total
Woodside Energy

**Association members**

African Refiners Association (ARA)
American Petroleum Institute (API)
Australian Institute of Petroleum (AIP)
Canadian Association of Petroleum Producers (CAPP)
Canadian Petroleum Products Institute (CPPI)
The Oil Companies' European Association for Environment, Health and Safety in Refining and Distribution (CONCAWE)
European Petroleum Industry Association (EUROPIA)
International Association of Oil & Gas Producers (OGP)
Petroleum Association of Japan (PAJ)
Regional Association of Oil and Natural Gas Companies in Latin America and the Caribbean (ARPEL)
South African Petroleum Industry Association (SAPIA)
World Petroleum Council (WPC)

**IPIECA**
5th Floor, 209–215 Blackfriars Road, London SE1 8NL, United Kingdom
Telephone: +44 (0)20 7633 2388 Facsimile: +44 (0)20 7633 2389
E-mail: info@ipieca.org Internet: www.ipieca.org

www.ipieca.org

| **Tesoro Reported Flare Data** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | **Plant Reported Data** | | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume | HHV | H2S | Mol. Wt | SOx | 75% HC 44 MW 98% eff |
| | | MMSCFD | (BTU/SCF) | (Mole %) | (lbs/mole) | (lbs/day) | (lbs) |
| | | | | | | | |
| 1/1/01 | | 6.69 | | | | | 11653 |
| 1/2/01 | | 5.33 | | | | | 9274 |
| 1/3/01 | | 6.47 | | | | | 11269 |
| 1/4/01 | | 4.99 | | | | | 8686 |
| 1/5/01 | | 5.89 | | | | | 10260 |
| 1/6/01 | | 5.13 | | | | | 8938 |
| 1/7/01 | | 5.75 | | | | | 10019 |
| 1/8/01 | | 5.25 | | | | | 9139 |
| 1/9/01 | | 5.00 | | | | | 8699 |
| 1/10/01 | | 5.48 | | | | | 9547 |
| 1/11/01 | | 5.03 | | | | | 8757 |
| 1/12/01 | | 5.23 | | | | | 9110 |
| 1/13/01 | | 5.51 | | | | | 9602 |
| 1/14/01 | | 6.83 | | | | | 11892 |
| 1/15/01 | | 4.89 | | | | | 8513 |
| 1/16/01 | | 5.12 | | | | | 8910 |
| 1/17/01 | | 4.90 | | | | | 8525 |
| 1/18/01 | | 4.75 | | | | | 8271 |
| 1/19/01 | | 5.96 | | | | | 10371 |
| 1/20/01 | | 4.41 | | | | | 7673 |
| 1/21/01 | | 7.27 | | | | | 12664 |
| 1/22/01 | | 7.22 | | | | | 12565 |
| 1/23/01 | | 6.36 | | | | | 11084 |
| 1/24/01 | | 7.49 | | | | | 13036 |
| 1/25/01 | | 4.26 | | | | | 7415 |
| 1/26/01 | | 4.91 | | | | | 8542 |
| 1/27/01 | | 4.78 | | | | | 8330 |
| 1/28/01 | | 5.41 | | | | | 9429 |
| 1/29/01 | | 4.74 | | | | | 8249 |
| 1/30/01 | | 5.81 | | | | | 10117 |
| 1/31/01 | | 5.37 | | | | | 9354 |
| 2/1/01 | | 4.26 | | | | | 7418 |
| 2/2/01 | | 4.74 | | | | | 8251 |
| 2/3/01 | | 5.30 | | | | | 9223 |

**Tesoro Reported Flare Data**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | | **Plant Reported Data** | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 2/4/01 | | 6.18 | | | | | 10763 |
| 2/5/01 | | 7.09 | | | | | 12353 |
| 2/6/01 | | 7.91 | | | | | 13769 |
| 2/7/01 | | 7.79 | | | | | 13570 |
| 2/8/01 | | 7.55 | | | | | 13153 |
| 2/9/01 | | 6.67 | | | | | 11618 |
| 2/10/01 | | 7.98 | | | | | 13899 |
| 2/11/01 | | 26.33 | | | | | 45857 |
| 2/12/01 | | 7.95 | | | | | 13846 |
| 2/13/01 | | 9.99 | | | | | 17393 |
| 2/14/01 | | 12.86 | | | | | 22402 |
| 2/15/01 | | 13.18 | | | | | 22953 |
| 2/16/01 | | 9.51 | | | | | 16564 |
| 2/17/01 | | 6.20 | | | | | 10789 |
| 2/18/01 | | 6.20 | | | | | 10790 |
| 2/19/01 | | 5.91 | | | | | 10294 |
| 2/20/01 | | 6.21 | | | | | 10823 |
| 2/21/01 | | 6.34 | | | | | 11049 |
| 2/22/01 | | 5.34 | | | | | 9302 |
| 2/23/01 | | 5.64 | | | | | 9819 |
| 2/24/01 | | 4.47 | | | | | 7787 |
| 2/25/01 | | 5.32 | | | | | 9271 |
| 2/26/01 | | 4.80 | | | | | 8361 |
| 2/27/01 | | 4.99 | | | | | 8689 |
| 2/28/01 | | 5.21 | | | | | 9070 |
| 3/1/01 | | 4.54 | | | | | 7909 |
| 3/2/01 | | 4.87 | | | | | 8488 |
| 3/3/01 | | 4.43 | | | | | 7722 |
| 3/4/01 | | 5.87 | | | | | 10227 |
| 3/5/01 | | 5.36 | | | | | 9331 |
| 3/6/01 | | 4.79 | | | | | 8339 |
| 3/7/01 | | 5.50 | | | | | 9582 |
| 3/8/01 | | 5.08 | | | | | 8853 |
| 3/9/01 | | 5.01 | | | | | 8719 |
| 3/10/01 | | 4.61 | | | | | 8032 |

**Tesoro Reported Flare Data**

| | | | Does not include pilot and purge gas | | | | District's VOC Estimate |
|---|---|---|---|---|---|---|---|
| | | | Plant Reported Data | | | | |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 3/11/01 | | 5.39 | | | | | 9386 |
| 3/12/01 | | 5.40 | | | | | 9405 |
| 3/13/01 | | 6.31 | | | | | 10981 |
| 3/14/01 | | 6.70 | | | | | 11662 |
| 3/15/01 | | 6.56 | | | | | 11423 |
| 3/16/01 | | 6.51 | | | | | 11337 |
| 3/17/01 | | 6.58 | | | | | 11452 |
| 3/18/01 | | 9.90 | | | | | 17244 |
| 3/19/01 | | 8.34 | | | | | 14515 |
| 3/20/01 | | 6.68 | | | | | 11641 |
| 3/21/01 | | 7.92 | | | | | 13785 |
| 3/22/01 | | 6.05 | | | | | 10528 |
| 3/23/01 | | 6.49 | | | | | 11306 |
| 3/24/01 | | 7.54 | | | | | 13131 |
| 3/25/01 | | 11.27 | | | | | 19627 |
| 3/26/01 | | 6.22 | | | | | 10827 |
| 3/27/01 | | 6.44 | | | | | 11208 |
| 3/28/01 | | 44.91 | | | | | 78216 |
| 3/29/01 | | 137.89 | | | | | 240130 |
| 3/30/01 | | 90.27 | | | | | 157198 |
| 3/31/01 | | 6.90 | | | | | 12018 |
| 4/1/01 | | 6.37 | | | | | 11092 |
| 4/2/01 | | 5.03 | | | | | 8752 |
| 4/3/01 | | 5.42 | | | | | 9430 |
| 4/4/01 | | 6.11 | | | | | 10639 |
| 4/5/01 | | 8.35 | | | | | 14535 |
| 4/6/01 | | 5.85 | | | | | 10195 |
| 4/7/01 | | 5.84 | | | | | 10163 |
| 4/8/01 | | 6.41 | | | | | 11157 |
| 4/9/01 | | 6.82 | | | | | 11868 |
| 4/10/01 | | 6.72 | | | | | 11703 |
| 4/11/01 | | 7.60 | | | | | 13242 |
| 4/12/01 | | 7.65 | | | | | 13330 |
| 4/13/01 | | 8.36 | | | | | 14551 |
| 4/14/01 | | 5.69 | | | | | 9905 |

**Tesoro Reported Flare Data**

| | | | Does not include pilot and purge gas | | | | District's VOC Estimate |
|---|---|---|---|---|---|---|---|
| | | Plant Reported Data | | | | | |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 4/15/01 | | 6.21 | | | | | 10808 |
| 4/16/01 | | 8.23 | | | | | 14336 |
| 4/17/01 | | 19.41 | | | | | 33803 |
| 4/18/01 | | 12.77 | | | | | 22245 |
| 4/19/01 | | 9.78 | | | | | 17023 |
| 4/20/01 | | 4.88 | | | | | 8498 |
| 4/21/01 | | 4.10 | | | | | 7148 |
| 4/22/01 | | 5.36 | | | | | 9342 |
| 4/23/01 | | 4.99 | | | | | 8692 |
| 4/24/01 | | 5.29 | | | | | 9220 |
| 4/25/01 | | 6.29 | | | | | 10955 |
| 4/26/01 | | 13.21 | | | | | 23003 |
| 4/27/01 | | 5.73 | | | | | 9978 |
| 4/28/01 | | 4.87 | | | | | 8475 |
| 4/29/01 | | 5.12 | | | | | 8916 |
| 4/30/01 | | 5.69 | | | | | 9902 |
| 5/l/2001 | | 5.24 | | | | | 9120 |
| 5/2/01 | | 5.45 | | | | | 9494 |
| 5/3/01 | | 4.44 | | | | | 7724 |
| 5/4/01 | | 7.19 | | | | | 12529 |
| 5/5/01 | | 5.58 | | | | | 9717 |
| 5/6/01 | | 9.16 | | | | | 15945 |
| 5/7/01 | | 6.64 | | | | | 11560 |
| 5/8/01 | | 6.54 | | | | | 11390 |
| 5/9/01 | | 6.07 | | | | | 10569 |
| 5/10/01 | | 5.20 | | | | | 9051 |
| 5/11/01 | | 5.32 | | | | | 9265 |
| 5/12/01 | | 5.28 | | | | | 9199 |
| 5/13/01 | | 5.65 | | | | | 9839 |
| 5/14/01 | | 4.66 | | | | | 8114 |
| 5/15/01 | | 4.95 | | | | | 8613 |
| 5/16/01 | | 5.07 | | | | | 8827 |
| 5/17/01 | | 4.53 | | | | | 7890 |
| 5/18/01 | | 5.70 | | | | | 9922 |
| 5/19/01 | | 4.97 | | | | | 8658 |

## Tesoro Reported Flare Data

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | **Plant Reported Data** | | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 5/20/01 | | 7.34 | | | | | 12783 |
| 5/21/01 | | 8.50 | | | | | 14795 |
| 5/22/01 | | 6.70 | | | | | 11663 |
| 5/23/01 | | 7.25 | | | | | 12629 |
| 5/24/01 | | 5.39 | | | | | 9379 |
| 5/25/01 | | 5.43 | | | | | 9453 |
| 5/26/01 | | 5.07 | | | | | 8832 |
| 5/27/01 | | 5.09 | | | | | 8863 |
| 5/28/01 | | 5.08 | | | | | 8850 |
| 5/29/01 | | 5.82 | | | | | 10137 |
| 5/30/01 | | 6.10 | | | | | 10624 |
| 5/31/01 | | 6.97 | | | | | 12138 |
| 6/l/2001 | | 5.62 | | | | | 9779 |
| 6/2/01 | | 4.56 | | | | | 7941 |
| 6/3/01 | | 4.81 | | | | | 8381 |
| 6/4/01 | | 4.70 | | | | | 8185 |
| 6/5/01 | | 4.83 | | | | | 8416 |
| 6/6/01 | | 5.12 | | | | | 8912 |
| 6/7/01 | | 5.96 | | | | | 10384 |
| 6/8/01 | | 5.21 | | | | | 9073 |
| 6/9/01 | | 4.90 | | | | | 8538 |
| 6/10/01 | | 4.91 | | | | | 8546 |
| 6/11/01 | | 4.66 | | | | | 8114 |
| 6/12/01 | | 4.86 | | | | | 8461 |
| 6/13/01 | | 5.57 | | | | | 9704 |
| 6/14/01 | | 5.18 | | | | | 9027 |
| 6/15/01 | | 5.27 | | | | | 9185 |
| 6/16/01 | | 5.61 | | | | | 9777 |
| 6/17/01 | | 5.62 | | | | | 9784 |
| 6/18/01 | | 5.60 | | | | | 9759 |
| 6/19/01 | | 5.81 | | | | | 10115 |
| 6/20/01 | | 8.62 | | | | | 15020 |
| 6/21/01 | | 8.28 | | | | | 14426 |
| 6/22/01 | | 9.24 | | | | | 16088 |
| 6/23/01 | | 6.61 | | | | | 11505 |

| **Tesoro Reported Flare Data** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | | **Plant Reported Data** | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume | HHV | H2S | Mol. Wt | SOx | 75% HC 44 MW 98% eff |
| | | MMSCFD | (BTU/SCF) | (Mole %) | (lbs/mole) | (lbs/day) | (lbs) |
| 6/24/01 | | 6.16 | | | | | 10736 |
| 6/25/01 | | 6.01 | | | | | 10468 |
| 6/26/01 | | 7.56 | | | | | 13167 |
| 6/27/01 | | 6.78 | | | | | 11810 |
| 6/28/01 | | 6.87 | | | | | 11967 |
| 6/29/01 | | 8.57 | | | | | 14920 |
| 6/30/01 | | 8.11 | | | | | 14124 |
| 7/l/2001 | | 6.62 | | | | | 11531 |
| 7/2/01 | | 8.80 | | | | | 15327 |
| 7/3/01 | | 8.37 | | | | | 14570 |
| 7/4/01 | | 8.54 | | | | | 14867 |
| 7/5/01 | | 6.88 | | | | | 11985 |
| 7/6/01 | | 6.40 | | | | | 11144 |
| 7/7/01 | | 6.02 | | | | | 10488 |
| 7/8/01 | | 7.99 | | | | | 13907 |
| 7/9/01 | | 6.83 | | | | | 11891 |
| 7/10/01 | | 6.33 | | | | | 11020 |
| 7/11/01 | | 9.49 | | | | | 16524 |
| 7/12/01 | | 8.56 | | | | | 14913 |
| 7/13/01 | | 8.25 | | | | | 14365 |
| 7/14/01 | | 7.57 | | | | | 13182 |
| 7/15/01 | | 6.31 | | | | | 10989 |
| 7/16/01 | | 6.30 | | | | | 10973 |
| 7/17/01 | | 6.50 | | | | | 11317 |
| 7/18/01 | | 6.99 | | | | | 12178 |
| 7/19/01 | | 7.16 | | | | | 12476 |
| 7/20/01 | | 9.42 | | | | | 16412 |
| 7/21/01 | | 7.69 | | | | | 13390 |
| 7/22/01 | | 7.77 | | | | | 13537 |
| 7/23/01 | | 7.82 | | | | | 13626 |
| 7/24/01 | | 10.18 | | | | | 17736 |
| 7/25/01 | | 5.86 | | | | | 10200 |
| 7/26/01 | | 5.64 | | | | | 9815 |
| 7/27/01 | | 5.91 | | | | | 10294 |
| 7/28/01 | | 6.88 | | | | | 11988 |

| **Tesoro Reported Flare Data** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | **Plant Reported Data** | | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 7/29/01 | | 7.21 | | | | | 12560 |
| 7/30/01 | | 7.64 | | | | | 13305 |
| 7/31/01 | | 8.53 | | | | | 14851 |
| 8/l/2001 | | 8.13 | | | | | 14159 |
| 8/2/01 | | 7.49 | | | | | 13041 |
| 8/3/01 | | 7.83 | | | | | 13637 |
| 8/4/01 | | 7.03 | | | | | 12236 |
| 8/5/01 | | 6.22 | | | | | 10840 |
| 8/6/01 | | 7.71 | | | | | 13426 |
| 8/7/01 | | 7.79 | | | | | 13563 |
| 8/8/01 | | 7.95 | | | | | 13851 |
| 8/9/01 | | 6.80 | | | | | 11847 |
| 8/10/01 | | 5.85 | | | | | 10181 |
| 8/11/01 | | 5.97 | | | | | 10398 |
| 8/12/01 | | 6.02 | | | | | 10482 |
| 8/13/01 | | 5.68 | | | | | 9887 |
| 8/14/01 | | 6.02 | | | | | 10483 |
| 8/15/01 | | 6.27 | | | | | 10921 |
| 8/16/01 | | 6.42 | | | | | 11175 |
| 8/17/01 | | 6.05 | | | | | 10527 |
| 8/18/01 | | 7.55 | | | | | 13143 |
| 8/19/01 | | 5.88 | | | | | 10247 |
| 8/20/01 | | 5.93 | | | | | 10329 |
| 8/21/01 | | 6.05 | | | | | 10535 |
| 8/22/01 | | 7.97 | | | | | 13881 |
| 8/23/01 | | 6.57 | | | | | 11432 |
| 8/24/01 | | 7.46 | | | | | 12984 |
| 8/25/01 | | 8.69 | | | | | 15135 |
| 8/26/01 | | 13.68 | | | | | 23827 |
| 8/27/01 | | 11.90 | | | | | 20726 |
| 8/28/01 | | 8.93 | | | | | 15550 |
| 8/29/01 | | 8.22 | | | | | 14307 |
| 8/30/01 | | 92.53 | | | | | 161129 |
| 8/31/01 | | 128.60 | | | | | 223949 |
| 9/l/2001 | | 46.32 | | | | | 80662 |

**Tesoro Reported Flare Data**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | | **Plant Reported Data** | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 9/2/01 | | 13.19 | | | | | 22969 |
| 9/3/01 | | 9.01 | | | | | 15684 |
| 9/4/01 | | 7.09 | | | | | 12344 |
| 9/5/01 | | 8.55 | | | | | 14886 |
| 9/6/01 | | 8.79 | | | | | 15302 |
| 9/7/01 | | 8.54 | | | | | 14874 |
| 9/8/01 | | 8.58 | | | | | 14940 |
| 9/9/01 | | 8.46 | | | | | 14727 |
| 9/10/01 | | 8.63 | | | | | 15023 |
| 9/11/01 | | 9.07 | | | | | 15801 |
| 9/12/01 | | 8.44 | | | | | 14702 |
| 9/13/01 | | 8.10 | | | | | 14101 |
| 9/14/01 | | 8.35 | | | | | 14542 |
| 9/15/01 | | 6.96 | | | | | 12124 |
| 9/16/01 | | 8.77 | | | | | 15268 |
| 9/17/01 | | 14.50 | | | | | 25243 |
| 9/18/01 | | 9.15 | | | | | 15926 |
| 9/19/01 | | 8.01 | | | | | 13950 |
| 9/20/01 | | 6.27 | | | | | 10914 |
| 9/21/01 | | 6.10 | | | | | 10626 |
| 9/23/01 | | 5.88 | | | | | 10244 |
| 9/28/01 | | 7.01 | | | | | 12202 |
| 9/29/01 | | 6.50 | | | | | 11322 |
| 9/30/01 | | 8.04 | | | | | 14006 |
| 10/l/2001 | | 6.95 | | | | | 12108 |
| 10/2/01 | | 7.98 | | | | | 13901 |
| 10/3/01 | | 7.17 | | | | | 12483 |
| 10/4/01 | | 7.19 | | | | | 12515 |
| 10/5/01 | | 9.41 | | | | | 16385 |
| 10/6/01 | | 6.17 | | | | | 10746 |
| 10/7/01 | | 6.01 | | | | | 10458 |
| 10/8/01 | | 5.29 | | | | | 9204 |
| 10/9/01 | | 5.78 | | | | | 10060 |
| 10/10/01 | | 6.80 | | | | | 11834 |
| 10/11/01 | | 7.69 | | | | | 13400 |

| **Tesoro Reported Flare Data** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | | **Plant Reported Data** | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 10/12/01 | | 7.75 | | | | | 13498 |
| 10/13/01 | | 6.68 | | | | | 11633 |
| 10/14/01 | | 6.57 | | | | | 11435 |
| 10/15/01 | | 8.45 | | | | | 14723 |
| 10/16/01 | | 6.25 | | | | | 10888 |
| 10/17/01 | | 9.46 | | | | | 16481 |
| 10/18/01 | | 5.80 | | | | | 10099 |
| 10/19/01 | | 5.57 | | | | | 9698 |
| 10/20/01 | | 5.12 | | | | | 8915 |
| 10/21/01 | | 4.89 | | | | | 8520 |
| 10/22/01 | | 5.21 | | | | | 9075 |
| 10/23/01 | | 4.79 | | | | | 8334 |
| 10/24/01 | | 5.17 | | | | | 9007 |
| 10/25/01 | | 7.07 | | | | | 12317 |
| 10/26/01 | | 5.15 | | | | | 8968 |
| 10/27/01 | | 6.36 | | | | | 11077 |
| 10/28/01 | | 6.60 | | | | | 11492 |
| 10/29/01 | | 4.70 | | | | | 8180 |
| 10/30/01 | | 4.94 | | | | | 8595 |
| 10/31/01 | | 5.25 | | | | | 9140 |
| 11/l/2001 | | 4.85 | | | | | 8454 |
| 11/2/01 | | 6.85 | | | | | 11936 |
| 1113/2001 | | 18.24 | | | | | 31772 |
| 11/4/01 | | 8.72 | | | | | 15180 |
| 11/5/01 | | 8.82 | | | | | 15359 |
| 11/6/01 | | 6.17 | | | | | 10750 |
| 11/7/01 | | 4.57 | | | | | 7964 |
| 11/8/01 | | 4.65 | | | | | 8099 |
| 11/9/01 | | 4.68 | | | | | 8152 |
| 11/10/01 | | 5.29 | | | | | 9212 |
| 11/11/01 | | 5.53 | | | | | 9626 |
| 11/12/01 | | 5.16 | | | | | 8990 |
| 11/13/01 | | 6.89 | | | | | 11999 |
| 11/14/01 | | 7.15 | | | | | 12443 |
| 11/15/01 | | 11.74 | | | | | 20437 |

**Tesoro Reported Flare Data**

| | | | Does not include pilot and purge gas | | | | **District's VOC Estimate** |
|---|---|---|---|---|---|---|---|
| | | **Plant Reported Data** | | | | | |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 11/16/01 | | 8.04 | | | | | 13998 |
| 11/17/01 | | 8.13 | | | | | 14151 |
| 11/18/01 | | 8.05 | | | | | 14017 |
| 11/19/01 | | 6.33 | | | | | 11029 |
| 11/20/01 | | 8.68 | | | | | 15120 |
| 11/21/01 | | 11.03 | | | | | 19216 |
| 11/22/01 | | 7.96 | | | | | 13858 |
| 11/23/01 | | 4.53 | | | | | 7886 |
| 11/24/01 | | 7.85 | | | | | 13671 |
| 11/25/01 | | 9.21 | | | | | 16031 |
| 11/26/01 | | 9.17 | | | | | 15964 |
| 11/27/01 | | 7.97 | | | | | 13884 |
| 11/28/01 | | 8.69 | | | | | 15129 |
| 11/29/01 | | 7.79 | | | | | 13565 |
| 11/30/01 | | 6.84 | | | | | 11904 |
| 12/1/01 | | 7.35 | | | | | 12792 |
| 12/2/01 | | 7.71 | | | | | 13428 |
| 12/3/01 | | 18.63 | | | | | 32439 |
| 12/4/01 | | 10.89 | | | | | 18972 |
| 12/5/01 | | 9.76 | | | | | 16993 |
| 12/6/01 | | 18.85 | | | | | 32826 |
| 12/7/01 | | 26.94 | | | | | 46912 |
| 12/8/01 | | 25.23 | | | | | 43942 |
| 12/9/01 | | 22.92 | | | | | 39921 |
| 12/10/01 | | 37.64 | | | | | 65541 |
| 12/11/01 | | 40.72 | | | | | 70912 |
| 12/12/01 | | 40.00 | | | | | 69651 |
| 12/13/01 | | 30.15 | | | | | 52509 |
| 12/14/01 | | 38.83 | | | | | 67624 |
| 12/15/01 | | 39.38 | | | | | 68583 |
| 12/16/01 | | 43.25 | | | | | 75315 |
| 12/17/01 | | 45.85 | | | | | 79852 |
| 12/18/01 | | 45.55 | | | | | 79329 |
| 12/19/01 | | 29.52 | | | | | 51399 |
| 12/20/01 | | 39.08 | | | | | 68061 |

| **Tesoro Reported Flare Data** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | **Plant Reported Data** | | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume | HHV | H2S | Mol. Wt | SOx | 75% HC<br>44 MW<br>98% eff |
| | | MMSCFD | (BTU/SCF) | (Mole %) | (lbs/mole) | (lbs/day) | (lbs) |
| 12/21/01 | | 42.36 | | | | | 73762 |
| 12/22/01 | | 46.75 | | | | | 81418 |
| 12/23/01 | | 46.40 | | | | | 80808 |
| 12/24/01 | | 40.83 | | | | | 71104 |
| 12/25/01 | | 17.11 | | | | | 29792 |
| 12/26/01 | | 10.42 | | | | | 18142 |
| 12/27/01 | | 7.41 | | | | | 12908 |
| 12/28/01 | | 30.63 | | | | | 53334 |
| 12/29/01 | | 20.76 | | | | | 36148 |
| 12/30/01 | | 4.95 | | | | | 8616 |
| 12/31/01 | | 20.88 | | | | | 36360 |
| I/l/2002 | | 28.86 | | | | | 50251 |
| 1/2/02 | | 9.18 | | | | | 15993 |
| 1/3/02 | | 18.87 | | | | | 32865 |
| 1/4/02 | | 38.64 | | | | | 67296 |
| 1/5/02 | | 34.43 | | | | | 59965 |
| 1/6/02 | | 30.77 | | | | | 53579 |
| 1/7/02 | | 19.76 | | | | | 34412 |
| 1/8/02 | | 16.80 | | | | | 29260 |
| 1/9/02 | | 35.67 | | | | | 62125 |
| 1/10/02 | | 27.22 | | | | | 47397 |
| 1/11/02 | | 27.22 | | | | | 47397 |
| 1/11/02 | | 28.65 | | | | | 49900 |
| 1/12/02 | | 35.64 | | | | | 62060 |
| 1/13/02 | | 36.58 | | | | | 63704 |
| 1/14/02 | | 38.55 | | | | | 67130 |
| 1/15/02 | | 35.87 | | | | | 62466 |
| 1/16/02 | | 33.11 | | | | | 57664 |
| 1/17/02 | | 31.99 | | | | | 55708 |
| 1/18/02 | | 30.36 | | | | | 52876 |
| 1/19/02 | | 32.99 | | | | | 57456 |
| 1/20/02 | | 19.91 | | | | | 34678 |
| 1/21/02 | | 14.97 | | | | | 26065 |
| 1/22/02 | | 21.89 | | | | | 38128 |
| 1/23/02 | | 27.51 | | | | | 47903 |

| **Tesoro Reported Flare Data** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | **Plant Reported Data** | | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume | HHV | H2S | Mol. Wt | SOx | 75% HC 44 MW 98% eff |
| | | MMSCFD | (BTU/SCF) | (Mole %) | (lbs/mole) | (lbs/day) | (lbs) |
| 1/24/02 | | 31.34 | | | | | 54582 |
| 1/25/02 | | 51.63 | | | | | 89916 |
| 1/26/02 | | 51.63 | | | | | 89916 |
| 1/27/02 | | 52.61 | | | | | 91609 |
| 1/27/02 | | 51.12 | | | | | 89014 |
| 1/28/02 | | 48.63 | | | | | 84693 |
| 1/29/02 | | 47.05 | | | | | 81937 |
| 1/30/02 | | 18.12 | | | | | 31562 |
| 1/30/02 | | 18.12 | | | | | 31562 |
| 1/30/02 | | 18.12 | | | | | 31562 |
| 1/31/02 | | 20.89 | | | | | 36373 |
| 2/l/2002 | | 25.01 | | | | | 43553 |
| 2/2/02 | | 33.55 | | | | | 58426 |
| 2/3/02 | | 31.63 | | | | | 55074 |
| 2/4/02 | | 34.85 | | | | | 60692 |
| 2/5/02 | | 34.31 | | | | | 59741 |
| 2/6/02 | | 41.87 | | | | | 72920 |
| 2/7/02 | | 46.34 | | | | | 80692 |
| 2/8/02 | | 36.00 | | | | | 62691 |
| 2/9/02 | | 39.49 | | | | | 68766 |
| 2/10/02 | | 37.40 | | | | | 65127 |
| 2/11/02 | | 28.96 | | | | | 50438 |
| 2/12/02 | | 39.05 | | | | | 68011 |
| 2/13/02 | | 12.53 | | | | | 21816 |
| 2/14/02 | | 34.03 | | | | | 59261 |
| 2/15/02 | | 25.04 | | | | | 43599 |
| 2/16/02 | | 30.81 | | | | | 53654 |
| 2/17/02 | | 29.01 | | | | | 50516 |
| 2/18/02 | | 29.43 | | | | | 51243 |
| 2/19/02 | | 31.65 | | | | | 55122 |
| 2/20/02 | | 43.48 | | | | | 75710 |
| 2/21/02 | | 39.19 | | | | | 68247 |
| 2/22/02 | | 56.13 | | | | | 97742 |
| 2/23/02 | | 51.44 | | | | | 89587 |
| 2/24/02 | | 47.74 | | | | | 83140 |

| **Tesoro Reported Flare Data** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | **Plant Reported Data** | | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume | HHV | H2S | Mol. Wt | SOx | 75% HC 44 MW 98% eff |
| | | MMSCFD | (BTU/SCF) | (Mole %) | (lbs/mole) | (lbs/day) | (lbs) |
| 2/25/02 | | 44.33 | | | | | 77204 |
| 2/26/02 | | 49.23 | | | | | 85726 |
| 2/27/02 | | 31.48 | | | | | 54816 |
| 2/28/02 | | 34.10 | | | | | 59376 |
| 3/l/2002 | | 38.78 | | | | | 67537 |
| 3/2/02 | | 37.74 | | | | | 65723 |
| 3/3/02 | | 48.94 | | | | | 85222 |
| 3/4/02 | | 31.05 | | | | | 54077 |
| 3/5/02 | | 41.44 | | | | | 72172 |
| 3/6/02 | | 44.17 | | | | | 76923 |
| 3/7/02 | | 37.88 | | | | | 65971 |
| 3/8/02 | | 25.54 | | | | | 44478 |
| 3/9/02 | | 28.10 | | | | | 48943 |
| 3/10/02 | | 49.74 | | | | | 86621 |
| 3/11/02 | | 46.45 | | | | | 80891 |
| 3/12/02 | | 41.73 | | | | | 72670 |
| 3/13/02 | | 43.71 | | | | | 76117 |
| 3/14/02 | | 41.63 | | | | | 72489 |
| 3/15/02 | | 39.93 | | | | | 69527 |
| 3/16/02 | | 43.15 | | | | | 75135 |
| 3/17/02 | | 33.09 | | | | | 57616 |
| 3/18/02 | | 39.78 | | | | | 69272 |
| 3/19/02 | | 39.51 | | | | | 68804 |
| 3/20/02 | | 35.12 | | | | | 61163 |
| 3/21/02 | | 30.88 | | | | | 53781 |
| 3/22/02 | | 35.16 | | | | | 61226 |
| 3/23/02 | | 27.19 | | | | | 47356 |
| 3/24/02 | | 27.44 | | | | | 47787 |
| 3/25/02 | | 7.61 | | | | | 13246 |
| 3/26/02 | | 20.46 | | | | | 35622 |
| 3/27/02 | | 27.26 | | | | | 47475 |
| 3/28/02 | | 40.65 | | | | | 70781 |
| 3/29/02 | | 34.94 | | | | | 60849 |
| 3/30/02 | | 15.55 | | | | | 27085 |
| 3/31/02 | | 11.88 | | | | | 20690 |

**Tesoro Reported Flare Data**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | | **Plant Reported Data** | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 4/1/02 | | 10.90 | | | | | 18985 |
| 4/2/02 | | 6.92 | | | | | 12057 |
| 4/3/02 | | 7.03 | | | | | 12241 |
| 4/4/02 | | 3.61 | | | | | 6295 |
| 4/5/02 | | 15.69 | | | | | 27328 |
| 4/6/02 | | 22.04 | | | | | 38373 |
| 4/7/02 | | 60.46 | | | | | 105290 |
| 4/8/02 | | 55.30 | | | | | 96309 |
| 4/9/02 | | 45.34 | | | | | 78961 |
| 4/10/02 | | 40.39 | | | | | 70328 |
| 4/11/02 | | 33.54 | | | | | 58415 |
| 4/12/02 | | 10.00 | | | | | 17408 |
| 4/13/02 | | 13.10 | | | | | 22815 |
| 4/14/02 | | 7.23 | | | | | 12585 |
| 4/15/02 | | 9.77 | | | | | 17009 |
| 4/16/02 | | 10.28 | | | | | 17911 |
| 4/17/02 | | 6.37 | | | | | 11086 |
| 4/18/02 | | 2.82 | | | | | 4918 |
| 4/19/02 | | 5.56 | | | | | 9678 |
| 4/20/02 | | 5.51 | | | | | 9592 |
| 4/21/02 | | 11.19 | | | | | 19490 |
| 4/22/02 | | 15.49 | | | | | 26977 |
| 4/23/02 | | 12.92 | | | | | 22507 |
| 4/24/02 | | 7.55 | | | | | 13154 |
| 4/25/02 | | 8.54 | | | | | 14873 |
| 4/26/02 | | 7.31 | | | | | 12725 |
| 4/27/02 | | 6.06 | | | | | 10558 |
| 4/28/02 | | 6.22 | | | | | 10825 |
| 4/29/02 | | 5.51 | | | | | 9602 |
| 4/30/02 | | 7.52 | | | | | 13093 |
| 5/l/2002 | | 5.54 | | | | | 9650 |
| 5/2/02 | | 9.86 | | | | | 17174 |
| 5/3/02 | | 8.83 | | | | | 15372 |
| 5/4/02 | | 21.36 | | | | | 37197 |
| 5/5/02 | | 15.56 | | | | | 27091 |

| **Tesoro Reported Flare Data** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | | **District's** |
| | | | **Plant Reported Data** | | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 5/6/02 | | 10.81 | | | | | 18822 |
| 5/7/02 | | 11.17 | | | | | 19450 |
| 5/8/02 | | 11.31 | | | | | 19690 |
| 5/9/02 | | 8.73 | | | | | 15208 |
| 5/10/02 | | 9.90 | | | | | 17249 |
| 5/11/02 | | 18.28 | | | | | 31837 |
| 5/12/02 | | 10.03 | | | | | 17467 |
| 5/13/02 | | 11.94 | | | | | 20790 |
| 5/14/02 | | 11.94 | | | | | 20798 |
| 5/15/02 | | 12.80 | | | | | 22293 |
| 5/16/02 | | 10.24 | | | | | 17832 |
| 5/17/02 | | 12.41 | | | | | 21611 |
| 5/18/02 | | 9.24 | | | | | 16096 |
| 5/19/02 | | 10.53 | | | | | 18332 |
| 5/20/02 | | 11.13 | | | | | 19389 |
| 5/21/02 | | 10.27 | | | | | 17888 |
| 5/22/02 | | 16.83 | | | | | 29308 |
| 5/23/02 | | 23.93 | | | | | 41679 |
| 5/24/02 | | 25.08 | | | | | 43669 |
| 5/25/02 | | 15.24 | | | | | 26535 |
| 5/26/02 | | 9.88 | | | | | 17213 |
| 5/27/02 | | 5.81 | | | | | 10122 |
| 5/28/02 | | 5.78 | | | | | 10061 |
| 5/29/02 | | 5.98 | | | | | 10406 |
| 5/30/02 | | 6.65 | | | | | 11579 |
| 5/31/02 | | 6.58 | | | | | 11462 |
| 6/1/02 | | 5.61 | 839 | 1.68 | 33.11 | 15940 | 9769 |
| 6/2/02 | | 5.72 | 839 | 1.68 | 33.11 | 16240 | 9961 |
| 6/3/02 | | 6.25 | 839 | 1.68 | 33.11 | 17760 | 10884 |
| 6/4/02 | | 7.28 | 839 | 1.68 | 33.11 | 20680 | 12678 |
| 6/5/02 | | 7.14 | 839 | 1.68 | 33.11 | 20280 | 12434 |
| 6/6/02 | | 4.78 | 839 | 1.68 | 33.11 | 13580 | 8324 |
| 6/7/02 | | 5.99 | 839 | 1.68 | 33.11 | 17020 | 10431 |
| 6/8/02 | | 9.21 | 839 | 1.68 | 33.11 | 21680 | 16039 |
| 6/9/02 | | 11.85 | 839 | 1.68 | 33.11 | 33640 | 20636 |

| **Tesoro Reported Flare Data** | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | **Plant Reported Data** | | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume | HHV | H2S | Mol. Wt | SOx | 75% HC 44 MW 98% eff |
| | | MMSCFD | (BTU/SCF) | (Mole %) | (lbs/mole) | (lbs/day) | (lbs) |
| 6/10/02 | | 18.48 | 839 | 1.68 | 33.11 | 5252 | 32182 |
| 6/11/02 | | 11.35 | 839 | 1.68 | 33.11 | 32260 | 19765 |
| 6/12/02 | | 7.74 | 839 | 1.68 | 33.11 | 22000 | 13479 |
| 6/13/02 | | 9.65 | 839 | 1.68 | 33.11 | 27420 | 16805 |
| 6/14/02 | | 5.45 | 839 | 1.68 | 33.11 | 15480 | 9491 |
| 6/15/02 | | 4.85 | 839 | 1.68 | 33.11 | 13780 | 8446 |
| 6/16/02 | | 4.83 | 839 | 1.68 | 33.11 | 13720 | 8411 |
| 6/17/02 | | 7.9 | 839 | 1.68 | 33.11 | 15500 | 13757 |
| 6/18/02 | | 4.8 | 839 | 1.68 | 33.11 | 22320 | 8359 |
| 6/19/02 | | 6.1 | 839 | 1.68 | 33.11 | 13540 | 10623 |
| 6/20/02 | | 5 | 839 | 1.68 | 33.11 | 17460 | 8707 |
| 6/21/02 | | 7.3 | 839 | 1.68 | 33.11 | 14240 | 12712 |
| 6/22/02 | | 11.5 | 839 | 1.68 | 33.11 | 20860 | 20026 |
| 6/23/02 | | 7.4 | 839 | 1.68 | 33.11 | 32720 | 12887 |
| 6/24/02 | | 6.7 | 839 | 1.68 | 33.11 | 21140 | 11668 |
| 6/25/02 | | 5.2 | 839 | 1.68 | 33.11 | 19060 | 9055 |
| 6/26/02 | | 6 | 839 | 1.68 | 33.11 | 14760 | 10449 |
| 6/27/02 | | 5.3 | 839 | 1.68 | 33.11 | 17080 | 9230 |
| 6/28/02 | | 5.5 | 839 | 1.68 | 33.11 | 15140 | 9578 |
| 6/29/02 | | 6.6 | 839 | 1.68 | 33.11 | 15740 | 11493 |
| 6/30/02 | | 7.4 | 839 | 1.68 | 33.11 | 18760 | 12887 |
| 7/1/02 | Foul water compressor down | 7.42 | 826 | 1.7 | 32.7 | 21240 | 12921 |
| 7/2/02 | | 6.26 | 826 | 1.7 | 32.7 | 17920 | 10901 |
| 7/3/02 | | 5.88 | 826 | 1.7 | 32.7 | 16840 | 10240 |
| 7/4/02 | | 6.15 | 826 | 1.7 | 32.7 | 17600 | 10710 |
| 7/5/02 | | 6.97 | 826 | 1.7 | 32.7 | 19960 | 12138 |
| 7/6/02 | | 6.17 | 826 | 1.7 | 32.7 | 17640 | 10745 |
| 7/7/02 | | 5.8 | 826 | 1.7 | 32.7 | 16580 | 10100 |
| 7/8/02 | | 6.38 | 826 | 1.7 | 32.7 | 18280 | 11110 |
| 7/9/02 | | 7.82 | 826 | 1.7 | 32.7 | 22400 | 13618 |
| 7/10/02 | #2 H2 Plant PSA vent to flare | 8.6 | 826 | 1.7 | 32.7 | 24620 | 14976 |
| 7/11/02 | | 7.02 | 826 | 1.7 | 32.7 | 20080 | 12225 |
| 7/12/02 | | 6.92 | 826 | 1.7 | 32.7 | 19800 | 12051 |
| 7/13/02 | | 6.98 | 826 | 1.7 | 32.7 | 19980 | 12155 |
| 7/14/02 | | 6.09 | 826 | 1.7 | 32.7 | 17440 | 10605 |

| Tesoro Reported Flare Data | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | District's |
| | | Plant Reported Data | | | | | VOC Estimate |
| Date | CAUSE/COMMENTS | Volume MMSCFD | HHV (BTU/SCF) | H2S (Mole %) | Mol. Wt (lbs/mole) | SOx (lbs/day) | 75% HC 44 MW 98% eff (lbs) |
| 7/15/02 | | 6.39 | 826 | 1.7 | 32.7 | 18280 | 11128 |
| 7/16/02 | | 6.15 | 826 | 1.7 | 32.7 | 17620 | 10710 |
| 7/17/02 | | 5.95 | 826 | 1.7 | 32.7 | 17020 | 10361 |
| 7/18/02 | #3 Crude furnace tripped off, #3 HDS Stripper was bypased to fix leak | 9.55 | 826 | 0.05 | 32.7 | 800 | 16631 |
| 7/19/02 | | 7.03 | 826 | 1.7 | 32.7 | 20120 | 12242 |
| 7/20/02 | | 5.65 | 826 | 1.7 | 32.7 | 16180 | 9839 |
| 7/21/02 | | 4.92 | 826 | 1.7 | 32.7 | 14080 | 8568 |
| 7/22/02 | | 4.53 | 826 | 1.7 | 32.7 | 12980 | 7889 |
| 7/23/02 | | 4.37 | 826 | 1.7 | 32.7 | 12520 | 7610 |
| 7/24/02 | | 5.23 | 826 | 1.7 | 32.7 | 14960 | 9108 |
| 7/25/02 | | 7.27 | 826 | 1.7 | 32.7 | 20800 | 12660 |
| 7/26/02 | Lost lean DEA pump, flared fule gas (see note 2) | 12.59 | 1092 | 3.5 | 32.7 | 49240 | 21925 |
| 7/27/02 | Adjusting unit rates after upset | 8.8 | 826 | 1.7 | 32.7 | 25180 | 15325 |
| 7/28/02 | #2 H2 Plant shutdown | 6.1 | 826 | 1.7 | 32.7 | 17480 | 10623 |
| 7/29/02 | Units are cut back due to H2 shortage | 3.97 | 826 | 1.7 | 32.7 | 11360 | 6913 |
| 7/30/02 | | 3.95 | 826 | 1.7 | 32.7 | 11320 | 6879 |
| 7/31/02 | | 3.27 | 826 | 1.7 | 32.7 | 9380 | 5694 |
| 8/1/02 | | 3.3 | 802.89 | 1.51 | 32.41 | 8420 | 5747 |
| 8/2/02 | | 7.3 | 802.89 | 1.51 | 32.41 | 18580 | 12712 |
| 8/3/02 | | 7.8 | 802.89 | 1.51 | 32.41 | 19940 | 13583 |
| 8/4/02 | | 6.1 | 802.89 | 1.51 | 32.41 | 15580 | 10623 |
| 8/5/02 | H2 Plant shutdown 13 hours | 16.1 | 802.89 | 1.51 | 32.41 | 19580 | 28037 |
| 8/6/02 | | 6.1 | 802.89 | 1.51 | 32.41 | 15620 | 10623 |
| 8/7/02 | | 4.8 | 802.89 | 1.51 | 32.41 | 15520 | 8359 |
| 8/8/02 | | 7.2 | 802.89 | 1.51 | 32.41 | 12300 | 12538 |
| 8/9/02 | | 5.3 | 802.89 | 1.51 | 32.41 | 18380 | 9230 |
| 8/10/02 | | 5.1 | 802.89 | 1.51 | 32.41 | 13580 | 8881 |
| 8/11/02 | | 7.8 | 802.89 | 1.51 | 32.41 | 12960 | 13583 |
| 8/12/02 | | 5.4 | 802.89 | 1.51 | 32.41 | 19780 | 9404 |
| 8/13/02 | | 4.8 | 802.89 | 1.51 | 32.41 | 13720 | 8359 |
| 8/14/02 | | 6 | 802.89 | 1.51 | 32.41 | 12080 | 10449 |
| 8/15/02 | | 6.3 | 802.89 | 1.51 | 32.41 | 15260 | 10971 |
| 8/16/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/17/02 | Previous 30 days average | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/18/02 | We had problems with data collection on July 17-28 and 31 | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |

**Tesoro Reported Flare Data**

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | Does not include pilot and purge gas | | | | **District's** |
| | | | **Plant Reported Data** | | | | **VOC Estimate** |
| Date | CAUSE/COMMENTS | Volume | HHV | H2S | Mol. Wt | SOx | 75% HC 44 MW 98% eff |
| | | MMSCFD | (BTU/SCF) | (Mole %) | (lbs/mole) | (lbs/day) | (lbs) |
| 8/19/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/20/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/21/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/22/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/23/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/24/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/25/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/26/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/27/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/28/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/29/02 | | 6.2 | 802.89 | 1.51 | 32.41 | 15700 | 10797 |
| 8/30/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| 8/31/02 | | 6.4 | 802.89 | 1.51 | 32.41 | 16300 | 11145 |
| | | | | | | | |
| | | | | | | | |
| Notes: | Data supplied by Tesoro except for last column which is the District's emission estimate based on information supplied by Tesoro | | | | | | |
| | Purge and pilot flows are not always included above | | | | | | |
| | Average based on reported values | | | | | | |
| | Number nonzero days | | 607 | | | | |
| | Total Emissions | | 14340536 | | | | |
| | **Average daily value for reported data is** | | **13** | **tons** | **Pilot and purge gas included** | | |
| | **Maximum reported value is** | | **120** | **tons** | | | |

**Exhibit 11**:

Brenda Shine Memorandum; Potential Low Bias of Reported VOC Emissions From the Petroleum Refining Industry (Jul. 2007)

# Technical Memorandum

**TO:** EPA Docket No. EPA-HQ-OAR-2003-0146

**FROM:** Brenda Shine, EPA/SPPD

**DATE:** July 27, 2007

**SUBJECT:** Potential Low Bias of Reported VOC Emissions from the Petroleum Refining Industry

## I. Purpose

Measurement studies performed in Europe over the past two decades and more recently in Canada, using differential absorption light detection and ranging systems (DIAL), indicate that emissions of VOC from refineries are significantly higher (10 to 20 times) than amounts estimated using standard techniques. This bias is apparently caused by omission or mischaracterization of significant emission sources, and the same quantification issues could exist in this country. Because our emission inventories are currently being used to draw conclusions regarding ozone control strategies and residual risk from air toxics, and because current emission levels from this industry are significant, we are in critical need of a confirming analysis of VOC and air toxic emissions estimates from US petroleum refineries. This document provides the basis for our hypothesis that there is a systematic low bias in reported emissions of VOC and air toxics from petroleum refineries.

## II. Background

### A. DIAL and the European and Canadian Experience

The most recent experience on a refinery in Canada was conducted for the Alberta Research Council by Spectrasyne Ltd, UK.[1] When the short term DIAL measurements were extrapolated to annual emissions, the annual emission rate of C2+ hydrocarbons (VOC) was 9970 tons per year, 15 times higher than the 670 ton per year estimate the facility had provided in their National Pollutant Release Inventory (NPRI) . Similarly, benzene emissions were 18 times higher than the reported NPRI estimates (40.1 TPY versus 2.2 tpy). Major contributors were the coker unit, product tanks, and cooling towers.

DIAL measurement studies have been conducted for a number of years in Europe, with Sweden having the most experience using DIAL to measure refinery emissions. As a result, Sweden has required remote sensing at refineries since the late 1980's and by 1996, all refineries were required to use DIAL measurements every 2-3 years. Initially, measurements indicated emissions of 10 to 20 times the calculated values, but after this long-term experience with the measurements, facilities now experience actual emission levels of 3 to 10 times higher than what estimation methods provide.[2]

In Britain, the National Physical Laboratory (NPL) developed the source and detection systems for the infrared DIAL in the mid to late 1980s. A joint project with British Petroleum commercialized the system in the late 1980s and spun off Spectrasyne Ltd. to provide the service and equipment. Both entities currently offer measurement capabilities at this time.

In general, the NPL notes that estimated emissions for a facility are lower than DIAL measurements, often due to facilities not including sources in their inventories or from malfunctioning equipment that is not normally monitored. For refineries, the NPL has found that emissions vary from 0.07 weight percent (wt %) to 0.3 wt % of crude throughput, with the average values at about 0.2 wt % of throughput.[3] Similarly, emissions, as a percentage of crude throughput from the Alberta refinery study represented 0.21 wt % of refinery throughput, while fugitive emissions accounted for 0.17 wt % of throughput.[4]

In addition to experience in Britain and Sweden, DIAL measurements on refineries have been conducted in a number of European countries, including Belgium, the Czech Republic, and Germany, and Germany also has formal standards pertaining to the application of DIAL.[5]

## B. Validation of DIAL

The general experience reported in the literature from the application of DIAL technology to quantify atmospheric emissions at petroleum refineries has been that, despite some limitations, DIAL is able to accurately quantify the amount of VOC emissions occurring at the time of measurement.[6] There have been a number of validation studies conducted by the NPL and other groups. During an NPL verification project, the DIAL measurements for a known methane release were within +- 10 percent of the actual values. In other experiments, the DIAL measurements were within +- 12 percent of the actual value of an aliphatic hydrocarbon plume and within +-15% of a toluene plume. Wind speed measurements, used to calculate flux, were cited as responsible for a significant part of the error.[7] Spectrasyne Ltd also conducted a number of mass emission correlation exercises between DIAL and other measurement techniques, including SF6 tracer gas releases and controlled releases of methane from a point source and a marine tanker vent. In all these exercises, the maximum divergence from the DIAL measurements recorded was 15%.[8] Finally, we note that CONCAWE, the European Oil industry's organization for environment, health, and safety conducted a study to compare DIAL measurements with flux measurements and AP-42 equations. The study showed that DIAL measurements were slightly lower than CONCAWE's flux measurements, and that the AP-42 equations compared well on an hourly basis.[9] The study was cited by the American Petroleum Institute in response to the Alberta Research Council Report addressing storage tank emission estimates as measured by DIAL and the validity of the AP-42 equations. The details of the modeling assumptions were provided for the measurement period; hourly average wind speed was used to estimate emissions for a given hour and these were the results compared. However, the AP-42 equations are set up to calculate yearly emissions using annual average inputs. Similar to the concern voiced by API discussed below regarding the extrapolation of hourly measurements to yearly estimates, this detailed modeling assessment does not necessarily indicate that the annual average inputs to the AP-42 equations yield good annual average estimates as asserted by the API letter.

### C. Industry's Response

As noted above, the American Petroleum Institute (API) prepared a letter taking issue with the comparison of the DIAL Canada study and the API estimation methods (AP-42 equations). [10] Additionally, Rob Ferry, API Consultant prepared a critique of the use of the DIAL method for quantifying VOC emissions. Generally, API's objection to the Canadian reports is not that the DIAL measurements are incorrect, but that they were taken over an inadequate time period to allow them to be used for calculating a yearly emission number. Secondly, they note that higher than expected emissions generally occur when there are extraordinary conditions or when emission sources are not properly operated or maintained.

## III. VOC and Air Toxic Emissions from US Refineries and Bias

### A. Current US Refinery Estimates and How They Compare to Measured Emissions

The 2002 national emissions inventory (NEI) indicates that there are 128,000 tons per year of VOC reported, and approximately 1000 tons per year of benzene reported emitted from approximately 150 refineries operating in the US. The total crude capacity of these refineries is approximately 16 MM bbls/day; assuming actual throughput is close to capacity, and using a crude specific gravity of .85, the average VOC emission factor is approximately .015 wt % of crude throughput, or about 4 times lower than the lowest emissions factor measured for VOC by the NPL DIAL system and an order of magnitude lower than the average NPL factor and the Alberta Research Council factor of 0.2 wt % VOC. The average benzene emission factor is 0.0001 wt%, approximately one-fifth of the 0.0005 wt % factor measured by the Alberta Research Council.

### B. Omissions and Mischaracterizations

As discussed previously, the general consensus from the Canadian and European studies regarding the reasons for a low bias in reporting of emissions from the industry is related to the omission or mischaracterization of significant emission sources, among them:

- exclusion of upsets, malfunctions, startups, and shutdowns from emissions inventories
- omission of sources that are unexpected or not measured, such as leaks in heat exchanger systems or emissions from process sewers
- exclusion of emission events such as tank roof landings
- improper characterization of input parameters for emission models such as not using actual tank or material properties in the AP-42 tank emission estimation methodologies

In general, our U.S. experience indicates that the same characterization and quantification issues exist at our U.S. refineries, as discussed in greater detail below.

#### 1. Exclusion of Upsets, Malfunctions, Startups, and Shutdowns from Emission Inventories

Our current National Emissions Inventory does not identify upsets, startups, or shutdowns as emission events, nor is the data specifically requested from the reporters (the states). In trying to understanding the order of magnitude of SSM and upsets in relation to routine operations, we reviewed the emission inventory data from the Texas Commission on Environmental Quality (TCEQ) for the 2004 reporting year. This data set contains emissions data for 30 of the approximately 150 U.S. refineries and accounts for over 25% of the US refining capacity. Additionally, the TCEQ inventory identifies emissions from routine events separately from upsets, startups, and shutdowns, so a comparison of reported emissions is possible. In general, the quantity of emissions reported as non-routine is smaller than the routine emissions. For VOC-unclassified contaminant, emissions of upsets and SSM were 5% of the emissions reported from routine events (578 TPY versus 11,032 TPY). However, for some compounds, such as 1,3-butadiene, emissions from SSM and upsets accounted for as much as 20% of the routine emissions (19.8 TPY versus 91 TPY). Additionally, for certain types of emission points, emissions from startups, shutdowns, and malfunctions make up the majority of the emissions. Finally, we should note that this comparison was done between *reported* upsets and SSM events and *reported* routine emissions. This comparison does not consider events such as upsets and SSM events are not properly characterized and reported to begin with.

2. Omission of Sources that are Unexpected or Not Measured

A number of emission events that are not measured or expected are in turn not characterized or reported in our inventories. For example, monitoring of cooling tower water return for VOC is required at some refineries because of state permitting and RACT rules, but not required on refineries at the Federal level (eg., by the Petroleum Refinery MACT standard.) Additionally, speciation of the VOC to individual HAP compounds is typically not required. Because there is no requirement to monitor for leaks, there is, in effect, no systematic mechanism for facility owners and operator to identify, quantify, and control emissions in a timely way. Further, there is potential for high emissions of VOC and HAP from such events. For example, in one release report submitted to the National Response Center in 2006, a facility initially reported potential emissions of 700 lbs/day each of benzene, toluene, and xylene from a reformer unit cooling tower, based on sampling of their cooling water return and the expected composition of the process streams that were being cooled. Upon further analysis and speciation of the cooling water, however, the facility submitted a final report indicating that the exchanger had leaked 800 lbs/day of propane and isobutane for approximately 8 days[11]. It is important to note that this facility monitored the tower and this is the reason why the leak was identified and reported. However, many refineries do not conduct routine cooling tower water monitoring. In a sampling of the refining industry to be used to supplement our emissions inventory for the purpose of risk modeling, we surveyed 22 refineries and requested emissions of benzene. Out of the 22 facilities surveyed, only 3 indicated that they have sampled their cooling towers for leaks. The remaining facilities that did report emissions used AP-42 VOC emission factors for cooling towers and an assumed speciation for benzene. Five facilities simply reported 0.

Another area that could be systematically overlooked in the process of quantifying emissions is the delayed coking process. In the measurements conducted at the Alberta Refinery, the coker area contributed to over 15% of the site VOC emissions and 26% of the benzene emissions, and measurements were made when the coke from the delayed coking unit was being drilled (after full water quench) and when it was not. Emissions were high when the coke was being drilled.[12] We note that currently, U.S refiners do not report any fugitive emissions of VOC or benzene from the delayed coking cutting/drilling/coke recovery process.

Similar concerns may be warranted regarding the wastewater treatment emission estimates. A recent Bay Area (BA) AQMD study evaluated collection system emissions for five Bay Area refineries[13]. Utilizing extensive sampling, flow measurements, and detailed TOXCHEM+ modeling, the study showed that 4 of the 5 refineries underestimated the VOC emissions from their wastewater collection system. Two refinery estimates were within a factor of two of the BA AQMD estimate (one higher and one lower), but one refinery had underestimated its emissions by a factor of 40 and another refinery underestimated its emissions by a factor of 1,400. In reviewing the emission estimates reported by the residual risk survey respondents for wastewater collection and treatment systems, we also note surprisingly low estimates for several refineries.

## 3. Exclusion of Emission Events Such as Tank Landings

Floating roofs are an effective method of controlling VOC emissions from storage tanks because they prevent direct contact of the stored liquid with ambient air and limit the creation of a saturated vapor in the headspace of the tank. However, if the liquid level in the tank is lowered to below the surface of the floating roof support legs, the roof will land on its legs, creating a saturated vapor space and limiting the control efficiency of the floating roof. Until recently, there had not been a generally accepted method available to estimate air emissions during the period when a floating roof was landed. TCEQ estimates that underreported landing loss emissions in the Houston-Galveston area alone totaled over 7000 tons of VOC in 2003.[14] EPA recently updated AP-42 to include API methodology for calculating roof landing losses. However, as with cooling tower leak monitoring, there does not appear to be a systematic mechanism on the Federal level for facility owners to identify, quantify, and control these events, although TCEQ has proposed rulemaking to limit the circumstances under which tank landings occur and has issued guidelines for reporting of these events in their inventories.

## 4. Improper Characterization of Parameters in Estimation Methodologies

All of the refinery measurements indicate that storage tanks are a major source of VOC emissions. In the Alberta refinery measurement study, emissions of VOC were 30 times higher and emissions of benzene were 100 times higher than emissions calculated using AP-42 equations. The AP-42 equations require a number of inputs about the tank and material characteristics and storage conditions. Mischaracterization of these inputs could lead to erroneous results and API points out that when the DIAL measurements indicate unexpectedly high emissions, it is either because conditions are on the high side of the range expected (eg., temperature, wind speed, or liquid level), or that conditions may be outside the scope of the method. These conditions include loading of non-stabilized crudes, or maintenance conditions, such as seal failures on floating roof tanks.[15] We agree that both of these concerns are potential sources of uncertainty, and that they could explain why the DIAL studies were higher than actual. However, while these uncertainties could explain differences on the order of two or three, it is difficult to explain differences on the order of 30 to 100. Given the magnitude of the difference, either emissions are zero most of the time (when events are not on the high side) or the annual emissions estimates are too low. No direct information is available on the actual condition of the tanks to assess if they were properly modeled. Further, there are numerous examples of tank maintenance issues that, if not characterized properly, would lead to erroneous results. For example, on March 11, 2003, the South Coast Air Quality Management District (SC AQMD) filed suit against BP West Coast Products, LLC. Most of the allegations accuse the company of failing to properly inspect and maintain 26 storage tanks equipped with floating roofs, as required under SC AQMD Rule 463. SC AQMD inspections revealed that more than 80 percent of the tanks had numerous leaks, gaps, torn seals, and other defects that caused excess emissions. [16]

## C. General Indicators of Low Emission Reporting Bias

Evidence regarding the underestimation of VOC emissions has been reported in the past. Of note is the Texas Air Quality Study-2000, where ambient concentrations of highly reactive VOC were found to be 10 to 1000 times higher than were reported in the Texas emission inventory for that year, and the NARSTO Emission Inventory Assessment which necessitated that reported VOC emissions be multiplied six fold before models and ambient measurements correlated. Finally, EPA's Office of Inspector General, in a March 22, 2006 report specifically recognized that the problem of under reporting of VOC emissions from the refining sector and concurred with the Agency shifting towards more direct, continuous monitoring and measurement of emissions from all major sources.

---

[1] Alberta Research Council Inc. "Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection" Prepared for Environment Canada. March 26, 2006.

[2] Executive Summary from Workshop entitled: "VOC Fugitive Losses: New Monitors, Emission Losses, and Potential Policy Gaps"

[3] USEPA. NPL Presentation, Appendix Item C-12. (revised)

[4] Alberta Research Council. Email correspondence from Allan Chambers to Roy Huntley, EPA, 11/01/06.

[5] Clearstone Engineering Ltd., Technical Report: A Review of Experiences Using DIAL Technology to Quantify Atmospheric Emissions at Petroleum Refineries. Prepared for Environment Canada. August 10, 2006.

[6] Clearstone Engineering Ltd.

[7] USEPA, p.10.

[8] Alberta Research Council, Appendix A, p.2.

[9] CONCAWE. VOCemissions from external floating roof tanks; comparison of remote measurements by laser with calculation methods. January 1995. Available at: http://www.concawe.org/DocShareNoFrame/docs/4/FDBIMDBCBLFOEJGCKIPLJPJJVEVC7191P3PDBK9DW3GK/CEnet/docs/DLS/Rpt_95-52-2004-01744-01-E.pdf

[10] Letter from Paula Watkins, API, to Mike Ciolek, U.S. EPA. August 9, 2006.

[11] NRC Incident Report 801202, Jun 19, 2006; TCEQ Incident Final Report 77203

[12] USEPA, page 5.

---

[13] Breen, D. 2004. *Proposed Revision of Regulation 8, Rule 8: Wastewater Collection Systems.* Staff Report. Prepared for Bay Area Air Quality Management District, San Francisco, CA. March 17, 2004.

[14] TCEQ Docket No. 2006-1804-RUL. Memorandum on Commission Approval for Proposed Rulemaking

[15] API, page 4.

[16] Whetzel, C, 2003. "South Coast Air District Seeks $319 For Violations at Los Angeles Area Refinery." The Bureau of National Affairs, Inc., Washington D.C

Exhibit 12:
Expert Opinion by Neil Carman, PH.D.
Comments on MHA Nation's Petroleum Refinery NPDES Permit and Supplemental Information Report
9/12/2011

# Comments on MHA Nation’s Petroleum Refinery NPDES Permit and Supplemental Information Report

Neil Carman, Ph.D.

9/12/2011

Comments on the Refinery's Effluent Discharge Alternatives

In the EPA's Record of Decision, August 3, 2011, the proposed MHA refinery's effluent discharge alternatives are presented (pp. 3-5) as alternatives A, B, C, and D. EPA's preferred alternative is A utilizing the discharge of effluent through an NPDES permit.

EPA previously raised concerns about the discharge of effluent from the refinery, since refineries generate significant quantities of wastewater streams contaminated with process chemicals.

EPA states on p. 3 of the ROD:

*Alternative A: (EPA’s Preferred Alternative) Discharge of effluent through an NPDES permit. Through the NPDES permit, EPA would authorize the MHA Nation to discharge treated wastewater from the refinery in compliance with permit limits, outfall locations, and monitoring and reporting requirements. Any discharges from the facility would need to meet the NPDES effluent limitations which incorporate the more stringent requirements of the technology-based effluent limits for the petroleum refining industry and water quality standards and criteria. All outfalls discharge into the wetlands at the northeast corner of the site, flowing north under Highway 23 into a tributary of the East Fork of Shell Creek. The number of the outfalls and the manner in which waste streams are combined differ among the refinery construction alternatives as described below.*

EPA recognized the need for a refinery wastewater treatment system that included more stringent effluent wastewater controls in its Final EIS Preferred Alternative.

EPA states on p. 5 of the ROD:

*IV. FINAL EIS PREFERRED ALTERNATIVE*

*The "agency's preferred alternative" is the alternative which the agency believes would fulfill its statutory mission and responsibilities, giving consideration to economic, environmental,*

*technical and other factors. The FEIS identifies EPA's preferred effluent discharge alternative as Alternative A, discharge of effluent through an NPDES permit, and recommends the refinery design modifications described in Alternative 4.*

EPA notes in the ROD that there was an analysis of the "group of surge tanks of sufficient volume to handle a certain storm event, and designed/engineered to required specifications" without considering recent unusually high rainfall and flood events in North Dakota.

Will the group of storm water surge tanks be adequate in capacity to handle a record rainfall and flooding that recently occurred in North Dakota?

Was the certain storm event smaller than the record rainfall and flooding?

EPA states on p. 4:

*Under Alternative 4 and A, uncontaminated stormwater would be collected and routed to the evaporation pond (water storage reservoir). Water from the evaporation pond would be used in refinery processes and in the fire water system which includes two fire water reservoirs. Surplus uncontaminated stormwater would be discharged through Outfall 001. Process wastewater from the refinery (primarily from the sour water stripper) would be routed directly to the wastewater treatment unit (WWTU). After treatment, the water would be conveyed to a series of final* *effluent release tanks before discharge from Outfall 002. Wastewater would be tested prior to release and if it does not meet discharge limits it would be recycled back to the wastewater treatment plant for further treatment. Potentially contaminated stormwater (oily) from the refinery process area, product loading area and tank farm would be conveyed to a group of surge tanks of sufficient volume to handle a certain storm event, and designed/engineered to required specifications. Depending on water quality, the wastewater in the surge tanks would be conveyed to either a release tank or to WWTU for treatment. Wastewater from the effluent release tanks would be discharged through NPDES Outfall 002a.*

In June 2011, areas in the midwest US including North Dakota experienced record flooding according to flood tracking charts for the U.S Geological Survey and related information and news reports. See USGS flood tracking charts for the June 2011 flooding in North Dakota at: http://nd.water.usgs.gov/floodtracking/

Record flooding in North Dakota occurred due to a coupling of heavy snow melt in Canada combined with high rainfall.

EPA needs to fully evaluate the June 2011 North Dakota record floods as to the number and size of surge tanks needed at the refinery to prevent high volume releases of storm water contaminated water. During an unusually high rainfall and flood such as occurred in June 2011, the refinery could release substantial quantities of process contaminated water as well, especially if the refinery were flooded and all the wastewater treatment systems overflowed due to an undersized storage and wastewater treatment capacity.

The East Shellfork tributary experiences flooding every spring according to local information. The closest community to the East Shellfork tributary is Makoti, ND and roads connecting Makoti to other communities were heavily flooded. Potential for refinery flooding needs to be addressed based on recent flooding and a potential for more severe flooding than occurred so far in 2011.

## Climate Change and Rainfall in North Dakota

Floods are expected to increase in frequency and severity as evidenced by the record flooding in North Dakota. Global warming and climate change must be considered in the NPDES permit analysis. Global warming and the pollutants that lead to global warming must be considered in the BACT analysis since EPA has ignored the role of climate change. Global warming will likely be the most pressing environmental and public health concern of our time. Even the Pentagon has recognized global warming as a serious threat. A 2004 report from the Pentagon synthesized some of the recent findings in the area of rapid climate change, warning of the possibility of global famine and wars over shrinking resources, and urging that global warming be raised "beyond a scientific debate to a national security concern."

## Comments on the Need for Cumulative Impacts Analysis of Hydrogen Sulfide ($H_2S$) Gas Emissions at the Refinery and the Oil Fields

The supplemental report in combination with the air modeling failed completely to assess a major hazardous chemical that can be present at much higher levels, the toxic gas hydrogen sulfide ($H_2S$), produced in the Bakken oils fields and is present in the Bakken crude oil.

Cumulative impacts of $H_2S$ from the refinery and the area oil wells need to be addressed in a new EIS since the Bakken crude has a higher sulfur content and likely a higher $H_2S$ content as well. I did not mention that in the 2009 petition to EPA on $H_2S$, but cumulative $H_2S$ are a basic concern in North Dakota with all the Bakken oil wells around the refinery area assuming they are close enough.

The following paragraphs and references are excerpted from a March 30, 2009 petition to EPA administrator on classifying hydrogen sulfide as a hazardous air pollutant. See attached March 30, 2009 petition to EPA on $H_2S$.

EPA needs to address adverse $H_2S$ impacts based on evidence of harmful exposures in numerous communities and its toxicological effects at low concentrations such as non-cancer effects and emerging evidence that $H_2S$ is a genotoxic agent, meaning it damages DNA. Even EPA has assessed the need to list $H_2S$ as a HAP, but no formal listing action has been taken. $H_2S$ is an unlisted hazardous air pollutant.

$H_2S$, well known to cause death at high concentrations and respiratory-brain-nervous system effects at lower levels, escaped addition to the original list of 188 HAPs in 1990 due to opposition from the oil and gas industry, despite the EPA's attempts to include it. In January 1999, strong public support to add $H_2S$ to Title III of federally recognized air toxics occurred when 145 public health, environmental and community groups in 32 states sent a request to EPA based on scientific studies suggesting chronic, low-level exposures cause permanent damage to the brain and central nervous system. Indeed, new toxicological evidence reveals $H_2S$ can cause neuron death in the brain and serves as a solid regulatory basis that $H_2S$ is far worse than just a stinky chemical triggering bad headaches, nausea and discomfort at citizens' home environment. The oil and gas industry has downplayed for decades the toxic effects of smelly $H_2S$ emissions when citizens have to breathe horrible, nauseating rotten egg odors, while industry officials allege it's little more than a foul smelling odor with no harmful effects at sublethal low concentrations. Citizens who wrote to EPA in January 1999 are still waiting for the agency to take action on this highly toxic substance.

Today, it is unacceptable for communities to continue suffering the ill effects of toxic hydrogen sulfide gas exposure when the technology to control it is available and affordable. As EPA has learned, environmental injustice is a fact of life for thousands of communities across the nation and these residents all have a right to clean, safe air. It's past time for EPA to take action to formally acknowledge hydrogen sulfide's serious acute and chronic toxicity. As EPA Administrator, you have CAA authority to do the right thing based on a compelling body of $H_2S$ medical evidence and air quality data indicating a need for better regulation of hydrogen sulfide. Specifically, CAA section 112(b)(2) provides "the Administrator shall periodically review the list established by this subsection and publish the results thereof and, where appropriate, revise such list by rule, adding pollutants which present, or may present, through inhalation or other routes of exposure, a threat of adverse human health effects…" Health studies support the need for EPA to list $H_2S$ under CAA section 112(b), especially since $H_2S$'s routine exposure effects— on a daily basis— are not addressed whatsoever under the accidental release provisions in section 112(r) of the CAA, where $H_2S$ is currently regulated. Section 112(r) is not designed or intended to address daily toxic exposures.

The EPA began an informal review in the last ten years due to EPA's continuing health concerns and a prior request by 145 organizations sent January 25, 1999 to EPA Administrator Carol Browner. EPA's Office of Air Quality Planning & Standards has performed a new IRIS assessment and made recommendations in 2007 to the Assistant Administrator for Air and Radiation of options to address $H_2S$. Nonetheless, EPA has yet to make a decision to formally list $H_2S$ as a CAA section 112(b) HAP and solicit comments in a Federal Register Notice.

Hydrogen sulfide, known as "poison gas" for its lethal properties, is probably the most common toxic air pollutant found in urban and rural communities. It is easily identifiable by its distinct rotten eggs odor. At least 73 industry categories emit $H_2S$ in varying rates and volumes. Citizens impacted by industry $H_2S$ have complained due to the acute and chronic effects of low level exposures. In recent years, $H_2S$'s health concerns have occurred over frequent obnoxious odors from confined animal feeding operations (CAFOs). Data from the Poison Control Centers National Data Collection system show from 1983-1992 acute exposure to $H_2S$ was linked to 29 deaths and 5,563 exposures, according to a 1995 article in the *American Journal of Emergency Medicine*. A U.S. multistate surveillance program found that 637 $H_2S$-related incidents occurred from 1993-2001, resulting in 63 public evacuations and injuring 185 people, according to a 2004 journal article written by federal health investigators and others.

## General information about the toxicity of hydrogen sulfide gas

Inhalation of $H_2S$ leads to adverse effects on consciousness, cardiac and pulmonary function depending on the level and length of exposure. Virtually all organ systems are affected by $H_2S$. The most vulnerable organs are those with exposed mucous membranes (e.g., eyes, nose and throat) and those with high oxygen demands (e.g., lungs, brain). Neurotoxicity of the central nervous system (causing nausea, dizziness, confusion, headache and sleeping problems) and pulmonary edema (build-up of fluid in the lungs) are other well-documented effects of hydrogen sulfide poisoning. Cardiovascular and gastrointestinal toxicity are associated with $H_2S$ exposure. Hydrogen sulfide creates health effects by binding with iron in blood and cells to block the flow of oxygen to tissues and disrupting systems.

Hydrogen sulfide is similar to hydrogen cyanide (HCN) in toxicity and cellular effects. $H_2S$ interferes with a crucial biological enzyme—cytochrome C oxidase, necessary for living cells to utilize oxygen and blockage of this vital enzyme may cause cellular death (1, 2). Cytochrome C oxidase is the last enzyme in a series in the respiratory electron transport chain of mitochondria inside the mitochondrial membrane. This key enzyme receives an electron from each of four cytochrome C molecules, and transfers them to one oxygen molecule, converting molecular oxygen ($O_2$) to two molecules of water ($H_2O$) in the cellular energy-making process. In the process, it binds four protons from the inner aqueous phase to make water, and in addition translocates four protons across the membrane, helping to establish a transmembrane difference of proton electrochemical potential that the enzyme ATP synthase then uses to make another vital cellular biochemical—ATP (adenosine triphosphate). ATP is the universal energy molecule in all living cells. ATP's cellular support function is so important that it is involved in triggering all muscle contractions including the heart and lungs. Without ATP, the heart and lungs fail to work.

Oxygen (as molecular oxygen $O_2$) is constantly required by living cells to run billions of complex biochemical reactions, activities and functions every single second to maintain life, including intricate cellular respiration in cascading pathways like the Krebs tricarboxylic acid cycle where the cell produces internal energy molecules in the form of ATP. Without plenty of ATP molecules being continuously supplied for cellular biochemical machinery to operate, living cells can not survive more than a few minutes before cell death occurs and tissues begin to die. Blockage of the enzyme cytochrome C oxidase by hydrogen sulfide inside red blood cells, the brain and lungs poses a serious threat to the biological integrity and well-being of the human brain and body.

How does $H_2S$ enter the body? There are three routes: inhalation—from breathing vapors absorbed through the lungs; oral—from ingestion of contaminated substances (especially water), absorbed through the intestinal tract; and skin—from dermal contact with contaminated substances (such as air), absorbed through the skin. The main route of absorption of $H_2S$ is through inhalation in a vast majority of communities.

Animal studies of $H_2S$ show widespread distribution in the body after inhalation exposures (3, 4), with a selective distribution to the brain stem area compared with other areas in the brain (5). Warenycia et al. (5) found the net uptake of sulfide was greatest in the brainstem (3.02 micrograms/g) compared to other neural regions as was the selective accumulation of sulfide as calculated from normalized blood flow rates. The results of subcellular analysis showed sulfide was detectable in fractions enriched in myelin, synaptosomes and mitochondria. A major sulfide portion was found in the mitochondrial fraction, where the cell’s critical energy-producing system resides. The sulfide content of these fractions increased 2- to 3-fold, the greatest increases occurring in myelin- and mitochondrial-enriched fractions (5). The brain stem is vital since it plays a primary role in the regulation of cardiac and respiratory functions. The medulla oblongata in the brain stem is the lower portion of the brainstem. It deals with autonomic physiological functions, such as breathing and blood pressure, and keeping us alive.

Research in animals has identified more than forty health effects of $H_2S$ primarily non-cancer effects. Medical data demonstrates that numerous similar health effects occur in human exposure to $H_2S$. Metabolism takes place by three pathways: oxidation to sulfate, methylation, and reaction with metallo- or disulfide- containing proteins. This last appears to be the main pathway for toxicity although new evidence may offer more insights on biological oxidation and reactions (6).

Human populations most sensitive to $H_2S$ are assumed to be the fetus (animal data only), children (7), persons with heart disease (8), individuals with asthma (9), individuals who metabolize organosulfides differently (10, 11, as reviewed in 12), and persons consuming alcohol (13, 14).

## Medical information on $H_2S$ toxicity and chronic exposure to low levels to the central nervous system (CNS)

Hydrogen sulfide's toxicity at 500-900 parts per million (and higher) is well documented as rapidly lethal to human beings by shutting down the brain's respiratory center. $H_2S$ works by rapidly interfering with the brain's respiratory command center (sending nerve signals to the lungs) and poisoning the blood's oxygen carrying ability, but long-term, low-level or chronic exposures have been generally considered to be less toxic and less harmful.

The driving regulatory assumption has been that if an exposure to $H_2S$ is not fatal, there are few, if any, lasting health effects. But that assumption became medically outdated in the 1990s based on numerous studies and medical conferences. Four public health scientists—including Kaye Kilburn, Ph.D., University of Southern California School of Medicine, Marvin Legator, Ph.D., toxicologist at the University of Texas Medical Branch-Galveston, and Bob Borga, Ph.D. — participated in an $H_2S$ panel at the American Public Health Association's (APHA) annual meetings on November 11, 1997, in Indianapolis, Indiana, to present and discuss ground breaking research demonstrating the extraordinarily toxic nature of $H_2S$ at the chronic, low levels to which communities across the nation are routinely exposed. These public health findings clearly support the thesis that exposure to hydrogen sulfide, even in extremely low concentrations, can cause lasting damage to the nervous system.

Dr. Kilburn has been conducting research on the health effects of exposure to $H_2S$ for many years, including in communities being routinely exposed (18-20). Describing a new study, he unequivocally stated at the 1997 APHA conference that "$H_2S$ poisons the brain, and the poisoning is irreversible" (18- 20, 24-26). Demonstrable symptoms of chronic exposure include pronounced deficits in balance and reaction time, as well as such ailments as dizziness, insomnia, and overpowering fatigue (18-20, 24-26).

In addition, Kilburn has emphasized that $H_2S$ research since 1990 has corrected the mistaken concept that people exposed to rotten egg, chemical name hydrogen sulfide, who are not killed, recover completely (20, 23-26). The correction came from following the exposed people and doing sensitive tests of brain functions. Kilburn noted that "…<u>their balance is abnormal, simple (one stimulus) and choice (two stimuli) reaction times are prolonged and abnormal, recall memory is impaired, as are attention and concentration measured by trail making B, that consists of connecting alternately ascending numbers and letters</u>. Studies showed residual impairment in people rendered unconscious or knocked down by hydrogen sulfide (26)." These data indicate irreversible damage occurs at levels of hydrogen sulfide in the 1 to 5 parts per million range. A factor in such damage is probably that exposures may be for 168 hours per week – every hour of every day in contrast to workplace exposures of 40 hours or less.

Recognition of this problem is shown by 34 states that have adopted standards for hydrogen sulfide in ambient air as low as 10 parts per billion (0.010 parts per million). Thus it's obvious that the 1970's occupation standard of 10 ppm is not only obsolete but dangerous to human brains. Prudent management of cities for people means avoidance of $H_2S$ exposure. Compromise pushes people prematurely into dementia like Alzheimer's disease.

Next, <u>$H_2S$-induced impairment</u> was found in those people without unconsciousness who were exposed at work or at home from sources such as waste sites, dumps and manure lagoons. To express diverse brain functions, Kilburn totals the numbers of abnormalities with higher numbers indicating greater severity. As a result, Kilburn concluded that <u>$H_2S$ damage to the brain is permanent as no treatment has ever reversed it</u> (20, 23, 26).

Dr. Legator and research associate Chantele Singleton utilized a carefully designed health "symptom survey" to evaluate adverse health effects associated with $H_2S$ (1, 21). In one study, they administered the survey to 97 community residents living within four miles of a large geothermal electric power plant in Hawaii, the Puna Geothermal Venture (PGV). PGV produces electricity from subsurface volcanic heat and releases hydrogen sulfide as a waste byproduct. Eighty-six percent of the subjects indicated that they had <u>experienced central nervous system impairment similar to those described by Doctor Kilburn's research</u>. But only 26% of those in a Puna, Hawaii control group—people who live some 20 miles away from the plant—reported such problems (1, 21, 22).

According to several studies by these researchers on chronic, low level $H_2S$ gas exposures, one may observe <u>abnormal neurobehavioral functioning and altered mood states (e.g., depression,</u>

fatigue, tension, vigor) (1). In addition, numerous CNS-brain effects occur including multiple effects: changes in brain density, headache, memory loss, reduced sense of smell, loss of balance, dizziness, sleep difficulties, and fatigue (1). Numerous cases reported in the literature support the CNS toxicity of $H_2S$ (1). Many of the effects are persistent (15, 16, 17).

Dr. Bob Borda, a neuropsychologist in Texas, put neighbors of the industrial plant through a battery of tests and found that many demonstrated attention deficits and an inability to process information quickly. The condition, Borda said, is analogous to an outdated computer program: “It runs, but it is maddeningly slow and inefficient (34).”

### Acute exposure to 25 ppb $H_2S$: Irritating to eyes of people in communities in US, Europe and New Zealand

A comprehensive literature review was conducted on the toxicology of the eye by Canadian public health scientists in 2006 (27). They reviewed ninety-six of the papers published in the last 100 years and concluded that $H_2S$ is irritating to the eye at ultra-low concentrations below 100 ppb (27). The purpose of the historical eye toxicology review by Lambert et al. was to address an incorrect conclusion reached in an Alberta Health and Wellness review in 2002 of the $H_2S$ literature suggesting “…that there is little evidence of eye irritation up to concentrations of 100 ppm $H_2S$…” and because the 2002 review incorrectly suggested that the $H_2S$ literature on the eye is a series of unsubstantiated claims reproduced in review articles dating back to the 1930s (27b). Lambert’s team sought to demonstrate the “divergence, consistency, and coherence of the perspectives and observations of $H_2S$ eye toxicity” including a reanalysis of all the papers considered in the 2002 Alberta Health and Wellness article (27b).

Lambert et al. reviewed available clinical studies, non-clinical, and case-control studies in ninety-six papers on the PubMed and Toxline databases. They pointed out that “...almost all the scientific studies we found that discussed the eye, reported eye effects below 100 ppm $H_2S$ in a variety of environmental contexts (Table 5)” (27). In conclusion, Lambert’s team notes: “In community settings, following short-term exposure, 25 ppb $H_2S$ appears to be the lowest concentration observed to irritate the eyes and, with chronic exposure, serious health effects on the eyes are suggested. Perhaps the most controversial question is whether $H_2S$ can cause irreversible health effects on the eye. Blindness was suggested by Ramazzini, however, many have claimed the eye heals completely (27).”

The South Karelia, Finland air pollution studies were among the $H_2S$ literature reviewed by Lambert et al. where effects of $H_2S$ were observed on the eyes of children at low concentrations as part of a series of investigations conducted by Haahtela et al. in 1992 and Marttila et al. in 1994-95 (27c, d, e). Lambert et al. stated: “The South Karelia air pollution studies documented public exposures to low levels of $H_2S$ and other reduced sulfides (methyl mercaptan, dimethyl sulfide and dimethyl disulfide) from pulp mills in Finland. Haahtela et al. (1992) presented survey results from a community that experienced low level acute $H_2S$ exposure: the maximum 4-hr concentration 135 µg/m3 (96 ppb) $H_2S$ and the 24-hr average of 35 and 43 µg/m3 (25 and 31 ppb $H_2S$). During the peak emissions, the $SO_2$ mean 1-hr average was only 3 µg/m3 and therefore not a significant cofounder. The authors concluded that the “observed symptoms correspond to the physiological effects of acute exposure of $H_2S$, suggesting direct irritative effect on mucous membranes and eye conjunctivitis but at lower concentrations than described previously” (Haahtela et al., 1992, p. 605).” (27c) Additional discussion is presented by Lambert et al. of why $H_2S$ was considered as the most likely cause of the effects observed in South Karelia and not other sulfur compounds (27).

Additional community investigations in South Karelia by Marttila et al. in 1994-95 confirmed the presence of low concentrations of $H_2S$ noted by Haahtela et al. in 1992 (27c, d). “Marttila et al. (1994) reported in the most polluted Karelia area that the annual mean $H_2S$ concentration was calculated as 8 µg/m3 (5.7 ppb) $H_2S$, the highest 24-hr concentration was calculated as 100 µg/m3 (71.4 ppb) $H_2S$ and maximum 4-hr average was measured as 56 µg/m3 (40 ppb) $H_2S$ (27d).” In 1995, Marttila et al. conducted surveys of the community in a reference (non-polluted) area, medium polluted and high polluted areas evaluating daily symptom intensity in relation to exposure levels (27e). Marttila et al. found in 1995 significant differences in the eye symptoms reported between the medium and reference communities (OR 3.17, 1.21-7.47) and high vs. reference (OR 5.0, 1.66-12.65) as cited by Lambert et al. (27e). With respect to symptoms, they observed a similar increase in reporting of intensity of nasal and pharyngeal symptoms (27e). They noted that the intensity of eye symptoms was significantly higher during days of TRS > 10 µg/m3 (27e). The parents reported their children’s eye symptoms over the past 12 months (OR 1.15, 95% CI 0.43-3.05) in the three communities (reference n=7/30, medium n=20/62, and high n-5/42) described in Lambert et al. (27e).

Another community health effects-eye study is also presented from Rotorua, New Zealand (natural geothermal seeps) where low concentrations of $H_2S$ were measured ranging from 20 µg/m3 (14 ppb median concentration), 35% of the measurements >70 µg/m3 (50 ppb), 10% >400 µg/m3 (286 ppb) $H_2S$, and 1,000 ppb was the highest concentrations for 30-minute average (27). In summary, Lambert et al. cites the Rotorua studies of McDougal and Garland (1945), Bates (1998), Fisher (1999), and Bates (2002) in their 2006 review (27) as further evidence in support of community settings where low $H_2S$ concentrations are associated with acute exposure to the eyes.

The Canadian public health scientists noted that in Terre Haute, Indiana, June 1964 according to an investigation by the US Department of Health, an $H_2S$ release from a chemical lagoon resulted in recorded concentrations as 0.022 – 0.125 ppm (22 ppb – 125 ppb) for 7 hours where citizens complained about burning eyes (27). A NIOSH report (p. 44) from 1977 is quoted: “this study did suggest that hydrogen sulfide can irritate the eyes and respiratory system at concentrations below 1 ppm (27).” Lambert et al. state: “In two sour gas blow-outs in Alberta, in the early 1980s, eye injury was documented to humans and animals at 0.5 ppm [500 ppb] $H_2S$. Community studies in the United States, Europe and New Zealand suggest that acute exposure to 25 ppb $H_2S$ is the lowest concentration to irritate the eyes; with chronic exposure, serious eye effects are suggested (27).”

Lambert et al. stressed that eye irritation caused by $H_2S$ is described as the first health effect to manifest at low levels by Ramazzini in 1713 (27), which is not surprising since $H_2S$ is also named “hydrosulfuric acid.” Yet less attention has been paid to $H_2S$’s acidic irritation to the eyes at ultra-low concentrations and the potential of damage to ultra-sensitive eye tissues. Eye irritation today is better described as occurring to the conjunctival and corneal tissues, although the mechanism remains unknown (27). One theory is that $H_2S$ reacts with liquid water in the eye and is converted to sulfurous acid ($H_2SO_3$) and sulfuric acid ($H_2SO_4$), both acidic sulfur compounds that are known to be irritating to eye tissues. A significant community-public health point by Lambert et al. is that short-term exposure to 25 ppb $H_2S$ irritates the eye because concentrations of 25 ppb and higher are more commonly observed in many communities close to refineries, oil & gas production wells, CAFOs, and other sources. EPA needs to more seriously assess the series of community $H_2S$ studies in the United States, Europe and New Zealand as substantial evidence that communities are likely being adversely impacted by $H_2S$ concentrations as low as 25 ppb. Evidence of eye irritation due to ultra-low $H_2S$ concentrations has been disregarded by industry and officials for far too long.

### Hydrogen sulfide’s cytotoxicity: $H_2S$ acts as a neuromodulator in four studies

Hydrogen sulfide is a well known cytotoxic gas recently proposed as a novel neuromodulator in four studies from 1996-2004 (28-31). A 2004 research team indicated it recently has been shown to stimulate N-methyl-d-aspartate (NMDA) receptors to enhance long-term potentiation suggesting a novel neuromodulatory role in vivo (28).

## Hydrogen sulfide’s cytotoxicity: $H_2S$ induces neuron death via glutamate receptors

Evidence in a new paper indicates that $H_2S$ is responsible for neuron death and this will significantly impact industry’s view that brain damage is a secondary effect from hypoxia as opposed to direct result of $H_2S$ exposure. A 2007 study in the *Journal of Neuropharmacology* conducted by biochemistry researchers found evidence that: “These data suggest that $H_2S$ induced neuronal death through ionotropic glutamate receptors, which recruits apoptosis to ensure cellular demise and employs calpains and lysosomal rupture. This study provides novel insights into cell death observed in neurodegenerative diseases involving glutamate receptor activation and perturbed $H_2S$ synthesis (32).” The new $H_2S$ neuronal induced-death evidence provides strong impetus for the EPA to move to listing $H_2S$ as a HAP as soon as possible.

## Hydrogen sulfide’s genotoxicity: new evidence $H_2S$ damages DNA from four studies

Teams of researchers at separate institutions have discovered evidence that $H_2S$ damages DNA in four recent studies (35-38). One team at the University of Illinois, Urbana, Illinois and a second team at the School of Medicine at the University of Singapore. Hydrogen sulfide has been shown previously to exert proapoptotic activity or cell death. However, the mechanism(s) by which $H_2S$ affects cell growth and function have not been addressed adequately. The Singapore team of Baskar et al. concluded: “We propose that the genotoxic action of $H_2S$ propels the cell toward apoptotic death triggered initially by stabilization of p53 and subsequently involving a cascade of downstream products. These results are of significance as they uncover a hitherto unknown and very fundamental role for $H_2S$ in determining cell fate (37).” The University of Illinois team of Attene-Ramos et al. indicated: “In this study, we examined the chronic cytotoxicity of sulfide using a microplate assay and genotoxicity using the single-cell gel electrophoresis (SCGE; comet assay) in Chinese hamster ovary (CHO) and HT29-Cl.16E cells. … These data indicate that given a predisposing genetic background that compromises DNA repair, $H_2S$ may lead to genomic instability or the cumulative mutations found in adenomatous polyps leading to colorectal cancer. (35, 36).” A fourth study investigated an association between effects of genetic polymorphisms of GSTT1 and GSTM1 and depression inventory scores of 124 healthy female individuals who were chronically exposed to natural sour gas containing sulfur compounds such as $H_2S$ (38). The study was conducted in a polluted area of the Middle East.

See attached March 2009 letter to EPA on $H_2S$

**Exhibit 13**:

Letter from Neil Carman to U.S. EPA Administrator Lisa Jackson (Mar 30, 2009)

SIERRA
CLUB
FOUNDED 1892

March 30, 2009

Lisa Jackson, Administrator
United States Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

RE: Hydrogen sulfide needs Hazardous Air Pollutant listing under CAA Title III

Dear Administrator Jackson:

The community, environmental, and public health organizations named below request that you formally list Hydrogen Sulfide ($H_2S$) as a hazardous air pollutant (HAP), as defined in Title III, section 112(b) of the 1990 Clean Air Act Amendments (CAA). We assert that EPA must act to address adverse $H_2S$ impacts based on evidence of harmful exposures in numerous communities and its toxicological effects at low concentrations such as non-cancer effects and emerging evidence that $H_2S$ is a genotoxic agent, meaning it damages DNA. EPA has assessed the need to list $H_2S$ as a HAP, but no formal listing action has been taken. $H_2S$ is clearly an unlisted hazardous air pollutant.

$H_2S$, well known to cause death at high concentrations and respiratory-brain-nervous system effects at lower levels, escaped addition to the original list of 188 HAPs in 1990 due to opposition from the oil and gas industry, despite the EPA's attempts to include it. In January 1999, strong public support to add $H_2S$ to Title III of federally recognized air toxics occurred when 145 public health, environmental and community groups in 32 states sent a request to EPA based on scientific studies suggesting chronic, low-level exposures cause permanent damage to the brain and central nervous system. Indeed, new toxicological evidence reveals $H_2S$ can cause neuron death in the brain and serves as a solid regulatory basis that $H_2S$ is far worse than just a stinky chemical triggering bad headaches, nausea and discomfort at citizens' home environment. The oil and gas industry have downplayed for decades the toxic effects of smelly $H_2S$ emissions when citizens have to breathe horrible, nauseating rotten egg odors, while industry officials allege it's little more than a foul smelling odor with no harmful effects at sublethal low concentrations. Citizens who wrote to EPA in January 1999 are still waiting for the agency to take action on this highly toxic substance.

Today, it is unacceptable for communities to continue suffering the ill effects of toxic hydrogen sulfide gas exposure when the technology to control it is available and affordable. As EPA has learned, environmental injustice is a fact of life for thousands of communities across the nation and these residents all have a right to clean, safe air. It's past time for EPA to take action to formally acknowledge hydrogen sulfide's serious acute and chronic toxicity. As EPA Administrator, you have CAA authority to do the right thing based on a compelling body of $H_2S$ medical evidence and air quality data indicating a need for better regulation of hydrogen sulfide. Specifically, CAA section 112(b)(2) provides "the Administrator shall periodically review the list established by this subsection and publish the results thereof and, where appropriate, revise such list by rule, adding pollutants which present, or may present, through inhalation or other routes of exposure, a threat of adverse human health effects…" Health studies support the need for EPA to list $H_2S$ under CAA section 112(b), especially since $H_2S$'s routine exposure effects—on a daily basis—are not addressed whatsoever under the accidental release provisions in section 112(r) of the CAA, where $H_2S$ is currently regulated. Section 112(r) is not designed or intended to address daily toxic exposures.

The EPA began an informal review in the last ten years due to EPA's continuing health concerns and a prior request by 145 organizations sent January 25, 1999 to EPA Administrator Carol Browner. EPA's Office of Air Quality Planning & Standards has performed a new IRIS assessment and made recommendations in 2007 to the Assistant Administrator for Air and Radiation of options to address $H_2S$. Nonetheless, EPA has yet to make a decision to formally list $H_2S$ as a CAA section 112(b) HAP and solicit comments in a Federal Register Notice.

Hydrogen sulfide, known as "poison gas" for its lethal properties, is probably the most common toxic air pollutant found in urban and rural communities. It is easily identifiable by its distinct rotten eggs odor. At least 73 industry categories emit $H_2S$ in varying rates and volumes. Citizens impacted by industry $H_2S$ have complained due to the acute and chronic effects of low level exposures. In recent years, $H_2S$'s health concerns have occurred over frequent obnoxious odors from confined animal feeding operations (CAFOs). Data from the Poison Control Centers National Data Collection system show from 1983-1992 acute exposure to $H_2S$ was linked to 29 deaths and 5,563 exposures, according to a 1995 article in the *American Journal of Emergency Medicine*. A U.S. multistate surveillance program found that 637 $H_2S$-related incidents occurred from 1993-2001, resulting in 63 public evacuations and injuring 185 people, according to a 2004 journal article written by federal health investigators and others.

## Congress and the 1990 CAA study—Hydrogen Sulfide Report to Congress

The Congress considered listing hydrogen sulfide in 1990 as a hazardous air pollutant under CAA section 112(b), which regulates industrial sources with routine emissions of HAPs. Listing was negated by lobbying by the oil and gas industry, despite the health concerns of EPA. The EPA Administrator was instead directed by Congress in 1990 under section 112(n)(5) of the CAA to carry out a study "to assess the hazards to public health and the environment resulting from the emissions of $H_2S$ associated with the extraction of oil and natural gas." However, it excluded many major point sources such as paper mills and others. The legal requirement to study $H_2S$ associated only with oil and gas wells had been added to the CAA by the Senate Committee on Environment and Public Works, chaired by the late Quentin N. Burdick of North Dakota, due to serious concerns about lethal $H_2S$ exposures. Witnesses testified before the Congress in 1990 that $H_2S$ emissions related to the extraction and refining of oil and natural gas had resulted in deterioration of air quality, death and injury to livestock, and evacuation and hospitalization of untold numbers of residents located near the release point of such toxic air emissions. Similar $H_2S$ problems continue to exist today due to a patchwork of inadequate regulations, weak $H_2S$ ambient air standards, lack of $H_2S$ ambient monitoring, and ineffective enforcement despite states' efforts to permit major sources for routine $H_2S$ emissions. Loopholes remain in regulating $H_2S$ and protecting public health as refineries receive higher sulfur crudes. The fact is $H_2S$ is a highly neurotoxic substance deserving a HAP listing and a more protective national approach.

Conclusions of the EPA study became the *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas* (the Report to Congress), issued in October 1993 by the EPA Office of Air Quality Planning and Standards (EPA-453/R-93-045). The outdated status of $H_2S$ since 1990 as a partly regulated air toxic is described in the Executive Summary of the 1993 Report to Congress where it states:

"[O]n the basis of information contained in accident records, it was determined at the time that $H_2S$ is a chief concern from an accidental release standpoint and it would be listed under the accidental release provisions in section 112(r) of the CAA, but not under section 112(b). Substances regulated under 112(r) are known or may be anticipated to cause death, injury, or serious adverse effects to human health or the environment upon accidental release."

The executive summary of the *Hydrogen Sulfide Report to Congress* emphasizes "the [further] assessment of $H_2S$ must include a review of existing State and industry control standards, techniques, and enforcement." However, we are not aware of ongoing efforts on $H_2S$ by EPA since the last review in 2007 to assess it as a HAP, although an updated HAP review by EPA appears necessary based on emerging medical evidence of the human health hazards of $H_2S$ exposure at low concentrations and its widespread occurrence in the U.S. from industrial sources.

Certainly the 112(r) approach to $H_2S$ is necessary for handling higher lethal concentrations of $H_2S$. Deaths occur each year in the U.S. from accidental exposure to lethal doses of $H_2S$ in the range of 500–900 parts per million (ppm). However, the weight of medical evidence strongly indicts $H_2S$ as posing a serious human health hazard at low levels of exposure far below the lethality range even less than 100 ppm. In fact even levels in the parts per billion (ppb) range are associated with adverse health effects like headaches, nausea and loss of well-being.

Public concerns about routine low-level emissions of $H_2S$ are well founded on its toxicity at unregulated low concentrations and its widespread occurrence in industries relying on processes using sulfur, sulfur compounds, or substances (i.e., oil and natural gas) containing significant sulfur as a natural contaminant. Since EPA submitted the *Hydrogen Sulfide Report to Congress* in October 1993, the agency has undertaken additional science reviews but chose not to pursue meaningful regulatory action as a national air quality priority to address widespread public health concerns about exposure to $H_2S$ at low concentrations.

### Industrial categories emitting hydrogen sulfide gas

The *Report to Congress on Hydrogen Sulfide Air Emissions Associated with the Extraction of Oil and Natural Gas* did not present a national emissions inventory of $H_2S$ emissions in 1993 from many other industrial categories. Yet additional sources of $H_2S$ include the following 73 industry sectors some with notorious $H_2S$ emissions:
• Sour crude oil petroleum refineries • Pulp and paper mills • Paper production • Municipal sewage treatment plants • Large hog & livestock Confined Animal Feeding Operations (CAFOs) • Sour natural gas processing plants • Sour crude oil/sour natural gas handling stations/bulk petroleum terminals • Oil & gas production wells, flares, treating equipment at well sites & crude oil tank batteries • Sour natural gas transmission stations & compressor station sites & thereon site treating equipment • Bulk sour crude oil storage and pipelines • Carbon black mfg • Portland cement kilns • Municipal waste landfills • Coke ovens • Coal gasification plants • Tanneries of animal hides using sodium sulfide • Slaughterhouses, chicken houses with waste chicken incinerators, and rendering plants • Geothermal power plants • Sulfur products & hydrogen sulfide production plants • Animal fat and oil processing operations • Asphalt storage facilities • Blast furnaces, breweries and fermentation processes • Fertilizer production • Glue manufacturing • Metal processing (gold ore, lead ore, lead removal, copper ore sulfidizing and metallurgy) • Barium carbonate & barium salt production • Phosphoric acid production • Miscellaneous processes including the manufacture of carbon disulfide, dyes, textile printing, thiophene, sulfur, soap, phosphate purification, hydrochloric acid purification, cellophane, rubber and plastics processing, silk making, rayon making, pyrite burning, photoengraving, synthetic fibers, polysulfide caulking production, bromide-bromine, artificial flavor making, additives & sealant mfg, and refrigerant making • Fish, sugar beet and sugar cane processing, as well as other miscellaneous sources.

### Many states lack effective hydrogen sulfide regulations and enforcement programs to protect public health

Every state has large sources of $H_2S$ and many have affected communities who have complained to officials for help. States like Ohio are among 16 with no $H_2S$ ambient air standards to enforce, and the lack of $H_2S$ public health regulations for communities creates a nightmare that too many residents endure by suffering adverse health effects above $H_2S$ health benchmarks. But even in the 34 states with $H_2S$ limits citizens complain of weak ambient air standards and lack of protection. In states with larger sources of $H_2S$ emissions and weak regulations, hydrogen sulfide is often the most common air pollution complaint filed with agencies. EPA's Regions are well aware of citizens filing thousands of complaints in Ohio, Michigan, Nebraska, Texas, Minnesota, Florida, Colorado, Alabama, Louisiana, New Mexico and others. Hundreds of $H_2S$ complaints have been filed by several communities.

### Environmental background concentrations of $H_2S$ versus industrial concentrations

Hydrogen sulfide is primarily produced by sulfur-reducing bacteria and certain industrial processes. Generally, areas that are not exposed to industrial releases of $H_2S$ have airborne concentrations of less than 1 ppb $H_2S$ as an ultra-low background level. Ultra-low background $H_2S$ levels are often below the odor threshold of 3-4 ppb and not associated with adverse health effects. Some natural areas away from industrial sites, however, can have higher ambient levels than 1 ppb, because $H_2S$ is a natural byproduct of decomposing organic matter that contains sulfur.

Oil refineries and sour natural gas processing plants handling hydrogen sulfide can have process concentrations reaching 30-40% in certain units and pipes where small problems can allow highly obnoxious $H_2S$ to be released. Industrial sources of $H_2S$ can produce average concentrations in affected neighborhoods in the low parts per billion range (10-100 ppb) during low $H_2S$ emissions, but maximum concentrations can reach 100-1,000 ppb and higher such as during industrial releases from oil pipeline breaks, leaking crude oil storage tanks, emergency flares with inefficient combustion, upset conditions in sulfur recovery units, abnormal conditions in amine treaters, fugitive leaks from process equipment, and other problems. Industrial accidents involving spills, leaks, and malfunctions of gases or liquids with $H_2S$ can trigger higher concentrations well into the 10-1,000 ppm range. The accumulation of $H_2S$ in low-lying areas can result in higher levels that can reach lethal concentrations.

**General information about the toxicity of hydrogen sulfide gas**

Inhalation of $H_2S$ leads to adverse effects on consciousness, cardiac and pulmonary function depending on the level and length of exposure. Virtually all organ systems are affected by $H_2S$. The most vulnerable organs are those with exposed mucous membranes (e.g., eyes, nose and throat) and those with high oxygen demands (e.g., lungs, brain). Neurotoxicity of the central nervous system (causing nausea, dizziness, confusion, headache and sleeping problems) and pulmonary edema (build-up of fluid in the lungs) are other well-documented effects of hydrogen sulfide poisoning. Cardiovascular and gastrointestinal toxicity are associated with $H_2S$ exposure. Hydrogen sulfide creates health effects by binding with iron in blood and cells to block the flow of oxygen to tissues and disrupting systems.

Hydrogen sulfide is similar to hydrogen cyanide (HCN) in toxicity and cellular effects. $H_2S$ interferes with a crucial biological enzyme—cytochrome C oxidase, necessary for living cells to utilize oxygen and blockage of this vital enzyme may cause cellular death (1, 2). Cytochrome C oxidase is the last enzyme in a series in the respiratory electron transport chain of mitochondria inside the mitochondrial membrane. This key enzyme receives an electron from each of four cytochrome C molecules, and transfers them to one oxygen molecule, converting molecular oxygen ($O_2$) to two molecules of water ($H_2O$) in the cellular energy-making process. In the process, it binds four protons from the inner aqueous phase to make water, and in addition translocates four protons across the membrane, helping to establish a transmembrane difference of proton electrochemical potential that the enzyme ATP synthase then uses to make another vital cellular biochemical—ATP (adenosine triphosphate). ATP is the universal energy molecule in all living cells. ATP's cellular support function is so important that it is involved in triggering all muscle contractions including the heart and lungs. Without ATP, the heart and lungs fail to work.

Oxygen (as molecular oxygen $O_2$) is constantly required by living cells to run billions of complex biochemical reactions, activities and functions every single second to maintain life, including intricate cellular respiration in cascading pathways like the Krebs tricarboxylic acid cycle where the cell produces internal energy molecules in the form of ATP. Without plenty of ATP molecules being continuously supplied for cellular biochemical machinery to operate, living cells can not survive more than a few minutes before cell death occurs and tissues begin to die. Blockage of the enzyme cytochrome C oxidase by hydrogen sulfide inside red blood cells, the brain and lungs poses a serious threat to the biological integrity and well-being of the human brain and body.

How does $H_2S$ enter the body? There are three routes: inhalation—from breathing vapors absorbed through the lungs; oral—from ingestion of contaminated substances (especially water), absorbed through the intestinal tract; and skin—from dermal contact with contaminated substances (such as air), absorbed through the skin. The main route of absorption of $H_2S$ is through inhalation in a vast majority of communities.

Animal studies of $H_2S$ show widespread distribution in the body after inhalation exposures (3, 4), with a selective distribution to the brain stem area compared with other areas in the brain (5). Warenycia et al. (5) found the net uptake of sulfide was greatest in the brainstem (3.02 micrograms/g) compared to other neural regions as was the selective accumulation of sulfide as calculated from normalized blood flow rates. The results of subcellular analysis showed sulfide was detectable in fractions enriched in myelin, synaptosomes and mitochondria. A major sulfide portion was found in the mitochondrial fraction, where the cell's critical energy-producing system resides. The sulfide content of these fractions increased 2- to 3-fold, the greatest increases occurring in myelin- and mitochondrial-enriched fractions (5). The brain stem is vital since it plays a primary role in the regulation of cardiac and respiratory functions. The medulla oblongata in the brain stem is the lower portion of the brainstem. It deals with autonomic physiological functions, such as breathing and blood pressure, and keeping us alive.

Research in animals has identified more than forty health effects of $H_2S$ primarily non-cancer effects. Medical data demonstrates that numerous similar health effects occur in human exposure to $H_2S$. Metabolism takes place by three pathways: oxidation to sulfate, methylation, and reaction with metallo- or disulfide- containing proteins. This last appears to be the main pathway for toxicity although new evidence may offer more insights on biological oxidation and reactions (6).

Human populations most sensitive to $H_2S$ are assumed to be the fetus (animal data only), children (7), persons with heart disease (8), individuals with asthma (9), individuals who metabolize organosulfides differently (10, 11, as reviewed in 12), and persons consuming alcohol (13, 14).

**Medical information on $H_2S$ toxicity and chronic exposure to low levels to the central nervous system (CNS)**

Hydrogen sulfide's toxicity at 500-900 parts per million (and higher) is well documented as rapidly lethal to human beings by shutting down the brain's respiratory center. $H_2S$ works by rapidly interfering with the brain's respiratory command center (sending nerve signals to the lungs) and poisoning the blood's oxygen carrying ability, but long-term, low-level or chronic exposures have been generally considered to be less toxic and less harmful.

The driving regulatory assumption has been that if an exposure to $H_2S$ is not fatal, there are few, if any, lasting health effects. But that assumption became medically outdated in the 1990s based on numerous studies and medical conferences. Four public health scientists—including Kaye Kilburn, Ph.D., University of Southern California School of Medicine, Marvin Legator, Ph.D., toxicologist at the University of Texas Medical Branch-Galveston, and Bob Borga, Ph.D. — participated in an $H_2S$ panel at the American Public Health Association's (APHA) annual meetings on November 11, 1997, in Indianapolis, Indiana, to present and discuss ground breaking research demonstrating the extraordinarily toxic nature of $H_2S$ at the chronic, low levels to which communities across the nation are routinely exposed. These public health findings clearly support the thesis that exposure to hydrogen sulfide, even in extremely low concentrations, can cause lasting damage to the nervous system.

Dr. Kilburn has been conducting research on the health effects of exposure to $H_2S$ for many years, including in communities being routinely exposed (18-20). Describing a new study, he unequivocally stated at the 1997 APHA conference that "$H_2S$ poisons the brain, and the poisoning is irreversible" (18- 20, 24-26). Demonstrable symptoms of chronic exposure include pronounced deficits in balance and reaction time, as well as such ailments as dizziness, insomnia, and overpowering fatigue (18-20, 24-26).

In addition, Kilburn has emphasized that $H_2S$ research since 1990 has corrected the mistaken concept that people exposed to rotten egg, chemical name hydrogen sulfide, who are not killed, recover completely (20, 23-26). The correction came from following the exposed people and doing sensitive tests of brain functions. Kilburn noted that "…their balance is abnormal, simple (one stimulus) and choice (two stimuli) reaction times are prolonged and abnormal, recall memory is impaired, as are attention and concentration measured by trail making B, that consists of connecting alternately ascending numbers and letters. Studies showed residual impairment in people rendered unconscious or knocked down by hydrogen sulfide (26)." These data indicate irreversible damage occurs at levels of hydrogen sulfide in the 1 to 5 parts per million range. A factor in such damage is probably that exposures may be for 168 hours per week – every hour of every day in contrast to workplace exposures of 40 hours or less.

Recognition of this problem is shown by 34 states that have adopted standards for hydrogen sulfide in ambient air as low as 10 parts per billion (0.010 parts per million). Thus it's obvious that the 1970's occupation standard of 10 ppm is not only obsolete but dangerous to human brains. Prudent management of cities for people means avoidance of $H_2S$ exposure. Compromise pushes people prematurely into dementia like Alzheimer's disease.

Next, $H_2S$-induced impairment was found in those people without unconsciousness who were exposed at work or at home from sources such as waste sites, dumps and manure lagoons. To express diverse brain functions, Kilburn totals the numbers of abnormalities with higher numbers indicating greater severity. As a result, Kilburn concluded that $H_2S$ damage to the brain is permanent as no treatment has ever reversed it (20, 23, 26).

Dr. Legator and research associate Chantele Singleton utilized a carefully designed health "symptom survey" to evaluate adverse health effects associated with $H_2S$ (1, 21). In one study, they administered the survey to 97 community residents living within four miles of a large geothermal electric power plant in Hawaii, the Puna Geothermal Venture (PGV). PGV produces electricity from subsurface volcanic heat and releases hydrogen sulfide as a waste byproduct. Eighty-six percent of the subjects indicated that they had experienced central nervous system impairment similar to those described by Doctor Kilburn's research. But only 26% of those in a Puna, Hawaii control group—people who live some 20 miles away from the plant—reported such problems (1, 21, 22).

According to several studies by these researchers on chronic, low level $H_2S$ gas exposures, one may observe abnormal neurobehavioral functioning and altered mood states (e.g., depression, fatigue, tension, vigor) (1). In addition, numerous CNS-brain effects occur including multiple effects: changes in brain density, headache, memory loss, reduced sense of smell, loss of balance, dizziness, sleep difficulties, and fatigue (1). Numerous cases reported in the literature support the CNS toxicity of $H_2S$ (1). Many of the effects are persistent (15, 16, 17).

Dr. Bob Borda, a neuropsychologist in Texas, put neighbors of the industrial plant through a battery of tests and found that many demonstrated attention deficits and an inability to process information quickly. The condition, Borda said, is analogous to an outdated computer program: "It runs, but it is maddeningly slow and inefficient (34)."

### Acute exposure to 25 ppb $H_2S$: Irritating to eyes of people in communities in US, Europe and New Zealand

A comprehensive literature review was conducted on the toxicology of the eye by Canadian public health scientists in 2006 (27). They reviewed ninety-six of the papers published in the last 100 years and concluded that $H_2S$ is irritating to the eye at ultra-low concentrations below 100 ppb (27). The purpose of the historical eye toxicology review by Lambert et al. was to address an incorrect conclusion reached in an Alberta Health and Wellness review in 2002 of the $H_2S$ literature suggesting "…that there is little evidence of eye irritation up to concentrations of 100 ppm $H_2S$…" and because the 2002 review incorrectly suggested that the $H_2S$ literature on the eye is a series of unsubstantiated claims reproduced in review articles dating back to the 1930s (27b). Lambert's team sought to demonstrate the "divergence, consistency, and coherence of the perspectives and observations of $H_2S$ eye toxicity" including a reanalysis of all the papers considered in the 2002 Alberta Health and Wellness article (27b).

Lambert et al. reviewed available clinical studies, non-clinical, and case-control studies in ninety-six papers on the PubMed and Toxline databases. They pointed out that "...almost all the scientific studies we found that discussed the eye, reported eye effects below 100 ppm $H_2S$ in a variety of environmental contexts (Table 5)" (27). In conclusion, Lambert's team notes: "In community settings, following short-term exposure, 25 ppb $H_2S$ appears to be the lowest concentration observed to irritate the eyes and, with chronic exposure, serious health effects on the eyes are suggested. Perhaps the most controversial question is whether $H_2S$ can cause irreversible health effects on the eye. Blindness was suggested by Ramazzini, however, many have claimed the eye heals completely (27)."

The South Karelia, Finland air pollution studies were among the $H_2S$ literature reviewed by Lambert et al. where effects of $H_2S$ were observed on the eyes of children at low concentrations as part of a series of investigations conducted by Haahtela et al. in 1992 and Marttila et al. in 1994-95 (27c, d, e). Lambert et al. stated: "The South Karelia air pollution studies documented public exposures to low levels of $H_2S$ and other reduced sulfides (methyl mercaptan, dimethyl sulfide and dimethyl disulfide) from pulp mills in Finland. Haahtela et al. (1992) presented survey results from a community that experienced low level acute $H_2S$ exposure: the maximum 4-hr concentration 135 µg/m3 (96 ppb) $H_2S$ and the 24-hr average of 35 and 43 µg/m3 (25 and 31 ppb $H_2S$). During the peak emissions, the $SO_2$ mean 1-hr average was only 3 µg/m3 and therefore not a significant cofounder. The authors concluded that the "observed symptoms correspond to the physiological effects of acute exposure of $H_2S$, suggesting direct irritative effect on mucous membranes and eye conjunctivitis but at lower concentrations than described previously" (Haahtela et al., 1992, p. 605)." (27c) Additional discussion is presented by Lambert et al. of why $H_2S$ was considered as the most likely cause of the effects observed in South Karelia and not other sulfur compounds (27).

Additional community investigations in South Karelia by Marttila et al. in 1994-95 confirmed the presence of low concentrations of $H_2S$ noted by Haahtela et al. in 1992 (27c, d). "Marttila et al. (1994) reported in the most polluted Karelia area that the annual mean $H_2S$ concentration was calculated as 8 µg/m3 (5.7 ppb) $H_2S$, the highest 24-hr concentration was calculated as 100 µg/m3 (71.4 ppb) $H_2S$ and maximum 4-hr average was measured as 56 µg/m3 (40 ppb) $H_2S$ (27d)." In 1995, Marttila et al. conducted surveys of the community in a reference (non-polluted) area, medium polluted and high polluted areas evaluating daily symptom intensity in relation to exposure levels (27e). Marttila et al. found in 1995 significant differences in the eye symptoms reported between the medium and reference communities (OR 3.17, 1.21-7.47) and high vs. reference (OR 5.0, 1.66-12.65) as cited by Lambert et al. (27e). With respect to symptoms, they observed a similar increase in reporting of intensity of nasal and pharyngeal symptoms (27e). They noted that the intensity of eye symptoms was significantly higher during days of TRS > 10 µg/m3 (27e). The parents reported their children's eye symptoms over the past 12 months (OR 1.15, 95% CI 0.43-3.05) in the three communities (reference n=7/30, medium n=20/62, and high n-5/42) described in Lambert et al. (27e).

Another community health effects-eye study is also presented from Rotorua, New Zealand (natural geothermal seeps) where low concentrations of $H_2S$ were measured ranging from 20 µg/m3 (14 ppb median concentration), 35% of the measurements >70 µg/m3 (50 ppb), 10% >400 µg/m3 (286 ppb) $H_2S$, and 1,000 ppb was the highest concentrations for 30-minute average (27). In summary, Lambert et al. cites the Rotorua studies of McDougal and Garland (1945), Bates (1998), Fisher (1999), and Bates (2002) in their 2006 review (27) as further evidence in support of community settings where low $H_2S$ concentrations are associated with acute exposure to the eyes.

The Canadian public health scientists noted that in Terre Haute, Indiana, June 1964 according to an investigation by the US Department of Health, an $H_2S$ release from a chemical lagoon resulted in recorded concentrations as 0.022 – 0.125 ppm (22 ppb – 125 ppb) for 7 hours where citizens complained about burning eyes (27). A NIOSH report (p. 44) from 1977 is quoted: “this study did suggest that hydrogen sulfide can irritate the eyes and respiratory system at concentrations below 1 ppm (27).” Lambert et al. state: “In two sour gas blow-outs in Alberta, in the early 1980s, eye injury was documented to humans and animals at 0.5 ppm [500 ppb] $H_2S$. Community studies in the United States, Europe and New Zealand suggest that acute exposure to 25 ppb $H_2S$ is the lowest concentration to irritate the eyes; with chronic exposure, serious eye effects are suggested (27).”

Lambert et al. stressed that eye irritation caused by $H_2S$ is described as the first health effect to manifest at low levels by Ramazzini in 1713 (27), which is not surprising since $H_2S$ is also named “hydrosulfuric acid.” Yet less attention has been paid to $H_2S$’s acidic irritation to the eyes at ultra-low concentrations and the potential of damage to ultra-sensitive eye tissues. Eye irritation today is better described as occurring to the conjunctival and corneal tissues, although the mechanism remains unknown (27). One theory is that $H_2S$ reacts with liquid water in the eye and is converted to sulfurous acid ($H_2SO_3$) and sulfuric acid ($H_2SO_4$), both acidic sulfur compounds that are known to be irritating to eye tissues. A significant community-public health point by Lambert et al. is that short-term exposure to 25 ppb $H_2S$ irritates the eye because concentrations of 25 ppb and higher are more commonly observed in many communities close to refineries, oil & gas production wells, CAFOs, and other sources. EPA needs to more seriously assess the series of community $H_2S$ studies in the United States, Europe and New Zealand as substantial evidence that communities are likely being adversely impacted by $H_2S$ concentrations as low as 25 ppb. Evidence of eye irritation due to ultra-low $H_2S$ concentrations has been disregarded by industry and officials for far too long.

**Hydrogen sulfide’s cytotoxicity: $H_2S$ acts as a neuromodulator in four studies**

Hydrogen sulfide is a well known cytotoxic gas recently proposed as a novel neuromodulator in four studies from 1996-2004 (28-31). A 2004 research team indicated it recently has been shown to stimulate N-methyl-d-aspartate (NMDA) receptors to enhance long-term potentiation suggesting a novel neuromodulatory role in vivo (28).

**Hydrogen sulfide’s cytotoxicity: $H_2S$ induces neuron death via glutamate receptors**

Evidence in a new paper indicates that $H_2S$ is responsible for neuron death and this will significantly impact industry’s view that brain damage is a secondary effect from hypoxia as opposed to direct result of $H_2S$ exposure. A 2007 study in the *Journal of Neuropharmacology* conducted by biochemistry researchers found evidence that: “These data suggest that $H_2S$ induced neuronal death through ionotropic glutamate receptors, which recruits apoptosis to ensure cellular demise and employs calpains and lysosomal rupture. This study provides novel insights into cell death observed in neurodegenerative diseases involving glutamate receptor activation and perturbed $H_2S$ synthesis (32).” The new $H_2S$ neuronal induced-death evidence provides strong impetus for the EPA to move to listing $H_2S$ as a HAP as soon as possible.

**Hydrogen sulfide’s genotoxicity: new evidence $H_2S$ damages DNA from four studies**

Teams of researchers at separate institutions have discovered evidence that $H_2S$ damages DNA in four recent studies (35-38). One team at the University of Illinois, Urbana, Illinois and a second team at the School of Medicine at the University of Singapore. Hydrogen sulfide has been shown previously to exert proapoptotic activity or cell death. However, the mechanism(s) by which $H_2S$ affects cell growth and function have not been addressed adequately. The Singapore team of Baskar et al. concluded: “We propose that the genotoxic action of $H_2S$ propels the cell toward apoptotic death triggered initially by stabilization of p53 and subsequently involving a cascade of downstream products. These results are of significance as they uncover a hitherto unknown and very fundamental role for $H_2S$ in determining cell fate (37).” The University of Illinois team of Attene-Ramos et al. indicated: “In this study, we examined the chronic cytotoxicity of sulfide using a microplate assay and genotoxicity using the single-cell gel electrophoresis (SCGE; comet assay) in Chinese hamster ovary (CHO) and HT29-Cl.16E cells. … These data indicate that given a predisposing genetic background that compromises DNA repair, $H_2S$ may lead to genomic instability or the cumulative mutations found in adenomatous polyps leading to colorectal cancer. (35, 36).” A fourth study investigated an association between effects of genetic polymorphisms of GSTT1 and GSTM1 and depression inventory scores of 124 healthy female individuals who were chronically exposed to natural sour gas containing sulfur compounds such as $H_2S$ (38). The study was conducted in a polluted area of the Middle East.

## Children and EPA's 1996 policy on setting standards designed to be protective of our youngest

President William Clinton's Executive Order of October 1995 put a new priority on the protection of children, since pollution standards have not been designed to protect our children from environmental insults such as ambient $H_2S$. Children are more vulnerable than adults to $H_2S$, first because they breathe more rapidly, inhaling more air pollution per pound of body weight than do adults. A resting infant, for example, inhales twice as much air, relative to its size, as does a resting adult. Second, national data show that children spend an average of about 50% more time outdoors than adults. Third, children are three times more active while outdoors than adults, engaged in sports and other vigorous activities; this increased activity raises breathing rates and significantly increases inhalation and in some cases swallowing of pollutants. Fourth, children are highly vulnerable to toxic substances because their bodies are immature and rapidly growing since their immune systems and developing organs are still immature. Fifth, children are in their prime learning years and $H_2S$ exposure causes brain damage. These are just a few critical reasons why EPA needs to move on $H_2S$ and provide better protection for the nation's children. The impairment of mental faculties in a child amounts to a lifetime of harm. Society pays an enormous cost for this harm besides individuals.

An equally persuasive argument is that exposure to toxic air contaminants like $H_2S$ during infancy or childhood could harm the development of respiratory, nervous, endocrine and immune systems, and could increase the risk of cancer later in life. Since $H_2S$ has been found by cancer researchers to display implications as a genotoxin, children need better protection and safeguards from this toxic air contaminant.

We are not doing enough to protect children attending the nation's Elementary Schools, according to a recent study in *USA Today*. How many children are attending Elementary Schools where exposure to hydrogen sulfide gas is a common occurrence? Unfortunately, EPA has no data on the number of affected school children and Elementary Schools in the nation, but numerous schools located near large oil refineries and oil & gas producing wells, for example, are in communities where $H_2S$ gas exposures are almost routine daily occurrences.

Along this line of concern for children, Dr. Kaye Kilburn reported an anecdotal observation from a teacher: "Hydrogen sulfide-exposed children have trouble recalling lessons and reciting, and they lose the ability to read. They eventually drop out of school. A patient of mine in Wilmington, who is a teacher, made this observation in the months after the Texaco refinery explosion exposed Long Beach and Wilmington to levels of H2S as high as 24 parts per million in 1992." (39)

## Environmental justice and hydrogen sulfide exposure: Petroleum refineries example

We want to impress upon EPA its obligation to fully comply with and enforce Title VI of the Civil Rights Act of 1964, together with President Clinton's February 11, 1994, Executive Order No. 12898 concerning the need for EPA to act on the environmental injustice in hundreds of communities impacted by $H_2S$ emissions.

We urge EPA to seriously consider that the $H_2S$ exposures in affected communities near major oil refineries, as one example, often create a disproportionate air toxics burden for people of color and low-income populations. Residents in the neighborhoods close to one of the largest $H_2S$ industrial categories, the one hundred and forty oil refineries in the US, are often low income areas. A preliminary survey shows in leading petroleum refining areas in EPA regions (2, 3, 4, 5, 6, 9, 10), a majority of residents in the refinery neighborhoods are people of color.

Environmental justice is a grave need and major issue for dozens of oil refinery communities in Texas, Louisiana, California, Illinois, Pennsylvania, New Jersey, Indiana, Ohio, Kentucky, Alabama, Tennessee, Michigan, and Mississippi, which contain the bulk of the nation's refineries, and where we stress that residents in refinery communities are disproportionately poor people of color. But besides the petroleum refining sector, several other industrial source categories are located in communities where people of color disproportionately reside.

An example of repeated serious $H_2S$ air pollution is a major Houston refinery reporting to the Texas Commission on Environmental Quality it released over 1,700 pounds of $H_2S$ into the air during major upset incidents over several years, and the $H_2S$ releases are a key reason why local residents often complained about noxious rotten egg odors. Yet few $H_2S$ violations were issued by state air agency and no nuisance odor conditions were confirmed despite the large releases of rotten egg gas and many complaints. This Houston oil refinery reported $H_2S$ releases as low as 1 pound to 235 pounds (#) including 18#, 20#, 27#, 37#, 68#, 74#, 155#, 159#, 235# and 305#. However, these $H_2S$

volumes were self-reported engineering estimates based on flare combustion efficiency calculations that assume 98% destruction was achieved and not based on actual $H_2S$ monitoring. If flares were not achieving 98% destruction, $H_2S$ releases may have been much higher than the estimated 1,700 pounds. Regulatory agencies in some cases tend to view residents living too close to industrial facilities as living in "industrial areas" where air pollution is bound to be a problem and suggest these people move away if they don't like the poor air quality.

U.S. oil refineries are importing sour crude oils with higher sulfur levels (higher $H_2S$) and a potential for worse $H_2S$ community impacts along pipeline routes and around the oil refineries. U.S. refineries have been seeking permit modifications at large plants to process higher sulfur crude oils from Venezuela, Mexico and now Canada (Alberta tar sands heavy crude oil). A powerful risk in higher sulfur in the Alberta tar sands heavy crude oil is an increased lethality hazard of higher $H_2S$ concentrations. Tar sands sulfur % is at least 4.4% and higher according to 2007 U.S. Geological Survey report (33) and it may contain 44,000 ppm of hydrogen sulfide when $H_2S$ is deadly at 500-900 ppm. Susceptible persons with vulnerable health conditions such as heart and/or lung ailments, including thousands of senior citizens, may die at only 50 ppm $H_2S$ levels, since lower $H_2S$ levels can more easily poison their comprised hearts and lungs. Great concern is for infants who may succumb at even lower $H_2S$ concentrations of 5-10 ppm exposures due to their uniquely vulnerable developing physiology, brain and nervous system. Higher sulfur crude oil is viewed by the oil industry as higher $H_2S$ concentrations to deal with and control.

### Three public health concerns result from higher $H_2S$ content in Canadian tar sands heavy crude oil

1. Lethal hydrogen sulfide levels may reach 90 times over the minimum instant kill concentrations. $H_2S$ is extremely dangerous being instantly lethal at 0.050% - 0.090% concentrations (500-900 ppm). The point is that pipeline breaks and leaks of crude oil with higher $H_2S$ gas concentrations pose a significantly higher risk to public health and the environment compared to crude oil with lower sulfur and lower $H_2S$ gas levels.
2. Increased chronic hydrogen sulfide exposure potential in affected communities. Pipelines and refineries handling higher sulfur crude with more $H_2S$ will mean more serious community exposures to sublethal concentrations and related health effects.
3. Corrosive acid gas. $H_2S$ is extremely corrosive and causes steel to experience sulfide stress cracking (SCC). $H_2S$ is called an "acid gas" because it's extremely acidic and eats through solid steel leaving holes in tanks, pipes and processing equipment. The extreme corrosivity of higher $H_2S$ in the Canadian tar sands heavy crude oil increases the potential for serious leaks and accidents from pipelines and increases the health hazards if accidental leaks occur. The presence of $H_2S$, a corrosive material, is of particular concern when it is also in the presence of other corrosive agents such as $CO_2$ +water, chlorides which cause chloride stress cracking (CSC), and oxygen ($O_2$) which causes rusting of steels and other materials. Such combination requires particular care in the selection of materials to resist such combined corrosion so as to adequately contain the $H_2S$.

### EPA needs an accurate national emissions inventory (EI) for hydrogen sulfide gas

The EPA Office of Air Quality Planning & Standards has estimated the $H_2S$ national emissions at more than 56,700 tons, but does not include sources such as CAFOs, municipal waste landfills, and sugar beet manufacturing. EPA needs a more accurate national EI for hydrogen sulfide gas from major industrial facilities, minor sources and exempted sources such as oil & gas wells. National number of sites with $H_2S$ will be enormous since oil & gas wells number in the tens of thousands alone. The California Air Resources Board provided a 1999 EI for $H_2S$ of 5,688,172 pounds, an indication of the large-scale $H_2S$ volume. (http://www.oehha.org/air/chronic_rels/pdf/7783064.pdf)

Nearly 200 Texas major industrial plants estimated releases at 7,187,988.4 pounds (3,594 tons) of $H_2S$ gas in 1997, according to EI records at the Texas Commission on Environmental Quality, not including landfills, CAFOs, oil & gas wells, and many minor facilities. That added 3,594 tons (3.3%) to the ~108,000 tons of air toxics emitted by Texas plants in 1997. Despite the need for a better national emissions inventory of $H_2S$ from potential sources, the EPA recognizes that $H_2S$ is a poorly regulated air pollutant with significant nationwide emissions estimated at more than 110 millions pounds annually. It is certainly ranks among the worst regulated air toxics.

### California: model state hydrogen sulfide gas program to manage chronic and acute exposure risks

California has a model state program on managing $H_2S$ emissions with an ambient air standard for both chronic and acute exposures and maintains a statewide continuous air monitoring network for $H_2S$. California has rules on

Construction and Demolition Debris landfills and enforces $H_2S$ emission limits for natural energy units (geysers). The most unique public health aspect is that California requires effected sources to model non-cancer and cancer risks for all listed toxic substances even $H_2S$. Facilities having a non-cancer risk below a Hazard Quotient (HQ) of 1 for $H_2S$ do not have to do any further assessments or control measures to reduce the risk to the community. But if the HQ is greater than 1, the facility is comprehensively evaluated by the air district office for the potency, toxicity, quantity of emissions released from the facility and any other factors the district considers may add to the risk. If the risk is deemed significant a public notification process is required as well as a requirement for the facility to implement a risk reduction plan.

State of California has recognized $H_2S$ as a toxic air contaminant for years, according to the Office of Environmental Health Hazard Assessment (OEHHA). OEHHA sets reference exposure levels (RELs) for toxic air pollutants and lists $H_2S$ as possessing an acute REL at 42 micrograms/cubic meter for one-hour triggering “headache and nausea in response to odor” effects and a chronic REL at only 10 micrograms/cubic meter (8 ppb). (http://www.oehha.org)

## Diurnal variation measured in hydrogen sulfide ambient concentrations

Hydrogen sulfide is heavier than air with a molecular weight of 34.08 making it heavier than molecular oxygen at 32.00 and molecular nitrogen at 28.013. Researchers have confirmed what citizens in dozens of $H_2S$ impacted communities have known for years: The odor of $H_2S$ is several times worse at night versus day in most cases, except when larger releases occur during the day (34). Tarver and Dasgupta conducted field studies in West Texas oil fields with a gas chromatograph to measure the variation of ambient $H_2S$ levels from day to night. They observed a marked variation: “At all locations, $H_2S$ concentrations consistently exhibited a strong diurnal pattern, with nighttime maxima in the range of 1-5 ppbv followed by rapid abatement at sunrise. By 10-11 AM, $H_2S$ levels fell below the instrument detection limit of 200 pptv” (34). Like other gases, $H_2S$ generally does not disperse as efficiently at night, with cooler air temperatures and low wind speed conditions. For residents in impacted communities, this diurnal pattern carries the implication that by far the worst $H_2S$ exposures are occurring when families are most likely at home, windows open (because houses in low-income communities lack air conditioning), and children are playing outside home from school. Night time is also a period when state and local regulators are the least likely to be available to verify unhealthy nuisance conditions, conduct $H_2S$ ambient air sampling to confirm the presence of the gas, and attempt to trace the $H_2S$ source in efforts to obtain compliance.

## Control technology for Hydrogen Sulfide

Major sources such as oil refineries and sour natural gas processing plants already implement air pollution control for $H_2S$ through a combination of processes like sulfur recovery units, amine gas treaters, hydrodesulfurization, sour gas absorbers, acid gas scrubbers, refinery fuel gas combustion, but may need to ratchet their emissions down some more to increase protection for local communities and install more ambient $H_2S$ air monitoring systems. As EPA recognizes, $H_2S$ pollution controls under the Clean Air Act’s Prevention of Significant Deterioration (PSD) program has had a beneficial effect on a few source categories such as kraft pulp mills and petroleum refineries. Sources affected by PSD have had to install controls to reduce point source emissions, while area source emissions from lagoons and wastewater treatment units have gone unregulated. Modeling studies of $H_2S$ at pulp and paper mills have indicated these area sources constitute the most significant risk to the public.

Voluntary efforts are being implemented in some sectors with relative success especially when encouraged by state and federal regulatory agencies. The California Air Resources Board and the air quality management districts have achieved reasonable success in reducing emissions and community impacts of $H_2S$ in California as confirmed by the state air monitoring network. EPA needs to look at model $H_2S$ programs in California and determine where industry may have made a more concerted effort to operate facilities in order to protect local communities from hydrogen sulfide releases. EPA Regions are working with the construction-demolition trade industry, the recycling industry, as well as several state offices to develop guidance on preventing $H_2S$ emissions from construction debris landfills. The guidance focuses on using proven operation and maintenance guidelines which include; segregation of wastes, pH adjustment, recycling, stormwater control, leachate management practices, and applying appropriate ground cover.

## Conclusion

Public health scientists have recognized for over a decade that hydrogen sulfide is a potent neurotoxin, and chronic exposure to low ambient levels causes irreversible damage to the brain and central nervous system. Ultra-low levels of $H_2S$ down to 25 ppb have been associated with acute exposure causing eye irritation in community settings in the United States, Europe and New Zealand. Now emerging scientific evidence supports $H_2S$ causes neuron death, confirming findings by Kilburn of irreversible brain damage. The latest scientific findings suggest $H_2S$ causes DNA damage as a genotoxic agent, which EPA can no longer ignore. The potential carcinogenic implications of $H_2S$ demand that EPA act to protect public health.

Children are among the most susceptible to this poison gas, and EPA needs to do a more effective job of protecting schoolchildren from $H_2S$ impacts. Today, it is unacceptable for communities to have to continue suffering the ill effects of $H_2S$ when the technology to monitor and control $H_2S$ emissions exists. As EPA has learned in the last four decades, environmental injustice is a significant fact of life for thousands of communities in this nation and these residents all have a right to clean, safe air.

It's time for the EPA to take action to formally acknowledge hydrogen sulfide's clear toxicity at low concentrations. As Administrator, you have CAA authority under section 112(b)(2) to act based on a pollutant that poses or may pose "…a threat of adverse human health effects..." Health studies confirm the need for EPA to list $H_2S$ under section 112(b) of the CAA and Title III, since routine daily exposure effects are not addressed under the accidental release provisions in section 112(r) of the CAA, where $H_2S$ is currently regulated. However, section 112(r) is not designed or intended to address daily exposures at sublethal concentrations, but section 112(b) can bridge this gap.

EPA, in addition, needs to require annual reporting of $H_2S$ as a toxic substance under the Toxic Release Inventory (TRI) reporting program, since $H_2S$ is not reported due to an administrative stay issued August 22, 1994 evidently under a legal threat by the American Petroleum Institute. It's extraordinary that industry has delayed reporting of $H_2S$ for twenty years. EPA needs a TRI reporting threshold of 1.0 pound for $H_2S$ and not 10,000 pounds as was originally the requirement. We request that EPA immediately lift the administrative stay on $H_2S$ and require TRI reporting in the next TRI submission cycle. The TRI data would also help EPA compile more accurate $H_2S$ data.

Please respond to this request for EPA to take action to list $H_2S$ under section 112(b) of the CAA. Address the EPA's response to Neil Carman at the contact information listed below.

Respectfully yours,

Neil J. Carman

Neil J. Carman, Ph.D.
Sierra Club's Clean Air Team and the
Lone Star Chapter of the Sierra Club
1202 San Antonio street, Austin, Texas 78701
Tel 512-472-1767; Fax 512-477-8526

Leslie G. Fields
National Environmental Justice and Community
Partnerships Director
Sierra Club
Washington, D.C.

Suzie Canales
Citizens for Environmental Justice
Corpus Christi, Texas

Hilton Kelly
Community In-Powerment and Development Association
Port Arthur, Texas

Jim Pew
Earthjustice Legal Defense Fund
Washington, D.C.

Eric Schaeffer
Environmental Integrity Project
Washington, D.C.

Matt Tejada, Ph.D.
Galveston Houston Association for Smog Prevention
& Mothers for Clean Air

Denny Larson
Global Community Monitor, National Refinery Reform
Campaign & National Bucket Brigade Coalition

Houston, Texas

Becky Bornhorst
Downwinders At Risk
Midlothian, Texas

Beth Zilbert
The People's Advocate
Lake Charles, Louisiana

Marylee M. Orr
Louisiana Environmental Action Network/
Lower Mississippi Riverkeeper
Baton Rouge, Louisiana

Mike Eisenfeld
San Juan Citizens Alliance
Farmington, New Mexico

Jaime Long
Citizens Against Environmental Destruction
Northern Michigan

Shirley J. McNall
(citizen in $H_2S$ impacted community)
Aztec, New Mexico

Bill Freese
Huron Environmental Activist League
Alpena, Michigan

Bob Shavelson
Cook Inletkeeper
Homer, Alaska

Sharon Wilson
Decatur, Texas

Oakland, California

Lorrie Cotterill
Groups Allied to Stop Pollution
Ferris, Texas

Paul Orr
Lower Mississippi Riverkeeper
Baton Rouge, Louisiana

Gwen Lachelt
EARTHWORKS', and
Oil & Gas Accountability Project
Durango, Colorado

Karen Hadden
Sustainable Energy & Economic Development Coalition
Austin, Texas

Kari Matsko
Northeast Ohio Gas Accountability Project
Mentor, Ohio

Lionel & Dorothy Milberger
(citizens in $H_2S$ impacted rural community)
Wheelock, Texas

Steve Brittle
Don't Waste Arizona
Phoenix, Arizona

E.M.T. O'Nan
Protect All Children's Environment
Marion, North Carolina

References
1. Morris, Debra L, and MS Legator: Hydrogen Sulfide, October 1996, privately circulated draft presentation.
2. Smith, RP, and RE Gosselin: "Hydrogen sulfide poisoning." J Occupational Medicine 1979; 21:93-7.
3. Nagata, T, et al: "Sulfide concentrations in postmortem mammalian tissues." J Forensic Science 1990;35(3):706-12.
4. Voight, GE, and P Muller: Acta Histochem 1955;1:223-39, as reviewed by Beauchamp, RP Jr, et al: "A critical review of the literature on hydrogen sulfide toxicity." CRC Crit Rev Toxicol 1983;13:25-97.
5. Warenycia, MW, et al: "Acute hydrogen sulfide poisoning. Demonstration of selective uptake of sulfide by the brainstem by measurement of brain sulfide levels." Biochem Pharm 1989;38:973-81.
6. Beauchamp, RP Jr, et al: 1983; op cit.
7. Dales, RE, et al: "Respiratory health of a population living downwind from natural gas refineries." Am Rev Respir Dis 1989;139:595-600.
8. Jappinen, P, and S Tola: "Cardiovascular mortality among pulp mill workers." Br J Ind Med 1990;47:259-62.
9. Jappinen, P, et al: "Exposure to hydrogen sulfide and respiratory function." Br J Ind Med 1990;47:824-8.
10. Mitchell, SC, et al:, "Genetic aspects of the polymodally distributed sulphoxidation of S-carboxymethyl-L-cysteine in man." Br J Clin Pharm 1984;18:507-21.
11. Harris, CM, et al: "The case of the black-speckled dolls: an occupational hazard of unusual sulphur metabolism." Lancet 1986;1:492-3.
12. Guidotti, TL: "Some unresolved questions of hydrogen sulfide." Int Arch Occup Env Health 1994;66:153-60.
13. Beck, JF, et al: "The combined toxicity of ethanol and hydrogen sulfide. Toxicology Letters." Toxicol Lett 1979;3:311-13.
14. Poda, G, and SC Aiken: "Hydrogen sulfide can be handled safely." Arch Env Health 1966;12:795-800.

15. Wasch, HH, et al: “Prolongation of the P-300 latency associated with hydrogen sulfide exposure.” Arch Neurol 1989;46:902-4.
16. Tvedt, B, et al: “Delayed neuropsychiatric sequelae after acute hydrogen sulfide poisoning: affection of motor function, memory, vision and hearing.” Acta Neurol Scand 1991;84:348-51.
17. Tvedt, B, et al: “Brain damage caused by hydrogen sulfide: A follow-up study of six patients.” Am J Ind Med 1991;20:91-101.
18. Kilburn, Kaye H: Panel on Hydrogen Sulfide, American Public Health Association’s annual meetings, November 11, 1997, Indianapolis, Indiana.
19. Kilburn, Kaye H: “Effects of hydrogen sulfide on neurobehavioral function.” Am J Med Sci 1993;306:301-5.
20. Kilburn, Kaye H, and RH Warshaw: “Hydrogen sulfide and reduced-sulfur gases adversely affect neurophysiological functions.” Tox Ind Health 1995;11:185-96.
21. Legator, MS, and C Singleton: Panel on Hydrogen Sulfide, American Public Health Association’s annual meetings, November 11, 1997, Indianapolis, Indiana.
22. Morris, Jim: “New alarm over hydrogen sulfide—Researchers document lasting damage to human nervous system.” A three-part investigative report, Houston Chronicle, November 1997. http://www.chron.com/archives
23. Borda, Bob: Panel on Hydrogen Sulfide, American Public Health Association’s annual meetings, November 11, 1997, Indianapolis, Indiana.
24. Kilburn, Kaye H, March 1, 2006 personal communication on neurotoxicity of hydrogen sulfide.
25. Kilburn, Kaye H. “Exposure to reduced sulfur gases impairs neurobehavioral function.” South Med J 1997;90:997-1006.
26. Kilburn, Kaye H. “Evaluating health effects from exposure to hydrogen sulfide: central nervous system dysfunction.” Environ Epidemiol Toxico 1999;1:207-17.
27. Timothy William Lambert, V.M. Goodwin, D. Stefani, L. Strosher. “Hydrogen sulfide ($H_2S$) and sour gas effects on the eye: A historical perspective.” Science of the Total Environment 367 (2006) 1-22.
27b. Alberta Health and Wellness, “Health effects associated with short-term exposure to low levels of hydrogen sulfide ($H_2S$): a technical review,” Alberta Health and Wellness, 2002. October, 81 pp, as reviewed by Lambert et al.; 2006; op cit.
27c. Haahtela et al., “The South Karelia air pollution study: acute health effects of malodorous sulfur air pollutants released by a pulp mill,” Am J Public Health 1992;82:603-5, as reviewed by Lambert et al.; 2006; op cit.
27d. Marttila et al., “The South Karelia air pollution study: the effects of malodorous sulfur air compounds from pulp mills on respiratory and other symptoms in children,” Environ Research 1994;66:152-9, as reviewed by Lambert et al.; 2006; op cit.
27e. Marttila et al., “South Karelia air pollution study: daily symptom intensity in relation to exposure levels of malodorous sulfur compounds from pulp mills,” Environ Research 1995;71:122-7, as reviewed by Lambert et al.; 2006; op cit.
28. Matthew Whiteman, J.S. Armstrong, S.H. Chu, S. Jia-Ling, B.-S. Wong, N.S. Cheung, B. Halliwell and P.K. Moore. “The novel neuromodulator hydrogen sulfide: an endogenous peroxynitrite ‘scavenger’?” J. Neurochemistry 2004 July;90(3):765-768.
29. Abe K., Kimura H. “The possible role of hydrogen sulfide as an endogenous neuromodulator.” J Neurosci. 1996; Feb 1;16(3):1066-71.
30. H. Kimura. “Hydrogen sulfide as a neuromodulator.” Mol Neurobiol. 2002 Aug;26(1):13-9.
31. Dominy JE, Stipanuk MH. “New roles for cysteine and transsulfuration enzymes: production of H2S, a neuromodulator and smooth muscle relaxant.” Nutr Rev. 2004 Sep;62(9):348-53.
32. NS Cheung, ZF Peng, MJ Chen, PK Moore, M Whiteman. “Hydrogen sulfide induced neuronal death occurs via glutamate receptor and is associated with calpain activation and lysosomal rupture.” Neuropharmacology 2007 Sep;53(4):505-14.
33. Meyer, R.F., Attanasi, E.D., and Freeman, P.A., 2007. “Heavy Oil and Natural Bitumen Resources in Geological Basins of the World: U.S. Geological Survey Open-File Report 2007-1084.”
34. Tarver, GA, and PK Dasgupta: “Oil Field Hydrogen Sulfide in Texas: Emission Estimates and Fate.” Environ Sci Tech 1997;31:3669-3676.
35. Matias S. Attene-Ramos, Elizabeth D. Wagner, Michael J. Plewa and H. Rex Gaskins. “DNA Damage and Cellular Stress Responses: Evidence That Hydrogen Sulfide Is a Genotoxic Agent.” Molecular Cancer Research 2006 4:9-14.
36. Matias S. Attene-Ramos, Elizabeth D. Wagner, H. Rex Gaskins and Michael J. Plewa. “Hydrogen Sulfide Induces Direct Radical-Associated DNA Damage.” Molecular Cancer Research May 1, 2007 5(5):455-459.
37. R. Baskar, L. Li, and P. K. Moore. “Hydrogen sulfide-induces DNA damage and changes in apoptotic gene expression in human lung fibroblast cells.” FASEB J, January 1, 2007 21(1): 247 - 255.
38. Mostafa Saadata and Zahra Zendeh-Boodia. “Association between genetic polymorphism of GSTT1 and depression score in individuals chronically exposed to natural sour gas.” Neuroscience Letters. Volume 435, Issue 1, 11 April 2008, Pages 65-68.
39. Kilburn, Kaye H: Letter-to-the-Editor: “Don’t Use Kids as Canaries at Belmont.” Monday, November 15, 1999. Los Angeles Times.

**Exhibit 14**:

U.S. EPA Development Document for Effluent Limitations Guidelines And New Source Performance Standards For The Petroleum Refining Point Source Category (1974)

220 Page Document Available Online at:
http://nepis.epa.gov/Exe/ZyNET.exe/30005S6J.TXT?ZyActionD=ZyDocument&Client=EPA&Index=Prior+to+1976&Docs=&Query=440174014A&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=pubnumber^%22440174014A%22&QFieldYear=&QFieldMonth=&QFieldDay=&UseQField=pubnumber&IntQFieldOp=1&ExtQFieldOp=1&XmlQuery=&File=D%3A\zyfiles\Index%20Data\70thru75\Txt\00000000\30005S6J.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h|-&MaximumDocuments=10&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=p|f&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL

**Exhibit 15**:

U.S. EPA Development Document for Effluent Limitation Guidelines: New Source Performance Standards and Pretreatment Standards for the Petroleum Refining Point Source Category (1982)

385 Page Document Available Online at:
http://nepis.epa.gov/Exe/ZyNET.exe/20011NWY.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1981+Thru+1985&Docs=&Query=440182014%20or%20Development%20or%20Document%20or%20for%20or%20Effluent%20or%20Limitation%20or%20Guidelines%20or%20New%20or%20Source%20or%20Performance%20or%20Standards%20and%20Pretreatment%20or%20Standards%20or%20for%20or%20the%20or%20Petroleum%20or%20Refining%20or%20Point%20or%20Source%20or%20Category&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=pubnumber^%22440182014%22&QFieldYear=&QFieldMonth=&QFieldDay=&UseQField=pubnumber&IntQFieldOp=1&ExtQFieldOp=1&XmlQuery=&File=D%3A\zyfiles\Index%20Data\81thru85\Txt\00000012\20011NWY.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h|-&MaximumDocuments=10&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=p|f&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL

**Exhibit 16**:

Email from Scott Wilson, Energy Coordinator, Industrial Permits Branch, Office of Waste Water Management, EPA to Sparsh Khandeshi

## Sparsh Khandeshi

---

**From:** Wilson.Js@epamail.epa.gov
**Sent:** Monday, September 12, 2011 1:38 PM
**To:** Sparsh Khandeshi
**Subject:** Refinery Limit Calculations

Sparsh:

Per you questions today regarding calculation of permit limits for petroleum refineries under the Effluent Limitations Guidelines at 40 CFR Part 419, I offer the following.

The isomerization process at refineries often falls under the Petrochemical Subcategory. The process is described in both the 1974 and 1982 Development Document for the ELG, which states that the wastewater pollutant loading from the process is very low. For isomerization and a few other processes that contribute a low pollutant loading, the ELG does not include a pollutant allocation. Therefore, no allocation should be calculated for the isomerization process when permit limits are being calculated. Since the ELG does not give a pollutant allocation for isomerization and refineries have little trouble meeting the technology based limitations prescribed by the ELG, this really should not be an issue at most refineries.

Please feel free to let me know if you have any additional questions.

Scott Wilson, Energy Coordinator
Industrial Permits Branch (4203M)
Office of Wastewater Management
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460
202-564-6087

**Exhibit 17:**

Technology Based Effluent Limit Calculations

**NSPS Effluent Limitations inputs (lbs/1000 bbl feedstock)**

| *Parameter* | *Max 1 day* | *Avg 30 day* |
|---|---|---|
| BOD 5 (lbs/day) | 7.7 | 4.1 |
| TSS (lbs/day) | 5.2 | 3.3 |
| COD (lbs/day) | 47 | 24 |
| Oil and Grease (lbs/day) | 2.4 | 1.3 |
| Phenolic Compounds (lbs/day) | 0.056 | 0.027 |
| Ammonia as N (lbs/day) | 8.3 | 3.8 |
| Sulfide (lbs/day) | 0.05 | 0.022 |
| Total Chromium (lbs/day) | 0.116 | 0.068 |
| Hexavalent Chromium (lbs/day) | 0.0096 | 0.0044 |
| pH | 6-9 | 6-9 |

LIMITS MULTIPLIED BY SIZE FACTOR (13,000 BBL/DAY)

| *1000 bbl feedstock/day* | *Size Factor* |
|---|---|
| Less than 24.9 | 0.73 |
| 25-49.9 | 0.76 |
| 50-74.9 | 0.83 |
| 75-99.9 | 0.91 |
| 100-124.9 | 0.99 |
| 125-149.9 | 1.08 |
| 150+ | 1.13 |

LIMITS MULTIPLIED BY PROCESS FACTOR (PROCESS CONIFGURATION = 3.94)

| *Process Configuration* | *Process Factor* |
|---|---|
| <4.49 | 0.73 |
| 4.5-5.49 | 0.8 |
| 5.5-5.99 | 0.91 |
| 6.0-6.49 | 0.99 |
| 6.5-6.99 | 1.08 |
| 7.0-7.49 | 1.17 |
| 7.5-7.99 | 1.28 |
| 8.0-8.49 | 1.39 |
| 8.5-8.99 | 1.51 |
| 9.0-9.49 | 1.65 |
| ≥9.5 | 1.72 |

PLUS RUNOFF LIMITS

**Runoff Limits**

| *Parameter* | *Max 1 day* | *Avg 30 day* |
|---|---|---|
| BOD 5 (lbs/day) | 2.53 | 1.39 |
| TSS (lbs/day) | 1.77 | 1.14 |
| COD (lbs/day) | 19.01 | 9.5 |
| Oil and Grease (lbs/day) | 0.82 | 0.42 |
| Phenolic Compounds (lbs/day) | 0.0184 | 0.0089 |
| Ammonia as N (lbs/day) | 0 | 0 |
| Sulfide (lbs/day) | 0 | 0 |
| Total Chromium (lbs/day) | 0.032 | 0.011 |
| Hexavalent Chromium (lbs/day) | 0.0033 | 0.0015 |
| pH | 6-9 | 6-9 |

| **New Source Performance Standards + Runoff Limits** | | **Final Permit Limits** | |
|---|---|---|---|
| *Max 1 day* | *Avg 30 day* | *Max 1 day* | *Avg 30 day* |
| 55.87 | 29.79 | 81 | 43 |
| 37.79 | 24.00 | 55 | 35 |
| 344.61 | 175.76 | 500 | 255 |
| 17.45 | 9.43 | 25.4 | 13.7 |
| 0.41 | 0.20 | 0.59 | 0.29 |
| 57.50 | 26.33 | 3.2 | 1.1 |
| 0.35 | 0.15 | - | - |
| 0.84 | 0.48 | 1.22 | 0.035 |
| 0.07 | 0.03 | 0.0067 | 0.0018 |
| 6-9 | 6-9 | 7-9 | 7-9 |