

## **APPENDIX F**

# **BENCHMARK REFORMULATED GASOLINE FUEL CYCLE**

**NREL Notes**  
**Appendix F: The Benchmark Reformulated**  
**Gasoline Fuel Cycle**

The authors of this appendix show the allocation of crude oil production inputs and outputs between natural gas and crude oil products (Table F-34), as well as the allocation of refining inputs and outputs between gasoline and all other products (Table F-76).

For the fuel cycle analyses presented in *Fuel Cycle Evaluations of Biomass Ethanol and Reformulation Gasoline, Volume I, Summary Report*, the refining allocation reported for 2000 and 2010 was applied to the crude oil production and transportation stages. In other words, in 2000 35 percent of a barrel of crude oil produced and transported become gasoline, and thus, only 35 percent of the inventory of inputs and outputs are included in the fuel cycle analysis. This extension of the refining allocation is not reflected in the data presented in this appendix.

This appendix does not consider the environmental releases associated with foreign oil production. The authors were instructed to document domestic oil production and the environmental releases associated with the oil that enters into the U.S. stream of commerce through imports. However, the fuel cycle analyses presented in Volume I, assumed that foreign oil production characteristics are substantially similar to those of domestic oil production. Foreign oil production and transportation characteristics were subject to the same allocation systems described above for domestic oil production and transportation. The inputs and outputs of foreign oil production should be characterized for future studies.

## APPENDIX F

### ENVIRONMENTAL CHARACTERIZATION OF THE BENCHMARK REFORMULATED GASOLINE FUEL CYCLE

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## APPENDIX F

### ENVIRONMENTAL CHARACTERIZATION OF THE BENCHMARK REFORMULATED GASOLINE FUEL CYCLE

#### F.1 Introduction and Background

In this appendix, an overview of the benchmark reformulated gasoline fuel cycle study is provided. This overview describes the study objectives, the general methodology and approach taken, the general study assumptions that were made, and the report structure. The general study assumptions are defined to be those that affect all areas of the project while the other assumptions, of which there are many, primarily affect a major area of the study, namely, crude oil production, crude oil transport, crude oil refining, and reformulated gasoline distribution and storage; these other specific assumptions are described separately as part of that subject area.

##### F.1.1 Introduction

The U.S. Department of Energy, through the National Renewable Energy Laboratory, has embarked upon a program to develop technologies for the production of fuel-grade ethanol from renewable biomass resources. The lignocellulosic-biomass-to-ethanol program will invest in the development of the process and will work closely with industry to move the new technology from the laboratory to the market place.

Given the complexity of interactions between energy resources, the environment, and society, it is becoming increasingly apparent that the societal choice of energy technologies must be based on a comprehensive analysis. One means of comprehensively assessing an emerging energy technology (e.g., biomass-to-ethanol) is to characterize and evaluate it using a total fuel cycle analysis. The assessment can include technical, economic, environmental, or other evaluation factors. In addition, the technology must be compared to a benchmark energy technology that can be either existing technologies or other alternatives. In other words, the role of the total fuel cycle analysis is to assess the merits of competing fuel technologies in similar end uses. The focus of this study was on environmental factors for the total fuel cycle.

With the passage of the Clean Air Act Amendments of 1990, a new, cleaner version of gasoline, called reformulated gasoline, was mandated beginning with a few cities in 1995. However, it is expected that by the years 2000 and 2010, reformulated gasolines will be commonplace. Accordingly, reformulated gasoline was chosen as the benchmark fuel for the full fuel cycle studies in the time period of interest.

## **F.1.2 Study Objective**

The major objective of this study was to evaluate the environmental characteristics of the reformulated gasoline fuel cycle from crude oil production through crude oil refining to reformulated gasoline distribution and retailing in the years 2000 and 2010. Environmental residuals estimates were based on current information and data as well as on reasonable assumptions of future activities and environmental consequences.

This assessment represents a "first-cut" look at the environmental characterization of the reformulated gasoline production and distribution fuel cycle on the basis of reasonable and simplistic technological, economic, environmental, and institutional factors. A rigorous and thorough impact analysis based on detailed, site-specific factors was not within the framework of this study. The results of this study provide a useful set of data on the environmental impacts of the reformulated gasoline fuel cycle. They provide a broad, national perspective and are not intended to address application-specific issues.

In reviewing the results, it is important to remember that they are based upon readily available information. Fuel cycle optimization and modeling were outside the scope of this study.

## **F.1.3 Study Methodology and Approach**

The reformulated gasoline fuel cycle that was evaluated consisted of four major stages:

- 1) primary resource extraction and preparation (i.e., crude oil production and field processing);
- 2) transportation and storage of the primary resources (i.e., crude oil transportation);
- 3) resource conversion and processing into a refined energy source (i.e., refining and blending); and
- 4) transportation, storage, and distribution of the refined energy source up to the point it first enters the consumer's gas tank (i.e., gasoline distribution).

Characterization of the fifth stage, fuel use or consumption, will be provided by others and was not part of this study.

Figure F-1 shows the flow of crude oil and reformulated gasoline in a schematic fashion and illustrates the boundaries of the four major stages.

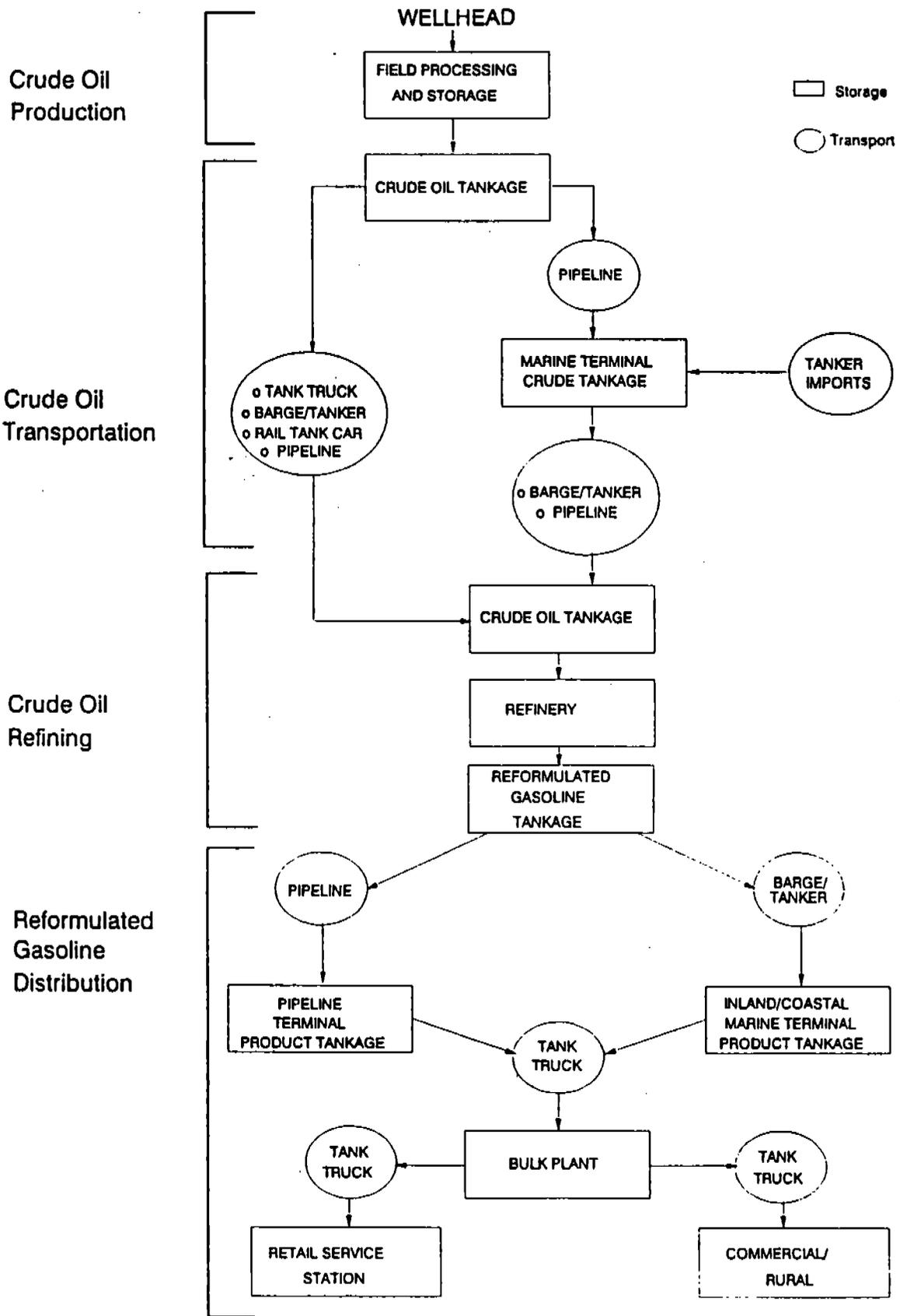


Figure F-1. Reformulated Gasoline Fuel Cycle Schematic

The fuel cycle analysis was conducted for two different time frames: 2000 and 2010. The technologies selected were consistent with the time period of the evaluation. Current data were used where appropriate, and the assumptions used to extrapolate estimates relevant to the 2000 and 2010 time frames were defined.

The National Energy Strategy (NES) scenario was used as the starting point for the selection of operating and environmental technologies. Once these representative technologies had been selected and assembled into an operating configuration for each of the four major areas, an inventory of the environmental effects associated with the four stages was assembled.

With respect to the full fuel cycle, the concentration of effort was placed on the operating phase of the fuel cycle. While major activities for each phase of the life cycle were qualitatively described, only the operating phase was quantitatively characterized with respect to inputs, outputs, and environmental residuals. Only primary inputs and outputs were considered at this time. Accordingly, the quantitative aspects of pre- and post-operation and the environmental effects of secondary inputs were left to future, more in-depth analyses, and are not included in this study.

Table F-1 shows the major activities associated with the different elements of the fuel cycle during the different phases of the fuel cycle. The goal of this study was to provide quantitative factors on the operation phases as inputs to an effort modeling environmental impacts that will be performed by others in the future.

#### **F.1.4 General Study Assumptions**

A number of general assumptions were used to guide the overall study. As mentioned above, assumptions associated with each stage of the fuel cycle are described separately in each section.

- **Basis for Study:** The NES scenario case was used as the benchmark in this study (NES, 1991).

The NES lays the foundation for a more efficient, less vulnerable, and environmentally sustainable energy future. It defines international, commercial, regulatory, and technological policy tools that will substantially diversify U.S. sources of energy supplies and offer more flexibility and efficiency in the way energy is transformed and used. In effect, NES provides a roadmap to a more secure and cleaner energy future through greater energy and economic efficiency and new technology.

**Table F-1.  
Benchmark Fuel Cycle -  
Major Activities for Each Phase in Life Cycle**

Fuel Cycle Stage	Pre-Operation Phase	Operation Phase	Post-Operation Phase
Production	Explore and Drill Production Wells, Build Gathering Plant	Produce Oil	Plug Wells, Dismantle Plant, Reclaim Materials and Land
Transportation	Build Infrastructure (Existing)	Move Oil to Refinery	Dismantle Infrastructure or Modify Use
Refining	Build Refinery	Operate Refinery	Dismantle Refinery, Reclaim Materials and Land
Product Distribution	Build Infrastructure (Existing)	Distribute Product	Dismantle Infrastructure or Modify Use
End Use	Build Vehicles	Operate Vehicles	Demolish Vehicles and Reclaim Materials

Key:  Quantitative Review  
 Qualitative Review  
 Beyond Scope

- **Infrastructure Assumptions:** "The infrastructure required to meet higher energy demand is assumed to be available at the right time when demand increases. Financial markets will supply the capital for the construction of this infrastructure and that such construction will not be prevented because of environmental concerns" (NES, 1991).
- **Full Fuel Cycle Scope Limits:** For this study, only the operating phase of the full reformulated gasoline fuel cycle was quantified. Pre-operation and post-operation phases were addressed only qualitatively. Also, for this study, only primary inputs and outputs were considered. In other words, fuels and chemicals generated and consumed within the process were not identified as separate inputs or outputs. However, if their use(s) generated

environmental consequences, they were characterized. For example, still gas generated during refining is burned for energy recovery. The environmental impact of this burning is included in the study.

A major source of environmental concern in the reformulated gasoline fuel cycle analysis is the pollution generated by the drilling and exploration of oil wells. Since drilling and exploration activities are considered pre-operational, their characterization was not included in this analysis. However, maintenance of active production assets (i.e., refineries and pipelines) was considered as an operating element.

- **Study Assumptions:** The scope of the study was limited to making simplistic and reasonable assumptions about the state of the reformulated gasoline industry in the years 2000 and 2010. The assumptions used in this study, therefore, may not be fully representative of the reformulated gasoline industry as it develops over time. They are, however, intended to provide a reasonable basis and approach for characterizing the fuel cycle within the study boundaries and limitations.
- **Methanol, Ethanol, and MTBE Assumptions:** The study is built around the NES strategy scenario which, by 2010, assumes that 1.9 million barrels per day of methanol and ethanol are supplied primarily to the automobile and light truck market in addition to the 6.3 million barrels per day of gasoline. The study assumes that the gasoline refining and distribution industry produces and distributes 6.3 million barrels a day of reformulated gasoline, including 11 percent methyl t-butyleter (MTBE). The methanol needed to produce the MTBE would be in addition to the methanol and ethanol used as neat fuels (no gasoline was set aside for blending to gasohol). Another 230,000± barrels per day of methanol would be required to produce MTBE. This study does not address environmental issues associated with the production/ importation, distribution, and use of methanol or ethanol nor does it include the impact of MTBE production and distribution.

### **F.1.5 Report Structure**

This report is organized according to the stages of the fuel cycle: production, transportation, refining, and distribution. In Section F.2 of this report, the environmental impacts of crude oil production are characterized and discussed. This section also describes the industry structure, assumptions, and data estimates for the major pollutants of interest. Both quantitative and qualitative aspects of the environmental impacts associated with crude oil production are described in this section. This section also contains a discussion and summary of the results including a tabular summary of the quantitative findings of environmental factors. References are separately tabulated at the end of each section.

Section F.3 provides similar information for crude oil transportation. Crude oil refining is addressed in Section F.4, while Section F.5 presents information on reformulated gasoline distribution.

Each of the environmental factors derived in the course of the study is either referenced as to its source or, where not directly attributable, its derivation is discussed in some detail. Where appropriate, calculations showing the derivation of the environmental factors are presented in the text or as figures accompanying the text.

#### **F.1.6 References**

*National Energy Strategy: Powerful Ideas for America*, First Edition, 1991/1992, Washington, D.C., February 1991.

## **F.2 Crude Oil Production**

This section presents information on the environmental impacts of crude oil production. The assumptions used during the assessment are identified followed by a detailed characterization of the environmental points of interest.

### **F.2.1 Industry Structure**

Of the total crude oil production of 9.2 million barrels per day (MMBD) in 1989, 85 percent came from onshore wells and 15 percent from offshore wells. The 603,000 producing wells attained an average productivity of 13 barrels per well per day, significantly below peak productivity of over 18 barrels attained in 1972 (DOE, 1990a).

The process of removing crude oil from beneath the earth's surface begins with exploration to find areas where petroleum is most likely to exist. Drilling, extraction, and onsite preparation comprise the production phase of crude oil recovery.

In general, crude oil production is influenced by several factors including reserve availability, drilling and recovery technology, and crude oil prices. Declining reserves are lowering the total amount of crude production. As oil is removed from the reservoirs, less remains for later production; what does remain is more difficult and expensive to recover. Many U.S. reservoirs have already been depleted of their easily recoverable reserves. U.S. production levels are also greatly influenced by crude oil prices. When the price of oil is low, it becomes less profitable to explore for and produce oil, and production usually declines. Most of the production technology information presented in this section was derived from a recently published report on the structure of the U.S. petroleum industry (DOE, 1991b).

Current exploration technology centers around seismic surveys. During a seismic survey, the ground is vibrated to create sound waves and to measure the time it takes for the sound waves to reflect from rock formations. Maps of the underground structure can be produced from these measurements.

Dynamite explosions were the primary means of producing vibrations in the past, but today, specially designed trucks which vibrate the ground with heavy weights are often used instead. The trucks are safer and less harmful to the environment. Computers filter out excess noise and otherwise aid the interpretation of seismic data. They also facilitate the production of maps; using new techniques, computers can create three-dimensional images of the underground structure. Methods of exploring from remote positions, including the recording of magnetic and gravity measurements from airplanes and ships, and the use of satellite images to locate areas for exploration, are being developed. Although scientific data can greatly improve the chances of finding oil in a particular area, there is no way to be sure oil exists, or that enough oil will be found to make its recovery profitable, without drilling a well. Under the National Energy Strategy (NES) scenario, the following exploration technological developments were considered (NES, 1991):

- Better reservoir data collection and analysis
- Enhance reservoir characterization and simulation
- Improved exploration technologies.

Once exploratory wells have established the presence of oil and the reservoir has been characterized, production can begin. The most common drilling technology uses a rotary rig.

A rotary-rig bit cuts and crushes rock as it descends. The bit is attached to the bottom of a long string of steel pipe. At the top of the string is the kelly, a pipe that is inserted through a steel disk known as the rotary table. The table turns, rotating the whole string of kelly, drill pipe, and bit. As a well gets deeper, more pipe is added to the drill string. The strength needed to support the drill string in the well is provided by a tall steel structure known as a derrick. The derrick contains heavy equipment which can lift the entire drill string from the well and then return it, an operation needed when testing, making repairs, or changing the bit (DOE, 1991b).

Drilling fluid, commonly referred to as drilling mud, is a mixture of minerals and water or oil and is critical to drilling. The mud is pumped down the well through the drill string and drill bit and circulated back to the top, pushing the pieces of rock which have been cut by the bit up and out of the hole. The mud also keeps the bit cool, coats the sides of the well to keep soft rock formations from caving in, and controls pressure from fluids in the formation to prevent blowouts (sudden explosive releases of gas or oil) (DOE, 1991b). Properties such as the density and thickness of the mud are specifically designed for each well. Some geologic formations allow the use of air as a drilling fluid.

In onshore operations, a rig usually drills a single vertical well. In recent years, there has been an increase in horizontal drilling activity. Horizontal wells are usually drilled as branches off of existing vertical wells. Horizontal drilling can reach difficult areas, such as under riverbeds and lakes, and can also increase the area of a reservoir that can be contacted by one well, substantially increasing the level of production. Horizontal drilling is considered an advanced technology in this study.

Offshore drilling methods are similar to those used onshore, but equipment must be adapted to meet the operating conditions. A special structure is needed to support the derrick and other drilling equipment. This structure may rest on the sea floor or float in or on the water. The type of structure chosen usually depends on the water depth, weather, sea conditions, and sea bottom in the area where drilling will occur (DOE, 1991b). Offshore rigs most often drill several wells from one location using directional drilling, where the angle of a well is diverted from vertical. Directional drilling allows several sources of crude oil to be tapped from one platform.

Petroleum in an underground reservoir is usually under great pressure. Because an open well has lower pressure, oil will flow toward it. The rate at which oil will flow through the reservoir and into a well, where it can be raised to the surface, depends on the permeability of

the rock formation, the pressure difference between the formation and the well, and the thickness, or viscosity, of the oil.

A well is considered to have natural lift if it has sufficient pressure and the oil has low enough viscosity to flow up through the well bore on its own. Gas or water, which reside in the reservoir with the oil, can provide the pressure needed to create the natural lift. Gas may be dissolved in the oil or form a "gas cap" (also known as associated gas) on the top of the oil, or both. Any water that is present in a reservoir will usually lie underneath the oil, because oil is lighter than water, and create a water drive, pushing oil toward the lower pressure in the well. If natural lift is not present, artificial lift methods must be used to bring the oil up. Many U.S. oil wells that at one time were driven by natural lift have over time lost much of their natural pressure because the gas has pushed most of the oil out of the reservoir (DOE, 1991b).

Artificial lift is usually provided by pumps or by gas lift. The most common type of pump is a walking beam pump (sometimes known as a horsehead pump), which provides the familiar up and down stroking action often seen at well sites. Sometimes electrically or hydraulically-powered submersible pumps are placed at the bottom of the well. Gas lift is created by injecting gas down the well between the casing and tubing. Valves are opened up in the tubing allowing the gas to mix with the oil, making it lighter and increasing its ability to flow.

The rate at which oil flows through the reservoir can be increased by stimulation techniques which enlarge the spaces in the formation. Acidizing and hydraulic fracturing are the most frequently used methods. In the former, an acid, usually hydrochloric acid, is pumped down the well into the pores where it eats away some of the rock and opens large spaces. In hydraulic fracturing, a fluid is pumped down, under pressure, causing the rock to crack. The fluid contains a propping agent, usually sand, which is forced into the cracks and holds them open, but still allows oil to flow through.

The recovery techniques described above are usually referred to as primary oil recovery methods. When, for a given reservoir, primary methods are no longer sufficient to generate an economic flow of oil or for other reasons are deemed inappropriate, secondary or tertiary recovery methods may be employed. The use of these methods depends on estimates of the amount of oil remaining and on the cost of the method. The most common secondary method is waterflooding. Water is injected through wells into the reservoir. Water injection wells are placed so that the water will push the oil ahead of it, out of the pore spaces, toward the producing well.

Once extracted, the mixture of crude oil, water, and gas is separated in special equipment such as heater treaters to prepare the as-extracted crude oil for shipment. For example, sediment may have to be removed, or a chemical treatment may be necessary to remove unwanted gases like hydrogen sulfide and carbon dioxide. Crude oil from offshore wells is

usually separated on the platform, then shipped via pipeline to storage and treatment facilities onshore (DOE, 1991b).

The physical properties of oil differ in each reservoir. The price for which oil can be sold depends not only on volume but also on the oil's characteristics, particularly its specific gravity and its sulfur content. Specific gravity is a measure of the density of the oil. Light, low density oil has a low specific gravity. However, the specific gravity of oil is usually measured on the American Petroleum Institute (API) scale which expresses gravity in terms of degrees API. A low specific gravity translates to high API gravity and vice versa. Thus, the lightest, least dense oils are those with the highest API gravities.

Oil volume can be measured by several techniques but is usually accomplished by gauging the flow through a meter. Temperature must also be measured because it affects the volume of the oil. Some sites today are equipped with Lease Automatic Custody Transfer facilities (LACTs) which do most of the measuring and sampling without human intervention. Oil that has been completely prepared is stored in tanks at the well site until it is transported to the refinery.

From an environmental perspective, the above process description provides some insight into the environmental concerns associated with oil production. Among the major concerns are air emissions and water effluents associated with the extraction and storage of crude oil.

### **F.2.2 Specific Assumptions**

The specific assumptions listed below are pertinent to assessing the environmental implications of crude oil production in 2000 and 2010:

- **Production by Source and Major Technology:** Table F-2 shows the major U.S. sources of petroleum energy expected under the NES Strategy scenario in 2000 and 2010. The table is arranged to show the basic division between lower 48 and Alaska production and highlights the entries of Arctic National Wildlife Refuge (ANWR) and Outer Continental Shelf (OCS) oils into the production phase. The table also shows the major extraction technologies employed, to the extent available from the NES (NES, 1991 and DOE, 1991a).
- **Environmental Impacts:** For purposes of characterizing the environmental impacts of crude oil production, Table F-2 can be reclassified by type of crude oil recovery technologies as shown in Table F-3. Conventional technology continues to provide the major portion of crude oil but enhanced and advanced oil recovery technologies play an

**Table F-2.  
NES Scenario Case - U.S. Sources and Technologies of Petroleum Energy in 2000 and 2010 (MMBD)**

Petroleum Source and Recovery Technologies	2000	2010
<b>Lower 48</b>		
Conventional <sup>1</sup>		
- Onshore	4.0	3.6
- Offshore	1.0	0.9
Natural Gas Liquids <sup>2</sup>	1.9	1.6
Enhanced Oil Recovery		
- Thermal	0.7	1.3
- Advanced and Other	<u>0.7</u>	<u>1.4</u>
Subtotal Lower 48	8.3	8.8
<b>Alaska North Slope</b>		
Conventional	0.9	0.7
Advanced Technology Oil Recovery <sup>3</sup>	0.0	0.5 <sup>4</sup>
Arctic National Wildlife Refuge (ANWR) <sup>5</sup>	<u>0.0</u>	<u>0.5</u>
Subtotal Alaska North Slope and ANWR	0.9	1.7
<b>Outer Continental Shelf (OCS)<sup>6</sup></b>	0.0	0.1
<b>Total Petroleum Energy - MMBD</b>	<b>9.3</b>	<b>10.6</b>
- Quads	18.3	21.4

<sup>1</sup> Conventional crude oil includes approximately 20 percent offshore oil and 10 percent stripper well oil in 2000 and 2010.

<sup>2</sup> Assumes that the natural gas liquids estimates of Table C-10 are for lower 48.

<sup>3</sup> Includes enhanced oil recovery.

<sup>4</sup> U.S. Department of Energy, *The Domestic Oil and Gas Recoverable Resource Base: Supporting Analysis for The National Energy Strategy*, Report No. SR/NES/90-05, Washington, D.C., Tables A1 and A2, pp. 28-30, December 1990.

<sup>5</sup> According to pp. 38 and 401, the resource peaks at 870,000 barrels/day in 2005.

<sup>6</sup> According to p. 39, resource enters production phase in 2010.

Source: Except as noted above, U.S. Department of Energy, *National Energy Strategy, Technical Annex 2, Integrated Analysis Supporting the National Energy Strategy: Methodology Assumptions and Results*, First Edition, 1991/1992, Report No. DOE/S-0086P, Washington, D.C., Table C-10, p. 122, 1991.

**Table F-3.**  
**U.S. Crude Oil Production by Major Technology in 2000 and 2010 (MMBD)**

Technology Type	2000	2010
Conventional - Onshore	4.7	4.7
- Offshore	1.2	1.1
EOR - Thermal	0.7	1.3
Other - Non-Thermal EOR, Advanced Technologies, etc.	0.7	1.9
Total Crude Oil	<u>7.3</u>	<u>9.0</u>
Natural Gas Liquids	1.9	1.6
Total Petroleum Energy - MMBD	9.3	10.6
- Quads	18.3	21.4

Source: Except as noted above in Table F-2, U.S. Department of Energy, *National Energy Strategy, Technical Annex 2, Integrated Analysis Supporting the National Energy Strategy: Methodology Assumptions and Results*, First Edition, 1991/1992, Report No. DOE/S-0086P, Washington, D.C., Table C-10, p. 122, 1991.

increasingly important role. In the absence of information otherwise, it is assumed that the current environmental consequences of conventional onshore and offshore production and thermal enhanced oil recovery (EOR) production will be the same in 2000 and 2010.

- **Crude Oil Exploration:** Crude oil exploration activities such as exploratory well drilling and seismic surveying were not considered to be part of the operating cycle for crude oil production. Construction of producing wells, gathering and processing systems, and crude oil site storage tanks were also considered pre-operational.
- **Crude Oil Well Development Residuals:** As mentioned previously, crude oil well exploration and development activities that generate drilling cuttings, drilling muds or fluids, air emissions from drilling equipment, etc. were not considered to be part of the operating cycle for crude oil production. Many of the pre-operational solid waste may in the future be regulated as hazardous by the U.S. Environmental Protection Agency (EPA).

- **Crude Oil Production Technology:** With regard to environmental effects and resource consumption, conventional crude oil production technology will remain essentially similar to current state-of-the-art technologies through 2010. Future enhanced oil recovery will be produced from currently known technologies. Advanced technologies that were considered in the NES include (NES, 1991):
  - Better reservoir data collection and analysis
  - Enhanced reservoir characterization and simulation
  - Improved exploration technologies
  - Horizontal drilling and completion
  - Improved enhanced oil recovery
  - Enhanced production technology.

Categories of resource recovery that were considered more speculative in nature, such as oil shales or gas hydrates, were not included because their economic exploitation was considered unlikely by 2030, given the expected economic conditions and anticipated technological development (DOE, 1990b).

- **Natural Gas Liquids:** Natural gas liquids, when used as refinery feedstocks, will be assumed to be refinery plant gate inputs. Inputs of natural gas liquids (NGLs) include liquefied petroleum gases (LPGs) and pentanes plus. Most of the LPG inputs to refineries are butanes for blending into gasoline or for use as alkylation unit feedstocks. Inputs of pentanes plus include pentanes, hexanes, and heavier hydrocarbons which are also used primarily for blending into gasoline. Unlike lease condensates, which are included in this study as part of crude oil production, most of the NGL liquids are a byproduct of natural gas production. Therefore, NGLs are considered to be a non-crude oil refinery input. Refinery analysis will define the requirement for NGLs in refineries.
- **Crude Oil Storage:** Crude oil storage tank facilities including Lease Automatic Custody Transfer facilities (LACTs) were considered to be transportation rather than production.
- **Environmental Residuals:** A crude oil production operation may be defined as the surface production equipment and the underground formation being exploited. For the purpose of this study, any material exchange outside of this system is considered to be an input, output, or waste. Wastes include produced water that is not reinjected into the originating or other reservoirs, controlled air emissions, and solid waste that are removed from the production site.

**Resource Inputs and Outputs:** Typical resource inputs to a crude oil production operation include labor, energy, chemicals, and land usage. Outputs include crude oil and byproduct natural gas. Although the consumption of fuels derived from the well is not considered as an input since these fuels are generated during crude oil production and are not an external input to the system, the environmental effects of burning these fuels is taken into account in this study.

- **Labor:** Ongoing oil production activities require labor and supervision for repair and maintenance of the lease equipment. Labor estimates are estimated only for direct labor, i.e., employment at off-site support facilities is not included. Labor requirements are expressed in terms of person-years required per barrel of crude oil produced.
- **Energy Inputs:** For the purpose of this study, energy produced or generated off-site and delivered to the crude oil production operation is defined as an input. However, crude oil producers often take advantage of the option of utilizing a portion of the product crude oil and/or natural gas generated to meet operational energy requirements. Thus, the required inputs of energy to crude oil producing operations from sources outside the oil field are low for the industry as a whole. Nevertheless, energy consumption generally plays a large part in determining the overall environmental effects from crude oil production. The most important energy-consuming operations in crude oil production are pumping and product separation.
- **Other Chemicals:** It is assumed that non-EOR onshore and offshore crude oil production operations generate more water (either from the producing well or from auxiliary water wells) than is required for operational use. Since the high salinity of most produced water generated from crude oil production operations limits its utility for other applications, it is assumed that all such excess produced water is reinjected. The consumption of chemicals other than water (e.g., emulsion breakers and corrosion inhibitors) was assumed to represent a minor input to all methods of crude oil production, since industry data indicate that this represents only a small fraction of the operating costs for these operations (DOE, 1990c).
- **Land Requirements:** Land area required for crude oil production is defined as the amount of area taken up by production operations that precludes other activities. For example, the area required for an offshore oil platform is assumed to be equal to the area of water

taken up by the platform and its corresponding 100-meter navigational safety zone. Since oil fields eventually become unproductive and may thereafter be returned to other uses, land requirements are quantified in terms of required area multiplied by the number of years of use envisioned for oil production.

- **Enhanced Oil Recovery:** The crude oil production industry uses both natural gas and crude oil to generate the steam used in steam-flooding of oil fields. However, data are not readily available regarding the environmental effects of natural gas-fired steam flooding, or its relative importance with regard to the crude oil-fired alternative. Therefore, in this study, crude oil-fired steam flooding was taken to be representative of both methods.

### **F.2.3 Process Description**

This section describes the various techniques used to extract crude oil. It also presents information on well operations.

#### **F.2.3.1 Crude Oil Production Technologies**

Crude oil production techniques are most generally classified as primary, secondary, or tertiary. Primary oil production, which relies on natural subsurface pressure to provide the motive force for driving crude oil to the surface, is the oldest and least energy intensive method. However, only a fraction of the petroleum reserves in most oil fields can be obtained through primary methods. As natural subsurface pressures decline, oil production rates decline to a point where oil field primary operations are no longer economic. At this point, secondary recovery techniques most commonly involving water injection may be used, depending on the size, location, and nature of the oil field. After secondary methods prove to be no longer economic, tertiary methods may be employed to recover a larger fraction of the oil field reserves. These oil production methods, collectively referred to as EOR, typically require a significant amount of energy to operate and, in many cases, have substantial environmental side-effects not experienced in primary oil production.

When oil fields are located under the seabed, crude oil recovery operations are staged from offshore platforms. Compared to onshore operations, offshore oil production is characterized by high per-well output of crude oil.

Crude oil production in the United States can be classified into one of four major methods:

- **Primary Onshore:** As mentioned above, primary crude oil production techniques rely on natural subsurface pressure or artificial lift to serve as the force for driving the crude oil to the surface through the producing well. Natural pressure in oil fields generally drives a mixture of crude oil, water,

and entrained (dissolved or mixed) natural gases to the surface. Over time, a combination of natural pressure subsidence and increased water content combines to make primary crude oil recovery techniques uneconomic.

- **Primary Offshore:** Oil is recovered from offshore fields using platforms that float on the water or are fixed to the seabed. Presently, offshore oil is produced mainly in the Gulf of Mexico and off the coast of California. In the future, NES calls for increased exploitation of offshore resources on the Outer Continental Shelf of the United States, mainly off the coasts of California and Alaska.
- **Secondary Oil Recovery:** Secondary recovery usually involves the injection of water (waterflooding) or gas into the reservoir in order to maintain pressure and thereby sustain oil production. Secondary recovery generally requires additional motive power over primary recovery to provide this additional pumping energy.
- **Tertiary (Enhanced Oil Recovery) Production:** EOR techniques are generally used to alleviate the factors that tend to decrease the flow of crude oil from an oil field. The effectiveness of EOR techniques in increasing the flow of crude oil from a field often relies on lowering the viscosity of the crude oil or increasing the subsurface pressure.

Enhanced oil recovery refers to methods used to extract crude oil from a field once primary production techniques have become uneconomic. A number of methods have been developed or proposed for EOR and are generally classified as:

- Thermal
- Gaseous
- Chemical
- Microbial.

All EOR methods operate on the principle of inducing a gradient in the subsurface oil field that will drive the remaining crude oil to the surface.

In steam flooding, steam is injected into an underground formation through either the producing well or a specifically designated injection well. In the first case, a period of steam injection is followed by a period of oil recovery. In the second case, the steam is injected in locations which will provide the best possible drive of oil toward the producing well. Steam for thermal enhanced oil recovery operations is typically produced in steam generators that burn crude oil or natural gas. For the purposes of this study, it was assumed that crude oil was the fuel for steam generation.

Although natural gas is also used in this application, little data are available to quantify its relative importance.

Due to the loss of heat from the steam to the wellbore and the high temperatures at greater depths, steam flooding is only practical for use in oil fields of 2000-3000 feet or less in depth. Other factors influencing the amount of steam required are the porosity and permeability of the geologic formation being exploited and other geologic factors. Frequently, steam flooding is particularly appropriate in removing the heavier oils found at these relatively shallow depths.

The production of crude oil using EOR methods is distinguished from primary oil recovery due to the environmental effects of increased energy consumption per barrel of crude oil produced and, in many cases, the side effects of particular EOR methods.

Currently, steam flooding is the most common EOR method practiced in the United States. Other methods, such as carbon dioxide injection, are predominant in some geographical areas.

### **F.2.3.2 Advanced Crude Oil Production Technology**

A number of advanced technologies were considered in the development of the NES Strategy scenario (NES, 1991; DOE, 1991b). This consideration included the following recovery technologies:

- Horizontal drilling and completion
- Improved enhanced oil recovery
- Enhanced production technology
- Superior hydrocarbon extraction techniques under adverse geological of geographical conditions.

The major contribution to crude oil production from these technologies, however, lies beyond the 2000 and 2010 timeframes of interest to this reformulated gasoline study, since production from the use of these technologies is assumed in the NES to not occur prior to 2010.

## **F.2.4 Process Environmental Points of Interest**

Process environmental points of interest during crude oil production include both environmental discharges associated directly with the crude oil production process as well as from the consumption of resources such as fuels. In evaluating the environmental impact of fuel production technologies, resource (e.g., electricity) consumption is often at least as important as direct discharges because of the discharges involved in providing or consuming these resources.

A number of distinct pollutant and/or waste types are generated as the result of operating a crude oil field. These types include:

- Materials mixed with the as-extracted crude oil (including water, sediment, and heavy petroleum fractions) that have no economic value and which must be disposed of as waste
- Emissions from equipment used to extract, transfer, or treat crude oil mixtures
- Materials contaminated with crude oil as a result of incidental spillage.

These and other pollutants are discussed in detail below.

### **F.2.4.1 Air Emissions**

Typical pollutants generated during crude oil production include carbon dioxide (CO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), sulfur oxides (SO<sub>x</sub>), total suspended particulates (TSP), and volatile organic compounds (VOCs). CO<sub>2</sub> is generated by complete combustion of carbon-based fuels. NO<sub>x</sub> consists of nitric oxide (NO) and nitrogen dioxide (NO<sub>2</sub>). NO<sub>x</sub> is formed through the combination of oxygen and nitrogen in the air during combustion processes, the rate of formation greatly increases with combustion temperature. CO is formed by the incomplete (often caused by low temperature) combustion of hydrocarbon fuels. SO<sub>x</sub> is formed by the combustion of (generally low quality) fuels containing sulfur, such as some diesel fuels or crude oil. TSP emissions are associated with combustion processes, as well as fugitive sources such as those resulting from construction activities. Most particulates are less than 10 microns in diameter. VOC emissions result from fugitive crude oil storage and transfer operations, processing of hydrocarbon compounds, and incomplete combustion of fossil fuels. All of these pollutants are regulated by Federal and state agencies to prevent adverse effects on human health and welfare.

Generic sources of air emissions resulting from all types of crude oil production technologies commonly include internal combustion engines employed (where electric motors are not used) to provide power for artificial lift and fuel for the heater treaters used in product separation

equipment. Other sources of air emissions include evaporation of hydrocarbons from storage tanks and oil spills and venting of gases from wells during normal operations.

Air emissions from the three types of crude oil production technologies are discussed below. These include onshore, offshore, and enhanced oil recovery technologies.

#### **F.2.4.1.1 Onshore Oil Recovery**

Air emissions from onshore oil recovery depend to a large degree on the type of equipment operated at the lease site. A typical lease for an onshore crude oil well in the lower 48 states might consist of 10 wells producing by artificial lift into a centrally located tank battery. The type of lift and prime mover used to pump crude oil from the ground varies by the depth of the well (see Table F-4). Air emissions and/or required electrical input for a given well depends on the type of equipment used to pump the crude oil from the ground and separate it into product. In general, deeper oil fields require larger amounts of energy to provide artificial lift. Rated power requirements for surface pumps range from 9 hp for ten 2000-ft wells to 100 hp for ten 12,000 ft wells (DOE, 1990c).

Air releases associated with primary onshore oil development and production are generally expected to be minor, short term, and very localized. Pre-operational emissions include road and pad development, resulting in small amounts of fugitive dust production, and vehicle and drilling equipment exhaust emissions. The availability of grid electricity for pumping and transfer operations tends to minimize the onsite generation of most air pollutants.

Estimates of air pollutant emissions from onshore crude oil recovery operations were derived from information presented by one primary study in which the energy and material inputs, process outputs, and emissions from a 400-well primary onshore extraction field located in the lower 48 states producing 100,000 barrels (bbl) per day (including 195 plugged, unproductive wells) were estimated (see Table F-5) (Aerospace, 1983). All energy for fluid transfer and compression operations was provided by grid electrical power. The only other major air pollutant-generating operation (besides pre-operational drilling) was identified to be the heater treater separators used in the field treatment of the as-extracted gas-water-oil mixture. These data indicate that separation operations in a crude oil field consume approximately 0.84 billion Btu of natural gas per trillion Btu of crude oil produced, or 4,872 Btu (4.872 scf) natural gas burned per bbl of crude oil produced.

**Table F-4.**  
**Type of Artificial Lift and Prime Mover Used for Each Depth and Area<sup>1</sup>**

Location	Depth							
	2,000 Ft		4,000 Ft		8,000 Ft		12,000 Ft	
	Lift	Power	Lift	Power	Lift	Power	Lift	Power
California	Rod	Motor	Rod	Motor	Hyd.	Motor	Hyd.	Motor
Oklahoma	Rod	Engine	Rod	Engine	Hyd.	Engine	Hyd.	Engine
S. Louisiana	Rod	Engine	Gas	Engine	Gas	Engine	Hyd.	Engine
S. Texas	Rod	Engine	Gas	Engine	Gas	Engine	Hyd.	Engine
W. Texas	Rod	Engine	Rod	Engine	Rod	Engine	Hyd.	Engine
Wyoming	Rod	Motor	Rod	Motor	Rod	Motor	Hyd.	Motor

<sup>1</sup>Hyd. = Hydraulic  
 Engine = Gas Engine  
 Motor = Electric Motor

Source: U.S. Department of Energy, *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations: 1986*, Report No. DOE/EIA-0185(86), Energy Information Administration, Office of Oil and Gas, Washington, D.C., 1986.

**Table F-5.**  
**Energy Consumption During Primary Onshore Oil Production**

Energy Resource Used	Per 10 <sup>12</sup> Btu Crude Oil Produced
Electric power for pumps	6.30 x 10 <sup>9</sup> Btu
Diesel fuel for drilling	7.60 x 10 <sup>9</sup> Btu
Heater treater separators	0.84 x 10 <sup>9</sup> Btu

Source: U.S. Department of Energy, *Energy Technology Characterizations Handbook: Environmental Pollution and Control Factors*, Third Edition, Report No. DOE/EP-0093, Washington, D.C., pp. 106, March 1983.

In addition, overall (drilling and production) emissions estimates for NO<sub>x</sub>, CO, hydrocarbons, SO<sub>x</sub>, and particulates were developed in the study (Aerospace, 1983). Production-only estimates were derived from those presented in this study based on the assumption that the air emissions were proportionate to energy consumption. The burners found in the heater treater separators in the oil fields were assumed to be similar to those utilized in industrial boilers. In addition, the emission factors for natural gas combustion were assumed to be the same as in industrial boilers (see Table F-6). This estimate may be conservative since many of these burners are located at remote unattended sites where optimal operating conditions are difficult to achieve.

**Table F-6.  
Emission Factors for Natural Gas Combustion in an Industrial Boiler**

Furnace Size	Emission Factor (lb/MMscf)			
	TSP	SO <sub>2</sub>	NO <sub>x</sub>	CO
10-100 MMBtu Input	1 - 5	0.6	140	35

Source: U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors: Volume 1. Stationary Point and Area Sources*, Fourth Edition, Report No. AP-42, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, September 1985 (Updated through October 1991).

Carbon dioxide (CO<sub>2</sub>) and methane emissions estimates were derived using the following information and assumptions: 1) the energy consumption attributed in the Aerospace, 1983 reference source, 2) assume natural gas was the only fuel employed in the heater treater separators, and 3) the emission factor for the generation of methane from natural gas combustion was obtained from recent EPA data (EPA, 1990). The combustion of natural gas (carbon content of 79 percent, including 0.66 percent CO<sub>2</sub>) with dry air was assumed to yield 2.89 pound (lb) CO<sub>2</sub> per lb of natural gas. Assuming a lower heating value of 20,300 Btu/lb, natural gas yields 137 lb CO<sub>2</sub> per million Btu burned.

Based on these data, the air emissions attributed to onshore crude oil production can be roughly estimated (see Table F-7), assuming that all pumping operations are accomplished using electrical power.

In general, the total VOC emissions generated by a given source will consist of a number of different organic compounds, or species. In this study, the estimates of total VOC emissions (lbs/bbl) were obtained for the various components of an active crude oil recovery operation. EPA speciation data were then applied to these estimates to arrive at an estimate for the generation rate of specific organic compounds.

**Table F-7.**  
**Air Emissions Factors for Onshore Crude Oil Production**  
**Per Barrel Crude Oil Produced (10<sup>6</sup> lb)**

TSP	SO <sub>2</sub>	NO <sub>x</sub>	CO	CO <sub>2</sub>
5-25 (15 avg.)	3	680	170	670,000

Source: EA Mueller, Baltimore, Maryland

Yearly per-well VOC emission factors have been developed by EPA for the various stages of onshore crude oil recovery (EPA, 1990). As shown in Table F-8, the total VOC emissions from a given onshore well will consist of a number of individual well components which include fugitive well emissions as well as evaporative emissions from the crude oil sump and the crude oil pit.

**Table F-8.**  
**VOC Emission Factors For Onshore Crude Oil Wells**  
**(lbs/well-yr)**

Component	Emission Factor
Fugitive Emissions	396.00
Crude Oil Sumps	9.00
Crude Oil Pits	9.00
Total	414.00

Source: U.S. Environmental Protection Agency, *Volatile Organic Compound (VOC)/Particulate Matter (PM) Speciation Data System*, Version 1-32a, Air Quality Management Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, September 1990.

In 1989, the average U.S. crude oil production was 13.3 bbl per well per day. Combining this average with the estimate of 414.00 lbs of VOCs per well per year, the total VOC emissions from onshore oil recovery are estimated to be 0.08528 lb per bbl of crude oil produced. This emission factor is then multiplied by speciation data provided by EPA to arrive at the emission rates for specific VOCs (see Table F-9).

**Table F-9.**  
**Emission Factors for VOCs from**  
**Onshore Oil Wells (lb/well-yr)**

Compound	Wt. %	lb/bbl
Isomers of Hexane	9.9	0.0084
Isomers of heptane	11.6	0.0099
Isomers of octane	8.7	0.0074
C-7 cycloparaffins	1.6	0.0014
C-8 cycloparaffins	0.6	0.00051
Isomers of pentane	5.6	0.0048
Methane	38.0	0.032
Ethane	6.4	0.0055
Propane	10.0	0.0086
N-butane	7.4	0.0063
Iso-butane	0.4	0.00034
Benzene	0.1	0.000085

Source: U.S. Environmental Protection Agency, *Volatile Organic Compound (VOC)/Particulate Matter (PM) Speciation Data System*, Version 1-32a, Air Quality Management Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, September 1990.

EA Mueller Inc., Baltimore, Maryland.

#### **F.2.4.1.2 Thermal Enhanced Oil Recovery (EOR)**

The primary sources of air emissions from thermal EOR are the steam generators used to produce steam. The primary fuel used in these operations is generally crude oil or natural gas, and although emissions are controlled, they are generally much higher than primary oil production for each barrel of crude oil produced. Other sources of air pollution from thermal

EOR involve well vents. Well vent emissions are primarily water vapor (containing condensible and noncondensable hydrocarbons), particulates, hydrogen sulfide, and mercaptans. Sulfur pollutants vary depending on the producing formation undergoing EOR. In larger thermal EOR operations, escaping steam and gas is captured by the operator, condensed, and separated. Marketable gases are added to natural gas delivery lines, and condensed oils are added to produced oil.

Air pollutant emissions from thermal EOR should be higher than those from primary onshore oil production since a considerable amount of incremental energy is required for onsite steam generation. Air pollutant emissions resulting from the steam generation operation predominate over other sources in the crude oil field when produced crude oil is burned onsite to provide this energy. As a result, although the emissions are controlled, these emissions are generally much higher than primary oil production for each barrel of crude oil produced. Electrical energy consumption for pumping operations in thermal EOR was estimated to be equivalent to primary onshore oil production.

Steam generators currently used in oil fields produce 75 to 85 percent quality steam, and differ from typical industrial boilers in that they are fired with crude oil produced at the site. Three barrels of oil are usually produced for each barrel burned; thus, the net production is two barrels (Kaplan, 1981). Steam generators burning crude oil emit  $\text{NO}_x$ , particulate matter (including trace metals), CO, hydrocarbons, and hydrogen sulfide.

Estimates of controlled air emissions from crude oil-fired, steam-flooded oil fields were obtained from a study which included well vents and steam generators (Kaplan, 1981). Where possible, emission factors used to derive these estimates were scaled using the average content of sulfur, nitrogen, and ash for oil in particular fields. Kaplan's study assumed that at some fields, associated natural gas would be burned instead of produced crude oil. Modeling the air emissions from seven steamflood fields in California indicate that the total emissions per barrel of crude oil produced would average 0.022 lb of TSP, 0.160 lb  $\text{SO}_x$  expressed as  $\text{SO}_2$ , and 0.172 lb  $\text{NO}_x$  expressed as  $\text{NO}_2$ . The uncontrolled emissions of CO were estimated at 0.077 lb per bbl.

$\text{CO}_2$  and methane emissions estimates were derived using the following information: 1) the average crude oil consumption attributed to this operation (Kaplan, 1981), 2)  $\text{CO}_2$  emissions resulting from the combustion of crude oil fuel at 0.00017 lb/Btu (Bartus, 1989) and 3) a methane emission factor from heavy oil combustion in industrial burners of 0.032 lb/bbl (EPA, 1991). Assuming that the combustion of 0.33 lb of crude oil per 1 lb of crude oil represents the main source of  $\text{CO}_2$  emissions for crude oil production by thermal EOR and that all power for pumping and fluid transfer is provided by electricity, the total  $\text{CO}_2$  emissions are estimated to be 360 lbs per bbl and for methane 0.032 lb/bbl.

VOC emissions from thermal EOR were calculated in the same manner as VOC emissions from onshore oil recovery. Yearly per-well VOC emission factors have been developed by EPA for the various stages of conventional onshore crude oil recovery (see Table F-10).

These estimates include complete well fugitive emissions and evaporative emissions from the crude oil sump and the crude oil pit, as well as emissions from the crude oil-fired steam generators used in thermal EOR. In 1989, the overall U.S. average for crude oil production was 13 bbl per well per day. Combining this average with the estimate of 433 lbs of VOC per well per year, the total VOC emissions for thermal EOR are estimated to be 0.089 lb per bbl of crude oil produced.

**Table F-10.**  
**VOC Emission Factors For Steam-flood Oil Wells**  
**(lb/well-yr)**

Source	Emission Factor
Complete Well Fugitive Emissions	396.00
Crude Oil Sumps	9.00
Crude Oil Pits	9.00
Crude Oil-fired Steam Generators (@ 0.28 lb/1000 gal, 0.33 bbl burned/bbl produced)	19.00
<b>Total</b>	<b>433.00</b>

Source: U.S. Environmental Protection Agency, *Volatile Organic Compound (VOC)/Particulate Matter (PM) Speciation Data System*, Version 1-32a, Air Quality Management Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, September 1990.

The characteristics of VOC emissions from the crude oil-fired steam generators is sufficiently different than those of the fugitive emissions from the oil well itself to require that the VOC emissions from each source be speciated separately. Speciation data for these two separate sources are presented in Tables F-11 and F-12. It should be noted that EPA considers speciation data from jet engines to be applicable to crude-oil fired turbines as well. Applying these factors to the above estimate of 433 lbs/bbl leads to the estimates shown in Table F-13.

**Table F-11.**  
**Speciation Data for Fugitive VOCs from**  
**Liquid Service Valves and Fittings in Oil and Gas Production**

Compound	Wt. %
Isomers of hexane	9.9
Isomers of heptane	11.0
Isomers of octane	8.7
C-7 cycloparaffins	1.6
C-8 cycloparaffins	0.6
Isomers of pentane	5.6
Methane	37.0
Ethane	6.4
Propane	10.0
N-butane	7.4
Iso-butane	0.4
Benzene	0.1

Source: U.S. Environmental Protection Agency, *Volatile Organic Compound (VOC)/Particulate Matter (PM) Speciation Data System*, Version 1-32a, Air Quality Management Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, September 1990.

EA Mueller, Baltimore, Maryland.

**Table F-12.**  
**Speciation Data for VOC Emissions from a Crude Oil-Fired Steam Boiler**

Compound	Wt. %
Methane	11.0
Formaldehyde	42.0
n-Butane	14.0
Hexane	5.0
Acetone	28.0

Source: U.S. Environmental Protection Agency, *Volatile Organic Compound (VOC)/Particulate Matter (PM) Speciation Data System*, Version 1-32a, Air Quality Management Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, September 1990.

**Table F-13.  
Crude Oil Production  
Speciated VOC Emissions (lbs per bbl of Crude Oil Produced)**

Compound	lb/bbl
Isomers of hexane	0.0086
Isomers of heptane	0.0099
Isomers of octane	0.0074
C-7 Cycloparaffins	0.0014
C-8 Cycloparaffins	0.00051
Isomers of pentane	0.0048
Methane	0.033
Ethane	0.0055
Propane	0.0086
n-Butane	0.0069
iso-Butane	0.00034
Benzene	0.000085
Formaldehyde	0.0016
Acetone	0.0011

Source: EA Mueller, Baltimore, Maryland

#### **F.2.4.1.3 Offshore Oil Recovery**

Generally, offshore operations generate more direct air emissions than onshore crude oil production operations due to the more energy intensive nature of these activities and the need to generate electrical power onsite. During the life cycle of an offshore oil production operation, air releases result from: platform emissions; drilling activities during exploration, delineation, and development; service vessel operation; evaporation of volatile hydrocarbons from surface oil slicks; and fugitive emissions during hydrocarbon venting and offloading.

During the production phase of offshore oil and gas extraction operations, the primary source of emissions is from natural gas turbines that provide power for oil pumping, water injection, and gas compression. The emissions consist primarily (See Table F-14) of NO<sub>x</sub> with lesser amounts of CO, VOC, TSP, and SO<sub>x</sub>. Other sources of air pollutants include leakage of VOC vapors from oil/water separators, pump and compressor seals, valves, and storage tanks. Flaring may take place periodically to burn off excess gas, resulting in some emissions of SO<sub>x</sub> and VOC. If the gas produced is high in hydrogen sulfide, the gas would have to pass through a desulfurization unit.

**Table F-14.**  
**Estimated Cumulative (Uncontrolled) Emissions**  
**for the Production Phase of a Gulf of Mexico Oil Field**

	Total 1994-2023 Uncontrolled	2000, Controlled per bbl <sup>1</sup>	2010, Controlled per bbl <sup>1</sup>
Crude oil production	160 x 10 <sup>6</sup> bbl	---	---
Natural gas production	1.6 x 10 <sup>12</sup> scf	9,900 scf	9,900 scf
Air emissions			
Suspended particulates	120 tons	1.6 x 10 <sup>-3</sup> lb	1.6 x 10 <sup>-3</sup> lb
Volatile organics <sup>2</sup>	19,000 tons	6.0 x 10 <sup>-2</sup> lb <sup>3</sup>	6.0 x 10 <sup>-2</sup> lb <sup>3</sup>
Sulfur oxides	88 tons	1.1 x 10 <sup>-3</sup> lb	1.1 x 10 <sup>-3</sup> lb
Carbon monoxide	6,600 tons	8.2 x 10 <sup>-2</sup> lb	8.2 x 10 <sup>-2</sup> lb
Nitric oxides	51,000 tons	1.3 x 10 <sup>-1</sup> lb <sup>4</sup>	6.4 x 10 <sup>-1</sup> lb <sup>4</sup>

<sup>1</sup>Calculated

<sup>2</sup>Excludes methane and ethane

<sup>3</sup>Assumes 75% Reduction

<sup>4</sup>Assumes 80% Reduction

Sources: U.S. Department of the Interior, *Gulf of Mexico Sales 139 and 141: Central and Western Planning Areas Draft Environmental Impact Statement*, Report No. MMS 91-0018, Minerals Management Service, New Orleans, Louisiana, pg. II-4, April 1991.

EA Mueller, Baltimore, Maryland.

For a pollution source located within 25 miles from shore, the Clean Air Act Amendments of 1990 requires that regulations would be the same as would be applicable if the source were located in the corresponding onshore area, including state and local requirements for emission controls, emission limitations, offsets, permitting, monitoring, testing, and reporting (DOI, 1991c). Facilities thereby located in areas adjacent to attainment areas would apply best available control technology (BACT), while emissions from facilities adjacent to nonattainment areas would be required to be offset. Emissions resulting from support vessels and tankers would also be accounted for in any permit applications and shall also be subject to emission control regulations. It has been concluded that offshore oil platforms in Alaska will be required to apply BACT methods to reduce NO<sub>x</sub> and VOC emissions (DOI, 1990).

NO<sub>x</sub> emissions from gas-fired turbines used to drive electrical generators, gas compressors, and water injection pumps can be mitigated by water injection into the combustion chamber of the turbine, a technique that has been proven to be effective in reducing NO<sub>x</sub> emissions by 70-80 percent. For VOC control, the combination of vapor recovery and floating roofs has the possibility of reducing emissions by 75-95 percent (DOI, 1990).

The types of VOCs encompassed in the total VOC emissions estimated above may be broken down according to speciation profiles generated by EPA (see Tables F-11 and F-15). The primary source of VOC emissions is estimated to be natural gas turbines. Other sources of fugitive VOC emissions in offshore oil production include crude oil storage transfer operations and hydrocarbon processing. Estimates of greenhouse gas emissions from offshore oil extraction have been given for offshore oil extraction and production (see Table F-16) in various areas of the Outer Continental Shelf (DOI, 1991b). If it is assumed that 80 percent of total methane emissions are attributable to the combustion of natural gas in turbines, with the remaining 20 percent being generated as fugitive emissions, the speciation profiles presented and Tables F-11 and F-15 can be used to derive the total VOC generation profile for offshore oil production (see Table F-16).

Estimates of greenhouse gas emissions resulting from offshore oil recovery operations have been made elsewhere (see Table F-17). It should be noted that these estimates include pre- and post-operational activities, and may therefore represent a liberal assessment of production-only impacts.

**Table F-15.**  
**Speciation Data for VOC Emissions from a Natural Gas-Fired Turbine**

Pollutant	Wt. %
Methane	70.0
Formaldehyde	30.0

Source: U.S. Environmental Protection Agency, *Volatile Organic Compound (VOC)/Particulate Matter (PM) Speciation Data System*, Version 1-32a, Air Quality Management Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, September 1990.

Speciation of the total suspended particulates reported in Table F-14 can be accomplished by applying factors obtained from EPA (See Table F-18), since the offshore oil platform can be expected to have no other significant sources of particulate

**Table F-16.**  
**Speciated VOC Emission Factors from Offshore Oil Production**  
**(lb/bbl crude oil produced)**

Pollutant	Emission Rate
Methane	$1.7 \times 10^{-2}$
Formaldehyde	$5.8 \times 10^{-3}$
Isomers of hexane	$8.9 \times 10^{-4}$
Isomers of heptane	$7.0 \times 10^{-3}$
Isomers of octane	$7.9 \times 10^{-4}$
C-7 Cycloparaffins	$9.6 \times 10^{-4}$
C-8 Cycloparaffins	$3.6 \times 10^{-4}$
Isomers of pentane	$3.4 \times 10^{-3}$
Ethane	$3.8 \times 10^{-3}$
Propane	$6.1 \times 10^{-3}$
n-Butane	$4.4 \times 10^{-3}$
iso-Butane	$2.4 \times 10^{-4}$
Benzene	$6.0 \times 10^{-5}$

Source: EA Mueller, Baltimore, Maryland

**Table F-17.**  
**Generation of Greenhouse Gases During Offshore Oil Field**  
**Development and Production**

	Total Emissions	Allocated Emissions (per bbl)
Crude oil	$8.2 \times 10^8$ bbl	---
Natural gas	$9.4 \times 10^{12}$ scf	$1.1 \times 10^4$ scf
Methane	$6.8 \times 10^3$ tons	$1.7 \times 10^{-2}$ lb
Carbon dioxide	$7.8 \times 10^7$ tons	$1.9 \times 10^2$ lb

Source: U.S. Department of the Interior, *Outer Continental Shelf Natural Gas and Oil Resource Management: Comprehensive Program 1992-1997 Draft Environmental Impact Statement Volume 1*, Report No. MMS 91-0044, Minerals Management Service, Herndon, Virginia, July 1991.

**Table F-18.**  
**Particulate Speciation for an Industrial Natural Gas Turbine**

Chemical	Size 0-10 $\mu$ m	Total PM	% PM <sub>10</sub>
Organic carbon	2.01	3.63	55%
Elemental carbon	5.43	9.81	55%

Source: U.S. Environmental Protection Agency, *Volatile Organic Compound (VOC)/Particulate Matter (PM) Speciation Data System*, Version 1-32a, Air Quality Management Division, Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, September 1990.

emissions. Using the percentage data contained in Table F-18, the reported value of  $1.55 \times 10^{-3}$  lb TSP per bbl of crude oil can be estimated to be 55 percent PM<sub>10</sub>, or  $8.6 \times 10^{-4}$  lb of PM<sub>10</sub> per bbl.

#### **F.2.4.1.4 Air Emissions Summary**

A summary of the air emission factors for the various types of crude oil recovery is presented in Table F-19. It should be emphasized that while the rates of air pollutant generation presented are comparable for all types of crude oil recovery, the prime mover for onsite transfer of crude oil in onshore and thermal EOR crude oil recovery is assumed to be electricity, for which no air pollutant generation rate is explicitly derived in this study.

Applying the factors in Table F-19 to the crude oil production estimates of Table F-3 results in total air emissions from crude oil production. The results of these computations are shown in Table F-20. Since the emissions from the advanced technologies are not known at the present time, it was assumed that their emissions will be a volumetric average of the conventional onshore, conventional offshore, and EOR technologies. Almost all of the criteria pollutants (i.e., NO<sub>x</sub>, CO, and SO<sub>2</sub>) are generated during fuel combustion.

In general, the total air emissions projected as a result of crude oil production in 2010 are expected to increase significantly over those projected in 2000. The primary factors determining this increase are:

- The projected overall increase in domestic oil production (see Table F-3)

**Table F-19.**  
**Air Emissions from Crude Oil Production by Recovery Method**  
**(lb pollutant emitted/bbl crude oil produced)<sup>1</sup>**

Pollutant	2000			2010		
	Onshore Oil Recovery	Thermal Enhanced Oil Recovery	Offshore Oil Recovery	Onshore Oil Recovery	Thermal Enhanced Oil Recovery	Offshore Oil Recovery
Nitrogen oxides	0.00068	0.17	1.4	0.00068	0.17	1.35
Carbon monoxide	0.00017	0.077	0.18	0.00017	0.077	0.18
Sulfur dioxide	0.0000030	0.16	0.0024	0.0000030	0.16	0.0024
Total suspended particulates	0.000015	0.0220	0.00086 <sup>2</sup>	0.000015	0.022	0.00086 <sup>2</sup>
Carbon dioxide	0.67	362.	190.	0.67	362.	190.
Isomers of hexane	0.0084	0.0086	0.00089	0.0084	0.0086	0.00089
Isomers of heptane	0.0099	0.0099	0.0070	0.0099	0.0099	0.0070
Isomers of octane	0.0074	0.0074	0.00079	0.0074	0.0074	0.00079
C-7 Cycloparaffins	0.0014	0.0014	0.00096	0.0014	0.0014	0.00096
C-8 Cycloparaffins	0.00051	0.00051	0.00036	0.00051	0.00051	0.00036
Isomers of pentane	0.0048	0.0048	0.0034	0.0048	0.0048	0.0034
Methane	0.032	0.032	0.017	0.032	0.032	0.017
Ethane	0.0055	0.0055	0.0038	0.0055	0.0055	0.0038
Propane	0.0086	0.0086	0.0061	0.0086	0.0086	0.0061
n-Butane	0.0063	0.0069	0.0044	0.0063	0.0069	0.0044
Benzene	0.000085	0.000085	0.00006	0.000085	0.000085	0.000060
iso-Butane	0.00034	0.00034	0.00024	0.00034	0.00034	0.00024
Formaldehyde	---	0.0016	0.0058	---	0.0016	0.0058
Acetone	---	0.0011	---	---	0.0011	---
Total volatile organic compounds	0.085	0.089	0.051	0.085	0.089	0.051

<sup>1</sup> Tabulated emissions do not include emissions resulting from the production of electrical power required in onshore and enhanced oil recovery methods.

<sup>2</sup> Particulate matter of less than 10µm in diameter (PM<sub>10</sub>)

**Table F-20.  
Crude Oil Production - Air Emission Estimates<sup>1</sup>**

Pollutant	2000		2010	
	per MMBtu	per year	per MMBtu	per year
Nitrogen oxides	0.046	700,000,000	0.042	790,000,000
Carbon monoxide	0.0069	110,000,000	0.0072	140,000,000
Sulfur dioxide	0.0030	47,000,000	0.0051	98,000,000
Total suspended particulates	0.00051	7,800,000	0.00079	15,000,000
Carbon dioxide	12.7	200,000,000,000	17	320,000,000,000
Isomers of hexane	0.0012	19,000,000	0.0013	24,000,000
Isomers of heptane	0.0016	25,000,000	0.0016	31,000,000
Isomers of octane	0.0011	17,000,000	0.0010	21,000,000
C-7 Cycloparaffins	0.00022	3,400,000	0.00023	4,300,000
C-8 Cycloparaffins	0.000084	1,300,000	0.000084	1,600,000
Isomers of pentane	0.00078	12,000,000	0.00079	15,000,000
Methane	0.0051	78,000,000	0.00514	98,000,000
Ethane	0.00089	13,000,000	0.0009	17,000,000
Propane	0.0014	22,000,000	0.0014	27,000,000
n-Butane	0.0010	15,000,000	0.0011	20,000,000
Benzene	0.000014	210,000	0.000014	270,000
iso-Butane	0.000056	860,000	0.000056	1,100,000
Formaldehyde	0.00021	3,300,000	0.00021	3,900,000
Acetone	0.000020	310,000	0.000034	650,000
Total volatile organic compounds	0.014	210,000,000	0.014	270,000,000

<sup>1</sup> Tabulated emissions do not include emissions resulting from the production of electrical power required in onshore and enhanced oil recovery methods.

- The need to step up crude oil production by the more polluting EOR methods, and to a lesser degree, energy-intensive offshore oil production methods.

Among the pollutants studied, the total SO<sub>2</sub> emissions are expected to undergo the largest proportional increase during the time period 2000-2010, primarily because of the expected increase in the combustion of relatively high-sulfur crude oils to fuel EOR operations. This trend may be somewhat negated if producers of EOR oil are able to make use of cleaner-burning fuels to power these energy intensive operations.

#### **F.2.4.2 Liquid Effluents**

The primary sources of pollutant releases to surface water during crude oil production are crude oil spillage and produced (formation) water discharges. In addition, releases to local groundwater can be caused by crude oil production operations that involve water or steam injection when increased pressure causes seepage of injected or reinjected materials through the formation into other underground aquifers. Leaching from unlined waste-disposal pits that store pre-operational wastes, accidental surface spills during storage and transport of waste effluent, and secondary fractures that may connect the formation with aquifers can also result in offsite releases. Nevertheless, these latter sources are neither systematic nor quantifiable since they depend on the nature of individual operations.

Produced water plays a unique role in crude oil production since it may be considered a waste, byproduct, or raw material depending on the specifics of a given crude oil recovery operation. Once drilling and other well development activities have been completed, the major waste stream generated by an operating crude oil well is the "water cut", or the fraction of the material coming out of the oil well that is water (see Table F-21). As an oil well ages, the proportion of water in the well effluent rises until it is no longer economic to recover the increasingly small proportion of oil.

Although comparable amounts of produced water are generated in the three representative modes of crude oil production, the manner in which this water is handled differs in each operation. Generally, most of the water from onshore oil production (primary, secondary, and EOR) is reinjected either to maintain reservoir pressure or as an approved disposal method. In the case of EOR, the oil well operator usually obtains additional water for steam injection in order to preserve and/or increase reservoir pressure.

In general, discharged produced waters are considered to be the major liquid effluent of concern from crude oil production operations. Contaminant levels observed in produced waters have not been shown to vary appreciably by location (onshore or offshore), but produced water from enhanced oil recovery operations tend to have lower concentration levels due to the recycling of purified water used to make steam.

**Table F-21.**  
**1985 U.S. Oil, Gas, and Associated Waste Production (MMbbl)**

	MMbbl	bbl/bbl
Total Crude Oil Production	3,275	--
Produced Water Generation		
Reinjected	13,020	3.98
Disposed (Injection)	5,750	1.76
Disposed (NPDES/percolation pits)	1,890	0.577
Total	20,660	6.32

Source: U.S. Environmental Protection Agency, *Report to Congress: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, Report No. EPA/530-SW-88-003, PB88-146220, Office of Solid Waste and Emergency Response, Washington, D.C., December 1987.

#### **F.2.4.2.1 Onshore Oil Recovery**

The two primary sources of pollutant releases to surface water during onshore crude oil production are produced (formation) water discharges and crude oil spillage. In general, water produced during onshore recovery operations is reinjected, but some wells produce an excess of water that must be disposed of during the operation of the well. Although most produced waters are brackish to highly saline, some are fresh enough for beneficial use. If water is to be discharged, it must meet certain water quality standards. Because water may not come from the treating and separating facilities completely free of oil, oil skimmer pits may be established between separating facilities and surface discharge.

Secondary releases to surface water during onshore crude oil production are crude oil spillage and surface water drainage from well pads and production and development sites. Such drainage may carry drilling mud, chemicals used in drilling and/or production, oil, grease, and other pollutants into nearby surface waters. Spills from facilities or equipment used to store or transport produced oil and gas may contaminate surface water supplies. Blowouts during production are unusual, but have the potential for polluting surface waters.

Recent estimates indicate that about 7 bbl of produced water are generated per bbl crude oil produced (EPA, 1987). However, in onshore crude oil production, only about 0.57 bbl of water is estimated to be actually disposed of through surface discharge or land treatment (see Table F-21). Using "best estimate" criteria as developed by EPA (see Table F-22), the most important pollutants released per bbl of crude oil output as a result of produced water

discharge are 0.0000039 lb arsenic, 0.000094 lb benzene, 0.0020 boron, 1.9 lb sodium, 1.5 lb chloride, and 4.6 lb mobile ions. The amount of oil and grease discharged to surface waters was estimated to be 0.03 lb/bbl (Aerospace, 1983).

**Table F-22.  
Produced Water Constituents and Concentrations<sup>1</sup>**

Constituent	Median (mg/l)	Upper 90% (mg/l)
Arsenic	0.02	1.7
Benzene	0.47	2.9
Boron	9.9	120
Sodium	9,400	67,000
Chloride	7,300	35,000
Mobile ions <sup>2</sup>	23,000	110,000

<sup>1</sup> The median constituent concentrations from the relevant samples in the EPA waste sampling/analysis study were used for a "best estimate" waste characterization, and the 90th percentile concentrations were used for a "conservative" waste characterization.

<sup>2</sup> Mobile ions include chloride, sodium, potassium, calcium, magnesium, and sulfate.

Source: U.S. Environmental Protection Agency, *Report to Congress: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, Report No. EPA/530-SW-88-003, PB88-146220, Office of Solid Waste and Emergency Response, Washington, D.C., December 1987.

#### **F.2.4.2.2 Thermal Enhanced Oil Recovery (EOR)**

Releases of water effluents to surface waters from thermal EOR are generally not significant since crude oil production using this method usually requires a net input of water, and any unusable produced water (and accompanying contaminants) is generally reinjected into the underground formations from which it was originally generated. However, groundwater contamination can occur during thermal EOR, either due to localized groundwater overdrafts (the removal of too much groundwater to meet EOR requirements), improper reinjection techniques, or both. If leakages occur during reinjection, or if groundwater is in short supply, EOR might result in significant groundwater problems in some areas of the United States. Potential sources of water contamination from thermal EOR for which little documentation is

available include incidental surface spills of oil and leakage from storage tanks, ponds, and pipelines.

On the whole, steamflood EOR operations consume more water than they produce and, therefore, no net release of produced water is assumed for this crude oil production method. This may not be the case for all EOR fields. Environmental releases (usually freshwater aquifer contamination) from this practice can occur given improper reinjection techniques; however, such situations are site specific and no general conclusions can be reached regarding their extent.

Estimates of oil and grease released as water pollutants from steam-flood EOR operations are 0.8 to 3.9 tons per trillion Btu of crude oil produced, which amounts to 0.01 to 0.05 lb per bbl crude oil produced (Aerospace, 1983). The arithmetic average of these two values, 0.03 lb/bbl, was used in this study to estimate the total oil and grease discharges from EOR technologies.

#### **F.2.4.2.3 Offshore Oil Recovery**

Generally, produced water resulting from offshore oil production operations are discharged directly from production platforms into surrounding waters. Daily discharges from platforms are generally less than 10,000 bbl, although discharges from facilities handling a number of platforms are usually larger. During initial oil production, produced water volumes represent a small fraction (less than 1 percent) of the total fluid extracted from with well, with oil composing almost the entire amount of fluid. As the reservoir is depleted, the ratio of produced water to oil increases to as much as 10 to 1. The most common chemical constituents found in produced waters are iron, calcium, magnesium, sodium, bicarbonate, sulfates, and chloride. In addition, produced waters contain entrained oil or petroleum hydrocarbons and measurable trace metal concentrations. Relative to ambient water, produced water has increased organic salts and increased trace metals. In addition, produced water is characteristically anoxic or low in dissolved oxygen and of a somewhat warmer temperature (86° to 104°F) than the water surrounding the platform. Because of rapid dilution, both dissolved oxygen and temperature gradients are most likely rapidly diminished.

Treated domestic waste (e.g., from sinks and showers) and sanitary (sewage) wastes are discharged from offshore oil facilities. It has been estimated that 5,000 gallons per day are discharged from a development platform. Sanitary discharges are regulated by EPA and others such that they must not contain any constituent in concentrations which exceed EPA criteria and a minimum chloride residual of 1.0 ppm. Sanitary waste effluent are rapidly dispersed and diluted in the water column.

Under normal offshore operations, varying degrees of water quality degradation could also occur as a result of discharges and construction related activities. Discharges primarily include produced water, sanitary and domestic wastes, and deck drainage. Deck drainage includes all effluent resulting from platform washings, deck washings, and runoff from curbs,

gutters, and drains, including drip pans and work areas. Constituents of concern in the effluent are oil and grease. The National Pollutant Discharge Elimination System (NPDES) permit regulations specify there should be "no discharge of free oil" in deck drainage which would cause a film, sheen, a discoloration on the surface of the water, or a sludge or emulsion to be deposited beneath the surface of the water. In compliance with this requirement, contaminated deck drainage is collected by a separate drainage system and treated for solids removal and oil/water separation. Separated oil is held for onshore disposal or recycling.

Other liquid waste streams that may be discharged during production include such items as desalinization unit discharge and cooling water. These discharges, also regulated by the NPDES permit system, are considered of minor concern in terms of effects on water quality because of their virtually non-toxic character and/or because they are discharged in such low volumes that any effect on ambient water quality is rapidly diluted.

Routine offshore oil production results in effluent discharges which have varying, though generally limited, effects on the ambient water quality of the area. These discharges are regulated by permits and subject to Federal and State criteria and standards. These include the Federal Water Pollution Control Act as amended by the Clean Water Act, Oil Pollution Act of 1990, and NPDES. With the exception of produced water, these discharges are considered of minor concern in terms of effects on water quality because of their virtually non-toxic character and/or because they are discharged in such low volumes that any effect on ambient water quality would be rapidly diluted. Formation, or produced, water is generally the most important discharge from offshore production operations.

Relative to ambient water, formation water has increased organic salts, increased temperature, decreased dissolved oxygen, and increased trace metals. Actual contaminant levels in a given sample of produced water have been shown to vary depending on the source. Produced waters from some fields have shown levels of priority pollutants several times higher than those found in seawater (see Table F-23) (DOI, 1991a). Statistical analyses performed by EPA show that produced water in the Gulf of Mexico averaged 25 mg/l (ppm) oil content (DOI, 1991a).

Generally, produced water from oil and gas operations in the Outer Continental Shelf are discharged directly from offshore production platforms into surrounding waters, although in the Gulf of Mexico, some may be piped ashore first and then discharged into nearshore or estuarine waters (DOI, 1991b). The generation of produced water from an offshore oil field over its 20-year life has been estimated to be 435 million bbl during the production of 50 million bbl of crude oil, or 8.7 bbl produced water per bbl of crude oil production (DOI, 1991c). For the purpose of this study, all of the produced oil was assumed to be discharged offshore into the surrounding seawater.

**Table F-23.**  
**Composition of Produced Water from a Selected Field in the Gulf of Mexico**

Pollutant	Concentration Range (µg/l)
Cadmium	2.4 - 10.0
Chromium	0.88 - 0.970
Mercury	0.076 - 0.24
Thallium	0.088 - 0.23

Source: U.S. Department of the Interior, *Outer Continental Shelf Natural Gas and Oil Resource Management: Comprehensive Program 1992-1997 Draft Environmental Impact Statement Volume 1*, Report No. MMS 91-0044, Minerals Management Service, Herndon, Virginia, July 1991.

Assuming the maximum values noted in this analysis to be representative of the amount of priority pollutants discharged in the produced water, the discharge of priority pollutants due to the production of 1 bbl of crude oil can be estimated to be 0.000032 lb cadmium, 0.0000029 lb chromium, 0.00000073 lb mercury, and 0.00000069 lb thallium.

Releases of oil and grease from offshore oil production were estimated from the levels of these pollutants expected to be found in the produced water discharge, plus the amount of spillage expected from platform operations. Studies have shown that produced water typically contains hydrocarbon levels of 25 ppm; this would amount to 0.077 lb/bbl crude oil produced. Estimates of oil spills from proposed Alaskan offshore drilling operations involving 6 platforms and 214 wells have been projected at the rate of 0.000024 bbl/bbl, or 0.0067 lb/bbl (DOI, 1990). Thus, the total rate of oil and grease discharge is expected to be 0.084 lb/bbl.

#### **F.2.4.2.4 Liquid Effluents Summary**

The liquid effluents factors resulting from crude oil production are shown in Table F-24. The estimated releases of contaminants to the surface water environment vary in direct proportion to the estimated amount of produced water assumed to be discharged. The largest water releases are estimated for offshore oil recovery, since it is current practice to discharge most produced water to the surrounding sea water. In contrast, onshore oil production is estimated to release only relatively small amounts of produced water due to higher rates of reinjection reported for this method of oil production. Since enhanced oil recovery operations generally consume more water than is produced, it is assumed that no net generation of produced water occurs for this method of oil recovery.

**Table F-24.**  
**Liquid Effluents Factors from Crude Oil Production by Recovery Methods**

Pollutant	2000			2010		
	Onshore	Enhanced Oil Recovery	Offshore	Onshore	Enhanced Oil Recovery	Offshore
Produced water, bbl/bbl	0.57	0	8.7	0.57	0	8.7
Oil & grease, lb/bbl	0.03	0.03	0.067	0.03	0.03	0.067
Arsenic, lb/bbl	0.000004	0	0.000061	0.000004	0	0.000061
Benzene, lb/bbl	0.000094	0	0.0014	0.000094	0	0.0014
Boron, lb/bbl	0.0020	0	0.030	0.0020	0	0.030
Sodium, lb/bbl	1.9	0	29	1.9	0	29
Chloride, lb/bbl	1.5	0	22	1.5	0	22
Mobile ions, lb/bbl	4.6	0	70	4.6	0	70

Source: EA Mueller, Baltimore, Maryland

Applying the factors shown in Table F-24 to the crude oil production projections of Table F-3 yields the total liquid effluents of Table F-25. The estimates presented in Table F-25 indicate an expected increase in total estimated water effluents from crude oil production for the period 2000-2010. Most of this projected increase results from a projected increase in offshore oil production.

Treatment methods for produced water discharges from offshore and offshore crude oil production were assumed to consist of oil and grease removal to the current EPA limits of 25 mg/l. In offshore operations, produced water is discharged directly to the surrounding ocean. In accordance with EPA findings of management practices for onshore operations, the non-reinjected produced water is assumed to be removed from the system by discharge into unlined disposal pits, surface streams, bays, or estuaries (EPA, 1987). More stringent regulations concerning removal of benzene, heavy metals, and chlorides may be forthcoming from states or the EPA in the future, but the extent of these new regulatory limits are uncertain, as are the effect these regulations will have on the management practices for produced water.

**Table F-25.  
Crude Oil Production - Treated Liquid Effluents Estimates**

Pollutant	2000		2010	
	per MMBTU	per year	per MMBTU	per year
Produced water (bbl)	0.34	5,300,000,000	0.30	5,700,000,000
Oil & grease (lb)	0.0063	98,000,000	0.0062	117,000,000
Arsenic (lbs)	0.0000020	37,000	0.0000020	40,000
Benzene (lbs)	0.000056	870,000	0.000049	930,000
Boron (lbs)	0.0012	18,000,000	0.0010	20,000,000
Sodium (lbs)	1.1	17,000,000,000	0.99	19,000,000,000
Chloride (lbs)	0.88	14,000,000,000	0.76	14,000,000,000
Mobile ions (lbs)	2.8	43,000,000,000	2.4	46,000,000,000

Source: EA Mueller, Baltimore, Maryland

#### **F.2.4.3 Solid Waste**

Solid waste generated during crude oil production operations can be broken down into two basic categories: those that are unique to crude oil production and those that are common to many industrial activities. Solid wastes unique to crude oil production (excluding development wastes) usually contain a large proportion of the undesirable byproducts of the water-gas-oil mixture that is initially extracted from the crude oil well. The most important wastes of this type include produced sand (underground solids carried up the well by the water-gas-oil mixture), the heavier fractions of the produced crude oil (which tends to settle to the bottom of production tanks), and miscellaneous materials (e.g., soil) contaminated by contact with crude oil. Solid wastes generated during crude oil production that are not unique to the oil industry include those generated by internal combustion engines, painting, and weed killing.

Many of the important wastes generated by the crude oil industry are generated in the pre-operational phase. For example, perhaps the greatest attention with regard to solid waste generation in the crude oil production industry is directed toward the handling of waste drill cuttings and drilling muds. The quantity of muds and cuttings discharged into the environment is dependent on the number of wells drilled and the depth of each well. During drilling, cuttings are removed from the hole, and separated from the drilling muds, and discharged. Muds are discharged in bulk when the mud type is changed, during cementing operations, or at the end of drilling.

To date, the generation and handling of solid waste resulting from routine crude oil production activities (as opposed to oil field development) have not been comprehensively treated. This is because these wastes are commonly considered to present little risk, they are produced in relatively small quantities, and commonly followed management practices are considered to be highly effective. Such wastes include sanitary waste (sewage), sediment from crude oil separation and storage tanks, and oily wastes resulting from spillage of crude oil.

Estimates of solid waste generation rates were calculated as the sum of generic wastes common to all oil recovery plus additional wastes unique to the individual methods.

#### **F.2.4.3.1 Generic Solid Wastes from Crude Oil Production**

A number of solid waste are common to most crude oil production sites, onshore or offshore. These solid wastes include:

- Production tank sediment
- Production tank bottoms
- Hydrocarbon-bearing materials
- Spent filters and backwash
- Radioactive wastes.

Contaminants in production tank sediment and bottoms, which vary with the type of crude oil, may include a mixture of clay, rust, sand, water, and some oil and wax. Produced sand that is entrained in the gas-water-oil mixture is trapped in line filters or settles to the bottom of production tanks. A fraction of viscous heavy hydrocarbons (unsalable as crude oil) also tends to settle to the bottom of production tanks, and eventually this waste must also be removed. Often, this material is sold to reclaimers who recycle it into low-grade fuel.

Wastes soaked with crude oil (e.g., soil, trash) are collected separately and are disposed of according to local regulatory requirements. No estimates for the amount of oily wastes generated during crude oil production were found.

Radioactive material is continuously generated in subsurface geological formations due to the radioactive decay of ores containing uranium and thorium. The production of crude oil generally involves the removal of significant amounts of subsurface materials containing these radioactive elements to the surface. These radioactive materials typically include drill cuttings and produced water, which may be distributed as waste and/or contaminate production equipment and piping, thus generating additional waste. Produced water from certain locations has been shown to contain small amounts of radionuclides, primarily in the form of radium, up to 4 times that normally found in seawater (DOI, 1991b). To the extent that produced water is not returned to the subsurface formations from which it was generated, it is possible that a net release of radionuclides will occur. However, sufficient data are not readily available to quantify such releases.

Partly because the management of generic oil field wastes is not strictly controlled, detailed statistics on the rate of generation of these wastes are not generally available. In the late 1980s, some estimates were made regarding oil field waste management practices (See Table F-26).

Statistics generated as a result of this effort did not provide a detailed characterization of the wastes disposed of by various management practices. However, general industry practices are such that most tank bottoms are sold to reclaimers, while most produced sand is either sent back down the well or spread on roads or land. Dividing the amount of waste estimated to have been generated in Table F-26 by the total crude oil production rate yields estimates of the total solid waste disposal per bbl of crude oil produced (see Table F-27).

For the purposes of this study, it was assumed that all wastes disposed of by land spreading, road spreading, or onsite burial was production tank sediment. All wastes disposed of off-site or incinerated were assumed to be tank bottoms. Injected, surface discharged, evaporated, and other wastes were assumed to be produced water, a non-solid waste. Wastes that were recycled onsite were not considered to be a waste for the purposes of this study. Assuming further that the forms of associated waste listed above are generated at roughly the same rate at onshore, offshore, and thermal EOR facilities, the following solid waste generation rates are estimated for all crude oil production operations:

Production Tank Sediment	0.00086
Production Tank Bottoms	0.0021

Solid waste generation rates for various crude oil production methods are summarized in Table F-28. No significant changes in solid waste generation rates are expected to occur in the 2000-2010 time frame. Projected total and per bbl emissions are presented in Table F-29.

Solid wastes unique to each of the three types of crude oil production technologies are briefly discussed below.

#### **F.2.4.3.2 Onshore Oil Recovery**

No incremental solid waste are expected for onshore oil recovery over those calculated for generic oil field wastes.

**Table F-26.**  
**1985 U.S. Oil, Gas, and Associated Waste Production (MMBbl)**

Produced water	
Reinjected	13,020
Disposed (injection)	5,750
Disposed (NPDES/percolation pits)	1,890
Total	20,660
Associated waste	
Injected	0.80
Surface discharge	0.06
Evaporation	0.4
Off-site disposal	6.1
On-site burial	0.6
On-site recycling	0.7
Land spreading	1.1
Road spreading	1.6
Incineration	0.008
Other	0.3
Total	12

Source: U.S. Environmental Protection Agency, *Report to Congress: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy*, Office of Solid Waste and Emergency Response, Report Number EPA/530-SW-88-003, PB88-146220, December 1987.

**Table F-27.**  
**Generic Associated Waste Generated by Crude Oil Production**  
**(bbl/bbl crude oil production)**

Fate of Waste	Amount (bbl/bbl)
Injected	0.0002
Surface discharge	0.00002
Evaporation	0.0001
Off-site disposal	0.0019
On-site burial	0.00003
On-site recycling	0.0002
Land spreading	0.00034
Road spreading	0.00049
Incineration	0.000002
Other	0.00009
Total	0.0037

Source: EA Mueller, Baltimore, Maryland.

**Table F-28.  
Solid Wastes Generated During Crude Oil Production (lb/bbl)**

Type of Waste	2000			2010		
	Onshore	TEOR	Offshore	Onshore	TEOR	Offshore
Tank bottoms	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021
Tank sediment	0.00086	0.00086	0.00086	0.00086	0.00086	0.00086
FGD sludge	---	3.4	---	---	3.4	---
Steam generator ash	---	0.000008	---	---	0.000008	---

Source: EA Mueller, Baltimore, Maryland.

**Table F-29.  
Projected Solid Waste Generation Rates (lb)**

Type of Waste	2000		2010	
	per MMBTU	per year	per MMBTU	per year
Non-Hazardous				
Tank bottoms	0.00036	5,600,000	0.00036 <sup>1</sup>	6,900,000
Tank sediment	0.00015	2,300,000	0.00015	2,800,000
Total Non-Hazardous				
Hazardous				
FGD sludge	0.062	960,000,000	0.11	2,000,000,000
Steam generator ash	0.00029	4,500,000	0.00050	9,600,000
Total Hazardous				
Total	0.063	9,700,000	0.11	2,100,000,000

<sup>1</sup> Currently, exempt from hazardous waste classification.

<sup>2</sup> Non-exempt from hazardous waste classification; may be hazardous based on character of individual samples.

Source: EA Mueller, Baltimore, Maryland.

### **F.2.4.3.3 Thermal Enhanced Oil Recovery (EOR)**

Two additional major types of solid waste are expected from crude oil-fired, steam-injected TEOR, both of which are generated by the steam production process. The combustion of crude oil in a steam generator results in the production of a certain amount of residual ash that must be disposed of. To meet stringent air quality regulations, flue gas desulfurization (FGD) equipment ("scrubbers") is used with steam generators that burn heavy oil. Cleaning of the flue gases reduces air pollution, but it also creates a secondary concern: the environmentally safe and cost-effective management of the liquid and solid wastes resulting from the operation of FGD equipment.

The amount and specific composition of scrubber effluent depends on the system used. For a 300 MMBtu/hr heat input system, the volume of scrubber effluent can range from 300 to over 5000 lb/hr, with water contents ranging from 17 percent to over 85 percent, respectively. Most of the solids from these systems are a combination of sulfites, sulfates, hyposulfite, or carbonates of sodium or calcium. The rate of production of scrubber solids from steam flood EOR averages about  $6.6 \times 10^{-4}$  lb/bbl of oil produced (Kaplan, 1981). Scrubber sludge (solids + water) averages about  $4.5 \times 10^{-3}$  per bbl of oil produced. Scrubber liquids must be treated onsite before disposal into local surface waters. Scrubber sludges are difficult and costly to dispose of and are a potential source of contamination of local surface and subsurface water at the disposal site.

Based on a crude oil combustion rate of 0.33 bbl per bbl of crude oil produced, the estimates in previous studies indicate a generation rate of 3.40 lb of FGD scrubber solids per bbl of oil produced. Heavy fuel oils generally consist of approximately 0.1 weight percent ash which will not burn and must be disposed of as a waste (Perry, 1973). This amounts to an additional about 0.000008 lb/bbl of crude oil produced.

### **F.2.4.3.4 Offshore Oil Recovery**

No incremental solid waste are expected for offshore oil recovery over those calculated for generic oil field wastes.

## **F.2.4.4 Process Inputs and Outputs**

### **F.2.4.4.1 Process Outputs**

- Crude Oil - Resource inputs and environmental discharges resulting from the operation of the three representative crude oil production technologies were normalized on the basis of one barrel of crude oil output.

- **Natural Gas** - Natural gas production is commonly associated with most oil production. In all types of onshore oil production (i.e., primary, secondary, and EOR), natural gas is commonly mixed with the crude oil recovered from the well. This natural gas is usually separated from the crude oil, and may thereafter be either sold or used onsite for a number of purposes. To arrive at an estimate for the actual output of natural gas, the reported 1989 associated natural gas production of 5.40 tcf from oil wells producing 7.63 MMbbl/day of crude oil was used (DOE, 1990a), for an average of 1,939 scf/bbl. Since the source used in this study for estimating environmental effects of steam-flooding reported no net generation of natural gas, no credit for associated natural gas production was given to EOR.

In offshore operations, natural gas production is even more intimately tied to crude oil production since both natural gas and crude oil wells are often drilled from the same platform. The economic incentive for the construction and placement of offshore oil platforms depends on the co-production of both of these energy resources. In this study, therefore, the amount of natural gas generated from an offshore platform was reported as a byproduct of crude oil production.

#### **F.2.4.4.2 Process Inputs**

##### **F.2.4.4.2.1 Onshore Crude Oil Production**

- **Labor** - Labor requirements for a 400-well onshore primary oil extraction field were estimated to be 9.7 person-years per trillion Btu of crude oil produced (Aerospace, 1983). At 5.8 MMBtu/bbl, this amounts to 0.000056 person-years per bbl of crude oil produced.
- **Electricity** - Grid electrical power is commonly employed in onshore extraction locations (where readily available) to power artificial lift and produced water transfer pumps. Electrical requirements for such operations in a 400-well primary onshore production field have been estimated at about 0.0063 Btu per Btu of oil produced, or 11.7 kWh per bbl of crude oil produced (DOE, 1983).
- **Water** - Onshore crude oil production was assumed to require no significant water input.
- **Area** - Cumulative land use requirements associated with the development and exploitation of onshore oil fields are difficult to quantify. Areas immediately adjacent to the well that are devoted to oil production equipment average about 1/2 acre in size, but associated

service roads and transfer pipelines (normally, several oil wells produce into a central tank battery) can encumber or affect significantly more land area. Moreover, areas devoted to oil leases can frequently be used for other purposes, such as cattle grazing.

Published estimates of the land area required in primary onshore oil extraction is 2000 acres (including transfer and storage facilities) for a 400-well field capable of producing 36 million bbl/yr for 26 years (DOE, 1983). This equals  $2.14 \times 10^{-6}$  acre-yr/bbl.

#### F.2.4.4.2.2 Offshore Crude Oil Production

- **Labor** - Labor requirements for an offshore oil field were estimated to be 11,300 man-yrs of effort, with a total production of 50 million bbl of oil and 0.77 tcf of natural gas (MMS, 1991b). Labor requirements for this mode of crude oil recovery is, therefore, estimated to amount to 0.00026 man-yr per bbl.
- **Electricity** - All electricity consumption for offshore oil recovery was assumed to be produced by onsite, natural gas-fired turbine generators.
- **Water** - Offshore crude oil production was assumed to require no significant water input.
- **Area** - The presence of offshore platforms, with a surrounding 100-meter navigational safety zone, results in the loss of approximately 15 acres of trawling area to commercial fishermen and may cause space-use conflicts. If this zone is not observed, underwater platform obstructions may cause gear conflicts that will result in such losses as catch, business downtime, and vessel damage. The removal of productive water surface area by offshore drilling platforms is offset to some extent by the beneficial increase in habitat for small fish and other marine organisms. A water surface of 450 acres has been estimated to be required for the 30 platforms needed to produce 160 million bbl of crude oil over 20 years in the Gulf of Mexico (MMS, 1991c). This amounts to 0.000056 acre-yrs/bbl.

#### F.2.4.4.2.3 Crude Oil Production Using Enhanced Oil Recovery

- **Labor** - Labor requirements for a 1,382-well lower 48 steam injection EOR field were estimated to be 780 workers for 15 years to produce 84.7 trillion Btu per year of crude oil at 6.3 MMBtu/bbl (Aerospace, 1983). Thus, a total of 0.21 billion bbl of crude oil requires 11,700 person-yr of labor, or 0.000058 person-yr/bbl.

- **Electricity** - Thermal EOR operations are assumed to require electrical inputs comparable to onshore crude oil recovery.
- **Water** - EOR operations typically require 7 bbl of treated water to satisfy the steam requirements of 1 bbl of crude oil production. However, after treatment, produced water often is able to satisfy a large proportion of these requirements. Estimates of water requirements for an oil field steam injection have been estimated at 102 acre-ft per trillion Btu crude oil produced (Aerospace, 1983). This amounts to a net input (required water less that produced onsite) of 0.082 bbl water per bbl of crude oil.
- **Area** - Most EOR is usually performed in areas where land has already been dedicated to crude oil production. However, additional acreage is often required in EOR operations in order to handle the amount of scrubber sludge generated during the cleanup of exhaust gases from steam generators. The incremental amount of land area required for treatment of these wastes has been estimated to be  $1.3-1.8 \times 10^{-7}$  acre-yr/bbl oil produced by EOR (Kaplan, 1981).

#### **F.2.4.4.3 Process Inputs and Outputs Summary**

The required inputs for various types of crude oil production are summarized in Tables F-30 and F-31. No significant changes in required inputs are expected to occur between 2000 and 2010.

#### **F.2.5 Non-Process Requirements**

Environmental concerns normally addressed for oil production in the United States are extensive. These concerns include the following:

- **Air Quality:** Air quality concerns include dust and emissions associated with road and drill pad construction and drilling operations as well as vehicular operations. The potential to create or release concentrations of harmful gases (hydrogen sulfide) at drill sites exists.

**Table F-30.**  
**Input and Output Factors for Crude Oil Production**  
**(per bbl of crude oil produced)**

Parameter	2000			2010		
	Onshore	TEOR	Offshore	Onshore	TEOR	Offshore
<b>PROCESS OUTPUTS</b>						
Crude oil, bbl	1	1	1	1	1	1
Natural gas, scf	1,939	0	15,400	1,939	0	15,400
<b>PROCESS INPUTS</b>						
Labor, person-yr	$5.5 \times 10^{-5}$	$5.8 \times 10^{-5}$	$2.6 \times 10^{-4}$	$5.5 \times 10^{-5}$	$5.8 \times 10^{-5}$	$2.6 \times 10^{-4}$
Electricity, kWh	11.7	11.7	---	11.7	11.7	---
Area, acre-yr	$2.1 \times 10^{-6}$	$2.1 \times 10^{-6}$	$5.6 \times 10^{-5}$	$2.1 \times 10^{-6}$	$2.1 \times 10^{-6}$	$5.6 \times 10^{-5}$
Water, bbl	---	$8.2 \times 10^{-2}$	---	---	$8.2 \times 10^{-2}$	---

**Table F-31.**  
**Total Projected Inputs and Outputs from Crude Oil Production**

Parameter	2000		2010	
	per MMBTU	per year	per MMBTU	per year
<b>PROCESS INPUTS</b>				
Labor (person-yrs)	0.000016	250,000	0.000015	290,000
Electricity (kWh)	1.65	26,000,000,000	1.70	32,000,000,000
Water (bbl)	0.0015	23,000,000	0.0026	49,000,000
Area (acre-yrs)	0.000002	32,000	0.000002	34,000
<b>PROCESS OUTPUTS</b>				
Crude oil (bbl)	0.172	2,700,000,000	0.17	3,300,000,000
Natural gas (MMscf)	0.00072	11,000,000	0.00063	12,000,000

- **Water Resources:** The development of oil and gas resources has the potential to affect surface and groundwater supplied through surface erosion, contamination of streams, contamination of aquifers, production of brine waters, and the introduction of toxic substances into the environment.
- **Soils:** The construction of roads and drill pads will result in soil disturbance. Soil disturbance attributable to the proposed action is a consideration of this assessment with respect to production in a quantitative way and with respect to exploration and well closure in a qualitative way. There are risks of accidental spills which have been identified as the principle cause of potential impacts.

Special problems exist with regard to soil disturbance in ANWR, where tracks across virgin tundra left by wheeled vehicles associated with Prudhoe Bay oil field activities have persisted for over 20 years since they were incurred. In the future, specialized vehicles (e.g. "rolligans" with extra-wide tires) may be employed to minimize such environmental damage.

- **Vegetation:** In onshore oil recovery, the construction of access roads and drill pads will result in the removal of a minimal amount of vegetation which tends to naturally regenerate relatively quickly. In ANWR, natural replacement of disturbed vegetation may be much slower.
- **Wildlife:** The construction of access roads and drill pads will result in the loss of wildlife habitat. Drilling operations adjacent to wildlife habitats during critical seasons of a particular species life cycle could result in habitat avoidance by the local population of that species. Protection of threatened and endangered species and their habitat from destruction and disturbance which results from a Federal action (oil and gas leasing) is required by U.S. Department of the Interior, Bureau of Land Management (BLM) policy and the Endangered Species Act. Wildlife habitat in general, and threatened and endangered species and their habitats, are addressed as environmental components in this study. This activity includes fish and shellfish resources. Offshore activities may cause inconvenience of fishermen.
- **Cultural/Paleontological Resources:** Protection of cultural and paleontological resources from damage or destruction resulting from a Federal action (oil and gas leasing) is required by a number of regulations. As such, these resources are evaluated and considered as environmental components addressed in an environmental review.

- **Socio-Economics:** Oil and gas leasing and development could create positive impacts to the states' social structure through increased economic activity and opportunities for employment. Often, previous economic activities such as livestock management can continue relatively undisturbed.
- **Land Utilization:** Once pre-operational activities of exploration and installation of production wells and oil gathering facilities are completed, producing oil wells with tank batteries for separating liquids and storage of product occupy a half acre or less. Temporary access roads, 16 to 40 feet wide, are built next to these well locations. The length of such roads will not generally exceed one-half mile, especially in densely-developed oil-producing areas. Produced crude oil can be removed from the site either by truck or by pipeline.

Areas covered by oil leases and exploited in this manner are not necessarily removed from other economic use, since other activities (e.g., livestock grazing) need not be precluded in the areas not physically occupied by the production facility.

- **Oil Spills:** While spills from crude oil production are potentially limited in nature, compared to an at-sea tanker spill, the event may be catastrophic at a local level. Offshore spills have greater potential for impact, for example, in the Beaufort and Chukchi Seas where bowhead and beluga whales concentrate seasonally (DOI, 1991c).
- **Odors and Noise:** Odors and noise are proximity events in most cases. Industrial noise can be mitigated by known techniques with respect to both processes and hearing protection for personnel. Noise can, however, can affect some wildlife by reducing reproduction rates (DOI, 1991c).
- **Other Concerns:** Many environmental concerns are site-specific. These can range from permafrost impacts in Alaska to concerns for wild horses and burros in the west. More common are concerns for livestock grazing, forestry, outdoor recreation, and visual resource management.

## **Occupational Health and Safety:**

The occupational safety hazards of petroleum extraction are predominantly due to the flammable nature of the liquids and gases handled in oil installations. Physical contact with or inhalation of toxic compounds--such as CO, hydrogen sulfide, ammonia, hydrogen cyanide, phenols, and benzene--could cause serious injury or death. These compounds can exist in products, byproducts, and waste and process streams and can be released during process disruptions and maintenance or turnaround operations.

Methane, ethane, and some of the lower olefins are classified as "simple asphyxiants" and high concentrations of them could result in asphyxia. Repeated or prolonged skin contact with oil may break down the protective surface of skin, or plug skin follicles, resulting in dermatitis.

In general, the potential health hazards that exist in the crude petroleum industry are numerous and varied; however, the incidence of occupational disorders among refinery employees is relatively low. Nevertheless, it is essential to take appropriate measures to minimize the workers' exposure with these hazardous substances and keep concentrations of these chemicals below the levels and standards set by relevant authorities.

According to the most recent (1988) Bureau of Labor Statistics report on occupational injuries and illnesses, crude petroleum and natural gas extraction [Standard Industrial Code (SIC) 131], had an incidence rate for injuries and illnesses of only 2.9 incidences per 100 full-time workers. In 1987, the Bureau of Labor Statistics reported an injury and illness rate of 2.5 incidences per 100 full-time workers, while API reported 2.7 incidences per 100 full-time workers (API, 1990). This rate is approximately a third of the overall oil and gas extraction category (i.e., SIC 13) of 8.3 incidences per 100 full-time workers.

The overall SIC 13 category includes establishments primarily engaged in: producing crude petroleum and natural gas; extracting oil from oil sands and oil shale; producing natural gasoline and cycle condensate; and producing gas and hydrocarbon liquids from coal at the mine site. However, Types of activities included are exploration, drilling, oil and gas well operation and maintenance, and the gasification, liquefaction, and pyrolysis of coal at the mine site. Detailed breakdown of the SIC 13 category is not available; therefore, it is not possible to associate specific injury and illness incidences to crude oil production. SIC 131's rate of 2.9

incidences is also approximately a third of the total private sector's rate of 8.6 incidences per 100 full-time workers in 1988 (DOL, 1990).

In 1988, SIC 131's lost workdays were correspondingly low at 36.0 days per 100 full-time workers, compared to SIC 13 and the private sector rates of 141.6 and 76.1, respectively (DOL, 1990).

Fatality incidences at the three-digit SIC Code (i.e., 131) are not provided by the Bureau of Labor Statistics; however, from the above review, it is reasonable to assume an incidence rate of 1/3 the private sector rate of 5.0, which amounts to a incidence rate of 1.7 fatalities per 100,000 full-time employees for SIC 131 (DOL, 1990).

In 1988, employment at crude petroleum extraction (i.e., production only) facilities was approximately 87,000 full-time employees. Applying the above factors to crude oil production estimates for 1988, and then for 2000 and 2010, provides total incidence rates, as shown in Table F-32.

## **F.2.6 Pre-Operation and Post-Operation Phase**

As described above in Section F.2.1 Industry Structure, crude oil production pre-operations consist primarily of seismic surveying, exploratory drilling, construction of an access infrastructure, including roadways and well site pads, and an oil gathering system including all necessary processing systems and temporary storage tanks. In developing an oil field, there will be requirements for earthmoving equipment, drilling equipment, and other special use equipment. Construction materials will include concrete, reinforcing bars, steel plate, pipe and tubing, oil country tubular goods, refined products, pumps and drivers, and various specialty items (Aerospace, 1983).

The pre-operational activities associated with oil exploration have proven to be controversial in environmentally sensitive and scenic areas such as the Arctic National Wildlife Refuge (ANWR) and the Outer Continental Shelf (OCS). Exploration for oil in these areas has been deferred for a number of reasons:

- Adverse visual impacts resulting from routine oil exploration and, potentially, development and production operations are seen as particularly important in areas with distinctive visual appeal
- The environmental sensitivity of arctic areas is expected to make these areas more susceptible to damage from routine oil exploration activities and compound the risks of accidental environmental releases

**Table F-32.  
Crude Oil Production - Occupational Health and Safety Projection for 2000 and 2010**

	Incidence Rate	Annual Incidents <sup>1</sup>	Incidents Per Barrel <sup>2</sup>	
			2000	2010
Injuries and illnesses, rate per 100 workers	2.9	2,523	$0.74 \times 10^{-6}$	$0.74 \times 10^{-6}$
Lost workdays, rate per 100 workers	36.0	31,320	$9.2 \times 10^{-6}$	$9.2 \times 10^{-6}$
Fatalities, rate per 100,000 workers	1.7	1.5	$0.44 \times 10^{-9}$	$0.44 \times 10^{-9}$

<sup>1</sup> Assumes 1988 employment levels continue until 2000 since indigenous oil production is about the same in 1988 and 2000. The incidence increases in 2010 are prorated on a volumetric basis.

<sup>2</sup> Assumes 9.3 MMBD in 2000 and 10.6 MMBD in 2010 per Tables F-2 and F-3.

Sources: U.S. Department of Labor, Occupational Safety and Health Administration, "Process Safety Management of Highly Hazardous Chemicals; Notice of Proposed Rulemaking," Federal Register, 29 CFR Part 1910, Washington, D.C., July 17, 1990.

EA Mueller, Baltimore, Maryland.

- Exploration for oil on federally-owned lands, especially designated wilderness areas, is more open to public debate than exploitation of privately-owned lands.

Pre-operational activities include the assessment of resources of the field as well as the prospects for economic oil recovery from the field. Additionally, all impact reviews and permit applications must be prepared.

Offshore exploratory and development activities require considerably more effort including exploratory rigs, barges and ocean going vessels designed specifically for drilling at sea. Other locations have site specific requirements, such as on the North Slope of Alaska.

Post-operation activities include plugging of unproductive wells with cement and then capping the pipe below ground level. Restoration activities are controlled on Federal lands by lease terms, regulations, and stipulations that may be attached to the lease to protect specific resource values identified by an environmental assessment or impact statement. Prior to operations, a site-specific environmental analysis of the proposed well site may result in

additional considerations before approval of the drilling permit (DOI, 1991a). Drilling operations on non-federal land require similar state controls and regulations.

### **F.2.7 Discussion and Summary**

The estimated resource consumption and environmental discharges attributable to the domestic production of crude oil in the years 2000 and 2010 are presented in Table F-33. These estimates were derived by multiplying the estimated resource consumption and residual pollutant factors for each representative crude oil recovery method developed in this section by the projections of crude oil production for these methods in the years 2000 and 2010 as contained in the NES.

The projections of total resource consumption and environmental discharges resulting from domestic oil production for the years 2000 and 2010 are influenced by two main trends projected in the NES:

- an increase in domestic crude oil production (although production is expected to undergo a subsequent decline)
- an increased proportion of the total domestic crude oil production attributed to EOR recovery techniques

Domestic liquids production by all recovery methods (including natural gas liquids) is projected in the NES to increase 23 percent, from 9.3 MMBD to 10.6 MMBD, between the years 2000 and 2010. About one-half of this increase, or 0.6 MMBD, is expected to result from increased EOR production. The remainder is expected to result from the more extensive and efficient use of conventional crude oil production techniques with environmental effects and resource consumption requirements comparable to present day technology.

Overall, the projected increase in domestic crude oil production over the 2000-2010 time period is expected to result in a proportionate increase in environmental discharges and resource consumption attributable to the crude oil production industry. Since it was assumed that conventional oil production technology will not change appreciably with regard to environmental effects for the time period under consideration, the principal source of the increased pollutant discharges will be the higher proportion of domestic crude oil being produced by EOR technologies. The most notable of these increases are expected to include:

- Fresh water consumption in areas where EOR is practiced
- Carbon dioxide emission rates

**Table F-33.  
Total Annual Inputs and Outputs for  
Crude Oil Production<sup>1</sup>**

	2000		2010	
	per MMBTU	per year	per MMBTU	per year
<b>PROCESS INPUTS</b>				
Labor (person-yrs)	0.000016	247,000	0.000015	287,000
Electricity (kWh)	1.7	26,000,000,000	1.7	32,000,000,000
Water (bbl)	0.0015	23,000,000	0.0026	49,000,000
Area (acre-yrs)	0.0000020	32,000	0.0000020	34,000
<b>PROCESS OUTPUTS</b>				
Crude oil (bbl)	0.17	2,700,000,000	0.17	3,300,000,000
Natural gas (MMscf)	0.00072	11,000,000	0.00063	12,000,000
<b>AIR EMISSIONS (lbs)</b>				
Nitrogen oxides	0.046	700,000,000	0.042	790,000,000
Carbon monoxide	0.0069	110,000,000	0.0072	140,000,000
Sulfur dioxide	0.0030	47,000,000	0.0050	98,000,000
TSPs	0.00051	7,800,000	0.00079	15,000,000
VOCs	0.014	210,000,000	0.014	270,000,000
Isomers of hexane	0.0012	19,000,000	0.0013	24,000,000
Isomers of heptane	0.0016	25,000,000	0.0016	31,000,000
Isomers of octane	0.0011	17,000,000	0.0011	21,000,000
C-7 Cycloparaffins	0.00022	3,400,000	0.00023	4,300,000
C-8 Cycloparaffins	0.000084	1,300,000	0.000084	1,600,000
Isomers of pentane	0.00078	12,000,000	0.00079	15,000,000
Methane	0.0051	78,000,000	0.0051	98,000,000
Ethane	0.00089	14,000,000	0.00040	17,000,000
Propane	0.0014	22,000,000	0.0014	27,000,000
n-butane	0.0010	16,000,000	0.0011	20,000,000
Benzene	0.000014	210,000	0.000014	270,000
iso-Butane	0.000056	860,000	0.000056	1,100,000
Formaldehyde	0.00021	3,300,000	0.00021	3,900,000
Acetone	0.000020	310,000	0.000034	650,000
Carbon dioxide	13.0	200,000,000,000	17.0	320,000,000,000
<b>WATER RELEASES</b>				
Produced water (bbl)	0.34	3,300,000,000	0.30	5,700,000,000
Oil & grease (lbs)	0.0063	98,000,000	0.0061	120,000,000
Arsenic (lbs)	0.0000020	37,000	0.000002	40,000
Benzene (lbs)	0.000056	870,000	0.000049	930,000
Boron (lbs)	0.0012	18,000,000	0.0010	20,000,000
Sodium (lbs)	1.1	17,000,000,000	1.0	19,000,000,000
Chloride (lbs)	0.88	14,000,000,000	0.76	15,000,000,000
Mobile ions (lbs)	2.8	43,000,000,000	2.4	46,000,000,000
<b>SOLID WASTE (lbs)</b>				
<b>Non-Hazardous<sup>1</sup></b>				
Tank bottoms	0.00036	5,600,000	0.00036	6,900,000
Tank sediment	0.00015	2,300,000	0.00015	2,800,000
Total Non-Hazardous	0.00051	7,900,000	0.00051	9,700,000
<b>Hazardous<sup>2</sup></b>				
FGD sludge	0.0062	960,000,000	0.11	2,000,000,000
Steam generator ash	0.00029	4,600,000	0.00051	9,000,000
Total Hazardous	0.062	960,000,000	0.11	2,000,000,000
<b>Total Solid Waste</b>	<b>0.063</b>	<b>970,000,000</b>	<b>0.11</b>	<b>2,000,000,000</b>

<sup>1</sup> Air emissions estimates do not include those associated with the generation of electric power or other resources consumed in the production process.

<sup>2</sup> Exempt from hazardous waste classification.

<sup>3</sup> Non-exempt from hazardous waste classification; may be hazardous based on character of individual samples.

- Sulfur dioxide emission rates
- Total suspended particulate emission rates
- Generator ash disposal requirements
- Fluidized bed desulfurization (FGD) sludge treatment requirements

Since most EOR is expected to occur in areas with existing oil fields, a notable increase in fresh water demand is projected for areas such as West Texas, Oklahoma, and California. Since these areas are in many cases operating at a water deficit, this development may further strain already aggravated situations. In addition, to necessitating increased EOR utilization, the aging of domestic crude oil fields is expected to result in a decline of co-produced natural gas.

Most of the expected effects of increased EOR technology implementation relate to the incremental energy consumption of this crude oil production method compared to the more traditional methods. However, most of the fuel for these operations is expected to be derived from the product stream, and, therefore, under the conditions of this analysis, the increased energy intensity is not reflected in the projected per-barrel energy requirements.

As noted previously, oil and natural gas production activities are often intimately tied on an economic basis, and this fact is reflected by the reported co-production of natural gas. However, it may be desired to estimate the resource consumption and environmental effects of crude oil production alone, independent of natural gas production. One method for developing such an estimate is to allocate the resource consumption and environmental effects reported in Table F-33 based on the amount of energy contained in each product. Using lower heating values of 5.8 MMBtu/bbl of crude oil and 1,000 Btu/scf of natural gas, it can be estimated that only about 58 percent of the values reported in Table F-33 are attributable to crude oil production alone. The results of this calculation are presented in Table F-34.

Since fossil fuels (e.g., crude oil) are expected to provide most of this energy, increased CO<sub>2</sub> generation rates are a direct result, a factor which should be relatively independent of the type of fossil fuel assumed to be used. Increased SO<sub>2</sub> generation rates are an expected result of increased burning of relatively high sulfur fuel (i.e., crude oil). Heightened SO<sub>2</sub> emission regulations would lessen these emissions, but this is likely to be at the cost of an even greater increase in FGD sludge generation (since it is assumed that conventional FGD systems would be used to meet these standards).

It is projected that the increased employment of crude oil-fired EOR will pose incremental solid waste disposal requirements due to the generation of the steam generator ash and FGD solids that are unique to this type of crude oil production. Options for the disposal of steam generator ash include landfilling and recycling by

**Table F-34.  
Allocated Emissions, Effluents, and Wastes for  
Crude Oil Production<sup>1</sup>**

	2000		2010	
	per MMBTU	per year	per MMBTU	per year
<b>PROCESS INPUTS</b>				
Labor (person-yrs)	0.0000093	140,000	0.0000087	170,000
Electricity (kWh)	0.96	15,000,000,000	0.99	19,000,000,000
Water (bbl)	0.00087	13,000,000	0.0015	29,000,000
Area (acre-yrs)	0.0000012	18,000	0.0000010	20,000
<b>PROCESS OUTPUTS</b>				
Crude oil (bbl)	0.17	2,700,000,000	0.17	3,300,000,000
Natural gas (MMscf)	NA	NA	NA	NA
<b>AIR EMISSIONS (lb)</b>				
Nitrogen oxides	0.026	410,000,000	0.024	460,000,000
Carbon monoxide	0.0040	62,000,000	0.0042	79,000,000
Sulfur dioxide	0.0017	27,000,000	0.0030	57,000,000
TSPs	0.00030	4,600,000	0.00046	8,700,000
VOCs	0.0080	120,000,000	0.0081	150,000,000
Isomers of hexane	0.00071	11,000,000	0.00073	14,000,000
Isomers of heptane	0.00094	15,000,000	0.00095	18,000,000
Isomers of octane	0.00062	9,600,000	0.00064	12,200,000
C-7 Cycloparaffins	0.00013	2,000,000	0.00013	2,500,000
C-8 Cycloparaffins	0.000049	750,000	0.000049	930,000
Isomers of pentane	0.00045	7,000,000	0.00046	8,700,000
Methane	0.0029	45,000,000	0.0030	57,000,000
Ethane	0.00052	8,000,000	0.00052	9,900,000
Propane	0.00082	13,000,000	0.00082	16,000,000
n-butane	0.00060	9,300,000	0.00061	12,000,000
Benzene	0.0000081	120,000	0.0000081	150,000
iso-Butane	0.000032	500,000	0.000033	620,000
Formaldehyde	0.00012	1,900,000	0.00012	2,300,000
Acetone	0.000012	180,000	0.000020	380,000
Carbon dioxide	7.4	110,000,000,000	9.6	180,000,000,000
<b>WATER RELEASES</b>				
Produced water (bbl)	0.20	3,100,000,000	0.17	3,300,000,000
Oil & grease (lb)	0.0037	57,000,000	0.0036	68,000,000
Arsenic (lbs)	0.0000014	2.2E+04	0.0000012	2.3E+04
Benzene (lbs)	0.000033	5.1E+05	0.000028	5.4E+05
Boron (lbs)	0.00069	11,000,000	0.00060	11,000,000
Sodium (lbs)	0.66	10,000,000,000	0.57	11,000,000,000
Chloride (lbs)	0.51	7,900,000,000	0.44	8,400,000,000
Mobile ions (lbs)	1.6	25,000,000,000	1.4	27,000,000,000
<b>SOLID WASTE (lbs)</b>				
<b>Non-Hazardous<sup>1</sup></b>				
Tank bottoms	0.00021	3,300,000	0.00021	4,000,000
Tank sediment	0.000086	1,300,000	0.000086	1,600,000
Total Non-Hazardous	0.00030	4,600,000	0.00030	5,600,000
<b>Hazardous<sup>2</sup></b>				
FGD sludge	0.36	560,000,000	0.062	1,200,000,000
Steam generator ash	0.00017	2,600,000	0.00029	5,600,000
Total Hazardous	0.36	560,000,000	0.62	1,200,000,000
<b>Total Solid Waste</b>	<b>0.36</b>	<b>560,000,000</b>	<b>0.62</b>	<b>1,200,000,000</b>

<sup>1</sup> Air emissions estimates do not include those associated with the generation of electric power or other resources consumed in the production process.

<sup>2</sup> Most water releases are from offshore platforms to the surrounding seawater.

addition to asphalt mixtures. FGD sludges are currently non-hazardous. Most commonly, these sludges are separated in settling ponds adjacent to the TEOR site, with subsequent discharge of aqueous fractions according to NPDES regulations and on-site landfilling of the remaining solids.

Projections of future per-barrel air emissions are highly sensitive to regulatory developments that cannot in general be reliably predicted. Nevertheless, increased future regulation of NO<sub>2</sub> emissions is assumed in this study, and the per-barrel generation of this pollutant is expected to decline. More stringent limits on NO<sub>2</sub> emissions are expected to have their greatest impact on offshore oil platforms which burn large amounts of natural gas in turbines to supply on-site power requirements. Increased regulation of VOC emissions (largely from well heads) from crude oil production has been proposed in the past, but such efforts have been constrained by concerns about their effect on economically marginal (e.g., stripper) wells.

Increased liquid effluent emissions are expected to affect mostly the ocean environment, since most of the increase in these emissions will be experienced in offshore oil recovery operations. With the exception of relatively large amounts of low-level hydrocarbons, the pollutants of most concern in these releases are already present in seawater, albeit at lower concentrations. Of more concern may be the discharge of entrained oil and other organic compounds in offshore discharges. At the present time, little regulatory interest is being expressed with regard to reducing the permitted threshold levels of these pollutants. Net effluent emissions from primary onshore oil and EOR operations are expected to be low, but the potential for contamination exists if produced waters and other effluents are not properly reinjected into subsurface formations.

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## **F.3 Crude Oil Transportation**

### **F.3.1 Petroleum Industry Transportation Infrastructure**

The petroleum transportation infrastructure can best be described as three separate distribution/storage systems. The three systems include Primary Distribution, Secondary Distribution, and Tertiary Storage Systems. The Primary Distribution System includes the transportation of crude and crude products from the wellhead or oil fields to the refinery and from the refinery to the gasoline bulk terminals. The Secondary Distribution System includes the bulk plants and retail service stations or fuel oil dealers where the products are sold and distributed to the end users. The Tertiary Storage segment includes all commercial, industrial, or agricultural storage of refined products. Crude oil transport and storage is included in the Primary Distribution System only. The following provides a description of the primary distribution system as it relates to the movement and storage of crude oil.

#### **F.3.1.1 Current Primary Distribution System**

The Primary Distribution system includes all of the transportation and storage of crude oil and its refined products before it reaches the secondary distribution system and tertiary storage system. The distribution begins with the crude oil stored near the wellhead(s) from which it is produced. Domestically produced crude is then transported from the storage by an overland pipeline network to either a marine bulk terminal storage facility or is transported by barge/tanker, rail car, tank truck, or overland pipeline to the refinery. Most of the crude oil produced on Alaska's North Slope is transported via pipelines to marine bulk storage facilities in Valdez, Alaska. The crude is then transported to the U.S. West and Gulf Coast ports via large ocean tankers. The marine terminals also receive imported crude from ocean tankers from foreign ports. Once the crude oil is collected at the marine terminals from either Northern Alaska or foreign imports, the crude is delivered to the refineries via tankers, barges, and pipelines. Tanker trucks are only used to transport crude from very remote lease tankage sites accounting for about two percent of domestic crude received by refineries. Likewise, the rail tank cars do not carry large amounts of crude oil to the refineries, but carry mostly heavy petroleum products such as asphalt or residual fuel oil which are difficult to move with other modes of transport. Once the crude has been delivered to the refineries, it is stored in tankage on-site or near the refinery before it is processed.

Table F-35 lists the current national breakdown of crude oil transportation by mode (EIA 1991 a; EIA 1991 b). As shown, 52 percent of the domestic crude oil is transported by tankers/barges, with 46 percent transported by pipeline, and the remaining two percent moved by truck or rail. The methodology used in this analysis assumed this percentage distribution of domestic crude transport by mode would not change significantly for the timeframes of the two scenarios considered for this report, i.e. 2000 and 2010. This assumption was based on the historical breakdown of crude

**Table F-35.  
Crude Oil Transportation by Mode of Travel in 2000 and 2010**

Mode of Transport	Domestic (%)	Imported (%)
Crude Oil		
- Tanker	44	100
- Inland Barge	8	0
- Rail	1	0
- Truck	1	0
- Pipelines	46	0

movement by mode over the last decade which indicates that the breakdown of domestic crude transport by mode has not changed significantly in the last decade (EIA 1991 a). Likewise, the current domestic crude storage infrastructure was assumed to be the same for the years 2000 and 2010 with respect to tank sizes, capacities, and facility designs.

Currently, most of the crude received by the refineries is delivered by pipeline with approximately 77 percent of the pumping horsepower (ORNL 1981) required by crude oil pipelines supplied by electrically driven pumps and the remainder supplied by reciprocating internal combustion engine-driven pumps.

### **F.3.2 Specific Assumptions**

In order to quantify emission factors for the transportation and storage of crude oil, several important assumptions were made with regard to the infrastructure currently in place. This section describes the assumptions made for determination of the emission factors for the transportation and storage of crude oil. The assumptions are separated into four different categories including general assumptions, crude tankage, crude transport, and marine terminal crude transfer and storage facility assumptions. The assumptions are listed for the years 2000 and 2010 when appropriate, since emission control technology effectiveness will differ for some parts of the infrastructure in each scenario.

#### **F.3.2.1 General Assumptions**

##### Years 2000 and 2010

- Lower Heating Value of crude = 138,000 Btu/Gallon (EIA 1991 c)
- Density of crude = 7.5 lbs/gal (EIA 1991 c)

- RVP of crude oil = 5.0 psi
  - based on assumptions made by EPA in their emission factor document, AP-42 (EPA 1985 a)
- Transportation of crude oil at ambient temperatures of 55 °F
  - average national daily temperature (U.S. Bureau of the Census 1989)
- Fuel spills along the crude oil transportation infrastructure are quantified based on accidental fuel spill data (USCG 1986). Small spills associated with typical operational procedures (such as those associated with hose disconnect) for the crude oil distribution infrastructure were not quantified due to a lack of industry data.
- Technologies used for transporting crude oil and gasoline in pipelines, marine vessels, rail cars, and tank trucks are based on typical industry characterizations (USCG 1986; EPA 1989; Arthur D. Little 1979).
- Efficiencies for electric motors and IC engines used to power pipelines, marine vessels, rail cars, and tank trucks will be the same for transporting equivalent masses of crude oil or gasoline in these transportation modes.
- Crude oil throughput through each leg of the assumed infrastructure was based on NES projections for years 2000 and 2010 (DOE 1991). Pipeline terminal throughput was assumed to be made up of 48 state production, while marine terminal throughput was assumed to be comprised of Alaskan crude output.

### **F.3.2.2 Crude Oil Tankage Assumptions**

#### Years 2000 and 2010

- Use vapor recovery systems for product transferral and storage at average efficiencies of 95 percent in 2000 and 98 percent in 2010 based on future New Source Performance Standard (NSPS) regulations for VOC control at bulk product terminals facilities (EPA 1988 b) and proposed benzene control regulations at bulk product terminal facilities (EPA 1989). The 95 percent efficiency rate (EPA 1989) for 2000 is an average value assumed for using carbon adsorption, thermal oxidizers, incineration, and refrigeration type vapor recovery equipment, while the 98 percent value (EPA 1989) for 2010 assumes the widespread use of thermal oxidizers and incineration units for vapor control. The higher

value in 2010 will be likely based on future VOC regulations for bulk storage facilities (EPA 1988 b).

- Use of fixed roof tanks for crude oil lease tankage (EIA 1991 a; Williams 1991).
- Use of internal floating roof tanks for storing crude oil at bulk terminals is based on future NSPS regulations for bulk gasoline storage facilities (EPA 1989; EPA 1988 b).
- Typical storage capacity of a crude oil lease tank is 210 barrels (Williams 1991).
- Typical storage capacity of a crude oil storage tank at a bulk terminal is 38,095 barrels (EPA 1989).
- Based on 210 barrel capacity, lease tank dimensions are 10 ft. in diameter and 15 ft. high (Williams 1991).
- Based on 38,095 barrel capacity, crude oil tank dimensions at a bulk terminal are 95 ft. in diameter and 30 ft. high.
- Crude oil lease tanks assumed to have a throughput of 780 barrels/year.
- Crude oil tanks in bulk terminals assumed to have a throughput of 1.9 million barrels/year.
- Crude storage tank spills are based on U.S. Coast Guard bulk storage spill data for crude oil and refined products (USCG 1986).

### **F.3.2.3 Crude Oil Transport Assumptions**

#### Years 2000 and 2010

- Lower Heating Value of No. 2 diesel fuel = 128,700 Btu/gal (ORNL 1991), carbon content of 87 percent, used by inland barges, rail, and tank trucks.
- Lower Heating Value of No. 6 diesel fuel = 137,500 Btu/gal, carbon content of 90 percent, used by ocean tankers.
- Spill rates were determined for each transport mode based on available spill data and were assumed the same for both 2000 and 2010.
- Pipelines

- 100 percent of the pumping horsepower is supplied by electric motors.

#### · Tanker/Barge

- Imported crude oil enters into the analysis after it has crossed into U.S. domestic waters (200 mile mark (Demby 1991)).
- Submerged loading practices only for all marine vessels based on characterization of current gasoline marketing practices (USCG 1986; EPA 1989; Arthur D. Little 1979), and future requirements to meet NSPS for VOC control from petroleum product transferral at bulk terminals and bulk plants (EPA 1988 b).
- All crude oil is loaded into cleaned or gas-freed cargo tanks on marine vessels based on future NSPS VOC regulations in place for gasoline bulk terminal loading practices (EPA 1988 b).
- Assumed the following estimates for product surface to the top of the tank based on EPA assumptions in its emission factor document, AP-42 (EPA 1985 a):
  - tankers = 10 feet
  - ocean and river barges = 5 feet
- 1990 marine tanker engine bsfc of 0.28 lb/bhp-hr based on low-speed marine diesel engine data (Sulzer Diesel 1990). This value will be used for 2000 and 2010 assuming that new tanker turnover is very slow.
- Ocean barge engine bsfc will be assumed to be equivalent to that of tankers based on the assumption that ocean barges also use low-speed diesel engines.
- 1990 inland barge engine bsfc of 0.37 lb/bhp-hr based on data from typical locomotive medium-speed diesel engines (Wakenell 1985). It was assumed that inland barges are propelled by tugboats which use medium-speed diesel engines. The efficiencies of medium-speed diesels do not vary considerably among applications. The 1990 values will be use for 2000 and 2010 assuming that new inland barge turnover is very slow.

- Total national marine ton-miles of crude oil and refined products assumed to be shipped 63 percent by tanker and 37 percent by barge (ANL 1982).

#### · Rail/Tank Truck

- Assume rail cars have the same vapor leakage rates as tank trucks based on a similar assumption by EPA in its emission factor document, AP-42 (EPA 1985 a), and since tank hatch designs – between these two transportation modes are similar.
- Use of vapor tight rail cars and tank trucks which must meet annual certification based on future NSPS requirements for VOC control from petroleum product transferral at bulk terminals and bulk plants (EPA 1988 b). Assume a 67 percent reduction in vapor emissions during loading practices with such rail cars and tank trucks based on EPA estimates in proposed benzene regulations for the gasoline industry (EPA 1989).
- Submerged loading practices only based on characterization of current gasoline marketing practices (USCG 1986; EPA 1989; Arthur D. Little 1979), and future NSPS requirements for VOC control from petroleum product transferral at bulk terminals and bulk plants (EPA 1988 b).
- Locomotive engine bsfc of 0.37 lb/bhp-hr based on data from typical locomotive medium-speed diesel engines was assumed (Wakenell 1985). The 1990 values will be used for 2000 and 2010 assuming that new locomotive turnover is very slow.
- Tank truck fuel economy of 5.3 MPG assumed for 1990 is based on average national value for tractor/trailer combinations (MVMA 1990) since this value generally represents Class 7 and Class 8 diesel trucks such as used on tank trucks. This value was projected to increase to 5.7 MPG in 2000 and 6.0 MPG in 2010 based on NES (DOE 1991) fuel economy projections for highway vehicles carrying freight. These values will be placed on a brake specific basis using bhp-hr/mile conversion data for future Class 8 trucks (MVMA 1983). An average haul length of 50 miles was assumed for petroleum product transport by tank truck.

### **F.3.2.4 Marine Terminal Crude Transferral and Storage Assumptions**

#### Years 2000 and 2010

- Receives crude oil from pipelines and import tankers
- Use vapor recovery systems for product transferral and storage at average efficiencies of 95 percent in 2000 and 98 percent in 2010 based on EPA estimates in NSPS regulations for future VOC control (EPA 1988 a,b) and proposed benzene control regulations at bulk product terminals facilities (EPA 1989). The 95 percent efficiency rate for 2000 is an average value assumed for using carbon adsorption, thermal oxidizers, incineration, and refrigeration type vapor recovery equipment, while the 98 percent value for 2010 assumes the widespread use of thermal oxidizers and incineration units for vapor control. The higher value in 2010 will be likely based on the future VOC regulations (EPA 1989).
- Use of internal floating roof tanks for storing product based on NSPS for bulk petroleum storage tanks (EIA 1991 a; EPA 1988 a).
- Typical storage capacity of a crude oil storage tank was assumed to be similar in size to a gasoline bulk storage tank, 38,095 barrels (EPA 1989).
- Based on 38,095 barrel capacity, crude storage tank dimensions are 95 ft. in diameter and 30 ft. high.
- Tank was assumed to have a 1.9 million barrel/year throughput or a tank turnover rate of 50 times per year (EPA 1985 a; EPA 1989).
- Crude storage tank spills are based on U.S. Coast Guard Bulk storage spill data for crude and products (USCG 1986).

### **F.3.3 Crude Transport Infrastructure for this Analysis**

In order to develop emission factors for the domestic transport and storage of crude oil, a product flow path was developed for use in this analysis based on the assumptions provided in the previous section and the primary distribution system currently in place in order to identify each source of air or liquid emissions throughout the crude transport and storage flow path. The path identified for the transport and storage of crude oil is included in the Primary Distribution System. Any emissions from the transport of imported crude oil by ocean barge or ocean tanker was included only within 200 miles of U.S. shores in this analysis. In other words, only emission sources from transporting crude oil on U.S. land and water (inside 200 miles) territories were considered in this analysis.

The crude oil transportation flow path in this analysis begins with the storage of crude oil in lease tankage near the wellhead. Lease tankage is usually an intermediate storage facility for domestically produced crude oil located near the wellhead(s). Almost all of the domestically produced crude oil is at some point stored in the lease tankage in order to meter the quantity of crude produced from the wellhead(s). The typical tank capacity used for storing crude oil near the wellhead(s) was assumed to be 210 barrels. The crude oil storage tank design was assumed to be of the fixed roof type for both the 2000 and 2010 scenarios. An assumed throughput of 780 barrels per year was assumed for each crude oil storage tank located near the wellhead(s).

As the crude is transported from the lease tankage, it is distributed between two flow paths. In the first flow path, the crude can be transported via pipeline, barge, tanker, rail car, or tank truck to crude storage tanks at a refinery. The second possible flow path can be a pipeline to a marine bulk terminal storage facility. The second flow path is representative of the domestic crude oil transported in the Alaskan pipeline system. This analysis assumed that crude oil storage tanks at bulk terminals such as marine terminals were the same size throughout the infrastructure since there is very limited data characterizing tank sizes, capacities, and populations by type of storage facility. From the marine terminal, the crude can be taken to the refinery by barge/tanker and/or a pipeline depending on the location of the refinery and which mode of transport is available or most economical. This analysis was performed with the assumption that by the year 2000, all of the pumping horsepower required by the crude oil pipeline infrastructure will be supplied by electrically driven pumps. This assumption is based on the current percentage of pipelines powered by electricity (77 percent) (ORNL 1981).

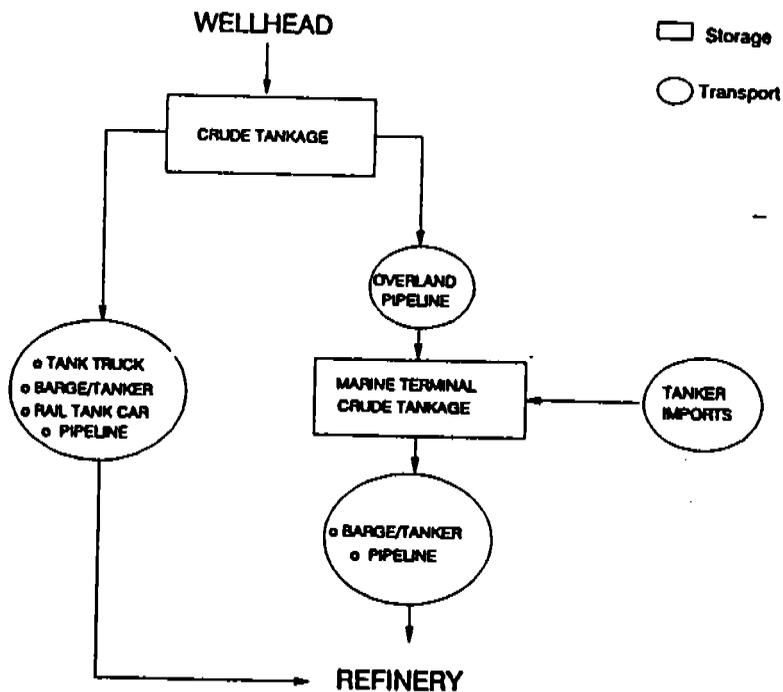
The crude oil transportation and storage flow paths used to determine all of the applicable emission factors are depicted in Figure F-2.

### **F.3.4 Process Environmental Points of Interest**

In this section, the environmental impacts of crude oil transportation infrastructure operation are addressed. First, the inputs and outputs of the crude oil infrastructure are identified and discussed. Then discussions and assessments of the environmental effects of the crude oil infrastructure are presented.

#### **F.3.4.1 Inputs and Outputs to Crude Oil Transport Operations**

An assessment of the inputs and outputs of the operational stage of the crude oil transportation infrastructure was made. The inputs relate to the requirements for moving the crude oil from the wellhead to the refinery, while outputs relate to those



**Figure F-2. Crude Oil Transportation and Storage Flow Path**

products resulting from the transportation movements and entering the refinery. Table F-36 summarizes the inputs and outputs to the crude oil transportation infrastructure.

Note that two types of diesel fuels are assumed to be used by the crude oil transportation modes. No. 2 diesel was assumed to be used by locomotives moving rail cars, tank trucks, and inland barges. While inland barges may utilize other types of fuels, No.2 diesel fuel was assumed for simplicity in this analysis. No. 6 diesel fuel was assumed for use in ocean tankers and barges. Crude oil pipeline pumps, as well as pumps used at bulk storage facilities were assumed to be driven exclusively by electric motors.

The crude oil input was derived from the NES crude oil production estimates for years 2000 and 2010 (DOE 1991). The input estimates for No. 2 diesel fuel and No. 6 fuel oil were derived from estimates of the national crude oil transportation by mode (EIA 1991 a; NPC 1991; API 1991) and weighting the transport efficiencies for those modes using these fuels along the infrastructure. The electricity input was estimated by accounting for and weighting the transportation efficiencies for using electricity for powering pipeline and bulk facility pumps along the crude oil transportation infrastructure. Labor

**Table F-36.**  
**Summary of Inputs and Outputs to Crude Oil Transportation Infrastructure**

Inputs			Outputs		
Substance	Quantity		Substance	Quantity	
	2000	2010		2000	2010
Crude Oil	9.3 million BBL/D	10.6 million BBL/D	Crude Oil <sup>1</sup>	9.3 million BBL/D	10.6 million BBL/D
No. 2 Diesel Fuel	3,920 BBL/D	4,220 BBL/D			
No. 6 Fuel Oil	238,000 BBL/D	267,000 BBL/D			
Electricity	187 million kw-hr/D	218 million kw-hr/D			
Replacement Parts	N/A <sup>2</sup>	N/A			
Labor	98,400 persons	112,000 persons			

<sup>1</sup> Crude oil output assumes negligible (less than one percent) product VOC and liquid spill losses over the crude oil transportation infrastructure based on the emission factors calculated below.

<sup>2</sup> N/A - not available

requirements were estimated from 1987 employment figures in the refining industry (API 1990), and total crude oil energy input to refineries in 1987 (EIA 1987).

Table F-35 lists the percent breakdown of crude oil transport by mode. Table F-37 depicts estimates of the crude oil transport efficiencies of each mode used in the crude oil transportation infrastructure. In general, the transport efficiencies were derived based on national statistics for energy consumption (EIA 1991 a; ORNL 1991; ANL 1982; MVMA 1990) and the amount of crude oil and refined products transported (EIA 1991 a,b) for each transportation mode. For most modes, transportation efficiencies of BTU/Ton-Mile were derived by dividing the total annual national energy consumption for moving crude oil and refined products by the total national annual amount of crude

**Table F-37.  
Crude Oil Transportation Mode Efficiencies**

Transportation Modes	Petroleum Product Transport Efficiency			
	Year 2000		Year 2010	
	BTU/Ton-Mile	hp-hr/10 <sup>9</sup> BTU	BTU/Ton-Mile	hp-hr/10 <sup>9</sup> BTU
Pipelines/Bulk Terminals and Plants				
- Electrically-Driven Pumps (ANL 1982, ORNL 1991)	275	1980	275	1980
Marine Vessels				
- Tanker/Ocean Barges (ANL 1982, ORNL 1991)	385	8340	385	8340
- Inland Barges (ANL 1982, ORNL 1991)	480	1070	480	1070
Rail Cars				
- Locomotives (ANL 1991)	497	3100	497	3100
Tank Trucks (Census Bureau 1990)				
- Crude Oil Transport	633	338	600	321
- Gasoline Transport	633	323	600	307

oil and refined products transported by those modes in ton-miles. This method is assumed to account for specific variations in volume flow and inefficiencies in each transport mode system, and therefore represents realworld conditions. Since electric motor and pump technologies in the crude oil transportation infrastructure are similar for pipelines and bulk product storage facilities, the same crude oil transport efficiencies as used in pipelines were assumed for bulk product facility electric pumps. The transportation efficiencies of tank trucks were derived from fuel economy data and assumed average product load and haul length carried by this mode. Limitations on data for calculating separate transportation efficiencies for crude oil and gasoline for most modes resulted in the use of the same transport efficiency for both. However, separate crude oil and gasoline transport efficiencies for tank trucks were able to be calculated. Figure F-3 lists the calculations used to estimate the modal transportation efficiencies.

Figure F-4 depicts the calculations for determining the fuel and electricity inputs to the crude oil transportation system.

### Pipeline Efficiency

Total crude and refined products transported by pipeline and energy required to move the crude and refined products in 1980 (ANL 1982)

581.53 billion ton-miles

0.16 quads

$$\text{BTU/ton-mile} = 0.16 \times 10^{15} / 581.53 \times 10^9 = 275.1$$

Total crude and refined products transported by pipeline in 1988 (ORNL 1991)

612 billion ton-mile

992 million tons

$$\text{BTU/ton} = 275.1 \times 612 \times 10^9 / 992 \times 10^6 = 169741.3$$

Applying mass energy content and BTU to hp-hr conversion:

$$\text{hp-hr}/10^9 \text{ BTU} = 1981.9$$

### Marine

Total freight ton-miles and energy to move those ton-miles in 1980 (ANL 1982)

#### **Tankers**

$$(1.81 + 253.45 + 92.7) \times 10^9 = 347.96 \text{ billion ton-miles}$$

$$(1.18 + 89.97 + 25.77 + 17) \times 10^{12} = 133.92 \text{ trillion BTU}$$

#### **Barges**

$$(203.47 + 1.49) \times 10^9 = 204.96 \text{ billion ton-miles}$$

$$(97.87 + 0.45) \times 10^{12} = 98.32 \text{ trillion BTU}$$

#### **Tanker**

$$\text{BTU/ton-mile} = 133.9 \text{ trillion} / 347.96 \text{ billion} = 384.9$$

#### **Barge**

$$\text{BTU/ton-mile} = 98.32 \text{ trillion} / 204.96 \text{ billion} = 479.7$$

Total crude and refined products transported by tanker and barge in 1988 (ORNL 1991)

#### **Tankers (Coastwise and Lakewise)**

505 billion ton-miles

272 million tons

#### **Barges**

38.8 billion ton-miles

203 million tons

#### **Tankers**

$$384.9 \times 505 \times 10^9 / 272 \times 10^6 = 714612.1 \text{ BTU/ton}$$

Applying mass energy content and BTU to hp-hr conversion:

$$\text{hp-hr}/10^9 \text{ BTU} = 8343.9$$

#### **Barges**

$$479.7 \times 38.8 \times 10^9 / 203 \times 10^6 = 91686.5 \text{ BTU/ton}$$

Applying mass energy content and BTU to hp-hr conversion:

$$\text{hp-hr}/10^9 \text{ BTU} = 1070.5$$

**Figure F-3. Crude Oil Transportation Mode Efficiency Calculation**

### Rail

497 BTU/ton-mile for all freight by rail (ANL 1991)

Total crude and refined products transported by rail in 1985 (ANL 1991)

21.4 billion ton-miles

40.1 million tons

$$497 * 21.4 * 10^9 / 40.1 * 10^6 = 265496.8 \text{ BTU/ton}$$

Applying mass energy content and BTU to hp-hr conversion:

$$\text{hp-hr}/10^9 \text{ BTU} = 3099.9$$

### Tank Truck

Assume fuel economy of 5.7 MPG for 2000 and 6.0 MPG for 2010

Assume average product load of 9,500 gallons of crude oil per haul

#### **Year 2000**

$$\text{BTU/ton-mile} = 137000 \text{ BTU/gal} / (5.7 \text{ MPG} * 9500 \text{ gal} * 8 \text{ lb/gal} * (\text{ton}/2000 \text{ lb})) = 632.5 \text{ BTU/ton-mile}$$

#### **Year 2010**

$$\text{BTU/ton-mile} = 137000 \text{ BTU/gal} / (6.0 \text{ MPG} * 9500 \text{ gal} * 8 \text{ lb/gal} * (\text{ton}/2000 \text{ lb})) = 600.9 \text{ BTU/ton-mile}$$

Assume average haul length for tank trucks of 50 miles

#### **Crude Oil, Year 2000**

$$632.5 \text{ Btu/Ton-Mile} * (50 \text{ miles}) = 31625 \text{ Btu/ton}$$

$$31625 \text{ Btu/Ton} * (\text{hp-hr}/2544 \text{ Btu}) * (\text{ton}/2000 \text{ lb}) * (7.5 \text{ lb/gal crude}) * (\text{gal}/138000 \text{ Btu}) = 337.8 \text{ hp-hr}/10^9 \text{ Btu}$$

#### **Crude Oil, Year 2010**

$$600.9 \text{ Btu/Ton-Mile} * (50 \text{ miles}) = 30045 \text{ Btu/ton}$$

$$30045 \text{ Btu/Ton} * (\text{hp-hr}/2544 \text{ Btu}) * (\text{ton}/2000 \text{ lb}) * (7.5 \text{ lb/gal crude}) * (\text{gal}/138000 \text{ Btu}) = 321.0 \text{ hp-hr}/10^9 \text{ Btu}$$

#### **Reformulated Gasoline, Year 2000**

$$632.5 \text{ Btu/Ton-Mile} * (50 \text{ miles}) = 31625 \text{ Btu/ton}$$

$$31625 \text{ Btu/Ton} * (\text{hp-hr}/2544 \text{ Btu}) * (\text{ton}/2000 \text{ lb}) * (6.0 \text{ lb/gal gasoline}) * (\text{gal}/115400 \text{ Btu}) = 323.1 \text{ hp-hr}/10^9 \text{ Btu}$$

#### **Reformulated Gasoline, Year 2010**

$$600.9 \text{ Btu/Ton-Mile} * (50 \text{ miles}) = 30045 \text{ Btu/ton}$$

$$30045 \text{ Btu/Ton} * (\text{hp-hr}/2544 \text{ Btu}) * (\text{ton}/2000 \text{ lb}) * (6.0 \text{ lb/gal gasoline}) * (\text{gal}/115400 \text{ Btu}) = 306.9 \text{ hp-hr}/10^9 \text{ Btu}$$

**Figure F-3. Crude Oil Transportation Mode Efficiency Calculations (Cont'd)**

### Electricity, No.2 Diesel Fuel, No.6 Fuel Oil

Total inputs of electricity, No.2 diesel fuel, and No.6 fuel oil were found by weighting the transport efficiencies (Table F-36) of the modes using each of these energy sources as they appear in the crude oil transportation infrastructure. Each weighted efficiency was added up to obtain a single overall weighted transportation efficiency for the modes using each fuel. Finally, to obtain the total amount of fuel and electricity as inputs to the system, the total crude oil energy input to the system was applied.

Weighting was done according to the percentages of crude throughput in each leg of the assumed crude oil transportation system in years 2000 and 2010, and according to the national percentage of crude oil carried by each mode. Additional weighting was performed for the marine terminals due to the imported tanker inputs to that leg of the infrastructure. The amount of imported crude was obtained and added to the amount of domestic crude entering the marine terminal to obtain a percentage of the overall crude flow for the segment of the marine terminal to the refinery. This percentage was then used to weight the transportation efficiencies of the individual sources between the marine terminal and the refinery.

The following method was used to find the weighted transportation efficiency factors for the crude oil transportation infrastructure:

x1 = efficiencies for electric pumps at crude tankage facilities = 1477.9 kw-hr/10<sup>9</sup>BTU

x2A = efficiencies for tankers = 8340 hp-hr/10<sup>9</sup>BTU

x2B = efficiencies for inland barges = 1070.5 hp-hr/10<sup>9</sup>BTU

x2C = efficiencies for rail locomotives = 3099.9 hp-hr/10<sup>9</sup>BTU

x2D = efficiencies for tank trucks = 338 hp-hr/10<sup>9</sup>BTU in 2000  
= 321 hp-hr/10<sup>9</sup>BTU in 2010

x2E = efficiencies for pipelines = 1477.9 Kw-hr/10<sup>9</sup>BTU

x3 = efficiencies for electric pumps at marine terminal facilities = 1477.9 kw-hr/10<sup>9</sup>BTU

y1A = percent of product moved by tankers = 44

y1B = percent of product moved by inland barges = 8

y1C = percent of product moved by rail locomotives = 1

y1D = percent of product moved by tank trucks = 1

y1E = percent of product moved by pipelines = 46

Year 2000

$$WTE = x1 + 0.88*((x2A*y1A)+(x2B*y1B)+(x2C*y1C)+(x2D*y1D)+(x2E*y1E)) + 0.12*(x2E) + 0.56*((x3+x2A+x2A*(y1A/(y1A+y1E))+x2E*(y1E/(y1A+y1E))))$$

Year 2010

$$WTE = x1 + 0.81*((x2A*y1A)+(x2B*y1B)+(x2C*y1C)+(x2D*y1D)+(x2E*y1E)) + 0.19*(x2E) + 0.57*((x3+x2A+x2A*(y1A/(y1A+y1E))+x2E*(y1E/(y1A+y1E))))$$

Total Fuel or Electricity = WTE \* Total Crude Oil Energy in 2000 and 2010

### Labor Input

Total employees in the refining industry in 1987 (API 1990)  
= 125,200

Total crude input to refineries in 1987 (EIA 1987)  
= 4,691,783,000 BBL = 2.72\*10<sup>16</sup> BTU

Persons/million BTU = 125200/2.72\*10<sup>10</sup> million = 0.000005

**Figure F-4. Crude Oil Transportation System Input Calculations**

### **F.3.4.2 Environmental Impact Estimates**

The environmental emissions from the crude oil transportation infrastructure can be placed into two main categories: air and liquid spill emissions. Each was assessed and is discussed below separately. A discussion of emission factor weighting also follows in the following.

#### Air Emissions

The types of air emissions from crude oil transportation include exhaust and evaporative emissions. Exhaust emissions result from the combustion of fuel to move the crude oil through the transportation system. Therefore, assessments were made of the exhaust emissions resulting from the combustion of fuel by tank trucks, locomotives, ocean tankers, and inland barges needed to transport crude oil. While there are exhaust emissions associated with electricity production, estimates of these emissions from sources using electricity in the crude oil transportation system were not included in this analysis, but will be accounted for in accompanying work.

Specific emission factors (g/bhp-hr) for HC, CO, NO<sub>x</sub>, and particulates were obtained for the marine, locomotives, and tank truck sources in the crude oil transportation infrastructure based on available documentation (EPA 1985 b). Differences in engine and emission control technologies for the various crude oil transportation modes for years 2000 and 2010 were accounted for in deriving the final emission factor estimates for these years. Then, using the crude oil transportation efficiencies of Table F-37, average BSFC values for each transportation mode, and fuel combustion source density and energy content, the g/bhp-hr emission factors were converted into units of grams of pollutant emitted per billion Btu of crude oil transported (g/10<sup>9</sup> BTU). Figure F-5 lists the calculations for determining the HC, CO, NO<sub>x</sub>, and particulate emission factors.

The CO<sub>2</sub> and SO<sub>2</sub> emission factors were derived differently than the other exhaust emission pollutants for the crude oil transportation system. Figure F-5 lists the calculations for determining the CO<sub>2</sub> and SO<sub>2</sub> emission factors. The CO<sub>2</sub> values for the marine, rail, and tank truck modes were derived based on fuel carbon content (87 weight percent (wt%) assumed for No. 2 diesel fuel, and 90 wt% carbon for No. 6 fuel oil), and average brake specific fuel consumption (BSFC) values. Similarly, the SO<sub>2</sub> emission factor values for these modes were derived based on fuel sulfur content (0.05 wt% assumed for No. 2 diesel fuel and No. 6 fuel oil based on current sulfur regulations for on-highway diesel fuel), and the same average brake specific fuel consumption (BSFC) values. It was assumed that all of the carbon and sulfur in the fuels would be oxidized to CO<sub>2</sub> and SO<sub>2</sub>, respectively, in making these calculations. Table F-38 depicts the BSFC values used for purposes of this analysis. The BSFC values for ocean tankers were estimated from actual low speed marine diesel engine data (Sulzer Diesel 1990). Inland barges were assumed to be either self-propelled by medium speed diesel engines or by tugboats using medium speed diesel engines. To estimate BSFC values for such vessels,

Calculations for HC, CO, NO<sub>x</sub>, and particulates

$$g/10^9 \text{ Btu} = (g/bhp-hr) * (1/BSFC) * (\text{fuel density}) * (1/\text{fuel energy}) * (2544 \text{ Btu/hp-hr}) * (\text{transportation efficiency})$$

Calculations for CO<sub>2</sub> and SO<sub>2</sub>

Assume use No.2 Diesel Fuel with 87 wt% carbon, and 0.05 wt% sulfur

$$0.87 * (44 \text{ lb CO}_2 / 12 \text{ lb C}) = 3.2 \text{ lb CO}_2 / \text{lb fuel}$$

$$0.0005 * (64 \text{ lb SO}_2 / 32 \text{ lb S}) = 0.001 \text{ lb SO}_2 / \text{lb fuel}$$

Now apply BSFC values, transportation efficiencies, and unit conversions for each mode:

For CO<sub>2</sub>

$$g \text{ CO}_2 / 10^9 \text{ BTU} = 3.2 * (\text{BSFC lb/bhp-hr})^2 * (\text{transport efficiency hp-hr}/10^9 \text{ BTU}) * (454 \text{ g/lb}) * (1/\text{BSFC}) * (1/\text{fuel energy}) * (\text{fuel density}) * (2544 \text{ Btu/hp-hr})$$

For SO<sub>2</sub>

$$g \text{ SO}_2 / 10^9 \text{ BTU} = 0.001 * (\text{BSFC lb/bhp-hr})^2 * (\text{transport efficiency hp-hr}/10^9 \text{ BTU}) * (454 \text{ g/lb}) * (1/\text{BSFC}) * (1/\text{fuel energy}) * (\text{fuel density}) * (2544 \text{ Btu/hp-hr})$$

For example:

Barges, CO<sub>2</sub>

$$3.2 * (0.37 \text{ lb/bhp-hr}) * (1070.5 \text{ hp-hr}/10^9 \text{ BTU}) * (454 \text{ g/lb}) * (\text{bhp-hr}/37 \text{ lb}) * (2544 \text{ Btu/hp-hr}) * (\text{gal}/128700 \text{ Btu}) * (7.0 \text{ lb/gal}) = 0.215 * 10^6 \text{ g CO}_2 / 10^9 \text{ BTU}$$

**Figure F-5. CO<sub>2</sub> and SO<sub>2</sub> Exhaust Emission Factor Calculations**

**Table F-38.**

**Brake Specific Fuel Consumption Values for Various Crude Oil Transportation Modes**

Transportation Modes	Product Transport Efficiency	
	Year 2000	Year 2010
Marine Vessels		
- Tanker/Ocean Barges	0.28 lb/bhp-hr	0.28 lb/bhp-hr
- River Barges	0.37 lb/bhp-hr	0.37 lb/bhp-hr
Rail Cars		
- Locomotives	0.37 lb/bhp-hr	0.37 lb/bhp-hr
Tank Trucks	0.46 lb/bhp-hr	0.44 lb/bhp-hr

actual medium speed diesel engine BSFC data for locomotives was assumed (ANL 1982). This locomotive BSFC value was applied to the inland barges since engine efficiencies of medium speed diesel engines do not vary appreciably among applications. Finally, all tank trucks were assumed to be powered by high speed diesel engines in determining BSFC values. In addition, unlike the other crude oil transport modes, BSFC improvements were assumed for tank trucks for years 2000 and 2010 relative to current BSFC levels. The tank truck BSFC values were estimated by projecting 1987 national average fuel economies for tractor/trailer combinations (MVMA 1990) to years 2000 and 2010 using National Energy Strategy (NES) projections (DOE 1991), and converting to BSFC values (MVMA 1983).

The exhaust emission factors for each crude oil infrastructure source for the years 2000 and 2010 are listed in Table F-39. These pollutants comprise the majority of mass exhaust emissions and are also significant in their potential for contributions to ambient ozone formation, CO concentrations, and acid rain. The CO<sub>2</sub> and SO<sub>2</sub> emission factors were generally assumed to remain constant for the years 2000 and 2010 except for tank trucks. For tank trucks, improved BSFC values in 2010 result in lower CO<sub>2</sub> and SO<sub>2</sub> emission factors in that year relative to year 2000.

The other major type of air emission from the crude oil transportation infrastructure is evaporative VOC emissions. These emissions result from the vaporization of fuel and subsequent release of these vapors to the atmosphere. Of course, evaporative VOC emissions are directly proportional to fuel volatility. In the case of crude oil, its volatility is low relative to petroleum products like gasoline; however, crude oil still contains volatile compounds which are released to the air at normal ambient temperatures. A Reid vapor pressure (RVP) of 5 psi was assumed for crude oil (EPA 1985 a) in all evaporative VOC emission calculations. In the crude oil transportation infrastructure, evaporative VOC emission occur from a variety of activities and processes such as during crude oil transit between facilities, loading and unloading of transport modes at facilities, and from storage at facilities.

Evaporative VOC emission factors for the crude oil infrastructure were estimated using the EPA document, AP-42 (EPA 1985 a). The AP-42 document details the air emissions of the crude oil transportation infrastructure in terms of specific equations to derive evaporative VOC emission factors. Figures F-6 through F-9 list the calculations used to derive the evaporative VOC emission factors for the various sources in the crude oil transportation system.

In general, the emission factors were derived for each source of the crude oil infrastructure in the 2000 and 2010 timeframes based on the characteristic source assumptions for these years. First, emission factors were calculated for each source without the use of emission control technology. These factors were considered to be "uncontrolled" emission factors. Once the "uncontrolled" emission rates were calculated percentage reductions for specific emission control technologies in place for each source

**Table F-39.**  
**Estimates of Exhaust Emission Factors for Crude Oil Transportation Infrastructure Sources**

Exhaust Emission Source	Exhaust Emission Factors (g/10 <sup>9</sup> Btu Throughput)											
	HC		CO		NO <sub>x</sub>		Part		CO <sub>2</sub>		SO <sub>2</sub>	
	2000	2010	2000	2010	2000	2010	2000	2010	2000	2010	2000	2010
<b>Marine Vessels</b>												
- Tanker/Ocean Barges	2480	2070	5380	3720	12400	8690	620	414	1.74*10 <sup>6</sup>	1.74*10 <sup>6</sup>	517	517
- Inland Barges	160	120	601	400	2800	2000	60.1	40.0	0.215*10 <sup>6</sup>	0.215*10 <sup>6</sup>	66.1	66.1
<b>Rail Cars</b>												
- Locomotives	464	348	1740	1160	8120	5800	174	116	0.623*10 <sup>6</sup>	0.623*10 <sup>6</sup>	191	191
Tank Trucks	102	50.5	305	202	386	202	8.14	8.08	0.0677*10 <sup>6</sup>	0.0639*10 <sup>6</sup>	20.7	19.6

Transit Loss Emission Factor, L1

Use AP-42 equation (EPA 1985 a),

$$L1^* = 0.1 * P * W$$

Crude Oil Properties

Assume RVP = 5 psi,

P = True vapor pressure @ 55°F = 2.6 psi

W = Density of condensed vapors @ 60°F = 4.5 lb/gal

$$L1^* = 1.17 \text{ lb/week-1000gal}$$

Estimate time (weeks) travelled by tankers and barges:

Average haul length for domestic tankers = 2000 miles

Average haul length for domestic barges = 200 miles

Assumed haul length in U.S. waters for imported tankers = 200 mile

Average haul length for domestic tankers and barges

$$= (2000+200)/2 = 1100 \text{ miles}$$

Average speed for domestic and imported tankers = 16 mph (API 1991)

Average speed for domestic barge = 8 mph (API 1991)

Average speed for tankers and barges

$$= (16+8)/2 = 12 \text{ mph}$$

Total time for product transport by domestic tanker and barge

$$= 1100/12 = 92 \text{ hours} = 3.8 \text{ days} = 0.55 \text{ weeks}$$

Total time for product transport by imported tanker

$$= 200/16 = 12.5 \text{ hours} = 0.5 \text{ days} = 0.07 \text{ weeks}$$

Transit Loss Emission Factor L1 = L1\* \* (total time in transit)

For domestic tankers, L1 = 1.17\*0.55 = 0.64 lb/1000gal

For imported tankers, L1 = 1.17\*0.07 = 0.08 lb/1000gal

For domestic barges, L1 = 1.17\*0.55 = 0.64 lb/1000gal

Loading Loss Emission Factor, L2

Use AP-42 equation (EPA 1985 a),

$$L2^* = 1.84 * (0.44 * P - 0.42) * \left( \frac{M * 1.02}{T} \right) + C$$

**Figure F-6. Evaporative VOC Calculations for Crude Transport by Tanker and Barge**

Crude Oil Properties

P = True Vapor pressure @ 55°F = 2.6 psi

M = Molecular weight @ 60°F = 50 lb/lb-mole

T = Assumed crude oil temperature = 515°F

C = EPA arrival emission factor for cleaned or gas-freed cargo tanks from AP-42 = 0.33

Uncontrolled loading loss emission factor,  $L2^* = 0.46$  lb/1000gal

Assume vapor control equipment for tanker and barge loading procedures:

Year 2000, 95% efficiency

Year 2010, 98% efficiency

Controlled loading loss emission factor,  $L2 = L2^* \cdot (\text{vapor control efficiency})$

For tankers and barges,

Year 2000,  $L2 = 0.46 \cdot (1-0.95) = 0.02$  lb/1000gal

Year 2010,  $L2 = 0.46 \cdot (1-0.98) = 0.01$  lb/1000gal

**Figure F-6. Evaporative VOC Calculations for Crude Transport by Tanker and Barge  
(Cont'd)**

Transit Loss Emission Factor, L1

From AP-42 (EPA 1985 a),

Average transit loss emission factor for tank cars and trucks with 10 RVP gasoline:

$$L1 = (0.0 + 0.01)/2 = 0.005 \text{ lb/1000gal}$$

Assume L1 for crude is proportional to the true vapor pressures of gasoline and crude,

True vapor pressure of 10 RVP gasoline @ 55°F = 4.7 psi

True vapor pressure of crude oil 55°F = 2.6 psi

For crude,

$$L1 = 0.005 * (2.6/4.7) = 0.003 \text{ lb/1000gal}$$

Loading Loss Emission Factor, L2

From AP-42 (EPA 1985 a),

$$L2^* = 12.46 * \frac{(S * P * M)}{T}$$

Crude Properties

RVP = 5 psi

P = 2.6 psi @ 55°F

S = 0.60 dedicated normal service

M = 50 lb/lb-mole @ 60°F

T = 515°F

Uncontrolled loading loss emission factor, L2\*

$$L2^* = 1.89 \text{ lb/1000gal}$$

Assume vapor control equipment for tank car and truck loading procedures:

Year 2000, 95% efficiency

Year 2010, 98% efficiency

Assume vapor tight cargo tank control efficiency for loading procedures:

Years 2000 and 2010, 67% efficiency

Controlled loading loss emission factor, L2 = L2\* \* (vapor tight cargo and control efficiencies)

For tank cars and trucks,

$$\text{Year 2000, } L2 = 1.89 * (1-0.67) * (1-0.95) = 0.03 \text{ lb/1000gal}$$

$$\text{Year 2010, } L2 = 1.89 * (1-0.67) * (1-0.98) = 0.01 \text{ lb/1000gal}$$

**Figure F-7. Evaporative VOC Calculation for Crude Transport by Rail and Tank Truck**

**VOC Storage Loss Emission Factor for Crude Oil**

Using AP-42:

**Lease Tankage**

**Storage Tank Assumptions:**

Tank Type: Fixed roof tank

Storage tank capacity = 210 bbls.

Tank dimensions = 10 ft. diameter X 15 ft. high

Tank throughput = 780 bbls/year (each tank)

Use AP-42 equation:

**Tank Breathing Loss:**  $L_t = L_b + L_w$

where:  $L_t$  = Total vapor loss

$L_b$  = breathing loss  
 $= 2.26/100 M_v (P/P_s - P)^{0.68} D^{1.73} H_v^{0.51} \Delta T^{0.50} F_p C K_c = 53 \text{ lb/yr}$

where:

$P = 2.6 \text{ psi at } 55 \text{ F}$

$P_s = 14.7 \text{ psi}$

$M_v = 50 \text{ lb/lb-mole}$

$K_c = 0.4 \text{ (for crude)}$

$D = 10 \text{ ft.}$

$H_v = 7.5 \text{ ft.}$

$\Delta T = 20 \text{ degrees F}$

$F_p = 1.00 \text{ (assume white tank)}$

$C = 0.5$

$L_w$  = working loss =  $2.40 \times 10^{-5} M_v P V N K_N K_c = 41 \text{ lb/yr}$

where:

$M_v = 50 \text{ lb/lb-mole}$

$P = 2.6 \text{ psi}$

$V = 8820 \text{ gallon tank capacity}$

$N = 3.7 \text{ turnovers/yr}$

$K_N = 1.0 \text{ (turnover factor)}$

$K_c = 0.4 \text{ (for crude)}$

**Crude Oil Properties:**

Assume RVP = 5 psi

Crude oil density = 7.5 lb./gal

Crude oil energy content = 138,000 Btu/gal.

True vapor pressure = @ 55 F = 2.6 psi

**Emission Factors:**

Uncontrolled Emissions:  $L_t = 53 + 41 = 94 \text{ lbs/yr}$

$L_t = 9442 \text{ g}/10^9 \text{ Btu throughput}$

**Year 2000**

Assume 95% vapor recovery efficiency

**Year 2000**  $L_t = 472 \text{ g}/10^9 \text{ Btu throughput}$

**Year 2010**

Assume 98% vapor recovery efficiency

**Year 2010**  $L_t = 189 \text{ g}/10^9 \text{ Btu throughput}$

**Figure F-8. Evaporative VOC Calculation for Crude Lease Storage**

**VOC Storage Loss Emission Factor for Crude Oil**

Using AP-42:

**Bulk Terminal Tankage**

**Storage Tank Assumptions:**

Tank Type: Internal floating roof tank

Storage tank capacity = 38,000 bbls.

Tank dimensions = 95 ft. diameter X 30 ft. high

Tank throughput = 2 MMbbls/year

Use AP-42 equation (3) for internal floating roof tanks.

Tank Breathing Loss:  $L_t = L_r + L_w + L_d + L_s$

where:  $L_t$  = Total loss

$L_r$  = rim seal loss =  $K_r V^* P^* D M_v K_c = 277$  lbs./yr

where:

$K_r = 3.0$

V (average assumed wind speed) = 10 mi/hr

$n = 0$

$P^* = 0.0486$  psi

D = 95 ft.

$M_v = 50$  lb/lb-mole

$K_c = 0.40$  (for crude oil)

$L_w$  = withdrawal loss =  $[(0.943) Q C W_L] / D [1 + (N_c F_c / D)]$   
= 902 lbs./yr

where:

Q =  $2 \times 10^6$  bbls/yr (each tank)

C = 0.0060

$W_L = 7.5$  lb/gal. (density of crude)

D = 95 ft. dia.

$N_c = 6$  (number of columns)

$F_c = 1.0$

$L_d$  = deck seam loss = 0 for welded tanks

$L_s$  = deck fitting loss =  $F_F P^* M_v K_c = 583$  lb/yr

where:

$F_F = 600$  (for 95 ft. dia tank)

$P^* = 0.0486$  psi

$M_v = 50$  lb/lb-mole

$K_c = 0.40$  (for crude oil)

**Crude Oil Properties:**

Assume RVP = 5 psi

Crude oil density = 7.5 lb/gal

Crude oil energy content = 138,000 Btu/gal.

True vapor pressure = @ 55 F = 2.6 psi

**Emission Factors:**

Uncontrolled VOC emissions:  $L_t = 277 + 902 + 583 = 1762$  lb/yr/tank

$L_t = 73$  g/10<sup>9</sup> Btu throughput

**Year 2000**

Assume 95% vapor recovery efficiency

$L_t = 3.7$  g/10<sup>9</sup> Btu throughput

**Year 2010**

Assume 98% vapor recovery efficiency

$L_t = 1.5$  g/10<sup>9</sup> Btu throughput

**Figure F-9. Evaporative VOC Calculation for Marine Terminal Storage**

in years 2000 and 2010 were applied to obtain final "controlled" emission factors for each year. The percentage reductions for source control technologies were assumed based on previously documented EPA estimates (EPA 1988 a).

The evaporative VOC emission factors for each source of the crude oil infrastructure are listed in Table F-40. for years 2000 and 2010. Note that the most significant VOC emissions per Btu of crude oil throughput occur from crude oil lease storage practices and crude oil tanker transit. Since the AP-42 evaporative VOC emission factor for tanker transit losses was dependent upon voyage length, two factors were calculated. The low value represents transit losses for import crude vessels which were assumed to transport crude oil only 200 miles, that is, only within recognized U.S. borders (Demby 1991). The high value represents domestic crude oil tanker transit for which an average distance of 1,100 miles was assumed (EIA 1991 a; NPC 1991; API 1991). Evaporative VOC emission factors for pipelines were generally assumed to be negligible; leaks from pipelines were assumed to be in the form of liquid spills.

**Table F-40.  
Crude Oil Transportation Infrastructure  
Evaporative Emission Factors For 2000 and 2010**

Source Category	VOC g/10 <sup>9</sup> Btu Throughput	
	2000	2010
Crude Lease Storage	472	189
Crude Transport		
- Pipeline		
- Tanker/Barge		
- Loading	65.8	32.9
- Transit	263-2120 <sup>1</sup>	263-2120
- Rail		
- Loading	63.5	32.9
- Transit	9.9	9.9
- Tank Truck		
- Loading	63.5	32.9
- Transit	9.9	9.9
Marine Terminal Crude		
- Unloading & Storage	3.7	1.5

<sup>1</sup> The low value represents import tankers transporting crude oil in U.S. waters (within 200 mile limit). The high value represents the average emission factor for domestic marine vessels.

The evaporative VOC emissions occurring along the crude oil transportation infrastructure are comprised of a variety of compounds. EPA has determined these compounds to be mainly the following: hexane, heptane, octane, pentane, methane, ethane, propane, butane, benzene, and toluene (EPA 1991).

### Liquid Spills

As mentioned previously, the other significant category of environmental emissions from the crude oil transportation infrastructure is liquid spills. Liquid spills in the crude oil transportation system might originate from "normal operation" such as during loading and unloading episodes of transport modes at bulk facilities, or through pipeline system seals. For instance, a small amount of crude oil might be spilled upon hose disconnect during marine vessel loading. Liquid spill data along the crude oil infrastructure for typical or "normal" operations were not available in the literature; it is assumed that these spills are typically very small and are unreported for this reason. Since spills resulting during normal crude oil transportation system operations are assumed to be small, such spills are not considered for this analysis.

However, data does exist for accidental spills of crude oil. These spills will tend to be very significant in size because of their accidental nature. U.S. Coast Guard data (USCG 1986) was obtained for reported accidental crude oil and refined product spills in U.S. borders (200 miles (Demby 1991)). The spill data encompassed 1983 to 1987 calendar years. Based on this historical data, average yearly spill rates in gallons of petroleum products were calculated for the potential sources within the crude oil transportation infrastructure on a national basis. Due to limitations in the data, the same spill rates were assumed for crude oil as well as refined products like gasoline. It was also assumed that these spill rates would also apply in years 2000 and 2010. It was assumed that recent legislation requiring new large petroleum transport marine vessels to utilize "double hull" construction would not significantly change the accidental spill rates assumed in this analysis. This assumption is based on the slow replacement or "turnover" rate of the marine tanker fleet.

Next, NES crude oil production for 2000 and 2010 (DOE 1991) was apportioned by national transport mode and bulk facility using national throughput estimates (EIA 1991 a; EIA 1991 b) and divided into the average liquid spill rates. This calculation provided liquid spill emission factors on a gram per billion Btu of crude oil throughput basis. Figure F-10 provides the calculations for estimating fuel spills in the crude oil transportation system. These estimates are listed in Table F-41. for each source of the crude oil transportation infrastructure in years 2000 and 2010. Note that tankers and barges were estimated to have the highest rates of crude oil spills, essentially due to the very large amounts of crude oil transported per voyage.

Crude Oil Storage Spill Rate

assumed to be the same for 2000 and 2010

from reference 6:

352,539 gallons of crude and petroleum product spilled at bulk storage facilities.

from reference 7: assume crude bulk storage throughput is similar to gasoline bulk storage throughput or  $1.23 \times 10^{11}$  Gal/yr.,

Gasoline Density = 6.0 lb/gal.

1 lb. = 454 g

$$\begin{aligned} \text{Emission Factor: Crude oil storage spill rate} &= 352,539 / 1.23 \times 10^{11} = 0.0248 \text{ Gal. spilled}/10^9 \text{ Btu throughput} \\ &= 0.0248(6.0)454 = \underline{68 \text{ g spilled}/10^9 \text{ Btu throughput}} \end{aligned}$$

Crude Oil Spill Rate by Mode of Transport

Assumptions: Spill rates were assumed to be the same as that for gasoline transport on a gallons spilled/ $10^9$  Btu transported basis.

Crude Oil Properties:

Density = 7.5 lb/gallon

Pipeline

**Emission Factor for 2000 and 2010**

$$\text{Pipeline spill rate} = (0.004 \text{ Gal spilled}/10^9 \text{ Btu transported}) \times (7.5 \text{ lb/gal}) \times (454 \text{ g/lb}) = \underline{13.6 \text{ g}/10^9 \text{ Btu transported}}$$

Marine Vessel

**Emission Factor for 2000 and 2010**

$$\text{Marine vessel spill rate} = (0.390 \text{ gal. spilled}/10^9 \text{ Btu transported}) \times (7.5 \text{ lb/gal}) \times (454 \text{ g/lb}) = \underline{1328 \text{ g}/10^9 \text{ Btu transported}}$$

Rail

**Emission Factor for 2000 and 2010**

$$\text{Rail tank car spill rate} = (0.140 \text{ gal. spilled}/10^9 \text{ Btu transported}) \times (7.5 \text{ lb/gal}) \times (454 \text{ g/lb}) = \underline{477 \text{ g}/10^9 \text{ Btu transported}}$$

Tank Truck

**Emission Factor for 2000 and 2010**

$$\text{Tank Truck spill rate} = (0.190 \text{ gal. spilled}/10^9 \text{ Btu transported}) \times (7.5 \text{ lb/gal}) \times (454 \text{ g/lb}) = \underline{647 \text{ g}/10^9 \text{ Btu transported}}$$

**Figure F-10. Calculations for Estimating Crude Oil Spill Emission Factors**

**Table F-41.  
Crude Oil Transportation Infrastructure  
Liquid Spill Emission Factors for 2000 and 2010**

Source Category	Spills g/10 <sup>9</sup> Btu Throughput	
	2000	2010
Crude Lease Storage	68.0	68.0
Crude Transport		
- Pipeline	14.0	14.0
- Tanker/Barge	1330	1330
- Loading		
- Transit		
- Rail	477	477
- Loading		
- Transit		
- Tank Truck	647	647
- Loading		
- Transit		
Marine Terminal Crude		
- Unloading & Storage	68.0	68.0

Weighted Emission Factors

Once each pollutant emission factor for the individual sources of the crude oil transportation infrastructure was determined, a single weighted emission factor was calculated for each pollutant to represent the entire operation of the crude oil infrastructure. When overall crude oil throughput over a specific period of time is applied to this overall weighted emission factor, the total mass of each pollutant emitted from the crude oil transportation infrastructure can be obtained for that same period of time. The weighting was essentially performed based on the crude oil infrastructure illustrated in Table F-35. First, for those legs of the crude oil transportation infrastructure with more than one transport mode, a weighted transport emission factor was calculated from the individual transport mode emission factors and the crude transport mode percentage

breakdown of Table F-35. Once the transport mode emission factors of the individual infrastructure legs were weighted to single values, these values along with the other source emission factors in each leg were weighted according to the percentages of crude throughput in those legs in years 2000 and 2010. Referring to Figure F-2, it was assumed that crude oil production in years 2000 and 2010 in Alaska would represent marine terminal throughput, while production from the remaining lower 48 states in the same years would represent pipeline terminals. Such an assumption is well-founded when reviewing crude oil movements from the two major production sites (Alaska and the South Coast (Texas and Louisiana)) to major refinery sites (West (California), South, East (New Jersey) Coasts) (EIA 1991 b). The substantial amount of Alaskan crude oil is pipelined to marine terminals and shipped by tanker to the West and South Coasts for refining. The South Coast crude oil production is typically pipelined to southern regional or East Coast refining sites. Thus, the NES crude oil production values for Alaskan and 48 state production (DOE 1991) were used to calculate percentage throughput values to be used to weight the emission factors for the sources in each of the two legs of the crude oil infrastructure.

Additional weighting was performed for the marine terminals due to the imported tanker inputs to that leg of the infrastructure. The amount of imported crude was obtained and added to the amount of domestic crude entering the marine terminal (i.e., Alaskan Crude) to obtain a percentage of the overall crude flow for the segment of the marine terminal to the refinery. This percentage was then used to weight the emission factors of the individual sources between the marine terminal and the refinery.

The weighted emission factors of each leg of the crude oil infrastructure were then added together to obtain overall weighted crude oil transportation infrastructure emission factors for each pollutant. Figure F-11 illustrates the emission factor weighting calculations used for the crude oil transportation system in this analysis. Tables F-42 and F-43 display the weighted emission factors for Exhaust, Evaporative VOC, and Liquid Spills for years 2000 and 2010.

### **F.3.5 Non-Process Requirements**

Several other environmental issues for crude oil transportation are discussed below:

- **Air Quality:** Certain toxic compounds of exhaust and evaporative VOC emissions are associated with crude oil transportation operations. These compounds are toxic in terms of their mutagenic or carcinogenic properties. Compounds such as benzene, formaldehyde, and 1,3 butadiene are representative of such emissions.

Emission factors for each source of the infrastructure were weighted according to their place within the system. All of the weighted values were then added up to obtain a single overall weighted emission factor representing the entire infrastructure.

Weighting was done according to the percentages of crude throughput in each leg of the assumed crude oil transportation system in years 2000 and 2010, and according to the national percentage of crude oil carried by the modes. Additional weighting was performed for the marine terminals due to the imported tanker inputs to that leg of the infrastructure. The amount of imported crude was obtained and added to the amount of domestic crude entering the marine terminal to obtain a percentage of the overall crude flow for the segment of the marine terminal to the refinery. This percentage was then used to weight the emission factors of the individual sources between the marine terminal and the refinery.

The following method was used to find the weighted pollutant emission factors for the crude oil transportation infrastructure:

x1 = emission factor for electric pumps at crude tankage facilities

x2A = emission factor for tankers

x2B = emission factor for inland barges

x2C = emission factor for rail locomotives

x2D = emission factor for tank trucks

x2E = emission factor for pipelines

x3 = emission factor for electric pumps at marine terminal facilities

y1A = percent of product moved by tankers = 44

y1B = percent of product moved by inland barges = 8

y1C = percent of product moved by rail locomotives = 1

y1D = percent of product moved by tank trucks = 1

y1E = percent of product moved by pipelines = 46

Year 2000

$$\text{WEF} = x1 + 0.88*((x2A*y1A)+(x2B*y1B)+(x2C*y1C)+(x2D*y1D)+(x2E*y1E))+0.12*(x2E) + 0.56*((x3+x2A+x2A*(y1A/(y1A+y1E)))+x2E*(y1E/(y1A+y1E)))$$

Year 2010

$$\text{WEF} = x1 + 0.81*((x2A*y1A)+(x2B*y1B)+(x2C*y1C)+(x2D*y1D)+(x2E*y1E))+0.19*(x2E) + 0.57*((x3+x2A+x2A*(y1A/(y1A+y1E)))+x2E*(y1E/(y1A+y1E)))$$

**Figure F-11. Method of Emission Factor Weighting**

**Table F-42.**  
**Overall Weighted Emission Factors for the Crude Oil Transportation Infrastructure in 2000**

Transport Infrastructure	Weighted Emission Factors (g/10 <sup>9</sup> BTU)							
	Exhaust HC	CO	NO <sub>x</sub>	Part	CO <sub>2</sub>	SO <sub>2</sub>	Evap VOC	Liquid Spills
Crude Oil	3000	6530	15300	752	2.11*10 <sup>6</sup>	629	2270	1880

**Table F-43.**  
**Overall Weighted Emission Factors for the Crude Oil Transportation Infrastructure in 2010**

Transport Infrastructure	Weighted Emission Factors (g/10 <sup>9</sup> BTU)							
	Exhaust HC	CO	NO <sub>x</sub>	Part	CO <sub>2</sub>	SO <sub>2</sub>	Evap VOC	Liquid Spills
Crude Oil	2460	4460	10500	495	2.08*10 <sup>6</sup>	620	1900	1850

- **Water Resources:** Surface and groundwater resources have the potential to be affected by crude oil transportation spills. Such effects may be in the form of bulk storage leaks, underground storage tank leaks, transportation mode transit and loading/unloading spills, and marine vessel ballasting practices. Although spills occurring during normal operations can result in significant contamination of surface and groundwater resources over time, the most detrimental impacts result from large accidental spills of crude oil.
- **Soils:** Similar to water resources, soils would be negatively impacted from crude oil spills. The most likely sources of soil contamination from the crude oil transportation system would be bulk storage tanks, and transit and loading/unloading spills from crude oil transportation modes.
- **Vegetation:** Vegetation is mainly affected from spills along the crude oil transportation infrastructure. Direct contamination or indirect impacts from groundwater contamination will negatively affect vegetation. Acid rain formation from certain types of electricity production for operating electric pumps in the crude oil distribution infrastructure also has a negative impact on vegetation growth.
- **Wildlife:** Direct exposure from crude oil spills is the most damaging and immediate effect of the crude oil transportation operations. Another indirect impact is the loss of indigenous vegetation due to crude spills and acid rain. Both marine and land wildlife can be affected by crude oil transportation.
- **Land Utilization:** Due to changes in crude oil production levels and/or sites, modifications to land-based (pipeline, rail and tank truck) crude oil transportation routes may be required. Additional land to lay pipeline, build rail lines and/or highways may be necessary to accommodate route changes. Also, crude oil production level or site changes may require additional marine bulk terminals as intermediate storage and transfer sites before the crude is transported to the refinery.
- **Odors and Noise:** Odors and noise are proximity events. Odors and noise can result from the activities at bulk facilities and from transportation modes. Both will impact humans and wildlife which come into contact with their sources. Protection can be offered to most persons employed within the crude oil transportation infrastructure in terms of respiratory and hearing protection.
- **Other Concerns:** Other environmental concerns with the crude oil transportation infrastructure are very site-specific. Certain aspects of local environments may be more susceptible to potential damage from crude oil

transport than those of other areas due to differences in geology and wildlife. It is beyond the scope of this study to identify such site-specific impacts.

**Occupational Health and Safety:** The primary occupational and safety impact on crude oil transportation workers is flammable nature of crude oil. Although not as volatile as gasoline, crude oil vapors when mixed with air can form explosive mixtures.

Many compounds in crude oil are highly toxic substances. Inhalation of these substances can cause respiratory or even neurological problems. Prolonged inhalation can result in permanent respiratory damage. Skin exposure to crude oil can result in dermatitis and other skin-related problems. Finally, many compounds in crude oil have been identified as carcinogens in laboratory animal experiments.

The Bureau of Labor Statistics reports the number of occupational injuries and illnesses associated with various industries (DOL 1990). One statistic covering the crude oil transportation infrastructure was injury and illness incidence rate by transportation mode. Table F-44 displays the average employment and injury and illness incident rates for pipelines (except natural gas), railroad transportation, trucking (local and long distances), water transportation, and the average private sector industry in 1988. Note that the trucking and water transportation industries exhibit higher injury and illness rates than those associated with pipelines and rail. Compared with the average private sector, only the trucking and water transportation industries had higher illness and injury rates; however, only the pipeline industry had a lower lost workday rate than the overall private sector industry average.

Fatality rates for the crude oil transportation infrastructure were also estimated. The rates for each transport mode were assumed to be represented by the Bureau of Labor's estimate for overall transportation and public utilities. Based on this assumption, the fatality rate for the crude oil transport modes is more than twice that of overall private industry.

**Table F-44.**  
**Occupational Health and Safety Projection to 2000 and 2010**

	SIC Code	Injury and Illness Rate per 100 Full-Time Workers	Lost Workdays Cases per 100 Full-Time Workers	Fatalities per 100,000 Full-Time Workers <sup>1</sup>
Pipeline, except natural gas	46	3.6	1.4	13.5
Railroad	40	6.9	4.9	13.5
Trucking, local and long distance	421	13.9	8.0	13.5
Water transportation	44	12.2	7.5	13.5
Average private Sector Industry		8.6	4.0	5.0

<sup>1</sup> Value based on overall transportation and public utilities.

### **F.3.6 Pre-Operational Phase of the Crude Oil Transportation Infrastructure**

There has been increasing concern and attention given to reducing the U.S. dependence on foreign oil imports. As a result of this concern, the domestic petroleum industry has put forth an effort into seeking out new domestic supplies of crude oil. The search for locating new domestic crude oil reserves for the years 2000 and beyond has included both off-shore and on-shore oil exploration, with off-shore exploration receiving the majority of the attention. This section will identify the "inputs" and "outputs" of the crude transportation infrastructure from a pre-operational (before transport) perspective. This section also provides a brief understanding of the possible environmental impacts from these "outputs" associated with the maintenance, development, or possible expansion of the existing domestic crude transportation infrastructure. The discussion of the pre-operational phase of the infrastructure is divided into three segments: transportation of crude by pipeline, marine vessel, and the storage of crude on land. The inputs and outputs of each of the three segments and their potential effects on the environment will be discussed briefly in the following.

### **F.3.6.1 Pre-Operational Phase**

There are currently two types of pipeline transportation systems used to move domestically produced crude oil; off-shore and on-shore pipelines. The environmental impacts of constructing these two types of networks will greatly differ since one will impact the land and its surrounding floral and faunal environments, while the other system will impact the underwater marine environment. The construction of on-shore pipelines include assembling the steel pipeline in sections and then welding the sections in place. The pipelines can be constructed either above or below ground depending on the specific geographic locations. Each type of on-shore pipeline design (above or below ground) will result in different specific environmental impacts.

The inputs required to construct on-shore pipelines in addition to building materials necessary for the pipeline will include construction equipment powered mostly by diesel engines as well as supplies of labor, and fuel.

The outputs or emissions of on-shore pipeline construction can be best summarized by identifying each emission source and their respective emissions associated with the pipeline construction. As described earlier in this report, diesel engines will emit several air pollutants from the combustion of diesel fuel of which HC, CO, NO<sub>x</sub>, CO<sub>2</sub> and particulate matter (PM) are of the greatest concern. The emissions from the labor used to construct the pipeline will include liquid and solid wastes generated at the pipeline work site. The solid waste can be a result of garbage or construction debris left behind, while the liquid waste could include fuel spills of either gasoline or diesel fuel since the construction equipment used in building the pipeline may require either or both of these fuels, with diesel fuel expected to make up the majority of the work site fuel demand.

Similarly, the inputs required to construct off-shore oil pipelines include building materials and construction equipment, labor and fuel. The equipment used in constructing off-shore pipelines consists mainly of marine vessels including supply and crew boats along with pipeline reel barges. Most of this marine equipment is diesel powered and will emit emissions similar to the land-based diesel equipment. Liquid emissions (either fuel or waste) from this equipment will impact the surrounding marine environment as well. Off-shore pipelines may require burying the pipelines in trenches in shallow water areas to protect it from surface obstacles such as marine vessels or floating ice. As a result of trenching operations, a large amount of bottom sediment is disturbed on the sea floor. The environmental impacts of this type of operation on marine life will vary based on the length, depth, and geographic location of the pipeline.

The inputs required for the pre-operational phase of marine vessel transport of crude oil include the materials (mostly steel), fuel (including electricity), land, and labor to construct ocean and river barges and tankers. These vessels are usually constructed at domestic ocean or river port facilities. Recent marine vessel construction trends have reduced the number of oil transport vessels built in the U.S. with more of the larger tankers being constructed in countries abroad.

The outputs of constructing these marine vessels include air emissions along with liquid and solid wastes generated at the vessel construction facilities. Air emissions are generated from the combustion of fossil fuels at the vessel construction facilities which can include gasoline, diesel fuel, and fuel oil combustion. Liquid emissions can result from spilled solvents used in the maintenance or construction process and from vessels leaking fuel at the construction or maintenance facility. The sources of these solid waste outputs include steel welding and cutting activities which occur during construction or dry-dock maintenance activities on marine tankers or barges. The outputs from crude transport vessel construction and maintenance can have specific effects on both the land and marine environments surrounding these facilities.

Once the crude has been transported by either pipeline or marine vessel, the oil is stored on land in large bulk storage tanks. The crude oil tank storage can be located either inland near oil fields or near coastal or inland waterways at marine bulk storage terminals. The inputs required for this part of the pre-operational phase include the materials, labor, land, and fuel required to construct this segment of the crude transportation infrastructure. The outputs of tank building activities will include engine emissions from construction equipment, which are expected to be mostly diesel powered. Liquid and solid waste is expected to be generated from both the labor and the equipment used at the tank work-site. The environmental impact that crude storage tank construction/maintenance will have can vary based on the geographic location of the tank site. Outputs from crude storage tank construction or maintenance activities near marine terminals will present different environmental impacts than tank activities located inland.

### **F.3.6.2 Post-Operational Phase**

The post-operational phase of the crude oil transportation infrastructure includes removing pipelines, marine vessels, and storage tanks from service. Railroad tank cars and highway tanker trucks were not considered a large part of the crude transportation infrastructure and thus were not considered in the post-operational phase. Taking the segments of infrastructure out of service is usually accomplished by disassembling the pipeline, vessel, or storage tank and either scrapping the materials (mostly steel) for recycling purposes or salvaging portions of the infrastructure for some other use. In order to decommission the three segments of this infrastructure, several inputs will be needed. There will be inputs of fuel, labor, and land for the post-operational phase. Heavy equipment mostly powered by diesel fuel will be used to disassemble these components of the infrastructure. There are possible air, liquid, and solid waste emissions from the cleaning (crude residue removal) of the steel or other materials which will be scrapped for recycling purposes. The environmental impacts of decommissioning each segment of the transportation infrastructure will vary based on the geographic location of the pipeline, marine vessel, or storage tank. When a pipeline or storage tank facility is decommissioned, the process of land reclamation is a possible option. Land reclamation may include environmental cleanup operations necessary to remove any toxic or hazardous materials or soil as a result of this pipeline/storage facility decommissioning.

### **F.3.7 Discussion and Summary**

For the crude oil transportation system analysis, domestic crude oil was assumed to be moved 44 percent by tanker, eight percent by barge, one percent by rail, one percent by tank truck, and 46 percent by pipeline for years 2000 and 2010. Imported crude oil was assumed to be brought into the U.S. exclusively by ocean tanker in this study. Crude oil flow from lease tankage was assumed to reside along two primary paths or legs. The first leg was assumed to consist of a direct route to the refinery, while the second leg comprising a route through intermediate storage at marine terminals before its ultimate destination at the refinery.

The inputs of the crude oil transport process were characterized as crude oil, No. 2 diesel fuel, No. 6 fuel oil, electricity, replacement parts, and labor. The output of the system consisted only of crude oil.

The main environmental impacts of the crude oil transportation infrastructure system could be categorized as air and liquid spill emissions. The air emissions consist of both exhaust and evaporative emissions. The exhaust emissions result from the combustion of fuel for transporting the crude through the infrastructure to the refinery. Specific exhaust emission factors for HC, CO, NO<sub>x</sub>, particulates, CO<sub>2</sub> and SO<sub>2</sub> were derived for the tank truck, locomotive, ocean tanker, and inland barge crude oil transportation modes for years 2000 and 2010.

Another air emissions of major importance from the crude oil infrastructure system is evaporative VOC emissions. Such emissions result from the vaporization of crude oil and the subsequent release of these vapors to the atmosphere. Evaporative VOC emissions could be released at a variety of points along the crude oil infrastructure including during transit between facilities, during loading and unloading at facilities, and from bulk storage at facilities. Estimates of evaporative VOC emission factors for various transport modes and facilities of the crude oil infrastructure system were derived from EPA sources for years 2000 and 2010 assuming the application of various types of vapor control equipment for these modes and facilities in these years.

The other main environmental impact of crude oil transportation comes in the form of liquid spills. Such spills may originate from "normal" operations, such from loading hose disconnect, or from accidental occurrences. Industry data on "normal" operations was not available. It was also assumed that such spills would be small and insignificant relative to accidental spills. Therefore, emission factors for "normal" operational spills were not estimated.

However, historical data was available for accidental spills for the transportation modes and bulk storage facilities of the crude oil transportation system. Based on this data, estimates of annual accidental spill rates along the crude oil transportation infrastructure system were determined for years 2000 and 2010. These rates were placed on a throughput basis using NES crude oil production estimates for years 2000 and 2010.

Once the exhaust, evaporative VOC, and liquid spill emission factors for components of the crude oil transportation system were derived, they were weighted based on total system throughput in order to estimate a single emission factor for each pollutant representing crude oil transport. The weighting was performed for the amount of crude oil assumed to flow through each leg of the crude oil transportation system assumed for this analysis. The percentage breakout for each leg was assumed based on NES crude oil production in Alaska and the lower 48 states in years 2000 and 2010. The crude oil produced in Alaska was assumed to represent the marine terminal leg of the overall infrastructure, while the lower 48 state production was assumed to represent the leg consisting of a direct route from lease storage to the refinery. Additional weighting was also performed for those portions of the system in which multiple transport modes were used, and to account for imported crude inputs to the marine terminal.

Table F-45 provides a summary of all inputs and outputs to the crude oil transportation infrastructure on both per million BTU of crude oil moved and per year bases. The per year estimates are derived by applying the NES crude oil production for years 2000 ( $5.39 \times 10^{13}$  Btu/Day) and 2010 ( $6.14 \times 10^{13}$  Btu/Day) to the weighted system inputs and emission outputs. It was assumed that crude oil production is equivalent to crude oil throughput to the refinery.

**Table F-45.  
Summary of Total Inputs and Outputs for Crude Oil  
Transportation Infrastructure in 2000 and 2010**

Inputs	2000		2010	
	per MMBTU	per Year	per MMBTU	per Year
Crude oil (bbl)	0.173	3,400 x 10 <sup>6</sup>	0.173	3,870 x 10 <sup>6</sup>
No. 2 diesel fuel (bbl)	0.000073	1,430,000	0.000069	1,540,000
No. 6 fuel oil (bbl)	0.00441	86,700,000	0.00435	97,500,000
Electricity (kWhr)	3.47	68.3 x 10 <sup>9</sup>	3.55	79.5 x 10 <sup>9</sup>
Labor (persons)	0.000005	98,400	0.000005	112,000
Replacement parts	NA <sup>1</sup>	NA	NA	NA
<b>Outputs</b>				
Crude oil (bbl)	0.173	3,400 x 10 <sup>6</sup>	0.173	3,870 x 10 <sup>6</sup>
Air emissions (lbs, tons)				
HC	0.00661	65,000	0.00542	60,800
CO	0.0144	142,000	0.00981	110,000
NO <sub>x</sub>	0.0336	331,000	0.0232	260,000
Particulates	0.00166	16,300	0.00109	12,200
SO <sub>2</sub>	0.00138	13,600	0.00136	15,300
CO <sub>2</sub>	4.65	45,700,000	4.58	51,400,000
Total Evaporative VOC	0.0050	49,200	0.00417	46,800
Liquid Spill Emissions (lbs, tons)	0.00415	40,800	0.00408	45,800

<sup>1</sup> NA = Not available.

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## **F.4 Crude Oil Refining**

The environmental impacts associated with crude oil refining are described in this section. The section begins with an overview of the refinery industry followed by a review of the specific assumptions used to project refinery operations to produce reformulated gasoline in the years 2000 and 2010. The process of producing reformulated gasoline is then described based on future reformulated gasoline specifications. This discussion is followed by a detailed characterization of the environmental, health, and safety impacts of the crude oil refining system.

### **F.4.1 Industry Structure**

Petroleum is the principal energy source of the United States. During 1989, about 34 quadrillion Btu (quads), or 42 percent of the total energy consumed in the United States came from petroleum (DOE/EIA, 1990). Petroleum consumption, which peaked at 49 percent of total energy use in 1977, has continued to drop as high petroleum prices and the relatively lower costs of other fuels, such as natural gas and coal, encouraged conservation and fuel switching.

At the beginning of 1990, the operating crude distillation capacity of U.S. petroleum refineries was 15.6 million barrels per day (MMBD) from 205 operating refineries. These refineries ranged in size from small refineries able to process 1,000 barrels of crude oil per day to those able to process more than 400,000 barrels per day. Most of the refineries are located in Texas, California, and Louisiana (DOE, 1991b).

The United States leads the world in refinery output, producing about 24 percent of the worldwide output of petroleum products. As of January 1, 1990, an estimated 21 percent of the crude oil refining capacity in the world was located in the United States. Nearly one-half of all U.S. refinery output is motor gasoline. The industry responds to changes in demand by adjusting refinery processes to vary the yield of gasoline and other products. For example, in 1921, the yield of gasoline per barrel of crude oil was about 27 percent. In 1990, the gasoline yield at U.S. refineries was about 46 percent, reflecting the high demand for automotive fuels (DOE, 1991b).

Petroleum refining is one of the leading manufacturing industries in the United States. The value of shipments by the petroleum refining industry accounts for about 4 percent of the value of shipments by the entire manufacturing sector of the U.S. economy (DOE, 1991b). In 1989, the value of shipments by the petroleum refining industry was an estimated \$147 billion.

The petroleum refining industry provides the link between crude oil and the finished product. Because the uses for crude oil as it comes from the ground are limited, the petroleum refinery is the key to unlocking the full potential of this valuable resource. There are many refinery

processes employed to transform crude oil into the array of products used in transportation, home heating, lubrication, and countless other applications.

The first phase in refinery processing, atmospheric distillation, uses heat to separate the various hydrocarbon components of crude oil according to their boiling points. Beyond the atmospheric distillation unit, or "downstream" from this initial refinery process, are more complex units that increase the refinery's flexibility to process a wide range of crude oils and increase the yield of lighter (low-boiling point) petroleum products such as gasoline. The streams of material coming from the distillation unit can be used as finished products or they can become feedstocks for the downstream processes. Downstream operations include vacuum distillation units; "cracking" units that use heat, pressure, or catalysis to increase the yields of lighter products; "reforming" units that upgrade low octane naphthas to a high octane gasoline blending component called "reformate;" and process units that combine molecules to yield products with specific properties. Some refineries also have operations to pretreat feedstocks, remove impurities, and enhance various product characteristics (DOE, 1990; DOE, 1991b).

Crude oil is not a homogeneous substance. Crude oil varies in color, specific gravity, viscosity, sulfur content, metals content, and other characteristics, depending on the source. The quality of crude oil depends largely on its geographic origin, although the time a reservoir has been in production is also a factor.

Not all refineries are alike either. The complexity of a refinery depends upon the physical properties of the crude oil to be processed and the characteristics of the desired product slate. Because refinery process requirements differ with the quality of crude oil inputs, a refinery's geographic proximity to the source of its crude oil inputs can influence its configuration. Modern refineries process various blends of many different crude oils, and different configurations of refining units are used to produce a given slate of products from available crude oils. A change in the availability of a certain type of crude oil can affect a refinery's ability to produce a particular product. Thus, the product slate at a given refinery is determined by a combination of demand, inputs and process units available, and the fact that some products are the result (co-products) of producing other products (DOE, 1991b).

#### **F.4.2 Specific Assumptions**

The specific assumptions that affect refinery operations with respect to the production of reformulated gasoline can be grouped into three categories:

- Crude oil characteristics
- Crude oil refining - the processing operations required to get to the products slate, and

- Reformulated gasoline specifications.

Each of these assumption areas is discussed below.

#### **F.4.2.1 Crude Oil Characteristics Assumptions**

- **Crude Slate in 2000 and 2010:** The physical properties of oil differ for each reservoir. The price for which oil can be sold depends not only on volume but also on the oil's characteristics, particularly its specific gravity and its sulfur content. Specific gravity is a measure of the density of the oil. Light, low density oil has a low specific gravity. However, the specific gravity of oil is usually measured on the American Petroleum Institute (API) scale that expresses gravity in terms of degrees API ( $^{\circ}$ API). A low specific gravity translates to high API gravity and vice versa. Thus, the lightest, least dense oils are those with the highest API gravities.

There are several ways to chemically characterize crude oil. These properties include API gravity, sulfur content, RVP, hydrocarbon content, carbon content, etc. For purposes of this study, crudes were characterized by API gravity and sulfur content. DOE's publication entitled *Petroleum Supply Annual* uses these same properties, namely API gravity and sulfur content, to characterize crude oil. Gravity was the main concern with respect to crude oil refining since complex/ integrated refineries can handle a wide range of sulfur contents and other crude oil properties such as paraffins, olefins, naphthenes, and aromatics contents.

Historical data on API gravities and sulfur contents of crude oil runs to U.S. refineries show that the quality of the U.S. crude oil pool is declining. This trend has, of course, been influenced by the increasing capability of U.S. refiners to process heavier and higher-sulfur crudes, the availability of such crudes, and, at times, attractive price differentials between them and lighter crudes. In general, the quality of crude oil processed by refineries is determined by:

- Crude oil types available (i.e., domestic and foreign sources)
- Refinery configuration (i.e., downstream processing capabilities to handle crude oil quality variations)
- Crude oil quality/price structure
- Marketable product slate that gives reasonably good refinery operating margins (Swain, 1991).

In general, the API gravity of crude oils processed in U.S. refineries appears to be declining rather quickly--about 0.20 °API/year--over the past 10-year period. Currently, U.S. refineries east of the Rocky Mountains are processing crudes with a composite gravity of greater than 31 °API and sulfur content slightly greater than 1 weight percent. These crude oils are considered in the medium-to-high gravity and low-to-medium sulfur group. As crude oils produced worldwide increasingly fall into the medium gravity group (20.0-30.0 °API), U.S. refiners will need to modify their heavy ends processing units to meet the demands of transportation fuels and other products (Swain, 1991). -

- **Refinery Scenarios for Reformulated Gasoline:** For purposes of this study, an assumption was made that the U.S. crude refining system can be characterized into two geographical components: one east of the Rocky Mountains that encompasses crude oils processed in the Petroleum Administration for Defense Districts (PADDs) I through IV and the other in PADD V. Table F-46 presents the gravity and sulfur content of the PAD Districts in 1990 and groups them into the two geographical components.
- **Projection of Crude Oil Gravity and Sulfur Content to the Years 2000 and 2010:** While it is clear that there has been a steady decline in gravity and steady increase in sulfur content of crude oil during the last 10 years (1980-1990), simple extrapolation of these trends to 2000 and 2010 may not be appropriate because the time frames are too far in the future. In the absence of gravity and sulfur projections in the NES or in the literature with the particular mix of crude source presented in the NES, an estimate of gravity and crude must be developed in order to assess the environmental impacts of refineries processing crude oil into reformulated gasoline.

For this estimate, a number of elements are known, as follows:

- First, the trend towards more integrated and flexible refineries means that lower API gravities and higher sulfur crudes can be processed.
- Secondly, as noted above, crude oils produced worldwide are falling in gravity and increasingly fall into the medium gravity group (20.0-30.0 °API) (Swain, 1991).

**Table F-46.**  
**Crude Oil Refining in 1990 (Actual) - Gravity and Sulfur Content**  
**by Petroleum Administration for Defense (PAD) District**

PROPERTY	PADD I	PADD II	PADD III	PADD IV	TOTAL PADD I - IV	PADD V	TOTAL U.S.
Volume of Crude Run							
Imports, MMBD	1.22	1.11	3.25	0.07	5.65	0.23	5.88
Domestic, MMBD	<u>0.06</u>	<u>1.90</u>	<u>2.81</u>	<u>0.39</u>	<u>5.16</u>	<u>2.36<sup>1</sup></u>	<u>7.52</u>
Total, MMBD	1.28	3.01	6.06	0.46	10.81	2.59	13.40
Gravity, °API	31.0	34.5	33.1	35.2	33.4	25.7	31.9
Sulfur, %	1.15	1.01	1.14	0.92	1.10	1.11	1.10

<sup>1</sup> Of the 2.36 MMBD, 1.43 MMBD was Alaskan. California, by subtraction, is 0.93.

Source: Swain, E.J., "U.S. Crude Slate Gets Heavier and Higher in Sulfur," *Oil & Gas Journal*, Vol. 89, No. 36, September 9, 1991.

- Third, there are gravity and sulfur pricing incentives.
- Finally, the NES scenario includes major increases in crude production by enhanced oil recovery for the years under consideration (DOE, 1991a). Table F-47 presents the production volume and average gravity of enhanced oil recovery (EOR) for 1990. This table shows that, while there are district differences in gravity between technologies and technology groups, the overall EOR gravity of 20.2 °API is at the low end of the medium gravity group.

There is also a distinct geographic difference in the gravity of crude oil recovered by EOR technologies in PADD V and the rest of the country (PADDs I through IV). Crude oil produced in PADD V using current EOR technologies, which is primarily steam-based, has a lower gravity while the crudes generated in the balance of the country has substantially higher gravity. This geographical difference between PADD gravities may tend to diminish in the future as EOR roughly doubles by the year 2000 and doubles again by 2010. Growth of this magnitude in EOR implies new EOR technologies and new EOR locations, including Alaska.

Accordingly, the simplifying assumption can be made that all future oil generated by EOR technologies has a gravity of 20.2.

Assuming that all future U.S. crude oil recovered through EOR will have a similar average API gravity of 20.2 allows an assessment of the impact of U.S. EOR on the overall crude oil gravity in 2000 and 2010 assuming no change in imported crude oil's gravity. These projections, which have taken only U.S. EOR into account, are shown in Table F-48. This table indicates that the overall U.S. gravity of crude oil recovered by EOR technologies drops from 31.9 °API in 1990 to 31.0 °API in 2000 and further drops to 30.1 °API in 2010 due to the impact of U.S. EOR of 20.2 °API alone. Stated another way, this table illustrates the impact of EOR on the total crude slate, both U.S. domestic and imported.

Of course, it is not known what the composition of U.S. EOR will be in the future or, for that matter, the characteristics of conventional domestic crude production and imported oil. It seems clear, however, that the trends shown in the last 10 years will continue in the same directions.

**Table F-47.**  
**U.S. Enhanced Oil Recovery/Production and Gravity in 1990 by Technology**

EOR Technology	Production, Barrels/Day	Average Gravity, °API
Thermal		
Steam	444,000	13.0
Combustion <i>in situ</i>	6,100	14.7
Hot Water	4,000	13.6
Total Thermal	454,000	13.0
Chemical		
Micellar-Polymer	600	35.9
Polymer	11,200	24.0
Caustic/Alkaline	0	0.0
Surfactant	20	30.0
Total Chemical	11,800	24.5
Gas		
Hydrocarbon Miscible/Immiscible	55,000	36.2
CO <sub>2</sub> Miscible	96,000	35.4
CO <sub>2</sub> Immiscible	95	26.0
Nitrogen	22,000	49.0
Flue Gas (miscible and immiscible)	17,300	32.1
Total Gases	190,400	36.8
Other		
Carbonated Waterflood	0	0.0
<b>Total</b>	<b>656,000</b>	<b>20.2</b>

Source: Moritis, G., "CO<sub>2</sub> and HC Injection Lead EOR Production Increase," *Oil & Gas Journal*, Vol. 88, No. 17, April 23, 1990.

**Table F-48.**  
**Estimated U.S. Enhanced Oil Recovery Crude Gravity for the Years 2000 and 2010**

	2000			2010		
	PADDs I-IV	PADD V	Total U.S.	PADDs I-IV	PADD V	Total U.S.
Crude Volume, MMBD <sup>1</sup>	14.2	3.4	17.6	14.9	3.5	18.4
Less:						
Lower 48 EOR, MMBD	1.1	0.3	1.4	2.2	0.5	2.7
Alaska EOR, MMBD <sup>2</sup>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>0.5</u>	<u>0.5</u>
Subtotal EOR, MMBD	1.1	0.3	1.4	2.2	1.0	3.2
Crude Volume less EOR, MMBD	13.1	3.1	16.2	12.7	2.5	15.2
1990 Average Gravity, °API	33.4	25.7	31.9	33.4	25.7	31.9
Factor, Vol. x API	437.5	79.7	517.2	424.2	64.3	488.5
EOR Volume, MMBD	1.1	0.3	1.4	2.2	1.0	3.2
EOR Assumed Gravity, °API	20.2	20.2	20.2	20.2	20.2	20.2
Factor, Vol. x API	22.2	6.1	28.3	44.4	20.2	64.6
Factors Addition	459.7	85.8	545.5	468.6	84.5	553.1
Average Gravity, °API	32.4	25.2	31.0	31.4	24.1	30.1

<sup>1</sup> Includes imported crude oil.

<sup>2</sup> For purposes of this analysis, the advanced recovery oil of Alaska is assumed to have EOR average gravity.

Sources: *National Energy Strategy: Powerful Ideas for America*, First Edition, 1991/1992, Washington, D.C., February 1991.

U.S. Department of Energy, *National Energy Strategy, Technical Annex 2, Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions and Results*, First Edition, 1991/1992 Report No. DOE/S-0086P, Washington, D.C., 1991.

Swain, E.J., "U.S. Crude Slate Gets Heavier and Higher in Sulfur," *Oil & Gas Journal*, Vol. 89, No. 36, September 9, 1991.

On the basis that these trends in crude oil gravity and sulfur contents will continue much as they have in the past 10 years, Table F-49 was constructed to project the 1980 to 1990 data to future years by the two geographical area components. As projected on this table, U.S. total gravity will decline from 31.9 °API in 1990 to 29.9 °API in 2000 and to 29.1 °API in 2010, while sulfur content will increase from 1.1 to 1.3 to 1.6 in the corresponding years.

#### F.4.2.2 Crude Oil Refining Assumptions

**Refinery Capacity and Locations:** No new grassroots refinery will be constructed between now and 2010. Any increase in refinery capacity including new equipment required to produce reformulated gasoline will be made up by adding new processes/equipment at existing refinery locations. Older/obsolete equipment will be replaced; however, such replacements will also occur at existing refineries. Thus, there will be no major shift in refining locations between now and 2010. Current domestic crude oil refinery capacity is shown in Table F-50.

**Refinery Type:** Depending on the processes used, refineries are usually grouped into two categories: simple/straight run refineries and complex/integrated refineries.

Simple/straight run refineries are those that can only process crude oil to one level of distillation. That is, they normally do not have the capability (downstream processing units) to change the boiling range of the material they process. They typically have only a crude oil distillation unit and possibly a reformer unit.

Complex/integrated refineries can convert material from one boiling range to another. They are capable of producing a range of products. They can also handle a wide range of crude oil. As shown in Table F-51, complex refineries currently account for 72 percent of all refineries and represent about 93 percent of crude capacity. This crude oil capacity at complex refineries is expected to increase in the future. Thus, only the complex type of refinery was evaluated in this study.

The product of the simple refineries along with the natural gas liquids will be used to provide the gasoline portion of the alcohol fuel blends. Non-gasoline fractions of simple refineries will be considered to be minor input streams to complex refineries.

**Table F-49.**  
**Projection of Crude Volumes, Gravity, and Sulfur Content to the Years 2000 and 2010**

	2000			2010		
	PADDs I-IV	PADD V	Total U.S.	PADDs I-IV	PADD V	Total U.S.
<b>Crude Volume<sup>1</sup></b>						
Domestic, MMBD	7.5	1.8	9.3	8.6	2.0	10.6
Imports, MMBD	<u>6.7</u>	<u>1.6</u>	<u>8.3</u>	<u>6.3</u>	<u>1.5</u>	<u>7.8</u>
Total, MMBD	14.2	3.4	17.6	14.9	3.5	18.4
<b>Gravity, Average °API</b>						
1990 Basis	33.4	25.7	31.9	33.4	25.7	31.9
Adjustment, -0.20°API/yr <sup>2</sup>						
x 10 yrs	(2.0)	(2.0)	(2.0)			
x 20 yrs				<u>(4.0)</u>	<u>(4.0)</u>	<u>(4.0)</u>
2000 and 2010 projection	<u>31.4</u>	<u>23.7</u>	<u>29.9</u>	29.4	21.7	27.9
<b>Sulfur, % 1990</b>						
1990 Basis	1.1	1.1	1.1	1.1	1.1	1.1
Adjustment, +0.023%/yr <sup>2</sup>						
x 10 yrs	+0.2	+0.2	+0.2			
x 20 yrs				<u>+0.5</u>	<u>+0.5</u>	<u>+0.5</u>
2000 and 2010 projection	<u>1.3</u>	<u>1.3</u>	<u>1.3</u>	1.6	1.6	1.6

<sup>1</sup> Assumes the 1990 ratio of 19.3% of total U.S. for PADD V continues in 2000 and 2010.

<sup>2</sup> Assumes continuation of 1980 to 1990 trends to 2000 and 2010.

Sources: *National Energy Strategy: Powerful Ideas for America*, First Edition, 1991/1992, Washington, D.C., February 1991.

U.S. Department of Energy, *National Energy Strategy, Technical Annex 2, Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions and Results*, First Edition, 1991/1992 Report No. DOE/S-0086P, Washington, D.C., 1991.

Swain, E.J., "U.S. Crude Slate Gets Heavier and Higher in Sulfur," *Oil & Gas Journal*, Vol. 89, No. 36, September 9, 1991.

**Table F-50.**  
**Major U.S. Refining Locations, 1990**

Refinery Locations	Refining Capacity MMBD
Pennsylvania	0.7
New Jersey	0.5
Delaware	<u>0.1</u>
Subtotal	1.3
Illinois	1.0
Indiana	0.4
Ohio	0.5
Kansas	0.4
Oklahoma	<u>0.4</u>
Subtotal	2.7
Texas	3.9
Louisiana	2.3
Mississippi	<u>0.4</u>
Subtotal	6.6
California	2.2
Washington	<u>0.5</u>
Subtotal	2.7
All Other	2.2
U.S. Total	15.5

Source: Thrash, L.A., "Annual Refining Survey," *Oil & Gas Journal*, Vol. 89, No. 11, March 18, 1991.

**Table F-51.  
Major Refinery Types, 1990**

Refinery Type	Number of Refineries	Crude Capacity, MMBD	% of Total Capacity
Simple/Straight Run	55	1,100,000	7
Complex/Integrated	119	14,400,000	93
Total	174	15,500,000	100

Source: Thrash, L.A., "Annual Refining Survey," *Oil & Gas Journal*, Vol. 89, No. 11, March 18, 1991.

- **Natural Gas Liquids:** Natural gas liquids were considered as a separate input to the gasoline refining process. No environmental residuals associated with its production were calculated.
- **Other Additives:** For both 2000 and 2010, the assumption was made that no lead will be added to gasolines. In addition, it was assumed that no MMT or other additives will be added since they are not currently approved by the U.S. Environmental Protection Agency (EPA).

The use of such additives as antioxidants, detergents, and scavengers were not addressed in this study, since they are usually added in very small amounts (about 1 percent). These additives are not normally manufactured in a refinery.

- **Complex Refinery Operations:** Almost all of the crude volume is fed first to atmospheric pressure distillation units. Then, some of the bottoms are vacuum distilled, and then the heavier fractions are to some extent cat-cracked, hydrocracked, and/or coked during "downstream processing." Such processes distinguish most U.S. refineries from the relatively small volume of "straight-run" processing, which does not contain cracking equipment. (Note: coking is a non-catalytic cracking process.) Hydrocracking is a catalytic process that uses hydrogen to help form high-octane isomers. Other processes used to make high-octane gasoline components include catalytic reforming [produces benzene, toluene, and xylenes (BTX) and hydrogen], and alkylation and isomerization (produces branched-chain alkanes). This investigation was centered around cracking, reforming, alkylation, and isomerization changes that will be needed to make reformulated gasoline.

Hydrocracking and reforming feedstocks must be desulfurized; most desulfurization is done catalytically with hydrogen and, to a small extent, process gases are desulfurized with chemical absorbents and adsorbents. Changes in refineries' hydrogen and butane balances were estimated in this study.

- **Refinery Optimization:** Over the years, refinery optimization of process inputs, product outputs, energy, economics, etc. has become quite sophisticated in the use of modeling and linear programming techniques. While these techniques can also be applied to minimize environmental impacts, neither resources nor time was available to this study to attempt to optimize the environmental aspects of refineries in producing reformulated gasolines as industry would.
- **Reformulated Fuel Products:** Refineries will produce regular, mid-grade, and premium reformulated gasoline fuels in 2000 and 2010. Premium fuels are necessary to fuel the high-compression engines that will be present in the national fleet. In addition, as vehicles age, carbon deposits build up in combustion chambers, which boosts the engines' demand for octane.
- **Octanes Required:** A trend toward increasing engine compression ratios (to conserve fuel) with corresponding higher octane requirements for gasoline is expected in the future. This upward trend, combined with consumer demand for premium and mid-grade gasolines, will diminish the percentage of regular grade in the year 2000. Some of the demand for premium may diminish as consumers become more educated regarding the true octane requirements of their engines, and reduce the needless use of premium in many present engines. Bonner and Moore Management Science predicts that the 1995 market for gasoline will be as follows: premium - 31 percent at 92 octane; mid-grade - 21 percent at 89 octane; and regular - 48 percent at 87 octane (Strauss, 1990). If it is assumed that these percentages and octane levels hold for the years 2000 and 2010, the target minimum octanes are as given in Table F-52 (Corbett, 1990). This table shows a future pool octane requirement of 89, which compares to the recent pool octane at 88.6.

**Table F-52.**  
**Minimum Octanes for Years 2000 and 2010**

	(R+M)/2	Volume Percent
Premium	92	31
Mid-Grade	$(94+84)/2 = 89$	21
Regular	$(91.8+82.5)/2 = 87.2$	48
Pool - Calculated	89.0	
- RON	93.7	
- MON	84.3	

Note: R = RON = Research Octane No.  
M = MON = Motor Octane No.

Sources: Strauss, Michael J., *The Oil Daily*, No. 9, July 26, 1990, pg. 659; quoting from a forecast by Bonner and Moore Management Science, Houston, Texas.

Corbett, Richard A., "Fuels for Tomorrow - OGJ Special," *Oil & Gas Journal*, Vol. 88, June 18, 1990.

- Oxygen Content of Gasoline:** It was assumed that by the year 2000, all U.S. gasoline is oxygenated and that the average oxygen content is 2 percent. (Percentages in this discussion of refining are defined in terms of liquid volume basis, unless stated otherwise.) As used herein, oxygen is in the form of such compounds as tertiary ethers and tert-butyl alcohol, and not methanol or ethanol. The primary oxygenate was methyl tert-butyl ether (MTBE); 11 percent MTBE corresponds to 2 percent oxygen. For simplicity, it is assumed that 11 percent MTBE will be in the U.S. gasoline pool in the years 2000 and 2010. No adjustments have been made for the lower energy density of MTBE compared to hydrocarbons.
- MTBE Manufacture:** MTBE was assumed to be the source of oxygenate in reformulated fuels. While MTBE may in some instances be manufactured in a refinery, for purposes of this study, MTBE was assumed to be manufactured elsewhere. Thus, MTBE was considered as a separate input to the gasoline refining process and, therefore, no environmental residuals associated with its production were calculated.

A significant amount of isobutylene, used to make MTBE, will come from refinery operations. As a result, isobutylene production impacts were included in the study. The other raw material required to make MTBE is

methanol. For purposes of this study, methanol was not considered a refinery product. According to NES, considerable amounts of methanol will be imported in 2000 and 2010 for transportation use (DOE, 1991a).

- **Reformulated Gasoline Component Blending:** It is assumed that blends of liquid volumes with varying parameters such as octane value, Reid vapor pressure, and aromatics and butane contents can be made linearly with no shrinkage of total liquid volume.
- **Refinery Scenarios:** The following refinery scenarios were investigated in this study.
  - United States less West Coast (PADDs I through IV), average crude slate, year 2000.
  - United States less West Coast (PADDs I through IV), average crude slate.
  - West Coast (PADD V), average crude slate, year 2000.
  - West Coast (PADD V), average crude slate, year 2010.
- **Basis for Refinery Emissions and Effluents Allocation to Reformulated Gasoline:** Emissions, effluents, and wastes estimates were developed, to the extent possible, by major refinery unit operation and then allocated between reformulated gasoline and byproducts on a volumetric basis.

With a scenario that included 11 percent MTBE equivalent in the gasoline pool, adjusted catalytic reforming and FCC operations, reduced amounts of alkylate and butane in the pool, blendstock and processing changes to reduce benzene content, and isobutylene production, the effects of these changes on other refinery processes, such as hydrogen manufacture, were accounted for in this study. As mentioned above, the crude throughput and downstream processing were characterized for the United States excluding the West Coast, and then for just the West Coast.

- **Air Emissions, Liquid Effluents, and Solid Waste Assumptions:**

**Air Emissions:** Emission factors for criteria pollutants, aldehydes, and ammonia were obtained from AP-42 and modified where appropriate to include abatement expected to be in place by 2000 (EPA, 1985a). Data from reporting required under California legislation AB 2588 for air toxics and from the EPA Toxic Release Inventories System were used to help quantify toxics. The emission factors for greenhouse gases such as carbon

dioxide and methane, which are not criteria pollutants, were derived from energy consumption data. For example, carbon dioxide emissions were calculated from refineries' fuels usage. Emission factors used for 2000 were assumed to be the same through the year 2010, except for adjustments required by regulations.

**Liquid Effluents:** Wastewaters emanate from several sources including cooling systems and steam boiler systems. It was assumed that wastewater from caustic breathing and the bottoms from sour water strippers, which flow to the API separators, were the main wastewater streams affected by reformulation.

**Solid Waste:** Refineries produce both hazardous and non-hazardous solid waste. Solid waste and sludges from boiler operations, including feedwater treatment sludges, were accounted for. Spent catalysts that cannot be recycled account for a large volume of the solid waste, with cat-cracking waste catalyst (non-hazardous) being the most voluminous. A portion of the other catalysts is non-recyclable and disposed of as hazardous waste, as are certain other solids (e.g., zinc oxide used to adsorb hydrogen sulfide in hydrogen plants). Non-hazardous solid waste can be disposed of in Class II landfills while hazardous solid waste need special handling. The quantities of solid waste disposed off-site from refineries were assumed to be proportional to the throughput for each process, and that the calculated amounts will hold through 2010, except for adjustments required by regulations.

**Refinery Vehicle Emissions:** Emissions and effluents from onsite vehicle operations are expected to be insignificant relative to other refinery emission and effluents. Consequently, they will not be considered in this study.

**Product Loading Emissions:** The emissions from loading finished product into pipelines, or other modes of transportation are accounted for in Section F.5.

**Alcohol Fuels:** Production of the alcohol fuels, methanol and ethanol, will not take place at U.S. refineries nor will alcohol fuel blending be done at U.S. refineries by the year 2000. These assumptions are consistent with current practice and reflect the realities of fuel alcohol supply and demand.

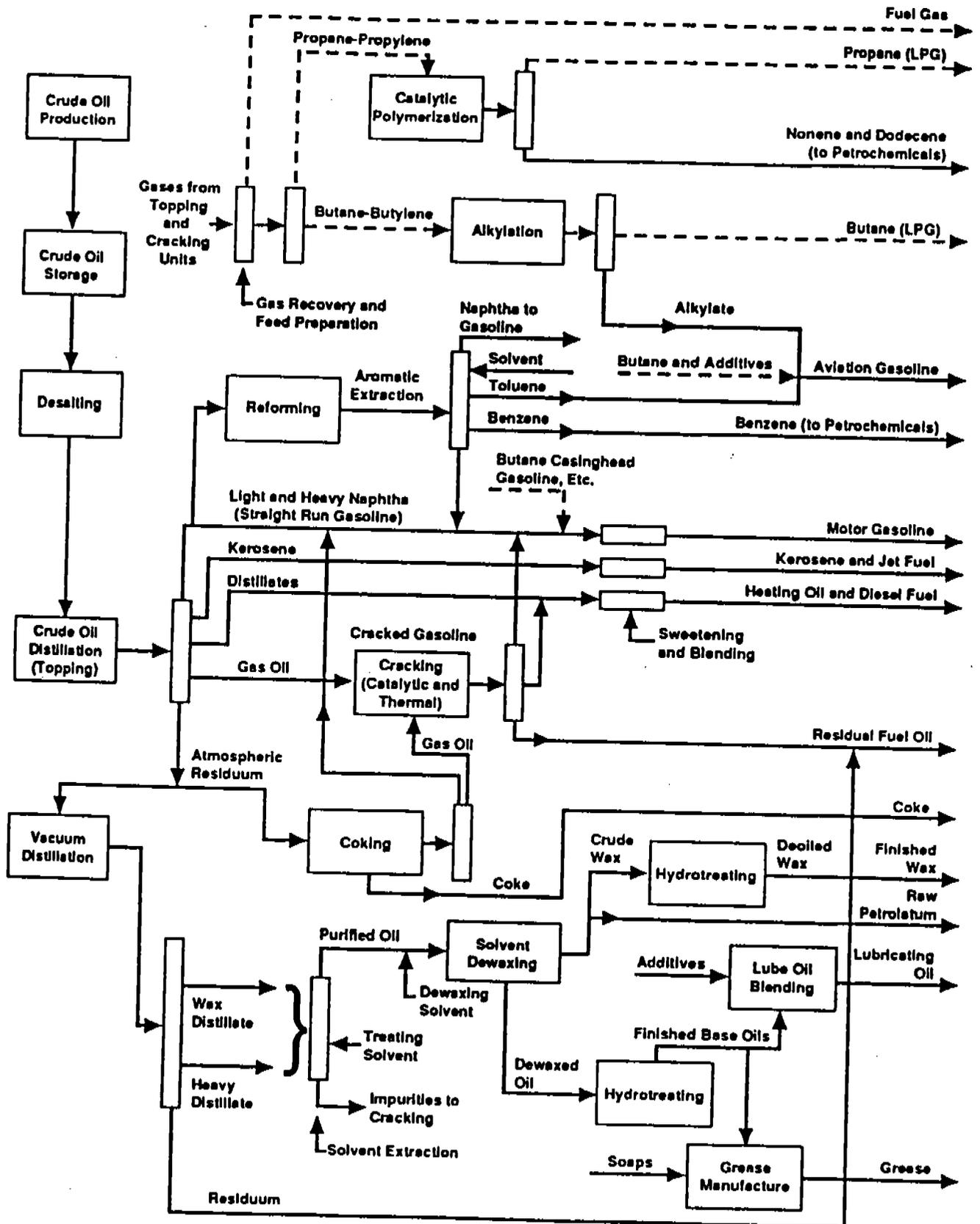
### F.4.2.3 Reformulated Gasoline Specifications for 2000 and 2010 Assumptions

- **Reformulated Gasoline Specifications Development:** Reformulated gasoline specifications are based on those given in the Clean Air Act Amendments of 1990 (CAAA, 1990), subsequent reformulated gasoline regulatory negotiation process agreements, and the Auto/Oil Air Quality Improvement Research Program results.
- **Reformulated Gasoline Composition:** All reformulated gasoline in both 2000 and 2010 will be oxygenated. The following lists estimates of the average reformulated gasoline composition and property characteristics expected in the years 2000 and 2010:
  - aromatic content: 25 vol%
  - benzene content: 1.0 vol%
  - olefin content: 15 vol% maximum
  - oxygen content: 2.0 wt%
  - summer RVP: 8.5 psi; annual average RVP: 9.0 psi
  - sulfur content: 100 ppm
- The refineries were assessed in this study primarily for gasoline production because gasoline is the economic driver of the production slate. No optimization analyses were conducted to address the demand for No. 2 diesel fuel, jet fuel, and other fuels for 2000 and 2010. It was assumed that the refineries will be able to produce the required amounts of these other fuels as postulated by NES.

### F.4.3 Process Description

Petroleum refineries differ widely in the processing steps they follow and with the types of products they generate. The product slate has always reflected changes in product demand. During the mid-1800s, coal distillation produced an oil used primarily for illumination. The growing demand for gasoline spurred the development of new refinery processes to increase gasoline yields and improve the quality of the finished product. Figure F-12 is a simplified diagram of a modern, complex refinery. The key unit operations are described as follows:

**Thermal cracking**, a severe form of heat processing, was the first downstream process that changed the petroleum refining industry. Thermal cracking was followed by other developments in the late 1920s and early 1930s. **Polymerization** produces high octane gasoline from byproducts of thermal cracking (olefins). **Vacuum distillation** further processes the "residuum," or product remaining in the bottom of the crude oil distillation column that will not distill at atmospheric pressure. The product left from the vacuum distillation process can be made to flow more easily by subjecting it to a thermal



Source: National Petroleum Council, *U.S. Petroleum Refining*, Washington, D.C., 1991.

Figure F-12. Simplified Flow Chart of a Complex Refinery

cracking process known as **visbreaking**. This process reduces the product's viscosity (the thick, gluey quality that impedes product flow). **Coking**, another severe thermal process, produces fuel gas, gasoline blending stocks, distillates, and petroleum coke from the products left from atmospheric or vacuum distillation.

During World War II, the petroleum industry focused its technological expertise on products essential to the war effort, especially high quality aviation fuel. One result was the development of **alkylation**, a process in which a catalyst is used to produce a high quality gasoline component. This process became widely used after the war to produce gasoline blending stocks. Other technological advances during the war included **catalytic cracking** and **isomerization**. Catalytic cracking is similar to thermal cracking, but utilizes a catalyst to accelerate the rate of the reaction. Isomerization is a process to produce high quality gasoline blending stocks called isomers by changing the arrangement of atoms in the hydrocarbon molecule without changing the chemical composition of the compound. The isomerization process uses heat and a catalyst to convert straight-chained hydrocarbon molecules to branched-chained hydrocarbon molecules with the same chemical composition. This process increases the octane number of the light gasoline components, normal pentane and normal hexane, that are found in light, straight-run gasoline.

**Catalytic reforming**, a revolutionary process for converting low grade naphthas to high octane gasoline, was a major development in the late 1940s. **Hydrotreating**, a process to remove contaminants that would damage the catalyst used in catalytic reforming, was developed in the mid-1950s. **Hydrocracking**, a process using hydrogen and catalysts to convert middle boiling range or residual products into lighter products, was developed in the 1960s.

As the sources of crude oil continue to shift, changes in the characteristics of crude oil inputs will continue to shape the configuration of U.S. refineries. Similarly, as the specifications for the major refinery output, i.e., gasoline, change in response to environmental, fuel economy, or other pressures, refinery configurations will respond. Thus, refinery configuration is constantly changing to meet current requirements. Changing the quality of crude oil inputs and changing product requirements will continue to stimulate technological advances and modifications in refinery configuration. Environmental requirements for cleaner burning fuels and cleaner refinery processes are foremost among the factors that will influence refinery configuration in the next decade. Innovations in catalyst design and refinery process units will allow greater flexibility in processing heavy residual oils. Newly developed catalysts will also help refiners meet environmental standards for sulfur in final products and in refinery emissions. Requirements for specialized hydrocrackers, hydrotreaters, and other down-stream units are likely to increase as refinery configurations adapt to increasingly stringent product specifications" (DOE, 1991b).

#### **F.4.4 Process Environmental Points of Interest**

Section F.4.2 provided a list of specific assumptions that were used to guide the overall crude oil refining system. In order to produce the reformulated gasoline specifications shown in Section F.4.2.3, current refinery operations will require some changes including reduced reformer severity, reduced throughput through catalytic reformers, etc. These technical considerations are the subject of this section. This section shows how the various unit operations in the refinery must be modified to produce the required gasoline specifications and to handle the increasing densities (decreasing API gravities) of crude oils. It should be noted that the refinery scheme described below represents only one of the possible approaches, given the latitude of refinery considerations available to produce reformulated gasoline. The approach taken is representative, from an environmental perspective, of the range of possible approaches.

##### **F.4.4.1 Overview and Rationale for Refinery Configuration**

**MTBE Content:** As mentioned above in the assumptions, the reformulated gasoline in 2000 and 2010 will be oxygenated at 2 weight percent oxygen. Assuming MTBE will provide the source of oxygen, approximately 11 percent of the gasoline pool will be comprised of MTBE, with the remaining 89 percent of the gasoline being reformate and other components. The other components include straight-run naphtha, isomerate, fluid catalytically cracked naphtha, light coker naphtha, hydrocrackate, alkylate, aromatic extracts (benzene, toluene, and xylenes), butane, and several other blendstocks, all of which are tabulated and discussed below. The tabulation gives the quantities as of mid-1989, and these quantities are used herein as being representative of the 1990 or present-day gasoline pool.

Achieving the 11 percent MTBE content in the gasoline pool will require a significant effort, since it will produce large strains on isobutylene supply required to manufacture MTBE and on other light olefins supply needed to produce similar ethers. It is assumed that the production of isobutylene, isoamylene, and propylene for feeding ether plants is part of the main refining process. Fluid catalytic cracking (FCC) operations were adjusted to produce more light olefins, with a loss in naphtha production.

Regulatory limitations on gasoline vapor pressure and the need to convert butane stocks to isobutylene for MTBE production will greatly diminish the quantity of butane presently added to gasoline blends.

**Aromatics and Benzene Contents:** Each refinery that reformulates will attempt to achieve the aromatics and benzene limits by altering processes in a way that is believed by each refinery owner to be optimum. This study does not attempt to determine any optima. The study's approach formulates the pool theoretically to 25 percent aromatics, or slightly below 25 percent, using a plausible scenario based mainly on changes to catalytic reforming operations, on a nationwide average basis. This approach also formulates the potential

average benzene content and discusses what blending and processing changes could be used to achieve a maximum benzene content of 1.0 volume percent.

**Octanes Required:** A precise estimate of the octanes required is not critical for this study, because a U.S. gasoline pool containing 11 percent MTBE equivalent will have an octane surplus. Consequently, the study developed a refinery configuration that includes a pool with reduced percentages of high-octane components such as reformate, alkylate, and butane.

A major problem under this scenario will be the production of adequate isobutylene needed for the manufacture of MTBE. With an octane surplus, alkylation can be reduced in throughput, making isobutane (which can be dehydrogenated to isobutylene) and butylene available. Adjustments in FCC operations will include increased production of light olefins, useful for MTBE feedstocks, with concurrent reduction in FCC naphtha blendstock production. Mandated gasoline vapor pressure limits and reduced volumes of non-oxygenated blendstocks will result in more butane being available for conversion to isobutylene. To meet the 25 percent aromatics limitation, adjustments in catalytic reforming operations were investigated, which, at the same time, help reduce benzene content. Additional changes in blendstock formulations and refining processes were needed to meet the 1.0 percent benzene limitation.

Even though an upward trend in octane demand might occur, an octane surplus is predicted if the percentage of MTBE equivalent is as high as 11 percent. That much MTBE equivalent in the pool, coupled with the growth of substitute fuels and energy sources after 2000, will result in a reduction of non-oxygenates blendstocks volume: 770,000 barrels per calendar day (BCD) less in 2000 and 1,393,000 BCD less in 2010, compared to 1990.

**Total Gasoline Volume:** The volume of gasoline demand as predicted by the NES scenario is shown in Table F-53.

**Crude Oils Characterization and Slates:** The assumptions of crude volumes, gravity, and sulfur content in 2000 and 2010 were presented in Table F-49 above.

#### **F.4.4.2 Aromatics Limit**

**Catalytic Reforming Operations:** Reforming operations will be affected in a number of ways: less throughput through catalytic reformers; less severity of reforming because fewer aromatics will be produced and 11 percent MTBE equivalent causes an octane surplus; and increased pre-distillation of C<sub>5</sub>s and C<sub>6</sub>s or extraction of benzene from the product reformate. In a recent study on refinery octane, it was estimated that reducing the refining severity by one octane will result in 2 percent less aromatics and 0.9 percent

**Table F-53.**  
**NES Strategy Scenario - Total U.S. Gasoline Demand**

Year	Demand, MMBD	MTBE Content	
		%	MMBD
1990	7.0	--	--
2000	7.0	11	0.8
2010	6.3	11	0.7

Source: U.S. Department of Energy, *National Energy Strategy, Technical Annex 2, Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions and Results*, First Edition, 1991/1992, Report No. DOE/S-0086P, Washington, D.C., 1991.

more gasoline yield (Unzelman, 1990). This study also shows an example of changing refinery severity by 5 octanes.

In this study on reformulated gasoline with 11 percent MTBE in the pool, a reduction in refinery severity of five octane numbers is assumed. At this level of severity reduction and calculated adjustments in the volumes of reformate, FCC naphtha, and alkylate, the potential octane surplus is reduced to one or less  $(R + M)/2$  octane number. There is a corresponding reduction of 8 percent aromatics in the reformate, and potential gain of five times 0.9 percent in the reformate yield volume, which must be accounted for in the overall reduced reforming charge volume.

The resulting aromatics content and octane numbers of the pool reformate are summarized in Table F-54. This table also shows 1990 values for comparison (Corbett, 1990). It should be noted that reduced throughput and severity results in less hydrogen being produced from catalytic reformers; this hydrogen and additional hydrogen requirements must be made up with new hydrogen production facilities.

**Table F-54.**  
**Reformate Properties**

Properties	1990	2000, 2010
Aromatics Content, %	66.2	58.2
RON	98.5	93.5
MON	88.4	85.5

The remainder of the blendstocks (excluding MTBE), referred to herein as "other" components in the U.S. gasoline pool, have an average aromatics content of 19 percent (refer to Figure F-13). These blendstocks contain no ethanol and less than one percent MTBE. Figure F-13 further shows that if the aromatics content of blendstocks other than reformate stays at 19 percent, then reformulated gasoline with 11 percent MTBE and 25 percent aromatics will include up to 20.7 percent reformate. This compares to present-day gasoline's reformate content of 27.2 percent in the pool. The corresponding remainder of the reformulated pool, 68.3 percent, accounts for the other components excluding MTBE at 11 percent.

**Volume of Gasoline Components:** The projected volumes of gasoline components are shown in Table F-55. If the 1990 pool is characterized with a total gasoline volume of 7,000,000 BCD and 27.2 percent reformate, the changes in the volumes of reformate and of other components for the years 2000 and 2010 are as shown in Table F-56.

Because decreased reforming severity results in more volume of reformate produced per barrel of crude oil charged into a refinery, the projected decrease in reforming charge compared to 1990 is 576,000 BCD in the year 2000 and 665,000 BCD in the year 2010.

The volume decreases in the other components noted in Table F-56 will be accomplished by individual refiners in a variety of ways. In this study, it was assumed that FCC feed rates will not be decreased, because light olefins produced by FCC will be needed for MTBE production. FCC operating conditions can be altered to increase light olefins production and correspondingly decrease FCC naphtha production, which is part of the pool. In order to help stay under the 25 percent aromatics and one percent benzene limitations, deliberately blending benzene, toluene, and xylenes and "other aromatics" should cease. As long as there is a potential octane surplus and a need for isobutylene, alkylate production can be curtailed. Deliberate additions of normal butane to the pool must also be curtailed in order to meet a summer limitation of 8.5 RVP.

In summary, the scenario used in this study includes: (a) eliminating 30,000 BCD of "other aromatics" in both years, and in 2010 eliminating 146,000 BCD of other "other" (with 32.2 percent aromatics); (b) reducing 1990 butane additions by approximately 50 percent to meet the RVP limitation (Figure F-14); (c) cutting back on catalytic reforming and alkylation to meet the year 2000 changes of Table F-56. For the year 2010 changes, which are even larger, FCC alterations to maximize light olefins at the expense of naphtha production were included as well as even larger alkylate reductions than for the year 2000 (Corbett, 1990). A summary is provided in Table F-57. Figure F-15 shows how the FCC alterations were applied. (An alternative method of reducing pool aromatics content and quantity of FCC naphtha, not used in this scenario, would be to lower the end point of heavy FCC naphtha. Such an alternative, however, will not increase light olefins supply needed to manufacture ethers such as MTBE.)

A. Determine Aromatics Content of Non-Reformate Gasoline Stocks

In a recent study, Corbett indicates the following composition of the U.S. gasoline pool (Corbett, 1990).

Volume fraction of all of the reformates: 0.272 = FR  
Fraction of all other components: 0.728 = FO (by subtraction)

Volumetric average aromatics content of all the reformates: 0.662 = AR

Aromatics fraction of the pool: 0.318

Therefore, the calculation of the aromatics content of the other components (AO) is as follows:

$$0.318 = 0.272 * 0.662 + FO * AO$$

$$AO = 0.1895$$

B. Determine Reformate Content of Reformulated Gasoline

Assume: 11% MTBE; aromatics content of non-reformate components (excluding MTBE) (i.e., AO) stays at 0.1895 as calculated in A above.

Maximum allowable aromatics fraction: 0.25

Aromatics fraction in reformate, from Table F-54: 0.582

With 11% MTBE, volume fraction of all other components: 0.89

Therefore:  $0.25 = FO * 0.1895 + FR * 0.582$

and:  $0.89 = FO + FR$

Solving these two equations simultaneously gives:

FO = 0.683, the fraction of non-reformate blendstock excluding MTBE

FR = 0.207, the fraction of reformate in the reformulated pool

**Figure F-13. Calculation of Aromatics Content of Non-Reformate Gasoline Stocks and Calculation of Reformate Content of Reformulated Gasoline**

**Table F-55.  
Refinery Reformulated Pool, BCD**

Component	2000	2010
11.0% MTBE	770,000	693,000
20.7% Reformate	1,449,000	1,304,000
68.3% Other Components	<u>4,781,000</u>	<u>4,303,000</u>
Total	7,000,000	6,300,000

**Table F-56.  
Changes from 1990 Volumes, BCD**

Component	1990	2000	2010
Total Gasoline	7,000,000	7,000,000	6,300,000
MTBE	(<1%)	770,000	693,000
Reformate	1,900,000	$\Delta = -451,000^1$	$\Delta = -596,000^1$
Other Components	5,100,000	$\Delta = -319,000^1$	$\Delta = -797,000^1$

<sup>1</sup> Compared to 1990.

**Table F-57.  
Breakdown of Volume Changes, BCD**

Component	1990	2000	2010
Other Aromatics Added to Pool	30,000	$\Delta = -30,000$	$\Delta = -30,000$
Other "Other," Containing 32.2% aromatics	146,000	no change	$\Delta = -146,000$
Butane Additions	211,000	$\Delta = -101,000$	$\Delta = -112,000$
Alkylate, Full-Range	787,000	$\Delta = -188,000$	$\Delta = -303,000$
FCC Naphtha, Full-Range	1,367,000	no change	$\Delta = -206,000$
Total Changes from 1990 in Volumes of Other Components		-319,000	-797,000

Unzelman recently reported that the blending RVP of n-butane (nC<sub>4</sub>) is 60 psi, while that for MTBE is 9 psi. The present or base year gasoline pool RVP is 9.5 psi, and from page 49 of the Corbett, 1990 reference, the pool totals 6760.2 kBCD (excluding aviation gasoline), containing 211 kBCD of nC<sub>4</sub>, and 1847.3 kBCD of reformates with RVP of 5.9 psi.

Step A: Determine the blending RVP of all the pool components excluding nC<sub>4</sub> and reformates:

$$\text{Volume of pool components} = 6720.2 - 211 - 1847.3 = 4661.9 \text{ kBCD}$$

and

$$9.5 = (4661.9 * \text{RVP} + 211 * 60 + 1847.3 * 5.9) / 6720.2 \quad \text{RVP} = 8.64 \text{ psi}$$

Step B: Determine the RVP of reformulated pool excluding nC<sub>4</sub>, with 11% MTBE, 20.7% reformate, and 68.3% other with an RVP as calculated in Step A. Assume no cosolvency effects.

$$\text{RVP} = 0.11 * 9 + 0.207 * 5.9 + 0.683 * 8.64 = 8.1 \text{ psi}$$

Note: One can add nC<sub>4</sub> to this reformulated pool to the extent of 0.4 psi additional to this calculated RVP to reach the allowed warm season maximum of 8.5 psi.

Step C: Determine the fraction of nC<sub>4</sub> (Fn) in reformulated pool at RVP = 8.5, by setting up an equation representing the RVP of the pool components excluding MTBE and reformate:

$$(0.683 - \text{Fn}) * 8.64 + \text{Fn} * 60 = 0.683 * 8.64 + 0.4$$

$$\text{Fn} = 0.0078$$

Step D: Apply this fraction of pool nC<sub>4</sub> to volume for year 2000 and to volume for year 2010 in the warm seasons, and then determine the annualized volume of nC<sub>4</sub>:

$$\begin{aligned} \text{Year 2000: gasoline volume} &= 7000 \text{ kBCD, from NES} \\ \text{n-butane volume} &= 7000 \text{ kBCD} * 0.078 = 55,000 \text{ BCD} \end{aligned}$$

If warm season is assumed to consume half of the year, then the annualized n-butane pool volume is  $2 * 55,000 = 110,000 \text{ BCD}$ , or approximately half of the present pool volume.

Note: Present pool volume: 211,000 BCD  
 Net available to make MTBE: 101,000 BCD  
 (Use this volume change for butane additions in Table F-57)

$$\begin{aligned} \text{Year 2010: gasoline volume} &= 6300 \text{ kBCD, from NES} \\ \text{n-butane volume} &= 6300 \text{ kBCD} * 0.0078 = 49,000+ \text{ BCD} \end{aligned}$$

Annualized n-butane volume:  $2 * 49,000+ = 99,000 \text{ BCD}$  or approximately half the present pool volume

Note: Present pool volume: 211,000 BCD  
 Net available to make MTBE: 112,000 BCD  
 (Use this volume change for butane additions in Table F-57)

**Figure F-14. Calculation of Butane Content**

Recently, Corbett examined the product yields from FCC operations for two scenarios: (a) one favoring gasoline yields, as done in 1990 and (b) the other favoring light olefins yields, as suggested in this study for the year 2010 (Corbett, 1990). Corbett evaluates the yields for ethane and lighter gases, propylene, propane, butylenes, isobutane, butane, gasoline (0.60 fraction of FCC charge in 1990), coke, and carbon monoxide. Shown below are example calculations, for determining the increased isobutane volume and decreased FCC gasoline volume relative to the base-year production of 2,582,710 BCD (Corbett, 1990; page 50) of FCC gasoline in the U.S. gasoline pool.

A. For the Isobutane and Gasoline Example Yields, Determine Ratio "R" of Yield with Increased Light Olefins vs. Base Year Scenario

With increased light olefins:

$$\text{Total butanes yield} = 0.205 * \text{FCC charge}$$

$$\text{Isobutane portion of butanes yield is } 0.26 * \text{total butanes, or } 0.0533 * \text{FCC charge}$$

$$\text{Gasoline yield} = 0.552 * \text{FCC charge}$$

With operations typical of year 1990:

$$\text{Isobutane portion of yield} = 0.29 * 0.154, \text{ or } 0.0447 * \text{FCC charge}$$

$$\text{Gasoline yield} = 0.60 * \text{FCC charge}$$

Ratio of yields:

$$\text{Isobutane in 2010 vs. 1990: } 0.0533/0.0447 = 1.19$$

$$\text{Gasoline in 2010 vs. 1990: } 0.552/0.60 = 0.92$$

B. Apply Ratios to Determine Changes from 1990 to 2010

$$\text{FCC charge volume in base year} = 2,582,710 \text{ BCD}/0.60 = "C"$$

$$\begin{aligned} \text{Isobutane: } (R - 1) * 0.0447 * C &= (1.19 - 1) * 0.0447 * C \\ &= 36,500 \text{ BCD more} \end{aligned}$$

$$\begin{aligned} \text{Gasoline: } (1 - R) * 2,582,710 \text{ BCD} &= (1 - 0.92) * 2,528,710 \text{ BCD less} \\ &= 206,600 \text{ BCD less} \end{aligned}$$

**Figure F-15. Calculation of the Potential Increased Yield of Light Olefins (Such as Butylene and Isobutane) by Altering Fluid Catalytic Cracking (FCC) Operations, with Coincident Reduced FCC Gasoline Yield**

**Role of Natural Gas Liquids and Simple Refineries:** It should be noted that because of the potential octane surplus, no changes are contemplated in the amounts of straight-run naphtha and natural gas liquids in 2000 and 2010 compared to 1990. These relatively low-octane components can stay in the pool without degrading octane levels below target values, even with increases in premium and mid-grade gasoline percentages of the gasoline market. These components cost less to produce in a form ready to blend than do gasoline components that are derived from refinery downstream processing, since they require minimal processing.

Also, natural gas and straight-run operations provide a low-cost source of butanes, thereby improving the potential for isobutylene production that will be needed to make MTBE.

In summary, there will still be a place for simple refineries making straight-run products other than heavy fuel oil in the NES scenario.

**Hydrogen Balance:** Hydrogen is used in large volumes in hydrocracking (which this NES scenario leaves unchanged) and in removing sulfur from catalytic reformer feedstock and from other stocks. This study assumes additional hydrogen production for mandated diesel sulfur limitation, and for making up lost hydrogen production associated with reforming changes (in proportion to reduced aromatics volume).

The common method of producing hydrogen in refineries, other than from catalytic reforming, is steam reforming of natural gas or naphtha. Each refiner will make the choice. For purposes of this study, natural gas is assumed to be the feedstock for the incremental hydrogen production needed.

#### **F.4.4.3 Benzene Limit**

Various studies indicate that the benzene content of the 1989 gasoline pool ranged between 1.6 and 2.0 percent (Corbett, 1990; Johnson, 1991). Several techniques are available to produce gasoline at the 1.0 percent limitation:

- Reduce volume of reformate in the pool
- Reduce severity of catalytic reforming
- Extract benzene from some of the reformate produced (or, alternatively, pre-distill C<sub>5</sub> and C<sub>6</sub> components out of reformate feedstocks).

One study indicates that 72 percent of the 1990 pool can achieve under one percent benzene from the first two techniques (Johnson, 1991). It is assumed that the other 28 percent contains 2.0 percent unless enough reformate extraction is done to reduce the benzene content to 1.0 percent. Table F-58 shows how the volume of benzene extracted is derived. In order to extract approximately 20,000 BCD of benzene, or alternatively to pre-distill reformate

feedstock, a very large quantity of reforming throughput must be treated--approximately 45 percent.

**Table F-58.**  
**Benzene Removed from Reformate, BCD**

Component	2000	2010
A. Total Gasoline	7,000,000	6,300,000
B. 28% of A	1,960,000	1,764,000
C. B x (2.0% - 1.0%)	20,000	18,000

In practice, it will be necessary to achieve a pool benzene content somewhat below 1.0 percent in order to ensure no exceedance. This can be accomplished by using the techniques above plus the elimination of deliberately blending aromatics into the pool.

#### **F.4.4.4 Butanes and the Availability of Isobutylene**

Table F-59 summarizes the quantities of butanes available in the years 2000 and 2010. In this table, the quantities of n-butane no longer added to gasoline were derived in Figure F-14. The increase in FCC light olefins was calculated using the procedure described in Figure F-15. The available amounts of butanes were determined as follows: using a typical butanes alkylation feed slate of 0.583 barrels of isobutane plus 0.53 barrels of butylenes per barrel of alkylate, these two factors were applied to the alkylate volume reductions given in Table F-57.

This tabulation indicates a shortfall in the year 2000; i.e., not enough isobutylene in the United States can be made available, even if available normal butane is isomerized and all available isobutane is dehydrogenated to isobutylene. However, in the year 2010, more than the required amount of butanes is available. For the year 2000, either 367,000 BCD of MTBE or 283,000 BCD of butanes must be imported if MTBE is the only oxygenate considered.

By the year 2010, imports of MTBE or butanes is unnecessary. This may prove fortunate for the United States. However, as one observer commented "But if oxygenating is a good thing here, it will likely demand application overseas as well (Johnson, 1991)." This scenario assumes that widespread use of MTBE overseas will not occur before the year 2000. In actual practice, not all of the ethers that will be required in the year 2000 pool will be derived from isobutylene. Some tert-amyl methyl ether, made from isoamylene

**Table F-59.  
Butanes Available to Help Meet Isobutylene Demand, BCD**

Components	Year 2000		
	Butylenes	i-Butane	n-Butane
Butane no longer added to gasoline			101,000 <sup>1</sup>
Butanes available if less alkylate made	99,000 <sup>2</sup>	110,000 <sup>2</sup>	
Increase FCC light olefins	No change from 1990		
Total butanes potentially available: 310,000 (makes 403,000 BCD MTBE) MTBE shortfall: 367,000 BCD (need 770,000 BCD MTBE)			
Components	Year 2010		
	Butylenes	i-Butane	n-Butane
Butane no longer added to gasoline			112,000 <sup>1</sup>
Butane available if made less alkylate	159,000 <sup>2</sup>	177,000 <sup>2</sup>	
Increase FCC light olefins	152,000 <sup>4</sup>	36,000 <sup>3</sup>	7,000 <sup>4</sup>
Total butanes potentially available: 643,000 BCD (makes 836,000 BCD MTBE) MTBE potential excess: 143,000 BCD (need 693,000 BCD MTBE)			

<sup>1</sup> From Figure F-14.

<sup>2</sup> Table F-57 full range alkylate volumes multiplied by typical alkylation feed slate of 0.58 barrel of isobutane per barrel of alkylate and 0.53 barrel of butylenes per barrel of alkylate.

<sup>3</sup> From Figure F-15.

<sup>4</sup> Similar calculations to Note 2.

(the C<sub>3</sub> analog of isobutylene), will be in the pool also. In other words, the use of other ethers will relieve some of the demand for MTBE.

#### **F.4.4.5 Summary of Reformulated Gasoline Pool**

As discussed earlier in Table F-54, the reduced severity of catalytic reforming drops the average reformate aromatics content to 58.2 percent. Extracting approximately 20,000 BCD from the reformate pool, or pre-distilling reforming feedstocks to an equivalent extent, would cause a further drop in the average reformate aromatics content to 56.8 percent.

For the year 2000, the refinery configuration includes eliminating certain aromatics and some of the butane now deliberately added to the gasoline pool, as well as reducing the amount of

alkylate. The net result is changes in the octane ratings and aromatics content of non-MTBE and non-reformate components. The characteristics of the reformulated pool, which include meeting aromatics, benzene, and vapor pressure limitations, are summarized in Table F-60.

**Table F-60.  
Year 2000 Gasoline Pool Characteristics**

Components	Volume Percent	Amount, MMBD	RON	MON	Aromatics Percent
MTBE	11.0	770,000	118.0	100.0	0.0
Reformate	20.7	1,449,000	93.3	85.5	56.8
Other	<u>68.3</u>	<u>4,781,000</u>	90.9	81.6	19.7
Total	100.0	7,000,000			
Pool Octanes and Aromatics			94.3	84.4	25.0
(RON + MON)/2			89.3 (Target is 89.0)		

For the year 2010, changes to pool components also include revising FCC operations to increase light olefins production at the expense of naphtha now blended into gasoline, and even greater reductions in the amount of alkylate. The result would be an increase in the percentage of aromatics in the non-reformate components, on average. To maintain the aromatics limitations, the refinery scenario includes eliminating the other "other" additions to the pool that are estimated to contain 32.2 percent aromatics. The characteristics of the 2010 reformulated pool are summarized in Table F-61.

With respect to gasoline to be blended downstream of the refinery with ethanol to produce an "E10" blend, the assumption is made, with respect to RVP, that refineries will be able to produce gasoline with vapor pressure limitations that can be directly used to make E10.

#### **F.4.4.6 Other Processes and Refining Scenarios**

The refining steps of main concern, after atmospheric distillation, are: vacuum distillation, thermal operations (mainly coking in modern complex refineries), catalytic cracking (mainly FCC), catalytic reforming, catalytic hydrocracking, hydrorefining, hydrotreatment (hydrogen desulfurization), and alkylation (Corbett, 1990). Hydrogen production and coke production are also reported. For each of these processes, the fraction of crude throughput is given in Table F-62 for the year 1990. This fraction is

**Table F-61.  
Year 2010 Gasoline Pool Characteristics**

Components	Volume Percent	Amount, BCD	RON	MON	Aromatics, Percent
MTBE	11.0	693,000	118.0	100.0	0.0
Reformate	20.7	1,304,000	93.3	85.5	56.8
Other	<u>68.3</u>	<u>4,303,000</u>	92.2	82.0	19.3
Total	100.0	6,300,000			
Pool Octanes and Aromatics			95.3	84.7	25.0
(RON + MON)/2			90.0 (Target is 89.0)		

also given for PADD V (west of Rockies) and for PADDs I-IV (rest of United States) separately for vacuum distillation, coking, and catalytic cracking, because the extent these processes are used depends on crude gravity, which is heavier in PADD V.

The crude runs given in Table F-62 and other crude properties were provided earlier in Tables F-46, F-48, and F-49 and are summarized in Table F-63.

**Vacuum Distillation and Coking:** The crude slate will be heavier (lower °API gravity), requiring more thermal operations (coking) to meet the increasing demands for middle distillates while avoiding increased production of residual fuel oil. PADD V refineries often run this way, relative to other U.S. refineries, by operating vacuum distillation at a higher fraction of crude runs. This type of operation is also done at some of the Louisiana refineries handling heavier crude, where the gravity is now averaging 29.9 °API. For example, the Mobil Refinery at Chalmette, Louisiana is reported to be running at the equivalent of 0.528 vacuum distillation capacity as a fraction of crude, and 0.19 coking capacity (Thrash, 1991). Both of these figures are well above the 1990 averages given for all of the United States in Table F-62, and appear adequate for handling the 29.4 degree gravity crude projected for PADD I-IV in 2010. In this study for PADDs I-IV, these Mobil Refinery values were adopted as shown in Table F-62 for the year 2010.

For the year 2000 in PADDs I-IV, fractions mid-way between these 2010 values and 1990 values for PADD I-IV were chosen.

The PADD V refineries were equipped by 1990 to handle very heavy crudes, and no changes are projected for vacuum distillation and coking fractions of crude runs in 2000. For PADD V in 2010, the Mobil Refinery at Torrance, California has been chosen as the model for this scenario, with existing vacuum distillation at 0.73 capacity (compared

**Refining Scenarios in the Years 2000 and 2010 by Geographic Area and Refinery Unit Operation Charges and Products**

	Charge							Product	
	Crude	Vacuum Distillation	Thermal Operation (Coking)	Catalytic Cracking	Catalytic Reforming	Catalytic Hydrocracking	Hydrorefining and Hydrotreating	Alkylation and Poly.	Coke <sup>1</sup>
<b>1990</b>									
<u>Fraction of Crude<sup>2</sup></u>									
All of U.S.	1.0	0.43	0.12	0.33	0.24	0.077	0.60	0.07	0.038
PADDs I-IV		0.41	0.10	0.35					
PADD V		0.535	0.28	0.25					
<u>kBCD</u>									
All of U.S.	13,400	5,762	1,608	4,422	3,216	1,032	8,040	938	61,000
PADDs I-IV	10,810	4,432	1,081	3,784					tons/day
PADD V	2,590	1,386	5,849	648					
<b>Year 2000</b>									
<u>Fraction of Crude</u>									
PADDs I-IV		0.47	0.14						
PADD V		0.535	0.21						
<u>kBCD</u>									
All of U.S.	17,600	8,493	2,702	4,422 <sup>3</sup>	2,640 <sup>4</sup>	1,032 <sup>3</sup>	12,480	750 <sup>5</sup>	102,700
PADDs I-IV	14,200	6,674	1,988	3,784 <sup>3</sup>					tons/day
PADD V	3,400	1,819	714	648 <sup>3</sup>					
<b>Year 2010</b>									
<u>Fraction of Crude</u>									
PADDs I-IV		0.52	0.19						
PADD V		0.73	0.37						
<u>kBCD</u>									
All of U.S.	18,400	10,303	4,126	4,422 <sup>3</sup>	2,551 <sup>4</sup>	1,032 <sup>3</sup>	15,710	635 <sup>5</sup>	156,800
PADDs I-IV	14,900	7,748	2,831	3,784 <sup>3</sup>					tons/day
PADD V	3,500	2,555	1,295	648 <sup>3</sup>					

<sup>1</sup> Coke fraction is relative to coking charge.

<sup>2</sup> Fractions based on stream day capacities as of 1-1-91 (*Oil & Gas Journal*, pg. 86, 3-18-91).

<sup>3</sup> For catalytic cracking and catalytic hydrocracking charge rates same as in 1990.

<sup>4</sup> For catalytic reforming reduce charge rates from 1990: -576 kBCD in 2000; -665 kBCD in 2010.

<sup>5</sup> For alkylation, reduce product rates from 1990: -188 kBCD in 2000; -303 kBCD in 2010.

**Table F-63.  
Crude Volumes and Key Properties by PADD and Year<sup>1</sup>**

		Amount, MMBD	Gravity, °API	Sulfur, Wt%
Year 1990	All of U.S.	13.4	31.9	1.1
	PADD I-IV	10.8	33.4	1.1
	PADD V	2.6	25.7	1.1
Year 2000	All of U.S.	17.6	29.9	1.3
	PADD I-IV	14.2	31.4	1.3
	PADD V	3.4	23.7	1.3
Year 2010	All of U.S.	18.4	27.9	1.6
	PADD I-IV	14.5	29.4	1.6
	PADD V	3.5	21.7	1.6

<sup>1</sup> From Tables F-46 and F-49.

to 1990 PADD V average at 0.535) and existing coking at 0.37 (compared to 1990 PADD V average at 0.21).

The volumes for vacuum distillation and coking for the years 2000 and 2010 in Table F-62 were derived for each PAD District by using these factors and the crude volumes given in Table F-63.

**Hydrotreating and Hydrorefining, and Hydrogen Production:** For these processes, the total hydrogen factor was applied to the crude volume given in Table F-63 for all of United States to obtain the 1990 volume (Thrash, 1990). For later years, this value was increased in proportion to the increases in crude volumes and crude sulfur contents.

Those processes that use hydrogen will be increasingly applied in the 1990s, since they remove sulfur from products as well as from catalytic reforming feedstock. Reduced sulfur in diesel fuel is mandated by EPA regulations. Catalytic reforming produces hydrogen that can be used for these processes, but additional hydrogen must still be produced to balance all of the hydrotreating and hydrorefining needs, as well as for hydrocracking. An article in the *Oil & Gas Journal* gives the amount of hydrogen produced for each barrel of catalytic reforming charge at various severity levels (Unzelman, 1990). The 1990 amount of reforming hydrogen was estimated for the 1990 average severity level of 98.5 RON and applied to the 1990 amount of gasoline pool reformat multiplied by 1.25 (the catalytic reforming charge/product ratio at this severity).

For the years 2000 and 2010, with less severity, catalytic reforming will produce less hydrogen per barrel of charge, but hydrotreating of the charge must continue at the same or higher hydrogen level per barrel of charge, adjusted upward in proportion to crude oil sulfur content and because of changes in other crude oil properties. These corresponding amounts of hydrogen for treating catalytic reforming feedstocks, for other hydrotreating and hydrorefining needs, and for hydrocracking were estimated and taken into account for 2000 and 2010. The increases needed for hydrogen production compared to 1990 were determined to be approximately 4,300 million cubic feet per day (MMCFD) for the year 2000 and 5,900 MMCFD for the year 2010.

**Coking and Coke Production:** The factors given near the top right of Table F-62 for coke production are short tons per barrel of coking charge. The 1990 factors for PADD I-IV and PADD V are the same, as no overall breakdown in coke production by PAD Districts is needed. The same factor was applied to each coking volume given for all of the United States for 2000 and for 2010.

#### **F.4.4.7 Air Emissions**

Petroleum refineries are sources of sulfur oxides ( $\text{SO}_x$ ), carbon monoxide (CO), nitrogen oxides ( $\text{NO}_x$ ), hydrocarbons, and particulates, which are all primary criteria pollutants. In addition, petroleum refineries can also emit many other hazardous air pollutants including hydrocarbons, sulfur compounds, nitrogen compounds, and trace elements (see Table F-64). Among these substances, polynuclear aromatic hydrocarbons (PAHs) are of special environmental and health concern. Several PAHs, most notably benzo(a)pyrene, have been shown to induce cancer, while others are suspected carcinogens or may inhibit or accelerate the activity of benzo(a)pyrene.

The actual impact of these emissions on ambient concentrations is site specific. Sources of atmospheric pollutants in petroleum refineries can be divided into process emission sources (or point sources) and fugitive sources.

##### **F.4.4.7.1 Point-Source Emissions**

Several operations within a refinery produce waste gases. Major point sources include Claus units, catalyst regenerators, process heaters and boilers, storage tanks, loading facilities, flares, process drains, wastewater treatment units, and cooling towers.

**"Claus Units:** Sulfur in crude oil occurs as hydrogen sulfide, mercaptans, thiophenes, sulfides, and polysulfides. The distribution and concentration of sulfur compounds differ for each crude oil. Sulfur removal from whole crude is generally not economical, but sulfur is routinely removed from various intermediate feedstock streams by hydrodesulfurization, which produces hydrogen sulfide. Several means, usually absorption, can be used to remove and concentrate the hydrogen sulfide.

**Table F-64.**  
**Hazardous Pollutants Potentially Emitted from Refinery Process Units**

Acetaldehyde	Coronene	Perylene
Acetic acid	Cresols	Phenanthrene
Aldehydes	Cresylic acid	Phenol
Alkyl sulfide	Cyanides	Pyrene
Ammonia	Dibenzothiophene	Pyridiness
Anthracenes	Diethylamine	Pyrroles
Aromatic amines	Dimethylphenol	Quinolines
Barium	Fluoranthrene	Strontium
Benzene	Formaldehyde	Sulfates
Benzo(a)pyrene	Formic acid	Sulfides
Benzo(e)pyrene	Furans	Sulfonates
Benzo(ghi)erylene	Hydrogen sulfide	Sulfones
Benzoic acid	Indoles	Sulfur oxides
Carbazoles	Ketones	Sulfur particulates
Carbon disulfide	Lead	Sulfuric acid
Carbon monoxide	Maleic acid	Tetraethyl lead
Carbonyl sulfide	Mercaptans	Thiophenes
Catalyst fines	Metalloporphrins	Thiosulfide
Chlorides	Methylethylamine	Thiphenols
Chromates	Methylmercaptan	Toluene
Cobalt	Molybdenum	Vanadium
Cobalt carbonyl	Nickel	Xylene
Coke fines	Nickel carbonyl	Xylenols
Copper	Nitrogen oxides	Zinc

Source: U.S. Department of Energy, *Energy Technologies and the Environment*, Report No. DOE/EH-0077, Office of Environmental Analysis, Washington, D.C., October 1988.

In recent years, the Claus process, which catalytically reacts hydrogen sulfide with sulfur dioxide (SO<sub>2</sub>) to recover elemental sulfur, has been often used to minimize SO<sub>x</sub> emissions and produce elemental sulfur for sale to other industries. In general, Claus sulfur plants are unable to remove all the sulfur from the waste gas stream and the tail gas from a Claus unit contains hydrogen sulfide, SO<sub>2</sub>, carbon dioxide (CO<sub>2</sub>), carbonyl sulfide, and CO. If not treated, the Claus-unit tail gas is often a main source of refinery emissions. There are several different methods for cleanup of this tail gas.

**Catalyst Regenerators:** Several petroleum refining operations use non-fluidized catalysts that become coated with carbon and metals and must be periodically regenerated to restore their activity. During regeneration, the carbon is oxidized to form CO and CO<sub>2</sub>. For most

processes, a catalyst must be regenerated only a few times a year. At these times, emissions, which typically contain incompletely burned wastes, may also include catalyst fumes, oil mists, hydrocarbons, ammonia, SO<sub>x</sub>, chlorides, cyanides, NO<sub>x</sub>, and aerosols; however, total emissions over the course of a year are negligible compared to regenerating catalytic cracking catalysts.

Regenerating the catalysts for catalytic cracking is a continuous process. Continuous catalyst regeneration can be a major source of emissions from a petroleum refinery and flue gases from regenerators contain particulates, SO<sub>x</sub>, CO, hydrocarbons, NO<sub>x</sub>, aldehydes, and ammonia.

**Boilers and Process Heaters:** Most refineries use boilers to provide steam or heat for the various processes and to drive steam turbines that generate electricity for process requirements. Process heaters are also used extensively in refining operations. Refinery boilers and heaters are fired with the most available fuel, usually gas or oil.

Flue gases released from boilers and heaters contain SO<sub>x</sub>, NO<sub>x</sub>, CO, CO<sub>2</sub>, and particulates. The quantity of emissions depends on the quality of fuel and combustion unit design and operation.

**Storage Tanks and Loading Facilities:** Hydrocarbons can be released from storage tanks during filling and standing. During filling, air containing hydrocarbon vapors can be displaced and released. During standing, changes in temperature and pressure affect relative amounts of liquid and vapor within a tank, which can also displace air containing hydrocarbons (this is known as breathing loss). Factors that influence losses are vapor pressure; temperature; throughput rates; and the color, condition, and type of tank.

Products leave a refinery either by pipeline or in tanks and drums by road, rail, or ship. During product transfers, hydrocarbons can be lost to the atmosphere in much the same way as during storage. The quantity of hydrocarbons lost from loading facilities depends on the type of product and the method of transfer.

**Other Point Sources:** In addition to using natural gas, refineries produce still gas and use large quantities of it for fuel and feedstock. Although production and consumption are balanced as much as possible, scheduled shutdowns and process disruptions can upset this balance and overload the waste gas recovery system. To meet this eventuality, refineries have waste gas disposal systems. Such a system can consist of a manifolded pressure-relieving system, or a blowdown and blowdown-recovery system, and a system of flares for burning excess gas. Emissions from the waste gas disposal system include hydrocarbons, SO<sub>x</sub>, CO<sub>2</sub>, CO, and NO<sub>x</sub>.

Refineries use large quantities of water for processes and cooling. The effluent streams, as well as some stormwater runoff that comes into contact with process waters, contain oil and must be treated prior to discharge. A refinery, therefore, has a complex drainage system that leads wastewater and some stormwater runoff to a treatment area. Hydrocarbons can enter

the atmosphere from the drainage system as well as the treatment area. However, new regulations governing VOC and other emissions are eliminating the potential for emissions from wastewater drainage and treatment systems.

Hydrocarbons can be found at low levels in nearly all the water used for process cooling. If process heat exchangers leak, the level of hydrocarbons present in the cooling water can increase substantially. Some of these hydrocarbons can be vaporized and emitted to the atmosphere in the cooling tower.

#### **F.4.4.7.2 Fugitive Emissions**

Emissions that are not released from point sources are fugitive emissions. Fugitive emissions that are of primary concern in refineries are leaks from plant equipment, especially line valves, flanges, sampling connections, open line ends, and pump and compressor seals. Although these components can be expected to have a low leak rate per unit, a major processing facility contains a large number of them. A typical refinery has about 22,000 in-line valves, 660 pumps, 130 compressors, 84,000 flanges, 170 relief valves, and 1,100 process drains (DOE, 1988). Leaks and emissions from these components can be considered system failures and are predictable only in terms of probability. This is in contrast to point sources, which are expected to have somewhat constant emissions.

EPA and the American Petroleum Institute (API) have estimated, for hydrocarbon emissions, the leak rates and effectiveness of controls for line components at refineries. Although fugitive emission rates per source appear to be small, the total annual fugitive emissions can be substantial. For a hypothetical 330,000-bbl/day refinery, non-methane hydrocarbon emissions were estimated to be 12,439 tons/year, of which 8,767 tons/year (70.4 percent) were from fugitive sources, 3,308 tons/year (26.6 percent) from storage tanks, and 364 tons/year (2.9 percent) from point sources. Valves were responsible for about 50-60 percent of the fugitive hydrocarbon emissions. These data were published in 1980. The corresponding emission factors for conditions in 1980 are: 0.073 tons hydrocarbons/1000 bbl of crude oil for fugitive emissions; and 0.0275 tons hydrocarbons/1000 bbl of crude oil for storage tank emissions" (DOE, 1988).

#### **F.4.4.7.3 Air Emission Estimates**

Table F-65 shows the calculated air emissions for the criteria pollutants: particulates (TSP), SO<sub>2</sub>, CO, non-methane hydrocarbons, and NO<sub>x</sub>. The corresponding emission factors based on gasoline produced are as shown in Table F-66. An example calculation that converts the air emissions totals in tons/day from Table F-65 to lbs/bbl in Table F-66 is as follows:

$$\begin{aligned} &60 \text{ tons particulates/day} * 2000 \text{ lbs/ton} \\ &\div 7,000,000 \text{ BCD in the year 2000} = 0.017 \text{ lb/bbl} \end{aligned}$$

**Table F-65.**  
**Crude Oil Refining**  
**Air Emissions Estimates for the Years 2000 and 2010, tons/day**

	Particulates, Total Suspended Solids	Sulfur Dioxide	Carbon Monoxide	Non-Methane Hydrocarbons	Nitrogen Oxides
<b>Factors</b>					
Catalytic cracking, lb/k-bbl charge	7	100	neg.	neg.	37.1
Fluid coking, lb/k-bbl charge	6.85	200	neg.	—	37.1
Vapor recovery/flare, lb/k-bbl crude	neg.	26.9	4.3	0.8	18.9
Sulfur recovery, lb/ton of sulfur		4			
Fuel oil combustion, lb/k-gal fuel	3.3	47	5	0.75	34
Coke & coal combustion, lb/ton	0.5	7.6	1	0.3	18
Natural gas combustion, lb/MMCF	1	0.6	40	1.4	275
Still gas combustion, lb/MMCF	1	1.2	40	1.4	275
Cooling tower emissions, lb/k-bbl crude				1.2	
<b>Year 2000 Emissions, tons/day</b>					
Catalytic cracking, 4422 kBCD	15	221	0	0	82
Fluid coking, 2702 x 1/4 kBCD	2	68	0	0	13
Vapor recovery/flare, 17600 kBCD	neg.	237	38	7	166
Sulfur recovery, 25000 ton/day		50			
Fuel oil combustion, 400 kBCD x 42 gal/B	28	395	42	6	286
Coke & coal combustion, 42000 ton/day	11	160	21	6.3	378
Natural gas combustion, 2200 MMCFD	1.1	1	44	2.0	303
Still gas combustion, 4080 MMCFD	2	3	81	29	561
Wastewater treating				17	
Cooling tower emissions, 17600 kBCD				11	
Fugitive emissions				129	
Storage tanks emissions				48	
<b>Total</b>	<b>60</b>	<b>1135</b>	<b>226</b>	<b>229</b>	<b>1789</b>
<b>Year 2010 Emissions, tons/day</b>					
Catalytic cracking, 4422 kBCD	15	221	0	0	82
Fluid coking, 4050 kBCD	3	101	0	0	19
Vapor recovery/flare, 18000 kBCD	neg.	242	39	7	170
Sulfur recovery, 30000 ton/day		60			
Fuel oil combustion, 400 kBCD x 42 gal/B	28	395	42	6	286
Coke & coal combustion, 93000 ton/day	23	353	47	14	837
Natural gas combustion, 2300 MMCFD	1	1	46	1.6	316
Still gas combustion, 4265 MMCFD	2	3	85	3	586
Wastewater treating				17	
Cooling tower emissions, 18000 kBCD				11	
Fugitive emissions				67	
Storage tanks emissions				25	
<b>Total</b>	<b>72</b>	<b>1376</b>	<b>259</b>	<b>135</b>	<b>2266</b>

Sources: Emission Factors from U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources*, Fourth Edition, Report No. AP-42, Research Triangle Park, North Carolina, September 1985 as modified in the text.

Year 2000 and 2010 calculations by EA Mueller, Baltimore, Maryland.

**Table F-66.  
Refinery Emission Factors, lb/bbl of Gasoline Produced<sup>a</sup>**

	Particulates, Total Suspended Solids	Sulfur Dioxide	Carbon Monoxide	Non-Methane Hydrocarbons	Nitrogen Oxides
Year 2000, 7000 kBCD	0.017	0.32	0.065	0.065	0.51
Year 2010, 6300 kBCD	0.023	0.44	0.082	0.043	0.71

<sup>a</sup> Calculations based upon all air emissions from refinery operations attributable to reformulated gasoline. The allocated emissions between gasoline and byproducts are shown in Table F-76.

The following assumptions were used to estimate the air emission factors from crude oil refining:

- Emission factors based on 1980 data given in Section F.4.4.7.2 for fugitive emissions and storage tank emissions have been applied with 90 percent capture and control assumed to be in practice in the year 2000 and 95 percent capture and control in the year 2010. These abatement efficiencies can be attained for fugitive emissions through inspection, maintenance, and valve replacement programs; and for storage tank emissions through more widespread use of floating reef tanks and vapor recovery systems.
- Emission factors published in AP-42 by the EPA were used (EPA, 1985a). AP-42, Table 9.1-1 gives the factors shown in Table F-65 for: catalytic cracking (assumed here to be all FCC by 2000); fluid coking (assumed here to be one-fourth of the coking capacity by 2000), with a CO boiler and electrostatic precipitator assumed to be installed at all FCC and fluid coking units by 2000; vapor recovery and flaring systems; and vacuum distillation. However, AP-42 shows that if the vacuum system emissions are abated, the discharges to the atmosphere will be negligible, and negligible discharges are not given in the table. Table 9.1-2 in AP-42 gives the cooling tower emission factors.
- AP-42, Table 5.18-1, gives emission factors for Claus sulfur recovery plants widely used in refineries. It was assumed that such plants would include Claus tail gas cleanup and would recover 99 percent of the sulfur not in heavy fuel oil or coke products or otherwise lost. Information within the table indicates that such recovery can be expected.

- AP-42, Table 1.3-1, gives uncontrolled emission factors for fuel oil combustion, in some instances based on sulfur content. AP-42 indicates that abatement can control 99 percent of the particulate and 90 to 95 percent of the SO<sub>x</sub>; 99 percent and 90 percent were used here, respectively, for year 2000. Sulfur content of heavy fuel oil is approximately 2.5 times the crude sulfur content; three percent sulfur in the fuel oil was assumed for year 2000 in order to compute emission factors using the formulas in AP-42. The same factors were used for the year 2010, assuming that rising sulfur content would be offset by improved abatement by that year.
- AP-42, Table 1.1-2, gives uncontrolled emission factors for coal combustion, which is practiced in refineries to the extent of 170,000 tons per year (DOE, 1990, Table 14). Abatement factors suggested in AP-42 were applied to arrive at the values given in Table F-65. It was assumed that coke would have similar properties, except with lower ash content.
- AP-42, Table 1.4-1, gives uncontrolled emission factors for natural gas combustion. It was assumed that still gas (refinery fuel gas) would have similar factors except that SO<sub>x</sub> would be double, due to higher sulfur content in refinery fuel gas.
- For estimating the emissions of hydrocarbons released from refinery wastewater treatment systems and process drains, the amounts reported by EPA were used, without applying emission factors (EPA, 1985b). This reference indicates that abatement efficiencies above 90 percent can be achieved. It was assumed that 90 percent efficiency would apply by year 2000. The emissions for existing refineries are given on pages 3-60, 63, and 66 (EPA, 1985b). These emissions are not directly related to crude volumes or to the modifications suggested for refining operations in this report, and were assumed to be the same in 2010 as in 2000.
- Emissions were taken as proportional to crude volumes for vapor recovery/flare operations, natural gas combustion, and still gas combustion. Catalytic cracking and fluid coking emissions were taken as proportional to process unit charge rates. It was assumed that the declining use of coal was offset by using coke until year 2000. Incremental coke production from year 2000 to 2010 was assumed to be combusted within refineries to produce steam and to cogenerate electric power.

#### **F.4.4.7.4 Carbon Dioxide**

Although carbon dioxide is not considered a pollutant, it is a greenhouse gas that may someday be subject to emissions regulations. Table F-67 gives the mass emission rates from U.S. petroleum refining, ranging from 596,000 tons/day in 1990 to 735,000 tons/day in 2000

and 934,000 tons/day in 2010. Table F-68 gives the corresponding emission factors, derived by dividing the rates in Table F-67 by gasoline production rates of 6,778,000 BCD in the base year; 7,000,000 BCD (from the NES) in 2000; and 6,300,000 BCD (from the NES) in 2010. The factors range from 0.088 tons/bbl in the base year to 0.12 tons/bbl in 1990 and 0.15 tons/bbl in 2010. With a high percentage of ether in the gasoline pool, this scenario projects lower octane numbers for the remainder of the pool. As a result, actual fuel usage and CO<sub>2</sub> produced will be less than that estimated in this study. White has indicated that refinery energy consumption is approximately 10 percent of refinery input energy, but the 10 percent is reduced by 0.18 points for each octane number reduction (White, 1982). Examples of how the rates are derived are as follows (using fuels consumption data in Table 45 of *Petroleum Supply Annual 1990*, Vol. 1, published by DOE's Energy Information Administration for base year data):

**Still Gas Combustion:** Still gas (refinery fuel gas) is mainly methane, ethanes, and propanes with heats of combustion ranging from 21,600 to 23,900 Btu/lb, and molecular weights of 16, 28 to 30, and 42 to 44, respectively. Some LPG, mainly propanes, are combusted with still gas. CO<sub>2</sub> has a molecular weight of 44. Ethane, for example, has two carbon atoms per molecule, so each pound-mole combusted forms two times 44 pounds of CO<sub>2</sub>; thus, the CO<sub>2</sub> rate is:

$$(2 * 44 \text{ mol wt}/30 \text{ mol wt}) * \text{lb}/22,300 \text{ Btu} = 132 \text{ lb}/\text{million Btu} \\ \text{or } 0.066 \text{ ton}/\text{million Btu}$$

Combusted in 1990: 239,400 kbbl FOE/year (plus 8,725 of LPG) where the fuel oil equivalent (FOE) is 6,000,000 Btu/bbl. This amounts to an average of 680 kbbl FOE/day.

$$\text{For 1990: } 680\text{k} * 6,000,000 \text{ Btu}/\text{day} * 0.066 \text{ ton}/1,000,000 \text{ Btu} \\ = 269 \text{ kton}/\text{day}$$

For 2000 and 2010: Assume amount combusted is proportional to crude oil throughputs.

**Fuel Oil Combustion:** From Perry's *Chemical Engineers Handbook*, 4th Edition, Chapter 9, the density and percent carbon of the mainly heavy fuel oil combusted in refineries is 340 lb/bbl and 89 percent, respectively; thus, the amount of carbon

**Table F-67.**  
**Carbon Dioxide Emission for the Years 2000 and 2010 (k-ton/day)**

	1990	2000	2010
Still gas combustion	269	353	361
Fuel oil combustion	17	22	23
Natural gas combustion and hydrogen manufacture	109	140	144
Coke, catalyst coke, and coal combustion	164	215	264
Combustion of unfinished oils, finished products, and miscellaneous	3.4	4.5	4.6
<b>Total</b>	<b>596</b>	<b>735</b>	<b>934</b>

**Table F-68.**  
**Carbon Dioxide Emission Factors for the Years 2000 and 2010 (ton/bbl gasoline)<sup>a</sup>**

	1990	2000	2010
Still gas combustion	0.040	0.050	0.057
Fuel oil combustion	0.0025	0.0032	0.0036
Natural gas combustion and hydrogen manufacture	0.021	0.034	0.042
Coke, catalyst coke, and coal combustion	0.024	0.031	0.042
Combustion of unfinished oils, finished products, and miscellaneous	0.0005	0.0006	0.0007
<b>Total</b>	<b>0.088</b>	<b>0.12</b>	<b>0.15</b>

<sup>a</sup> Calculations based upon all CO<sub>2</sub> emissions from refinery operations attributable to reformulated gasoline. The allocated emissions between gasoline and byproducts are shown in Table F-76.

combusted is 303 lb/bbl of fuel oil. Carbon has a molecular weight (atomic weight) of 12, so the CO<sub>2</sub> rate is 44/12 times 303 lb/bbl times the bbl/day of fuel oil, divided by 2000 to obtain ton/day.

**Natural Gas Combustion and Hydrogen Manufacture:** Refineries often use natural gas as one of their fuels and also as a feedstock for steam-methane reformers for producing hydrogen. Hydrogen is also manufactured from naphtha, but the vast majority is from natural gas. The CO<sub>2</sub> produced from combusting natural gas is computed similar to the still gas calculation given above, except that the main constituent is methane. The CO<sub>2</sub> produced from steam-methane reforming is calculated at 1 mole per 4 moles of hydrogen produced, or 1 cu ft per 4 cu ft of hydrogen, and each cu ft of CO<sub>2</sub> weighs 0.116 lb. The base year hydrogen production rate is 2,478 million cu ft/day (Thrash, 1991; page 86). The increases in hydrogen production over the base year are given in the last paragraph of Section F.4.4.6 in this report for the years 2000 and 2010.

**Coke and Coal Combustion:** From Perry's *Chemical Engineers' Handbook*, 4th Edition Chapter 9, the maximum carbon contents of petroleum coke and coal were assumed to be 95 and 85 percent, respectively. The amount of CO<sub>2</sub> produced from combustion is 44/12 times the amount of carbon burned. For the years 2000 and 2010, it is assumed that virtually all coal combustion now in refineries will be replaced by coke, since the refining scenario also includes modified FCC operations to increase light olefins production. Corbett recently indicated that the amount of catalyst coke (which is combusted in FCC units) will increase by the ratio of 6.4/5.0 (Corbett, 1990). This increase in coke combustion along with increased crude throughput, are accounted for in the year 2010 CO<sub>2</sub> rate.

**Unfinished Oils, Finished Products, and Miscellaneous Fuels:** The CO<sub>2</sub> rate is calculated similar to that for fuel oil, except that 85 percent carbon content in the fuel is assumed.

Other sources of carbon dioxide not discussed above include CO boilers and the offgases of other processes that are deemed too minor to recover or reuse elsewhere and are combusted for their fuel value.

#### **F.4.4.7.5 Toxic Air Pollutants**

In addition to criteria pollutants such as hydrocarbons, CO, SO<sub>2</sub>, particulates, and NO<sub>x</sub>, refineries emit hazardous pollutants which will require the application of maximum achievable control technology in the late 1990s. Some data on the quantities discharged are available in the Toxics Release Inventories System Database, and in detail in reporting required in California by state legislation AB 2588. Toxics reported to the San Francisco Bay Area Air Quality Management District for a 132,000 BCD modernized complex refinery (Tosco Corporation, Marting, California) handling a wide variety of imported and heavy California crude oils are summarized in Table F-69.

**Table F-69.**  
**Uncontrolled Toxic Air Emissions from a Typical Refinery**

Carcinogens	Lb/Yr	Sources
Arsenic	0.12	Boiler, fire pumps, reciprocating engines
Benzene	19311	Fluid coker (including CO boiler), FCCU CO boiler, coke- and oil-fueled boiler, fired heaters and reboilers, fuel-oil fired boilers, gas-fueled turbines and reciprocating engines, flare, gasoline tank, fugitive emissions
Benzo(a)pyrene	276	Fluid coker (including CO boiler), FCCU CO boiler, coke- and oil-fueled boiler, fired heaters and reboilers, reciprocating engines for fire pumps
Beryllium	0.070	Coke- and oil-fueled boiler, reciprocating engines for fire pumps
1,3-Butadiene	817	Fugitive emissions
Cadmium	0.31	Fluid coker (including CO boiler), coke- and oil-fueled boiler, reciprocating engines for fire pumps
Chromium VI	0.01	Coke- and oil-fueled boiler
1,2 Dibromoethane	0.31	Gasoline tanks and fugitive emissions at loading facility
1,2 Dichloroethane	6.99	Gasoline tanks and fugitive emissions at: wharf area, loading facility, and vehicle service stations
Formaldehyde	5053	Fluid coker (including CO boiler), FCCU CO boiler, coke- and oil-fueled boiler, fired heaters, gas-fueled turbines and reciprocating engines, reciprocating engines for fire pumps
Nickel	4.99	Fluid coker (including CO boiler), coke- and oil-fueled boiler, reciprocating engines for fire pumps
Non-Carcinogens	Lb/Yr	Sources
Ammonia	400	Tanks for 12% aqueous ammonia
Lead	0.28	Coke- and oil-fueled boiler, reciprocating engines for fire pumps
Manganese	0.41	Fluid coker (including CO boiler), coke- and oil-fueled boiler, engines for fire pump
Mercury	0.090	Coke- and oil-fueled boiler, reciprocating engines for fire pumps
Toluene	6236	Gasoline tanks, fugitive emissions
Xylene	29546	Gasoline tanks, fugitive emissions

Source: Toxics Emissions Data submitted by Tosco Corporation, Marting, California, to the San Francisco Bay Area Air Quality Management District in 1990 as required by California legislation AB 2588.

Note that the fire pump engines are diesel fueled and are tested once per week.

From these data, emission factors relative to the 132,000 BCD crude oil capacity could be derived and used for 1990 operations. However, for some of the toxics, the extent of abatement expected in 2000 and 2010 cannot be predicted. Regulations by the EPA will require certain control technology, not quantitative emissions limits. Local regulations will be based on downwind ground-level ambient concentrations related to health-risk assessments.

#### **F.4.4.8 Water Effluents**

Raw refinery wastewater prior to treatment contains large quantities of free and emulsified oil. In addition, water-soluble hydrocarbons, such as phenolic compounds, that are present in the crude petroleum or generated in process units will also be present in the wastewater prior to treatment.

"Crude petroleum contains a variety of sulfur compounds that are removed from the finished product in various amounts, depending on product specifications. Due to the contacts between oil and water at various stages of the refining operation, significant quantities of sulfur compounds enter the wastewater stream. Most of these sulfur compounds are sulfides.

Since petroleum also contains a number of nitrogen compounds, refinery wastewater typically contains appreciable quantities of ammonia. Carbonaceous and inorganic particulate matter from a variety of sources, such as incomplete combustion in desalting and coking and soil erosion, are also present in refinery wastewater, thus contributing to the level of total suspended solids (TSS).

Because most of these pollutants can be oxidized, refinery wastewater will exert a chemical oxygen demand (COD). In addition, some compounds are biodegradable, which exerts a biochemical oxygen demand (BOD). Crude petroleum also contains a variety of trace heavy metals, such as nickel and vanadium, that may also contaminate process water. Corrosion inhibitors, such as chromate salts, have been used in cooling water and can be included in wastewater discharges, but the use of chromate is being phased out.

The refinery wastewaters include, depending on the individual plant characteristics, nonprocess and process wastewaters. As discussed below, treatment of these waste streams, beginning with the API separators, greatly reduces these contaminants.

#### **F.4.4.8.1 Process Wastewaters**

The sources of process and utility wastewaters within a refinery include cooling tower blowdown, boiler blowdown, oily process water, sour water, spent caustic solutions, and blowdown from air pollution control equipment.

Oily process wastewaters usually contain oil, sulfides, ammonia, and oxygen-consuming organics. A refinery typically generates oily process wastewater that is some combination of condensed blowdown from vapor cooling, process water, vent-scrubber water from controlling process gases, tank drainage, blowdown from the liquid seals for flares, laboratory drainage, and water contaminated by equipment maintenance and cleanup operations. Lead in these wastewaters will continue to diminish as leaded gasoline declines and is phased out in 1996.

Condensing the steam from a variety of processes produces sour water. The principal sources of sour water are hydrotreating and other accumulators; fractionation processes associated with cracking; and hydrocracking and coking units. Sour water generally represents 8-18 percent of a refinery's total process wastewater. In general, it is characterized by small amounts of organic acids and relatively high concentrations of sulfides, ammonia, mercaptans, and phenolics. Most of the sulfides and ammonia are stripped from the sour water prior to discharge to wastewater treatment facilities.

Some wastewater streams contain spent caustic solutions, which are used to neutralize and extract acidic materials from crude fractions and byproducts. Spent caustic solutions contain sulfides, mercaptans, sulfates, sulfonate, phenolates, naphthenates, and other similar organic and inorganic compounds. Spent caustics are often used in-plant for adjustment on wastewater streams or sent off-site for recovery of organic acids. In this study, caustic waste streams are discussed and characterized as part of solid and other wastes (Section F.4.4.9) rather than as a wastewater.

Blowdown from air pollution control equipment is the wastewater discharged from exhaust gas scrubbers in refineries that control emissions from combustion processes.

Cooling tower blowdown is the concentrated wastewater discharge from the cooling tower water cycle, which is produced in relatively small quantities when solids that build up during evaporation are eliminated. Blowdown contains high concentrations of dissolved solids and low concentrations of water treatment chemicals, such as chromium, zinc, chlorine, and biocides. Cooling towers are common in the refining industry, particularly in areas where an abundant source of fresh water for once-through cooling is not available. Chromium and zinc are being phased out as cooling tower treatments.

Boiler blowdown is the concentrated wastewater discharge from a boiler-type heating or steam-generating system. The contaminants in boiler blowdown discharges are typically much lower than those of discharges from cooling tower blowdown. However, the volume of blowdown from boilers is typically smaller than that from cooling towers.

#### **F.4.4.8.2 Nonprocess Wastewaters**

In a refinery, sanitary wastewater typically has the pollutant characteristics of domestic sewage, and it is normally treated by biological oxidation. Sanitary wastewater may also be discharged directly to a municipal sewage system or included in process wastewater for onsite treatment. Sanitary wastewater is a minor source compared to process wastewaters.

Refinery stormwater, the plant runoff from precipitation, can be contaminated by raw materials or products, such as oil and grease. Control measures for stormwater pollution includes housekeeping measures, storm-sewer segregation, and stormwater retention facilities. Stormwater can be a significant source of wastewater and refineries are moving to reduce process wastewater by segregating clean stormwater falling in nonprocess areas for separate reuse or discharge" (DOE, 1988).

#### **F.4.4.8.3 Process Wastewater Estimates**

The quality of raw process wastewater can vary widely from plant to plant, depending on process characteristics and operating methods. Quantity also varies; for example, refineries using once-through cooling discharge much more water than those using cooling tower systems that recycle the bulk of the cooling water.

EPA has determined the designated priority pollutants that are likely to be detected in refinery wastewater. These toxic pollutants include benzene, ethylbenzene, toluene, 2,4-dimethylphenol, acenaphthene, fluoranthene, chrysene, phenanthrene, arsenic, cyanide, copper, lead, nickel, and zinc.

Table F-70 gives the process wastewater effluent factors (untreated) for 1990, 2000, and 2010 and the barrels per calendar day (BCD) volume throughput applicable for each process. The accompanying text reference notes explain how the factors were changed, where modification was appropriate for the future years. From Table F-70, the year 2000 process wastewater effluent (untreated) is 356 million gallons/day rising to 467 million gallons per day in 2010.

Volume figures (in thousands of barrels per calendar day, kBCD) given in Table F-70 are from Table F-62, except hydrogen units are millions of cubic feet per day, MMCFD, as quantified in text reference note 2 below. The following text reference notes accompany and are an integral part of Table F-70:

**Table F-70.**  
**Crude Oil Refining**  
**Refinery Process Wastewaters (Untreated) Volume Estimates for 2000 and 2010**

Wastewater Source	Published Effluent Factor <sup>1</sup>	Year 2000			Year 2010			Text Reference Notes
		Adjusted Factor	kBCD	MM Gal Per Day	Adjusted Factor	kBCD	MM Gal Per Day	
Crude Storage, Desalt, Atm Distill.	4.4	4.40	17600	77.00	4.40	18400	81.00	1
Gases Water Wash	3.3	3.90	17600	69.00	5.90	18400	105.00	
Vacuum Distillation	7.3	7.30	8500	62.00	7.30	10300	75.00	2
Hydrogen Production (per MMCFD)	111.0	111.00	6800	0.75	111.00	8300	0.93	
Lt. Hydrocarbon Hydrodesulfurization	1.9	2.25	2600	56.00	6.40	2600	16.00	3
Catalytic Reforming	1.2	1.20	2600	3.00	1.20	2600	3.00	4
Isomerization Water Wash	1.2	1.42	1000	1.00	1.75	960	1.60	
Alkylation Water Wash	6.5	6.50	750	4.90	6.50	630	4.10	5
Middle Distillates Hydrotreat	5.2	6.15	9800	61.00	7.56	13000	99.00	3
Catalytic Cracking	9.5	9.50	4400	42.00	9.50	4400	42.00	6
Hydrocracking	4.5	4.50	1000	4.60	4.50	1000	4.60	
Lube Oil Solvent Refining	13.0	13.00	300	3.90	13.00	320	4.10	6
Dewaxing	12.5	12.5	300	3.80	12.50	320	3.90	6
Coking	6.4	6.4	2700	17.00	6.40	4100	26.00	
<b>Total</b>				<b>356.00</b>			<b>467.00</b>	

<sup>1</sup> Untreated effluent factors are in gallons of wastewater per barrel of hydrocarbon processed.

Sources: Effluent Factors from U.S. Environmental Protection Agency, *VOC Emissions from Petroleum Refiner Wastewater Systems - Background Information for Proposed Standards*, Report No. EPA 450/3-85-001a, Office of Air and Radiation, Table 3-2, Washington, D.C., February 1985.

Adjusted Factors from EA Mueller as discussed in the text reference notes.

1. Gas processing includes caustic washing to remove sulfur compounds, followed by water washing to remove traces of caustic. Disposal of spent caustic is accounted for in Table F-73 ("Solid and Other Wastes from Petroleum Refineries for the Years 2000 and 2010"); this table accounts for the disposal of water from the step following caustic washing. It is assumed that the volume of water disposed is equal to the volume of caustic that can be derived from the published effluent factor given in this table. The published factor has been adjusted for two conditions: (a) crude sulfur content changing from 1.1 percent to 1.3 percent in 2000 and to 1.6 percent in 2010; (b) in 2010, the scenario includes catalytic cracker operational modifications such that C<sub>3</sub> gas produced is up 50 percent and C<sub>4</sub> gas is up 33 percent. In order to derive an effluent factor applicable to total crude throughput, the published factor has been multiplied by the sulfur ratio plus the gas ratio times catalytic cracker charge divided by crude throughput.
2. Hydrogen production is figured at total hydrogen demand minus hydrogen available from catalytic reforming, and including hydrogen needed for hydrotreating, hydrotreating (other than desulfurization of catalytic reforming charge done with catalytic reforming hydrogen), and catalytic hydrocracking.
3. Desulfurization of catalytic reforming feed is involved, using the catalytic reforming charge rates and the factor adjusted for 1.3 percent crude sulfur content in 2000 and 1.6 percent in 2010.
4. Caustic washing is involved, with water wash volume and adjustment for crude sulfur content handled as described above. The isomerization processing rate for 1990 is 836,000 BCD (Johnson, 1991; page 86). From Table F-57, for 2000, an additional 101,000 BCD of butane must be isomerized; for 2010, an additional 112,000 BCD must be isomerized.
5. Alkylation water wash is done to remove the acid used in the alkylation process, and is not related to crude sulfur content.
6. The source cited on Table F-70 gives solvent refining and dewaxing process throughput rates at 230,000 BCD. This figure has been increased in proportion to the projected crude volumes.

Table F-71 gives data on treated wastewater from the facility as a whole in terms of release parameters such as chemical oxygen demand (COD), total suspended solids (TSS), total organic carbon (TOC), etc. These pollutants are calculated based on crude

**Table F-71.  
Treated Wastewater Composition for the Years 2000 and 2010<sup>1</sup>**

Pollutant	Median Untreated Effluent Factor lb/k-bbl Crude	Treatment Removal Factors, % <sup>2</sup>	Year 2000		Year 2010	
			@17,600 kBCD Crude, lb/yr	@7,000 kBCD Gasoline, lb/bbl	@18,400 kBCD Crude, lb/yr	@6,300 kBCD Gasoline, lb/bbl
BOD	70	99	$4.5 \times 10^6$	$1.8 \times 10^{-3}$	$4.7 \times 10^6$	$1.8 \times 10^{-3}$
COD	116	95	$38 \times 10^6$	$15 \times 10^{-3}$	$38 \times 10^6$	$15 \times 10^{-3}$
TOC	49	90	$31 \times 10^6$	$12 \times 10^{-3}$	$33 \times 10^6$	$13 \times 10^{-3}$
TSS	21	85	$20 \times 10^6$	$7.8 \times 10^{-3}$	$21 \times 10^6$	$8.2 \times 10^{-3}$
Ammonia Nitrogen	9.8	99	$0.63 \times 10^6$	$0.25 \times 10^{-3}$	$0.65 \times 10^6$	$0.25 \times 10^{-3}$
Phenols	1.3	99	$0.084 \times 10^6$	$0.033 \times 10^{-3}$	$0.087 \times 10^6$	$0.034 \times 10^{-3}$
Sulfides	0.7	100	--	--	--	--
Oil and Grease	26	99	$1.7 \times 10^6$	$0.67 \times 10^{-3}$	$1.7 \times 10^6$	$0.67 \times 10^{-3}$
Total Chromium	0.17	95 <sup>3</sup>	$<0.055 \times 10^6$	$<0.0043 \times 10^{-3}$	$<0.055 \times 10^6$	$<0.0043 \times 10^{-3}$

<sup>1</sup> Calculations based upon all treated wastewater effluents from refinery operations attributable to reformulated gasoline. The allocated emissions between gasoline and byproducts are shown in Table F-76.

<sup>2</sup> Using activated sludge.

<sup>3</sup> Assumed.

Sources: U.S. Department of Energy, *Energy Technologies and the Environment*, Report No. DOE/EH-0077, Washington, D.C., October 1988.

Treatment removal factors and subsequent calculations by EA Mueller.

input and, subsequently, expressed in terms of pounds per barrel of reformulated gasoline output. However, reformulated gasoline represents only a fraction of the total refinery product data. Thus, the effluent estimates must be allocated among all refinery outputs. The allocated effluent factors between gasoline and byproducts are shown in Table F-76.

#### **F.4.4.9 Solid and Other Wastes**

Petroleum refineries generate a wide variety of solid, semi-solid, and liquid waste streams, of which many contain materials on the EPA toxic substances list. The nature and quantity of wastes produced by refineries are variable and are still being investigated. Most waste streams can be divided into two main categories: those that are intermittently generated and those that are continuously generated. Intermittent wastes include process vessel sludge and scale and other deposits generally removed during plant turnarounds, storage tank sediments, and product treatment wastes, such as spent catalysts and filter clays, spent caustic solutions, and spent amine solutions (DOE, 1988).

Continuous wastes require disposal at less than two-week intervals. The solid and semi-solid wastes can be further divided into two groups: process wastes and wastewater treatment wastes. Major process wastes include spent catalysts and catalyst fines, and spent or spilled grease and wax wastes from lube oil processing. Wastewater treatment wastes can include sludges from activated sludge (biological oxidation) units and sludges skimmed from dissolved air flotation (DAF) units.

##### **F.4.4.9.1 Intermittent Solid and Other Wastes**

"Sediments accumulate at the bottom of crude oil storage tanks, which are cleaned periodically to remove the sediment. Contaminants in crude oil tank sludge, which vary with the type of crude oil and handling and shipping methods, may include a mixture of rust, clay, sand, water, and some oil and wax. Solids also settle to the bottoms of tanks for finished products, such as gasoline. The accumulated sludge is removed when the type of stored product changes, the sediment exceeds a specified limit, or the tank needs repair. The characteristics of the deposited sludge vary with the type of product, such as leaded or unleaded gasoline, stored in the tank.

Solids that settle in the API separator, a type of primary wastewater treatment unit, are periodically removed with a vacuum truck. Refinery API separators are usually connected to the plant's sewer for oily water. Therefore, sludges from API separators are mixtures of all chemicals that a refinery produces and uses.

Alkylation sludges are produced by both the sulfuric and hydrofluoric (HF) acid alkylation processes. In the sulfuric acid alkylation process, the spent acid is usually regenerated by an offsite producer of sulfuric acid, and it accumulates in storage tanks for batch transportation to the reclaimer. Sludge from these tanks contains polymerized hydrocarbons, tank scale, and sulfuric acid and is usually removed when the tank is either cleaned or repaired. Spent HF

acid is usually neutralized with spent lime from the boiler feedwater treatment to produce calcium-fluoride sludge, which is insoluble.

In systems using cooling towers, sludge that settles in the cooling tower basin is removed during cooling tower downtime. Contaminants of cooling water sludges include those carried in the water supply and those generated as a result of water treatment.

Heat-exchanger bundles are periodically cleaned during plant shutdown. Scale and sediment containing rust and oil resulting from such cleaning are either flushed into the process sewer system or scraped out for disposal in landfills.

For processes that use a fixed-bed catalyst, these catalysts eventually become inactive and are replaced in the reactors with fresh catalyst. Many of these catalysts contain valuable metals. Some of these metals, such as platinum and palladium, represent the active catalytic component; others are contaminants in the feedstock that adhered to the catalyst. After the valuable compounds are recovered, spent catalysts are disposed of as solid waste.

Some refineries have stormwater settling basins that collect silt, which must be periodically removed. The quantity of silt depends on the amount of rainfall and pavement at the refinery, rather than the refinery's complexity.

#### **F.4.4.9.2 Continuous Solid and Other Wastes**

In some refineries, mainly older, non-modernized ones, fixed-bed clay is used to remove color bodies, chemical treatment residues, and traces of moisture from various products, such as gasoline, kerosene, jet fuel, and light fuel oil. Clay is also used to treat lube oils, a process in which clay is mixed with the oil and subsequently removed with a rotary vacuum filter. Depending on the specific use, spent filter clays can contain metals, ash, oil, and acidic and carbonaceous residues.

In many refineries, wastewater receives additional treatment to remove oil and solids by the dissolved air floatation process (DAF). The process takes place in a circular tank, with or without chemicals, using small air bubbles to bring fine particles of solids and oil to the surface, where they are skimmed off for treatment and disposal.

Skimmed oil from the API separators is usually pumped into a recovered oil tank where the mixture is separated into three fractions: oil, water, and emulsion. The oil and water are recycled. The emulsion layer may be fed to desalter units or disposed of as a sludge or further treated (demulsified) by chemical or physical means. Chemical demulsification is the use of specific agents, heat, and settling. Physical treatment removes suspended solids by centrifugation or vacuum filtration and separates water and oil in settling tanks. In either process, the solids are disposed of, the oil is reprocessed, and the water is recycled.

In the process of biologically treating wastewater streams, excess biosludge is created that, for efficient operation, must be controlled. Biosludge contains biological solids and heavy metals, has a very high water content, and is dewatered prior to disposal.

Catalysts from FCCs are continuously regenerated by burning the coke that forms on the catalyst during the cracking process. The flue gas from the regenerator passes through a series of cyclones that recover most of the catalyst. The recovered catalyst is then returned to the reactor vessel. Because of current and future air pollution regulations, more refineries have installed electrostatic precipitators or equivalent devices to remove any catalyst fines that would otherwise be released to the atmosphere with the flue gas. These catalyst fines can be disposed of or sold.

Stretford units are used to remove hydrogen sulfide from process gas streams by reacting it with sodium carbonate to form sodium bicarbonate and sodium hydrosulfide. Elemental sulfur is then removed through a catalytic reaction. The blowdown from Stretford units, called Stretford solution, contains sodium carbonate, sodium bicarbonate, sodium hydrosulfide, and some heavy metals, such as chromium and lead.

Coke that is produced in the course of various refinery operations, especially fluid and delayed coking, is usually sold to metallurgical processing companies or as industrial fuel. Coke fines are generated intermittently and their quantity is a function of handling techniques. A certain amount of spillage and consequent contamination with dirt results during loading operations onto trucks and railroad cars" (DOE, 1988).

#### **F.4.4.9.3 Solid and Other Wastes Characteristics**

A number of factors associated with refinery operations may affect the composition and quantity of specific solid and other waste streams. One factor is the type of crude feedstock. The constituents of crude oil may vary widely, and its heavy metal content, for example, has a significant impact on the potentially hazardous metal content of crude oil storage-tank bottoms, FCC wastes, and wastewater treatment sludges. A second factor is found in process units; differences in wastewater and air pollution control processes may markedly affect the quantity as well as the composition of potentially hazardous waste material. For example, alkylation units that use HF acid produce a sludge high in fluoride, while alkylation units that use sulfuric acid do not. A third important factor is the level of technology used in the process. Processing kerosene with hydrotreating, rather than clay filters, will decrease the quantity of solid waste generated. A fourth factor affecting waste generation is that of operational practices and control. Reclamation of metals from spent catalysts and improved material handling procedures may significantly reduce the quantity of solid waste generated by a refinery.

#### F.4.4.9.4 Refinery Waste Estimates

The throughput volumes given in Table F-62 have been used with effluent factors to estimate the solid and other waste volumes, and the quantities of certain constituents present in these wastes. The effluent factors were adjusted so that they could be applied to gasoline production volumes. For these factors, late 1980s data are available for each process. Some of these factors have been used unchanged, such as for crude atmospheric distillation. Other factors, such as for caustic-washing to remove sulfur compounds, have been increased in proportion to projected crude oil sulfur content. The factors are in units of mass discharged per barrel of crude.

Table F-72 gives, for the year 1988, the tons of wastes other than wastewater, including liquid and solid or semi-solid forms, the basic effluent factors, and constituents such as metals, phenols, and cyanide. Table F-73 gives the effluent factors, relative to the volume of gasoline produced, for these other wastes and the corresponding mass discharge rates per year. From Table F-73, the total solid and other wastes in the year 2000 is 5,100 lbs per 1000 bbl of gasoline, or 5.1 lbs per bbl, if all the wastes were attributed to reformulated gasoline production. For the year 2010, the total effluent factor for solid and other wastes is 6.0 lbs per bbl of gasoline produced. However, reformulated gasoline represents only a fraction of the total refinery product data. Thus, the effluent estimates must be allocated among all refinery outputs. The following notes accompanying this table include bases for adjusting the basic effluent factors to the years 2000 and 2010:

1. Factors are adjusted for crude throughput and gasoline produced. Crude volume in 2000 is 1.313 times volume in 1990. Crude volume in 2010 is 1.340 times volume in 1990. Gasoline volume in 1990 is 6,788 kBCD; in 2000 it is 7,000 kBCD; in 2010 it is 6,300 kBCD.
2. Factors are adjusted for crude throughput and sulfur content, and gasoline produced. Sulfur content in 2000 vs 1990 is 1.3/1.1; sulfur content in 2010 vs 1990 is 1.6/1.1.
3. Factors are adjusted for crude throughput, gasoline produced, and increased inorganic wastes associated with cooling towers, boilers, boiler feedwater treatment, and hydrogen production.
4. Factor adjusted for gasoline produced, and increased by the ratio of total production in 2000 or in 2010 over non-leaded production in base year. The non-leaded volume in base year is taken as 6,788 kBCD less 9.1 percent leaded (Swain, 1991; page 50).

**Table F-72.**  
**1988 Solid and Other Wastes From Petroleum Refineries<sup>1</sup>**

Description <sup>a</sup>	k-tons <sup>a</sup>	lb/k-bbl <sup>a</sup>	Units, lb/k-bbl <sup>b</sup>										
			Chromium	Lead	Selenium	Arsenic	Mercury	Beryllium	Nickel	Silver	Cadmium	Phenols	Cyanide
Biosludge	786	634	0.0025	0.0006	0.0001	0.0024	0.0001	0.0000	0.0000	0.0002	0.0002	0.0029	0.0000
Spent Caustics	656	529											
DAF Float	655	529	0.074	0.0040	0.0011	0.0011	0.0000	0.0000	0.0000	0.0001	0.0000	0.0034	0.0001
API Separator Sludge	355	287	0.073	0.0075	0.0000	0.0018	0.0001	0.0000	0.0003	0.0001	0.0001	0.0039	0.0000
Pond Sediments	266	215											
Other Inorganic Wastes NOS	213	172											
Nonleaded Tank Bottoms	129	104	0.0002	0.0004	0.0012	0.0000	0.0000	0.0000	0.0028	0.0001	0.0000	0.0002	0.0008
Stop Oil Emulsions	224	181	0.0095	0.0051	0.0002	0.0013	0.0001	0.0000	0.0091	0.0001	0.0000	0.0027	0.0000
Other Wastes NOS	412	333											
FCC Catalysts	193	156	0.0075	0.0013	0.0000	0.0002	0.0000	0.0001	0.038	0.0003	0.0000	0.0003	0.0000
Contaminated Soils/Solids	240	194											
Other Contaminated Soils	68	55											
Other Separator Sludges	104	84											
Waste Coke/Carbon/Charcoal	67	54											
Hydroprocessing Catalysts	36	29											
Other Oily Sludges/Inorg. Wastes	61	49	0.0014	0.0018	0.0003	0.0011	0.0000	0.0000	0.0034	0.0000	0.0000	0.0012	0.0011
Other Spent Catalyst NOS	37	30	0.0004	0.0021	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Waste Sulfur	22	18											
Waste Amines	14	11											
Leaded Tank Bottoms	8	6	0.0001	0.0047	0.0000	0.0018	0.0000	0.0000	0.0019	0.0000	0.0000	0.0001	0.0000
Waste Oils/Spent Solvents	7	6											
Heat Exch. Bundle Cleaning Solids	5	4	0.0012	0.0003	0.0001	0.0000	0.0000	0.0000	0.0005	0.0000	0.0000	0.0001	0.0000
<b>Total</b>	<b>4,558</b>	<b>3,679</b>	<b>0.17</b>	<b>0.038</b>	<b>0.0031</b>	<b>0.0097</b>	<b>0.0004</b>	<b>0.0001</b>	<b>0.55</b>	<b>0.0009</b>	<b>0.0004</b>	<b>0.015</b>	<b>0.0021</b>

<sup>1</sup> Includes semi-solid and those liquid wastes not included in wastewater.

Sources: a. American Petroleum Institute, *The Generation of Wastes and Secondary Materials in the Petroleum Refining Industry*, Health and Environmental Affairs Dept., Washington, D.C., February 1991.

b. U.S. Department of Energy, *Energy Technologies and the Environment*, Report No. DOE/EA-0077, Washington, D.C., October 1983.

Solid and Other Wastes From Petroleum Refineries for the Years 2000 and 2010<sup>1</sup>

Description	Recent k-tons	1990 Factor lb/k-bbl <sup>2</sup>	Year 2000		Year 2010		Text Reference Notes
			Factor lb/k-bbl <sup>3</sup>	k-lb/year	Factor lb/k-bbl <sup>4</sup>	k-lb/year	
<b>Hazardous and Potentially Hazardous Wastes<sup>5</sup></b>							
DAF Float	655	529	673	1720400	765	1759200	1
API Separator Sludge	355	287	365	932400	415	953400	1
Other Inorganic Wastes NOS	213	172	438	1118900	498	1144100	3
Nonleaded Tank Bottoms	129	104	111	283600	111	255100	4
Other Contaminated Soils	68	55	53	136000	59	136000	6
Other Separator Sludges	104	84	107	273200	121	279300	1
Waste Coke/Carbon/Charcoal	67	54	0	0	0	0	7
Other Oily Sludges/Inorg. Wastes	61	49	63	160200	71	163800	1
Other Spent Catalyst NOS	37	30	55	140900	67	153200	9
Waste Sulfur	22	18	27	68300	37	86000	2
Leaded Tank Bottoms	8	6	0	0	0	0	10
Heat Exch. Bundle Cleaning Solids	5	4	5	13100	6	13400	1
<b>Subtotal - Hazardous and Potentially Hazardous Wastes</b>	<b>1,724</b>	<b>1,392</b>	<b>1,897</b>	<b>4,847,000</b>	<b>2,150</b>	<b>4,944,000</b>	
<b>Non-Hazardous Wastes</b>							
Biosludge	786	634	808	2063800	918	2111000	1
Spent Caustics	656	529	797	2036900	1114	2562700	2
Pond Sediments	266	215	547	1397300	621	1428800	3
Slop Oil Emulsions	224	181	230	588300	262	601600	1
Other Wastes NOS	412	333	410	1048700	481	1106500	1
FCC Catalysts	193	156	151	386100	168	386000	5
Contaminated Soils/Solids	240	194	188	480100	209	480000	6
Hydroprocessing Catalysts	36	29	44	113600	49	113600	8
Waste Amines	14	11	17	43500	24	54700	2
Waste Oils/Spent Solvents	7	6	7	18400	8	18800	1
<b>Subtotal - Non-Hazardous Wastes</b>	<b>2,834</b>	<b>2,288</b>	<b>3,199</b>	<b>8,177,000</b>	<b>3,854</b>	<b>8,864,000</b>	
<b>Total - Solid and Other Wastes</b>	<b>4,560</b>	<b>3,680</b>	<b>5,100</b>	<b>13,000,000</b>	<b>6,000</b>	<b>13,800,000</b>	

<sup>1</sup> Includes semi-solid and those liquid wastes not included in wastewater.

<sup>2</sup> Factor for 1990 = (recent tons) \* (2000 lb/ton)/(365 days \* recent gasoline volume/day). The 1989 gasoline volume was 6788 kBCD. This factor is calculated based upon gasoline production. Allocation of these wastes between gasoline and other products will be made in Table F-76.

<sup>3</sup> Factor for 2000 = (6788 kBCD/7000 kBCD) \* (factor for 1990 adjusted upward in proportion to change in crude oil volumes from 1990). See text reference notes.

<sup>4</sup> Factor for 2010 = (6788 kBCD/6300 kBCD) \* (factor for 1990 adjusted upward in proportion to change in crude oil volumes from 1990). See text reference notes.

<sup>5</sup> EA Mueller assessment of hazardous or potentially hazardous wastes.

Source: American Petroleum Institute, *The Generation of Wastes and Secondary Materials in the Petroleum Refining Industry*, Health and Environmental Affairs Dept., Washington, D.C., February 1991. Factors are per 1000 bbl of gasoline produced.

5. FCC catalyst waste is constant for all years - no change in FCC charge (although FCC operations are modified in year 2010 to change product mix).
6. Assume no change in refinery land, so soils contamination is the same for all years.
7. Assume that a coke-fueled cogeneration boiler burns all waste carbon products as well as some of the coke produced.
8. Hydroprocessing catalyst wastes are proportional to total volumes for: hydrodesulfurizing throughput of catalytic reforming feed or corresponding hydrogen production from catalytic reforming, plus hydrogen used for hydrorefining and hydrotreating of stocks.
9. Other spent catalysts, a portion of which cannot be returned to the manufacturer for recycling, include shift catalysts for hydrogen production and sulfur recovery plant catalyst. Factor is adjusted for crude throughput, gasoline volume, sulfur content of crude plus an allowance for non-recyclable portions of catalysts used for other processes such as shift catalyst.
10. By 1996, leaded gasoline is mandated to be phased out completely. Assume no leaded tank bottoms are disposed of by the year 2000.

#### **F.4.5 Non-Process Requirements**

In sharp contrast to the wide range of non-process environmental concerns discussed above for crude oil production, the expected refinery non-process environmental concerns will be fewer in number and less diverse in nature primarily because the basic refinery structure and supporting infrastructure that exists today is expected to remain in place in the years 2000 and 2010. This expectation follows from the assumption that there will be no new "greenfield" refineries built in the United States in the time period of interest.

The above expectations are not intended to suggest that there will be no non-process environmental concerns, rather, that the concerns will be those of an existing facility, including process modifications, upgradings, and expansions. In particular, concerns for occupational health and safety, reduction of hazardous wastes, subsurface water protection, land protection, odors, aesthetics as well as others may come to the forefront as discussed below.

- **Water Resources:** Continued operation and past practices have the potential to affect groundwater supplies through percolation, contamination of aquifers, and the introduction of toxic substances. Surface waters may be affected through surface erosion and contamination of streams.
- **Soil:** Soil contamination from spills and leakage from process streams and releases from waste treatment equipment and impoundments constitute the principal risks to soil. On the other hand, dirt (soil) entering refinery oily water systems becomes a burden in the API separators and an expense consideration to the refinery operator because it must be disposed of as a hazardous waste. One refiner has spent \$1.6 million for 8,300 cubic yards of concrete on paving projects to avoid this problem (Hethcoat, 1990). As the use of surface impoundments decline, contamination from this source will also decline.
- **Odors and Noise:** Odors and noise are proximity events in most cases. Industrial noise can be mitigated by known techniques with respect to both processes and hearing protection for personnel. Odors can migrate to impact non-refinery personnel, particularly where there is a collection of refineries in an area.
- **Other Concerns:** Many environmental concerns, including aesthetics, are site-specific. Additionally, given the recent regulatory climate and the long time frame of the study, it can be expected that there will be a changing pattern of concerns over the period covered by the study.
- **Occupational Health and Safety:** "The occupational safety hazards of petroleum refining are predominantly due to the flammable nature of the liquids and gases handled in oil refinery installations. In air, the product vapors and gases form explosive mixtures. Physical contact with, or inhalation of, toxic compounds--such as CO, hydrogen sulfide, ammonia, hydrogen cyanide, phenols, and benzene--could cause serious injury or death. These compounds can exist in products, byproducts, and waste and process streams and can be released during process disruptions and maintenance of operating requirements. Other, less significant occupational safety hazards in petroleum refineries include exposure to high temperatures, vibration, and corrosive materials and accidents due to falls, bumps, and heavy equipment.

Many compounds present a respiratory hazard. Liquid fuel products, such as gasoline and kerosene, produce a severe chemical pneumonitis if inhaled. The gaseous petroleum fractions and more volatile products, such as gasoline, have a mild anesthetic effect. Methane, ethane, and some of the lower olefins are classified as "simple asphyxiants" and high concentrations

of them could result in asphyxia. Accidental inhalation of certain organic solvents could result in neuropathy; long-term exposure to them could damage the peripheral as well as the central nervous system.

The lighter fractions of oil, such as hexanes and aromatics, are all grease solvents; repeated or prolonged skin contact with them will break down the protective surface of skin, resulting in primary irritant dermatitis. Heavier, more viscous products, such as lube oil and cutting oils, could plug skin follicles and lead to dermatitis.

Benzene is an insidious toxicant that destroys blood-forming tissue. Chronic benzene exposure could lead to a progressive disease in which bone marrow function becomes increasingly depressed, resulting in anemia, leukopenia, or thrombocytopenia in the peripheral circulatory system. Some of the heavier fractions of petroleum product systemic intoxications. A large number of halogenated hydrocarbons, such as chlorinated naphthalene and carbon tetrachloride, are known to be liver poisons. Hemolytic anemia and hepatic and renal disorders have been reported in workers who have inhaled concentrated naphthalene vapors.

Certain fractions of heavy residual oils contain materials that are carcinogenic in test animals. This carcinogenic potential appears to be associated with the presence of PAHs. To date, however, there has been no widely accepted evidence that petroleum refinery workers experience an excess risk of cancer from exposure to petroleum. Recent studies suggest an increased risk to the digestive system and possible cancers among various groups of refinery workers.

In addition to the above hazards, petroleum refinery workers may be exposed to other toxic agents (such as hydrogen sulfide, hydrogen fluoride, and lead compounds) and physical hazards (such as noise, asbestos, and silica dust).

During the past decade, several epidemiological studies have evaluated the health of refinery workers. In general, the results suggest that, while potential health hazards that exist in the petroleum industry are numerous and varied, the incidence of occupational disorders among refinery employees is relatively low. Meanwhile, it is essential to take appropriate measures to minimize the workers' exposure with these hazardous substances and keep concentrations of these chemicals below the levels and standards set by relevant authorities" (DOE, 1988).

While the refining industry has a lower rate of injuries and illnesses than other industries as a whole, its potential for catastrophic accidents is high.

In 1987, petroleum refining (SIC 291) had an occupational injury and illness rate of 5.6 incidences per 100 full-time workers (API, 1990). These incidences can be compared to the total private sector incidence rate of 8.3 per 100 full-time workers (DOL, 1990a).

In 1989 and 1990, however, there was a series of oil refinery and petrochemical plant explosions and fires that, some say, portend serious safety problems in the industries involved (Alnsworth, 1990).

On July 17, 1990, the Occupational Safety and Health Administration of the U.S. Department of Labor, issued a notice of proposed rulemaking on Process Safety Management (PSM) of highly hazardous chemicals that will affect the petroleum refining industry. Among the claimed benefits of the proposed rulemaking is an estimate of risk reduction of 80 percent of fatalities and injuries and illnesses (DOL, 1990b). As of October 1991, no final rules have been issued. There is industry opposition to the rulemaking that will cover 27,775 businesses employing 2.2 million workers and entail direct annual cost of \$637.7 million to those businesses affected (DOL, 1990b).

For purposes of estimating the impact of this rulemaking on the petroleum refining industry in 2000 and 2010, the following approach was used:

- Recognition was given that the petroleum refining industry has traditionally been safety conscious and has had a recent occupational injury and illness rate of approximately 6.0 per 100 workers compared to 8.5 for the industry as a whole.
- The greatest improvement of the proposed rule making will come in industries other than petroleum refining.
- While it is widely expected that there will eventually be a rulemaking, such rulemaking may be a modification of the original proposed rules.
- The 80 percent reduction may not be achievable in practice.

Given these considerations, a "risk" reduction factor of 50 percent was chosen for petroleum refining in 2000 and 2010.

This assumed risk reduction estimate of 50 percent translates into the following for the years 2000 and 2010 assuming that the number of workers in petroleum refining remains constant:

- Occupational Injuries and Illnesses: Petroleum Refining (SIC 291) (DOL, 1990a; API, 1990)

6 incidences/100 workers/year x 50 percent risk reduction factor = 3.0 incidences/100 workers/year

3.0 incidences/100 workers/year x 122,000 workers (API, 1990) = 3,700 incidences/year

- Lost Workdays: Petroleum Refining (SIC 291) (DOL, 1990a)

$[(56.0 + 59.0)/2]$  workdays lost/100 full-time workers x 50 percent risk reduction factor = 28.8 workdays lost/100 full-time workers

28.8 workdays lost/100 full-time workers x 122,000 workers (API, 1990) = 35,000 lost workdays/year

- Occupational Fatalities: Manufacturing (DOL, 1990a - Petroleum Refining not broken out)

$[(4.4 + 3.6)/2]$  fatalities/100,000 full-time workers x 50 percent risk reduction factor = 2.0 fatalities/100,000 full-time workers

2.0 fatalities/100,000 workers x 122,000 workers = 2.4 fatalities/year

Table F-74 projects these incidences to the years 2000 and 2010.

#### **F.4.6 Pre-Operation and Post-Operation Phase**

The last "greenfield" complex refinery built in the United States was completed in 1971. At the time, it was the largest refinery built at one time. The Alliance Refinery of Belle Chase, Louisiana, operated by BP Oil Co., is a single-train complex (one unit per process) and is completely integrated. The processing units were all built at the same time and were designed to conserve energy and minimize waste generation whenever possible by feeding hot charge directly from one unit to the other, with minimal intermediate tankage. Major processing units include: crude distillation, fluid catalytic cracking, catalytic reforming, alkylation, aromatics extraction, hydrogen treating, and

**Table F-74.  
Refinery Occupational Health and Safety Projection to 2000 and 2010**

	Incidence Rate	Annual Incidents <sup>1</sup>	Incidents Per Barrel <sup>2</sup>	
			2000	2010
Injuries and Illnesses Rate per 100 workers	3.0	3,700	$1.4 \times 10^{-6}$	$1.4 \times 10^{-6}$
Lost Workdays, Rate per 100 workers	28.8	35,000	$14 \times 10^{-6}$	$14 \times 10^{-6}$
Fatalities, Rate per 100,000 workers	2.0	2.4	$0.94 \times 10^{-9}$	$0.94 \times 10^{-9}$

<sup>1</sup> Assumes 1988 employment levels continue to 2000 since refinery production is about the same in 2000 and 1988. The incidence increases in 2010 are prorated on volume.

<sup>2</sup> Assumes U.S. gasoline demand of 7.0 MMBD in 2000 and 6.3 MMBD in 2010 per Table F-53.

sulfur recovery. Materials of construction included concrete, steel, specialized materials, etc.

Crude oil enters the refinery through a 10-inch pipeline from offshore Louisiana and travels through a series of processing units. Over 95 percent of the finished prime fuel products leave the refinery via a 20-inch pipeline (Hethcoat, 1990). These prime fuels include motor gasolines, jet fuel, and diesel fuel. Other products include propane, benzene, mixed xylenes, carbon black feedstock, sulfur and petroleum coke.

The refinery processing system occupies only 38 acres, although the overall refinery property totals 690 acres. A segregated sewer system allows for separate handling of contaminated and noncontaminated storm water runoff. Almost all of the clean process water streams, such as cooling water, are handled separately to minimize contamination and blowdown water. Process wastewater is treated by an advanced treatment system that includes API separators, DAF treatment, equalization, activated sludge biological treatment, and a polishing lagoon (Hethcoat, 1990).

As indicated above, facilities of this type are not expected to be built in the United States through the year 2010. There is expectation, however, that existing refineries will continue to install more segregated sewer systems and advanced treatment systems.

On the other hand, a number of refineries, particularly smaller ones, are expected to be closed as a result of a switch by the military in the type of jet fuel to commercial specification, the Clean Air Act Amendments of 1990, as well as the general competitive market forces and

equipment obsolescence of any industry. A remediation program will be required for a refinery that is to be closed.

#### **F.4.7 Discussion and Summary**

With a 2000 and 2010 gasoline pool containing an average of 2 percent oxygen, the corresponding amount of MTBE as the primary oxygenate is 11 percent. The 25 percent aromatics limit can be met by blending in less reformate, reducing the present 27 percent reformate content to approximately 21 percent and reducing reforming severity by approximately 5 octane numbers. In other words, the reformate content of gasoline can be reduced by 6 percentage points.

MTBE has an (R+M)/2 octane rating of 109, versus 93.5 for reformate. If 11 percent of a blending component with 109 octane is added to the pool, and a component with 93.5 octane is subtracted to the extent of 6 percentage points, then an octane surplus results. In order to balance this octane surplus against the other requirements for reformulated gasoline in 2000 and 2010, other components of the gasoline must be adjusted, i.e., removed. The other components that can be subtracted from the pool include high-octane hydrocarbons such as alkylate and butane. Such a blending strategy makes butanes (now used for making alkylate and increasing gasoline vapor pressure) available for manufacturing MTBE. Lowering the vapor pressure in the warm season of each year is required in the recently enacted CAA Amendments.

Other refining and blending modifications which could help meet future reformulated gasoline requirements include reducing gasoline end point, especially for FCC naphtha, or operating FCC units to favor the production of light olefins such as butylenes with a simultaneous reduction of FCC naphtha volume. However, the first option does not improve butylenes supplies, which are needed for making MTBE.

Even with 11 percent MTBE in the pool, achieving a 1.0 percent benzene limitation will require additional large-scale catalytic reforming modifications as well as stopping deliberate blending of benzene and other aromatics into the gasoline pool. Either catalytic reformer charge can be pre-distilled to remove C<sub>5</sub> and C<sub>6</sub> hydrocarbons, or some of the benzene contained in reformate can be extracted.

A scenario for refining and blending was developed in this study (see Tables F-60 and F-61) which achieves the specified octane targets, 25 percent aromatics content, less than 1 percent benzene, and a warm-season Reid Vapor Pressure less than 8.5 psi and annual average RVP of 9.0 psi, with 11 percent MTBE in the U.S. gasoline pool in the years 2000 and 2010. This scenario is not an attempt to achieve the optimum, but it is intended to be a plausible one on an average, nationwide basis. Each refinery will try to achieve an optimum strategy for their individual situation. The scenario evaluated in this study includes:

- Reducing severity and reformate volume (Tables F-54, F-55, and F-56)

- Reducing alkylate and butane volumes in the pool (Table F-57)
- Diverting butanes to maximizing and producing isobutylene, used to make MTBE (Table F-59)
- Increasing FCC light to olefins production in 2010, up to which date the U.S. may be able to import worldwide supplies of isobutylene or MTBE (Figure F-15)
- Extracting benzene from reformat (Table F-58)
- Eliminating deliberate blending of other aromatics (Table F-57)
- Increasing the manufacture of hydrogen to make up for reduced production of catalytic reforming hydrogen (Section F.4.4.6) .

At the same time, the scenario includes increased vacuum distillation and coking volumes to contend with the trend toward using heavier crude oils, and increased hydrotreating and caustic washing to contend with higher sulfur contents in crude oils. The volumes for each refining process have been quantified in Table F-62 for 2000 and for 2010, with west coast (PAD District V) vacuum distillation, coking and crude oil gravity distinguished from the rest of the United States. (PAD Districts I-IV) east of the Rocky Mountains.

Emissions and effluents have been projected for 2000 and for 2010 based on the throughput volumes for each refining step as given in Table F-62. Air pollutants emissions are quantified in Tables F-65 and F-66; carbon dioxide in Tables F-67 and F-68; wastewater in Tables F-70 and F-71; and other liquid, semi-solid and solid wastes in Tables F-72 and F-73. Overall input and output quantities, air emissions, effluents, and waste factors are summarized on an unallocated basis in Table F-75. In other words, 100 percent of each emission, effluent, and waste factor in Table F-75 were ascribed to gasoline produced with zero percent to other refined products. However, reformulated gasoline represents only a fraction of the total refinery production rate. Thus, the emission, effluent, and waste estimates must be allocated among all refinery outputs. The allocated pollutant factors between gasoline and other refinery products are shown in Table F-76.

It is important to note that if the emissions and effluents are compared to present levels, the increases are mainly caused by the processing of heavier crude oils with increased sulfur content at increased crude oil volumes. The heavier crude oils will result in increased coking, with corresponding higher amounts of coking emissions and effluents.

**Table F-75.**  
**Total Annual Inputs and Outputs for Reformulated Gasoline Refining<sup>1</sup>**

Inputs	2000		2010	
	Refinery Total	Per MMBTU of Reformulated Gasoline <sup>1,2</sup>	Refinery Total	Per MMBTU of Reformulated Gasoline <sup>1,2</sup>
Crude oil (bbl) <sup>3</sup>	6,424 x 10 <sup>6</sup>	0.519	6,716 x 10 <sup>6</sup>	0.603
MTBE (bbl) <sup>4</sup>	281 x 10 <sup>6</sup>	0.023	253 x 10 <sup>6</sup>	0.023
Natural gas (MMCFD) <sup>5</sup>	1,503,000	0.00012	1,685,000	0.00015
Electricity (kWh) <sup>6</sup>	42.8 x 10 <sup>9</sup>	3.45	44.7 x 10 <sup>9</sup>	4.02
Catalysts <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>
Other <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>
<b>Outputs</b>				
Other refinery products (bbl) <sup>8</sup>	4,700 x 10 <sup>6</sup>	0.380	5,300 x 10 <sup>6</sup>	0.477
Reformulated gas (bbl) <sup>9</sup>	2,600 x 10 <sup>6</sup>	0.206	2,300 x 10 <sup>6</sup>	0.207
Air emissions (tons) <sup>10</sup>				
HC	84,000	6.74 x 10 <sup>-6</sup>	49,000	4.44 x 10 <sup>-6</sup>
CO	83,000	6.65 x 10 <sup>-6</sup>	95,000	8.51 x 10 <sup>-6</sup>
NO <sub>x</sub>	653,000	52.7 x 10 <sup>-6</sup>	827,000	74.5 x 10 <sup>-6</sup>
Particulates	22,000	1.77 x 10 <sup>-6</sup>	26,000	2.37 x 10 <sup>-6</sup>
SO <sub>2</sub>	414,000	33.4 x 10 <sup>-6</sup>	502,000	45.2 x 10 <sup>-6</sup>
CO <sub>2</sub>	268 x 10 <sup>6</sup>	21,600 x 10 <sup>-6</sup>	341 x 10 <sup>6</sup>	31,000 x 10 <sup>-6</sup>
Wastewater (MMGal) <sup>11</sup>	130,000	10.5	171,000	15.4
BOD (lb)	4.5 x 10 <sup>6</sup>	0.36 x 10 <sup>-3</sup>	4.7 x 10 <sup>6</sup>	0.42 x 10 <sup>-3</sup>
COD (lb)	38 x 10 <sup>6</sup>	3.1 x 10 <sup>-3</sup>	38 x 10 <sup>6</sup>	3.4 x 10 <sup>-3</sup>
TOC (lb)	31 x 10 <sup>6</sup>	2.5 x 10 <sup>-3</sup>	33 x 10 <sup>6</sup>	3.0 x 10 <sup>-3</sup>
TSS (lb)	20 x 10 <sup>6</sup>	1.6 x 10 <sup>-3</sup>	21 x 10 <sup>6</sup>	1.9 x 10 <sup>-3</sup>
NO <sub>3</sub> N (lb)	0.63 x 10 <sup>6</sup>	0.051 x 10 <sup>-3</sup>	0.65 x 10 <sup>6</sup>	0.059 x 10 <sup>-3</sup>
Phenols (lb)	0.084 x 10 <sup>6</sup>	0.0068 x 10 <sup>-3</sup>	0.087 x 10 <sup>6</sup>	0.0078 x 10 <sup>-3</sup>
Sulfides (lb)	--	--	--	--
Oil and grease (lb)	1.7 x 10 <sup>6</sup>	0.14 x 10 <sup>-3</sup>	1.7 x 10 <sup>6</sup>	0.15 x 10 <sup>-3</sup>
Total chromium (lb)	<0.055 x 10 <sup>6</sup>	0.0044 x 10 <sup>-3</sup>	<0.055 x 10 <sup>6</sup>	<0.0050 x 10 <sup>-3</sup>
Solid and other wastes (lb) <sup>12</sup>				
Non-hazardous	8.18 x 10 <sup>9</sup>	0.660	8.86 x 10 <sup>9</sup>	0.798
Hazardous or potentially hazardous	4.85 x 10 <sup>9</sup>	0.391	4.94 x 10 <sup>9</sup>	0.445

<sup>1</sup> Assuming all inputs and outputs are entirely allocated to reformulated gasoline.

<sup>2</sup> In the year 2000, 7.0 x 10<sup>6</sup> BCD reformulated gasoline \* 365 days/year \* 42 gal/bbl \* 115,400 Btu (LHV)/gal = 12.4 x 10<sup>9</sup> MMBtu/yr. Similarly, in the year 2000, based upon 6.3 x 10<sup>6</sup> BCD reformulated gasoline: 11.1 x 10<sup>9</sup> MMBtu/yr.

<sup>3</sup> Table F-49: 17.6 MMBD and 18.4 MMBD in 2000 and 2010, respectively. Includes natural gas liquids.

<sup>4</sup> Table F-55 times 365 days/year.

<sup>5</sup> Assumes future years natural gas consumption is proportional to crude oil plus use in hydrogen production at a rate of 1 MMCF natural gas for each 4 MMCF hydrogen. Accordingly, 6778/4 MMCFD in 2000; 8378/4 MMCFD in 2010 = +618,493 MMCF/yr natural gas; +764,493 MMCF/yr natural gas.

<sup>6</sup> Purchased electric power.

<sup>7</sup> Not calculated.

<sup>8</sup> Expressed as fuel equivalent barrels of byproducts but also includes minor amounts of recovered sulfur, catalyst to recycle, marketable coke, etc.

<sup>9</sup> Table F-53 times 365 days/year.

<sup>10</sup> Table F-65 times 365 days/year except CO<sub>2</sub> from Table F-67.

<sup>11</sup> Table F-71.

<sup>12</sup> Table F-73.

**Table F-76.**  
**Emissions, Effluents and Wastes of Refining Allocated to Reformulated Gasoline<sup>1</sup>**

Inputs	2000		2010	
	Refinery Totals Allocated to Gasoline <sup>1</sup>	Per MMBTU of Reformulated Gasoline <sup>1,2</sup>	Refinery Totals Allocated to Gasoline <sup>1</sup>	Per MMBTU of Reformulated Gasoline <sup>1,2</sup>
Crude oil (bbl) <sup>3</sup>	2,248 x 10 <sup>6</sup>	0.182	2,015 x 10 <sup>6</sup>	0.181
MTBE (bbl) <sup>4</sup>	281 x 10 <sup>6</sup>	0.023	253 x 10 <sup>6</sup>	0.023
Natural gas (MMCFD) <sup>5</sup>	526,000	42.4 x 10 <sup>-6</sup>	506,000	45.6 x 10 <sup>-6</sup>
Electricity (kWh) <sup>6</sup>	15.0 x 10 <sup>9</sup>	1.21	13.4 x 10 <sup>9</sup>	1.21
Catalysts <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>
Other <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>	NC <sup>7</sup>
<b>Outputs</b>				
Other refinery products (bbl) <sup>8</sup>	NA	NA	NA	NA
Reformulated gas (bbl) <sup>9</sup>	2,600 x 10 <sup>6</sup>	0.206	2,300 x 10 <sup>6</sup>	0.207
Air emissions (tons) <sup>10</sup>				
HC	29,000	2.36 x 10 <sup>-6</sup>	15,000	1.33 x 10 <sup>-6</sup>
CO	29,000	2.33 x 10 <sup>-6</sup>	28,000	2.55 x 10 <sup>-6</sup>
NO <sub>x</sub>	229,000	20.8 x 10 <sup>-6</sup>	248,000	22.4 x 10 <sup>-6</sup>
Particulates	7,700	0.62 x 10 <sup>-6</sup>	7,900	0.71 x 10 <sup>-6</sup>
SO <sub>2</sub>	145,000	11.7 x 10 <sup>-6</sup>	151,000	13.6 x 10 <sup>-6</sup>
CO <sub>2</sub>	93.9 x 10 <sup>6</sup>	7,600 x 10 <sup>-6</sup>	102 x 10 <sup>6</sup>	9,200 x 10 <sup>-6</sup>
Wastewater (MMGal) <sup>11</sup>	46,000	3.68	51,000	4.62
BOD (lb)	1.6 x 10 <sup>6</sup>	0.13 x 10 <sup>-3</sup>	1.4 x 10 <sup>6</sup>	0.13 x 10 <sup>-3</sup>
COD (lb)	13 x 10 <sup>6</sup>	1.1 x 10 <sup>-3</sup>	11 x 10 <sup>6</sup>	1.0 x 10 <sup>-3</sup>
TOC (lb)	11 x 10 <sup>6</sup>	0.88 x 10 <sup>-3</sup>	10 x 10 <sup>6</sup>	0.90 x 10 <sup>-3</sup>
TSS (lb)	7.0 x 10 <sup>6</sup>	0.56 x 10 <sup>-3</sup>	6.3 x 10 <sup>6</sup>	0.57 x 10 <sup>-3</sup>
NO <sub>3</sub> N (lb)	0.22 x 10 <sup>6</sup>	0.018 x 10 <sup>-3</sup>	0.20 x 10 <sup>6</sup>	0.018 x 10 <sup>-3</sup>
Phenols (lb)	0.029 x 10 <sup>6</sup>	0.0024 x 10 <sup>-3</sup>	0.026 x 10 <sup>6</sup>	0.0023 x 10 <sup>-3</sup>
Sulfides (lb)	--	--	--	--
Oil and grease (lb)	0.60 x 10 <sup>6</sup>	0.049 x 10 <sup>-3</sup>	0.51 x 10 <sup>6</sup>	0.045 x 10 <sup>-3</sup>
Total chromium (lb)	<0.019 x 10 <sup>6</sup>	<0.0015 x 10 <sup>-3</sup>	<0.0017 x 10 <sup>6</sup>	<0.0015 x 10 <sup>-3</sup>
Solid and other wastes (lb) <sup>12</sup>				
Non-hazardous	2.86 x 10 <sup>9</sup>	0.231	2.66 x 10 <sup>9</sup>	0.239
Hazardous or potentially hazardous	1.70 x 10 <sup>9</sup>	0.137	1.48 x 10 <sup>9</sup>	0.134

Reference Table F-75 assuming all inputs and outputs are allocated between reformulated gasoline and byproducts. The allocation in the base year 1989/1990 is 0.46 of refinery emissions and wastes to gasoline; however, this allocation changes in the years 2000 and 2010 to 0.35 and 0.30, respectively, as the refineries process more crude but produce less gasoline per the NES scenario (DOE, 1991a). MTBE is an exception to the allocation since it is entirely used as a component of reformulated gasoline.

In the year 2000, 7.0 x 10<sup>6</sup> BCD reformulated gasoline \* 365 days/year \* 42 gal/bbl \* 115,400 Btu (LHV)/gal = 12.4 x 10<sup>9</sup> MMBtu/yr. Similarly, in the year 2000, based upon 6.3 x 10<sup>6</sup> BCD reformulated gasoline: 11.1 x 10<sup>9</sup> MMBtu/yr.

Table F-49: 17.6 MMBD and 18.4 MMBD in 2000 and 2010, respectively. Includes natural gas liquids.

Table F-55 times 365 days/year.

Assumes future years natural gas consumption is proportional to crude oil plus use in hydrogen production at a rate of 1 MMCF natural gas for each 4 MMCF hydrogen. Accordingly, 6778/4 MMCFD in 2000; 8378/4 MMCFD in 2010 = +618,493 MMCF/yr natural gas; +764,493 MMCF/yr natural gas.

Purchased electric power.

Not calculated.

Table F-53 times 365 days/year.

Not Allocable.

Table F-65 times 365 days/year except CO<sub>2</sub> from Table F-67.

Table F-71.

Table F-73.

With regard to higher sulfur contents, even though more desulfurization will occur and sulfur plants can recover 99 percent, the volumes of non-recyclable waste catalysts, spent chemical from caustic washes, wash water used following caustic washes, and air discharges of sulfur-containing compounds will increase.

The refining scenario depicted in this study includes reduced reforming severity and throughput volume, resulting in less hydrogen availability for desulfurization and hydrotreating. Making up this hydrogen with steam reforming will result in more non-recyclable waste catalyst and solid adsorbents used in hydrogen manufacture. The proposed extraction of benzene from reformat may result in emissions from handling the chemicals used as extracts - because of this some refiners may opt to predistill catalytic reforming charge stocks instead of extraction from product reformat. Refiners who opt to adjust catalytic cracking operations to favor light olefins production will need to combust more carbon in their catalyst regenerators, ultimately resulting in more emissions from CO boilers used for generator discharges. However, all of these potential increases in emissions and effluents caused by refinery processing changes are small compared to the effects of changing crude oil properties and volumes.

#### **F.4.8 References**

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## **F.5 Reformulated Gasoline Distribution and Storage**

### **F.5.1 Gasoline Transportation Infrastructure**

The current gasoline transportation infrastructure is included in all three parts of the petroleum transportation and storage phases discussed in Section F.3; Primary Distribution, Secondary Distribution, and Tertiary Storage. The Primary Distribution system as it relates to gasoline begins from the refinery and continues as the gasoline is transported and stored at the bulk terminals. The Secondary Distribution system for gasoline begins from the receipt of the gasoline at the bulk plants and includes the distribution to the gasoline retail outlets. The last segment of the gasoline transportation infrastructure is the Tertiary Storage segment which includes all agricultural, commercial, and industrial sectors that store gasoline. The following will provide a description of all three of these segments and how it relates to gasoline transportation and storage.

#### **F.5.1.1 Primary Distribution System for Gasoline**

The Primary Distribution system for gasoline begins with the gasoline leaving the refinery by either barge, tanker, or pipeline. Any gasoline leaving the refinery by tanker truck was not included in the distribution system considered for this analysis. The gasoline transported by barge or tanker is taken to a marine bulk storage terminal where the gasoline is stored in large (several million gallons) storage tanks. Similarly, the gasoline which is transported from the refinery by pipeline is sent to a pipeline bulk storage terminal where the gasoline is stored in similar size tanks. The gasoline which is stored at both of these bulk terminals (marine and pipeline) is then delivered to the bulk plants by tanker trucks for storage. Tanker trucks also deliver gasoline from the bulk terminals directly to retail outlets. However, this analysis assumes that most of the gasoline is moved through bulk plants before being delivered to retail outlets. The bulk plants store smaller quantities of product than bulk terminals. Once the gasoline has been delivered to the bulk plants, it has now entered the Secondary Distribution System.

#### **F.5.1.2 Secondary Distribution System for Gasoline**

The Secondary Distribution System for gasoline includes the bulk plant storage facilities and the tank trucks which distribute the gasoline to the end users. Tank trucks typically deliver the gasoline from the bulk plants to the retail outlets and commercial or rural accounts.

#### **F.5.1.3 Tertiary Storage System for Gasoline**

The storage capacities and inventories of gasoline held by end-users represent the tertiary storage of the petroleum distribution system. This storage capacity and gasoline inventory makes up a significant portion of the total U.S. gasoline storage capacity and inventory. The segments which were included for discussion for this part of the transportation infrastructure

include only commercial, and agricultural end user storage facilities since these accounts were estimated to store and consume the most gasoline within the tertiary storage segment. The storage capacity in the agricultural sector includes all farms and ranches, while the commercial segment includes commercial vehicle fleet refueling facilities.

## **F.5.2 Specific Assumptions for the Reformulated Gasoline Transportation Infrastructure**

Several important assumptions were made with regard to the infrastructure currently in place to adequately quantify the emission factors for the transportation and storage of reformulated gasoline. This section will describe the assumptions made for determination of the emission factors for each segment of the transportation infrastructure of reformulated gasoline. The assumptions are separated into seven categories including: general assumptions, gasoline transport, pipeline terminal transferral and storage, marine terminal transferral and storage, bulk plant transferral and storage, commercial/rural transferral and storage, and retail station transferral and storage assumptions. The assumptions are listed for the years 2000 and 2010 when appropriate, since the emission control effectiveness will differ for some segments of the infrastructure in each scenario.

### **F.5.2.1 General Assumptions**

#### Years 2000 and 2010

- Lower Heating Value of Gasoline = 115,400 Btu/gallon
- RVP of gasoline = 9.0 psi
  - based on 1992 summertime gasoline volatility regulations (EPA, 1991a) and Clean Air Act Amendment of 1990 provisions (U.S. Congress, 1990)
- Transportation of gasoline at ambient temperatures of 55 °F (U.S. Census Bureau, 1989)
  - assumed average national temperature representing the typical ozone non-attainment period
- Fuel spills along the gasoline transportation infrastructures will be quantified based on accidental fuel spill data (U.S. Coast Guard, 1986). Small spills associated with normal operational procedures (such as those associated with hose disconnect) for most of the gasoline distribution infrastructure will not be quantified due to a lack of industry data. Gasoline spill data at service stations will be provided, however, based on

actual measured data for normal end-use vehicle refueling operations (EA Mueller, 1989).

- Efficiencies for electric motors and IC engines used to power pipelines, marine vessels, and tank trucks will be the same for transporting equivalent masses of crude oil or gasoline in these transportation modes.
- Reformulated gasoline throughput through each leg of the assumed infrastructure was based on NES projections for years 2000 and 2010 (DOE, 1991) and current estimates of gasoline product flow (NPC, 1991). Gasoline flow out of the refinery was assumed to split into the following throughput percentages for each of the two legs: 84 percent moved through pipeline terminals and 16 percent through marine terminals.

### **F.5.2.2 Reformulated Gasoline Transport Assumptions**

#### Years 2000 and 2010

- Lower Heating Value of No. 2 diesel fuel = 128,700 Btu/gal (ORNL, 1991), carbon content of 87 percent, used by inland barges, rail, and tank trucks.
- Lower Heating Value of No. 6 diesel fuel = 137,500 Btu/gal, carbon content of 90 percent, used by ocean tankers (SwRI, 1985)
- Spill rates were determined for each transport mode based on available spill data and were assumed the same for both 2000 and 2010.
- Pipeline
  - Use of 100 percent electric-powered pumps
- Tanker/Barge
  - Submerged loading practices only for all marine vessels based on characterization of current gasoline marketing practices (EPA, 1989; EPA, 1985a; Arthur D. Little, 1979), and future NSPS requirements for VOC control from petroleum product transferral at bulk terminals and bulk plants (EPA, 1988a).
  - Assume that all product is loaded into cleaned or gas-freed cargo tanks on marine vessels based on future VOC regulations in place for gasoline bulk terminal loading practices (EPA, 1988a).

- Assume the following ullage spaces based on EPA assumptions in its emission factor document, AP-42 (EPA, 1985b):
  - tankers = 10 feet
  - ocean and river barges = 5 feet
- 1990 tanker engine bsfc of 0.28 lb/bhp-hr based on low speed marine diesel engine data (Sulzer, 1990). This value will be used for 2000 and 2010 assuming that new tanker turnover is very slow.
- Ocean barge engine bsfc will be assumed to be equivalent to that of tankers based on the assumption that ocean barges also use low speed diesel engines.
- 1990 river barge engine bsfc of 0.37 lb/bhp-hr based on data from typical locomotive medium speed diesel engines (SwRI, 1985). It was assumed that river barges are propelled by tugboats which use medium speed diesel engines. The efficiencies of medium speed diesels do not vary considerably among applications. The 1990 values will be used for 2000 and 2010 assuming that new ocean barge turnover is very slow.

· Rail/Tank Truck

- Rail cars are assumed to have the same vapor leakage rates per unit of fuel as tank trucks based on a similar assumption by EPA in its emission factor document, AP-42 (EPA, 1985a) and since tank hatch designs between these two transportation modes are similar.
- Use of vapor tight rail cars and tank trucks which must meet annual certification based on future NSPS requirements for VOC control from petroleum product transferral at bulk terminals and bulk plants (EPA, 1988a). Assume a 67 percent reduction in vapor emissions during loading practices which such rail cars and tank trucks based on EPA estimates in proposed benzene regulations for the gasoline industry (EPA, 1989).
- Submerged loading practices are only based on characterization of current gasoline marketing practices (EPA, 1989; EPA, 1985a, Arthur D. Little, 1979), and future NSPS requirements for VOC control from petroleum product transferral at bulk terminals and bulk plants (EPA, 1988a).

- Locomotive engine bsfc of 0.37 lb/bhp-hr based on data from typical locomotive medium speed diesel engines (SwRI, 1985). The 1990 values will be used for 2000 and 2010 assuming that new locomotive turnover is very slow.
- A tank truck fuel economy of 5.3 MPG was assumed for 1990 based on the average national value for tractor/trailer combinations (MVMA, 1990) since this value generally represents Class 7 and Class 8 diesel trucks such as used for tank trucks. This value was projected to be 5.7 MPG in 2000 and 6.0 MPG in 2010 based on NES (DOE, 1991) fuel economy projections for highway vehicles carrying freight. These values are on a brake specific basis using bhp-hr/mile conversion data for future Class 8 trucks (MVMA, 1983). An average haul length of 50 miles was assumed for gasoline transport by tank truck.

#### · Spills

- Spills occurring during the transport of gasoline by all modes are based on published U.S. Coast Guard spill data (U.S. Coast Guard, 1986). The spill rate (gallon/year) was based on a four year average (1983 to 1986) of spills as recorded by the Coast Guard. The spill rates in 2000 and 2010 were determined for each mode of gasoline transportation based on NES values given for total petroleum liquids transported in years 2000 and 2010. The breakdown of gasoline transport by mode was assumed to be the same for the years 2000 and 2010 (DOE, 1991).

### **F.5.2.3 Pipeline Bulk Terminal Assumptions**

#### Years 2000 and 2010

- Pipeline terminals receive gasoline deliveries from pipelines only.
- Pipeline terminals use internal floating roof tanks for storing product based on NSPS for bulk petroleum storage tanks (EPA, 1988b; EIA, 1991a). Each tank is assumed to have a 1.6 million gallon capacity based on average capacities characterized in proposed future benzene regulations (EPA, 1989).
- A typical pipeline bulk terminal facility has four internal floating roof tanks (EPA, 1989).

- Based on a 1.6 million gallon storage capacity, the internal floating roof gasoline storage tank dimensions were assumed to be 95 ft. in diameter and 30 ft. high.
- In this analysis, each pipeline terminal is assumed to operate 260 days per year.
- Each pipeline terminal has a typical throughput of 65 million gallon per year (based on 260 operating days) with the four floating roof tanks (EPA, 1989).
- Pipeline terminals use vapor recovery systems for product transferral and storage with average efficiencies of 95 percent in 2000 and 98 percent in 2010 based on EPA estimates in future NSPS regulations for VOC control at bulk product terminal facilities (EPA, 1988a; EPA, 1988b) and proposed benzene control regulations at bulk product terminal facilities (EPA, 1989). The 95 percent efficiency rate for 2000 is an average value assumed for using carbon adsorption, thermal oxidizers, incineration, and refrigeration type vapor recovery equipment, while the 98 percent value for 2010 assumes the widespread use of thermal oxidizers and incineration units for vapor control. The higher value in 2010 will be based on the future VOC regulations (EPA, 1989).

#### **F.5.2.4 Marine Bulk Terminal Assumptions**

##### Years 2000 and 2010

- Marine terminals receive gasoline deliveries from tankers and barges.
- Marine terminals use internal floating roof tanks for storing product based on NSPS for bulk petroleum storage tanks (EPA, 1988b, EIA, 1991a). Each tank assumed to be 1.6 million gallons based on average capacities characterized in proposed future benzene regulations (EPA, 1989).
- A typical marine bulk terminal facility has four internal floating roof tanks (EPA, 1989).
- Based on a 1.6 million gallon storage capacity, the internal floating roof gasoline storage tank dimensions were assumed to be 95 ft. in diameter and 30 ft. high.
- In this analysis, each marine terminal is assumed to operate 260 days per year.

- Each marine bulk terminal has a typical throughput of 65 million gallons per year (based on 260 operating days) with the four floating roof tanks (EPA, 1989).
- Marine terminal storage tanks use vapor recovery systems for product transferral and storage at average efficiencies of 95 percent in 2000 and 98 percent in 2010 based on EPA estimates in future NSPS regulations for VOC control at bulk product terminals facilities (EPA, 1988a) and proposed benzene control regulations at bulk product terminals facilities (EPA, 1989). The 95 percent efficiency rate for 2000 is an average value assumed for using carbon adsorption, thermal oxidizers, incineration, and refrigeration type vapor recovery equipment, while the 98 percent value for 2010 assumes the widespread use of thermal oxidizers and incineration units for vapor control. The higher value in 2010 will be likely based on the future VOC regulations (EPA, 1989).

#### **F.5.2.5 Bulk Plant Assumptions**

##### Years 2000 and 2010

- Bulk plants receive gasoline from tank trucks.
- A typical bulk plant facility uses 3 fixed roof storage tanks of 15,000 gallons each (EPA, 1989, EIA, 1991a).
- Based on a 15,000 gallon capacity tank, each tank is assumed to be 16 ft. in diameter and 10 ft. high.
- A typical bulk plant is assumed to have a throughput of 1.7 million gallons per year based on 260 operating days/year (EPA, 1989).
- A bulk plant facility uses a vapor balance system (Stage 1 controls) for product transferral and storage at average efficiencies of 95 percent based on EPA estimates in future regulations for benzene control at bulk product terminals facilities (EPA, 1989).

### **F.5.2.6 Commercial/Rural Account Assumptions**

#### Years 2000 and 2010

- Commercial and rural accounts receive gasoline from tank trucks.
- Commercial and rural accounts use underground gasoline storage tanks of 4,000 gallons each. Assumption is based on project team experience with fleet vehicle operations and refueling facilities. Such tanks will also have to be constructed to meet EPA leak containment regulations (EPA 1988c).
- Vehicle refueling vapor emissions are based on an EPA estimated and experimentally derived refueling vapor generation equation.
- Refueling spill rate based on actual in use data collected (EA Mueller, 1989).
- Storage tank vapor losses attributed to "breathing" were based on average breathing losses as reported in AP-42 (EPA, 1985a).
- Commercial and rural accounts use Stage 2 vapor recovery systems with typical efficiencies of 95 percent when refueling vehicles based on EPA estimates (U.S. Congress, 1990; EPA, 1989; Multinational Business Services, 1987).

### **F.5.2.7 Retail Service Station Assumptions**

#### Years 2000 and 2010

- Receives gasoline from tank trucks.
- Vehicle refueling vapor emissions are based on an EPA estimated and experimentally derived refueling vapor generation equation.
- Refueling spill rate based on actual in use data collected (EA Mueller, 1989).
- Storage tank vapor losses attributed to "breathing" were based on average breathing losses as reported in AP-42 (EPA, 1985a).
- Retail service stations use vapor balance systems (Stage 1 controls) for product transferral from tank trucks to storage at average efficiencies of 95 percent based on EPA estimates in future regulations for VOC control at bulk product terminals facilities (EPA, 1989).

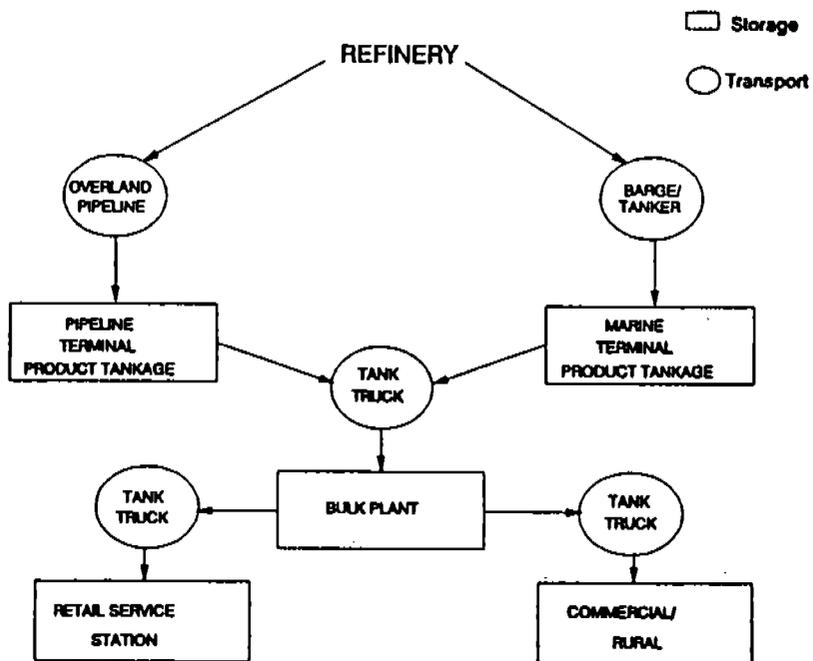
- Typical service stations use underground tanks of 10,000 gallons each based on characterization given in proposed future benzene control regulations (EPA, 1989). Such tanks will be constructed to meet EPA leak containment regulations (EPA, 1988).
- Service stations use Stage 2 vapor recovery systems with typical efficiencies of 95 percent when refueling vehicles based on EPA estimates (U.S. Congress, 1990; EPA, 1989; Multinational Business Services, 1987).

### **F.5.3 Infrastructure for Gasoline Transport and Distribution**

In order to develop the quantitative emission factors for the domestic transport and storage of reformulated gasoline, a flow path was developed which included the three transport and storage phases (Primary, Secondary, and Tertiary) of the current infrastructure described earlier. The infrastructure assumed for this report was based on this flow path and in conjunction with the specific assumptions listed earlier. The gasoline flow path for this analysis is shown in Figure F-16. Imported gasoline was not included in this analysis of the reformulated gasoline distribution system.

The reformulated gasoline transportation and storage flow path begins with the transport of the gasoline from the refinery to the bulk storage terminals. Bulk storage terminals can best be defined as gasoline storage facilities having a storage capacity greater than 50,000 barrels. There are two types of bulk terminals which typify the gasoline transportation infrastructure: pipeline terminals and marine terminals. The pipeline terminals receive the gasoline from the refinery via pipelines, while the marine terminals receive shipments from the refinery via tanker and barge. In developing emission factors for this segment of gasoline transportation, the gasoline pipeline pumps were assumed to be all electrically driven for both scenarios, i.e. 2000 and 2010.

The ocean tankers and barges were assumed to be operated by low-speed diesel engines consuming mostly No. 6 diesel fuel, while tugboat propelled river barges used to transport gasoline were assumed to use medium-speed diesel engines using mostly No. 2 diesel fuel. Table F-77 lists the current breakdown of domestic gasoline transportation by mode of travel. This breakdown was also assumed to be in place in years 2000 and 2010 for reformulated gasoline. As shown, 56 percent of the gasoline will be transported by pipelines, and 35 percent transported by tanker or barge. This analysis assumed that no gasoline would be transported by rail in the years 2000 and 2010, while only 9 percent of the gasoline is transported by tanker trucks.



**Figure F-16. Reformulated Gasoline Transportation Infrastructure**

**Table F-77.  
Reformulated Gasoline Transportation by Mode of Travel  
in 2000 and 2010**

Mode of Transport	Domestic (%)	Imported (%)
Reformulated Gasoline		
- Tanker	22	
- Inland Barge	13	
- Rail	0	
- Truck	9	
- Pipelines	56	

The current U.S. bulk terminal population is estimated to number approximately 1500, with the typical bulk gasoline terminal having a daily throughput of about 250,000 gallons (EPA, 1989). This analysis assumed that the number of and type of storage tanks, their capacities and dimensions would be the same for a typical pipeline and marine bulk terminal. The typical throughput for a gasoline bulk terminal was also assumed to be unchanged for the years 2000 and 2010. Bulk terminal facility spill rates were assumed to be the same for both pipeline and marine terminals since existing spill data is not available for each type of terminal. It was also assumed that the current bulk terminal characteristics, with respect to the number and type of storage tanks, would be unchanged for reformulated gasoline use in the years 2000 and 2010. The bulk terminal facilities were assumed to be equipped with some type of vapor recovery system with a vapor control efficiency for the year 2000 expected to be 95 percent, and 98 percent for the year 2010.

Reformulated gasoline transportation continues from the bulk terminals to the bulk plants via tanker trucks. Tanker trucks were assumed to be tractor/trailer combinations using diesel engines with a fuel economy of 5.7 MPG for the year 2000 and 6.0 MPG in 2010. The fuel economy improvement is based on an NES MPG improvement for all trucks carrying freight. Once the gasoline has been delivered to the bulk plants it is considered to be in the Secondary Distribution System.

Bulk plants, as considered for this report are defined as bulk storage facilities that have a total storage capacity of less than 50,000 barrels and only receive product deliveries from tanker trucks. This analysis assumed a U.S. bulk plant population of 15,000 each having a daily throughput of about 6500 gallons (EPA, 1989). The analysis was conducted considering that the number of storage tanks, type of tanks and daily throughput would be the same for the years 2000 and 2010. The spill rates at bulk plants were calculated based on spill rate data for all petroleum bulk storage facilities. This spill rate was the same rate as pipeline and marine bulk terminal storage facilities. In quantifying the vapor emissions from bulk plants, it was assumed that by the year 2000 bulk plants will be using vapor recovery systems to limit VOC emissions. The vapor recovery systems are assumed to have an efficiency of 95 percent, with the vapor recovery efficiency expected to remain constant for the 2010 scenario.

The Secondary Distribution of reformulated gasoline continues with the transport from the bulk plants to the public retail outlets such as service stations and convenience stores. This transport was assumed to be accomplished by tanker trucks. In this analysis it was assumed that a typical service station uses underground storage tanks of 10,000 gallon capacities each (EPA, 1989). Each service station uses vapor recovery controls (Stage 1 and Stage 2) by the year 2000 with each method obtaining a 95 percent efficiency. Stage 1 vapor recovery is a vapor balance system which draws the vapors from the underground storage tanks back into the tanker truck when the tanker truck unloads the product into the retail outlet storage tank. The Stage 2 vapor recovery systems are placed on the refueling pump nozzles at the retail outlets. This system collects vapors which are generated during the vehicle refueling process. Both of these vapor recovery systems are assumed to be in place by the year 2000 with the

same efficiency expected for each system in 2010. The refueling spill rates at retail outlets used in determining the refueling emission factors are based on observed spill data at retail outlets, while the uncontrolled vehicle refueling vapor emissions were determined based on EPA experimentally derived formulas (Multinational Business Services, 1987).

In addition to deliveries to retail outlets, bulk plants also supply gasoline to the tertiary storage segment of the gasoline infrastructure. The tertiary segment as considered for this report, is made up of commercial and agricultural accounts. The gasoline delivered to these segments are transported from the bulk plants by tank trucks. To quantify emission factors for these commercial and rural accounts, it was assumed that these facilities typically use 4000 gallon capacity underground storage tanks. The same vapor recovery systems used at the retail outlets were assumed to be employed at the commercial/rural facilities by the year 2000, with the same vapor recovery efficiencies in the year 2010. Likewise, the refueling spill rates and refueling vapor generation rates at the commercial and rural facilities were assumed to be the same as those calculated for the retail outlets since vehicles at both types of facilities are refueled in a similar manner.

#### **F.5.4 Process Environmental Points of Interest**

In this section, the environmental impacts of reformulated gasoline transportation infrastructure operation are addressed. The section includes a discussion of the inputs and outputs of the reformulated gasoline infrastructure. In addition, the major environmental effects of the reformulated gasoline infrastructure are presented and quantified.

##### **F.5.4.1 Inputs and Outputs to Reformulated Gasoline Transport Operations**

An assessment of the inputs and outputs of the reformulated gasoline transportation process was made. The inputs relate to the requirements for moving the reformulated gasoline from the refinery to the end-use sector, while outputs relate the actual products produced from this process. The inputs and outputs are summarized in Table F-78.

No. 2 diesel was assumed to be used by locomotives moving rail cars, tank trucks, and inland barges. No. 6 diesel fuel was assumed for use in ocean tankers and barges. Pipeline pumps, as well as pumps used at bulk storage facilities were assumed to be driven exclusively by electric motors.

**Table F-78.  
Input and Output Estimates Reformulated Gasoline Distribution System**

Inputs			Outputs		
Substance	Quantity		Substance	Quantity	
	2000	2010		2000	2010
Reformulated Gasoline	7.0 million BBL/D	6.3 million BBL/D	Reformulated Gasoline <sup>1</sup>	7.0 million BBL/D	6.3 million BBL/D
No. 2 Diesel Fuel	11,300 BBL/D	9,730 BBL/D			
No. 6 Fuel Oil	12,500 BBL/D	11,300 BBL/D			
Electricity	193 million kw-hr/D	173 million kw-hr/D			
Replacement Parts	N/A <sup>2</sup>	N/A			
Labor	780,000 persons	702,000 persons			

<sup>1</sup> Reformulated gasoline output assumes negligible product VOC and liquid spill losses over the transportation infrastructure based on the emission factors calculated below.

<sup>2</sup> N/A - not available

The reformulated gasoline inputs and outputs were derived from the NES projections for years 2000 and 2010 (DOE, 1991). The input estimates for No. 2 diesel fuel and No. 6 fuel oil were derived from estimates of the national gasoline transportation by mode (NPC, 1991) and weighting transport efficiencies for those modes using these fuels along the infrastructure. The electricity input was estimated by accounting for and weighting the transportation efficiencies for using electricity for powering pipeline and bulk facility pumps along the reformulated gasoline distribution infrastructure. Labor requirements were derived from 1987 employment figures in the gasoline wholesale and retail industry (API, 1990), and the total gasoline supplied to final end users in 1987 (API,1990).

A percentage breakdown of gasoline transport by mode for years 2000 and 2010 is provided in Table F-77. Table F-79 depicts the estimates of the petroleum product transport efficiencies by mode. These are the same transportation efficiencies which

**Table F-79.  
Petroleum Product Transportation Mode Efficiencies**

Transportation Modes	Petroleum Transport Efficiency			
	Year 2000		Year 2010	
	BTU/Ton-Mile	hp-hr/10 <sup>9</sup> BTU	BTU/Ton-Mile	hp-hr/10 <sup>9</sup> BTU
Pipelines/Bulk Terminals and Plants				
- Electrically-Driven Pumps (ANL 1982, ORNL 1991)	275	1980	275	1980
Marine Vessels				
- Tanker/Ocean Barges (ANL 1982, ORNL 1991)	385	8340	385	8340
- Inland Barges (ANL 1982, ORNL 1991)	480	1070	480	1070
Tank Trucks (Census Bureau 1990)				
- Crude Oil Transport	633	338	600	321
- Gasoline Transport	633	323	600	307

were used for the crude oil transportation modes. Limitations on data for calculating separate transportation efficiencies for crude oil and gasoline for most modes resulted in the use of the same transport efficiencies for both. However, separate crude oil and gasoline transport efficiencies for tank trucks were able to be calculated. Since electric motor and pump technologies in the reformulated gasoline distribution system infrastructure are similar for pipelines and bulk product storage facilities, the same petroleum transport efficiencies as used in pipelines were assumed for bulk product facility electric pumps. The calculations for the transportation efficiencies are provided in Figure F-3 of Section F.3. of this report.

The calculations for determining the fuel, electricity, and labor inputs to the reformulated gasoline distribution system are listed in Figure F-17.

### Electricity, No.2 Diesel Fuel, No.6 Fuel Oil

Total inputs of electricity, No.2 diesel fuel, and No.6 fuel oil were found by weighting the transport efficiencies (Table F-36) of the modes using each of these energy sources as they appear in the reformulated gasoline distribution infrastructure. Each weighted efficiency was added up to obtain a single overall weighted transportation efficiency for the modes using each fuel. Finally, to obtain the total amount of fuel and electricity as inputs to the system, the total reformulated gasoline energy input to the system was applied.

The weighting of the individual transportation efficiencies was essentially performed based on the percentage of current gasoline flow through each of the two legs of the assumed reformulated gasoline distribution system. This same flow was assumed for reformulated gasoline since little shift in gasoline consumption sectors should occur in 2000 and 2010 relative to the present. Then using these percentages, the transportation efficiencies of the individual sources along each of these branches were weighted. Additional weighting was performed for those segments of the distribution system with multiple reformulated gasoline transport modes.

The following equations were used to derive the weighted transportation efficiencies for the reformulated gasoline distribution system:

$$x2A = \text{efficiencies for tankers} = 8343.9 \text{ hp-hr}/10^9\text{BTU}$$

$$x2B = \text{efficiencies for inland barges} = 1070.5 \text{ hp-hr}/10^9\text{BTU}$$

$$x2D = \text{efficiencies for tank trucks} = 323.1 \text{ hp-hr}/10^9\text{BTU in 2000} \\ = 306.9 \text{ hp-hr}/10^9\text{BTU in 2010}$$

$$x2E = \text{efficiencies for pipelines} = 1477.9 \text{ Kw-hr}/10^9\text{BTU}$$

$$x5 = \text{efficiencies for electric pumps at pipeline terminals} = 1477.9 \text{ Kw-hr}/10^9\text{BTU}$$

$$x6 = \text{efficiencies for electric pumps at marine terminals} = 1477.9 \text{ Kw-hr}/10^9\text{BTU}$$

$$x7 = \text{efficiencies for electric pumps at bulk plants} = 1477.9 \text{ Kw-hr}/10^9\text{BTU}$$

$$x8 = \text{efficiencies for electric pumps at service stations} = 1477.9 \text{ Kw-hr}/10^9\text{BTU}$$

$$x9 = \text{efficiencies for electric pumps at commercial/rural facilities} = 1477.9 \text{ Kw-hr}/10^9\text{BTU}$$

$$y1A = \text{percent of product moved by tankers} = 22$$

$$y1B = \text{percent of product moved by inland barges} = 13$$

$$y1D = \text{percent of product moved by tank trucks} = 9$$

$$y1E = \text{percent of product moved by pipelines} = 56$$

Year 2000 and 2010

$$\text{WTE} = 0.84*(x2E+x5) + 0.16*(x2A*(y1A/(y1A+y1B))+x2B*(y1B/(y1A+y1B))+x6) + x2D + x7 \\ + 0.95*(x2D+x8) + 0.05*(x2D+x9)$$

$$\text{Total Fuel or Electricity} = \text{WTE} * \text{Total Reformulated Gasoline Energy in 2000 and 2010}$$

### Labor Input

$$\text{Total employees in the gasoline wholesale and retail industry in 1987 (API,1990)} \\ = 805,900$$

$$\text{Total gasoline supplied to end-use in 1987 (API,1990)} \\ = 2630089*10^3 \text{ BBL} = 1.275*10^{16} \text{ BTU}$$

$$\text{Persons/million BTU} = 805900/1.275*10^{16} \text{ million} = 0.000063$$

**Figure F-17. Reformulated Gasoline Distribution System Input Calculations**

#### **F.5.4.2 Environmental Impact Estimates**

The reformulated gasoline distribution infrastructure will produce a variety of environmental impacts. Most important among these will be air and liquid spill emissions. Assessments of each of these two types of emissions were made and are discussed below. Also, a discussion of emission factor weighting also follows.

##### Air Emissions

Two main types of air emissions will result from reformulated gasoline distribution: exhaust and evaporative emissions. Exhaust emissions result from the combustion of fuel to move the reformulated gasoline from the refinery to end use. Therefore, assessments were made of the exhaust emissions resulting from the combustion of fuel by tank trucks, ocean tankers, and inland barges needed to transport reformulated gasoline. While there are exhaust emission associated with electricity production required to operate pipeline pumps and bulk product facility pumps, assessments of these emission were not made in this analysis but will be addressed in accompanying work.

Specific exhaust emission factors (g/bhp-hr) for HC, CO, NO<sub>x</sub>, and particulates were obtained for each transport mode of the reformulated gasoline distribution infrastructure based on available EPA documentation. Differences in engine and emission control technologies for the various reformulated gasoline transportation modes for years 2000 and 2010 were accounted for in deriving the specific emission factors for each exhaust emission source for these years. Finally, using the petroleum product transportation efficiencies of Table F-79, average BSFC values, and combustion fuel source density and energy content, the g/bhp-hr exhaust emission factors were converted into units of grams of pollutant emitted per billion Btu of reformulated gasoline transported (g/10<sup>9</sup> BTU).

The CO<sub>2</sub> and SO<sub>2</sub> emission factors for the marine and tank truck modes were derived using a different method than was used for the other exhaust emissions. These emission factors were estimated based on fuel carbon and sulfur content and the average brake specific fuel consumption (BSFC) values. Table F-80 depicts the BSFC values used in this analysis. The specific calculations for deriving the all of the exhaust emission factors are provided in Figure F-5 in Section F.3 of this report.

The exhaust emission factors for each reformulated gasoline distribution source for the years 2000 and 2010 are listed in Table F-81. These pollutants comprise the majority of mass exhaust emissions and are also significant due to their potential for contributions to ambient ozone formation, CO concentrations, and acid rain. The CO<sub>2</sub> emission factors were generally assumed to remain constant for the years 2000 and 2010 except for tank trucks. For tank trucks, improved BSFC values in 2010 result in lower CO<sub>2</sub> and SO<sub>2</sub> emissions in that year relative to year 2000.

**Table F-80.  
Brake Specific Fuel Consumption Values for Various Reformulated  
Gasoline Distribution System Transportation Modes**

Transportation Modes	Product Transport Efficiency	
	Year 2000	Year 2010
Marine Vessels		
- Tanker/Ocean Barges	0.28 lb/bhp-hr	0.28 lb/bhp-hr
- River Barges	0.37 lb/bhp-hr	0.37 lb/bhp-hr
Tank Trucks	0.46 lb/bhp-hr	0.44 lb/bhp-hr

The other major type of air emission from the reformulated gasoline distribution infrastructure is evaporative VOC emissions. These emissions result from the vaporization of fuel and subsequent release of these vapors to the atmosphere. Of course, evaporative VOC emissions are directly proportional to fuel volatility. Therefore, reformulated gasoline will produce much higher evaporative VOC emissions than low volatility products like crude oil. A Reid vapor pressure (RVP) of 9 psi was assumed for reformulated gasoline in all evaporative VOC emission calculations to be consistent with U.S. Clean Air Act Amendments of 1990 provisions (U.S. Congress, 1990). In the reformulated gasoline transportation infrastructure, evaporative VOC emission occur from a variety of activities and processes such as during product transit between facilities, loading and unloading of product at facilities, and from bulk storage at facilities.

Evaporative VOC emission factors for the reformulated gasoline infrastructure were estimated using the EPA document, AP-42 (EPA, 1985a). The AP-42 document details the specific equations for estimating evaporative VOC emission factors for various operational practices within the gasoline distribution system. Figures F-18 through F-22 present the specific calculations used to derive the evaporative VOC emission factors for the sources of the reformulated gasoline distribution system.

In general, the emission factors were derived for each source of the reformulated gasoline distribution infrastructure in the 2000 and 2010 timeframes based on the characteristic source assumptions for these years. The methodology used was to first calculate "uncontrolled" evaporative VOC emission factors for each source, and then apply percentage reductions for the use of vapor control equipment such that "controlled" emission factors were obtained. The percentage reductions for specific vapor control

**Table F-81.**  
**Estimates of Exhaust Emission Factors for Reformulated Gasoline Transportation Infrastructure Sources**

Exhaust Emission Source	Exhaust Emission Factors (g/10 <sup>9</sup> Btu Throughput)											
	HC		CO		NO <sub>x</sub>		Part		CO <sub>2</sub>		SO <sub>2</sub>	
	2000	2010	2000	2010	2000	2010	2000	2010	2000	2010	2000	2010
Marine Vessels												
- Tanker/Ocean Barges	2480	2070	5380	3720	12400	8690	620	414	1.74*10 <sup>6</sup>	1.74*10 <sup>6</sup>	517	517
- Inland Barges	160	120	601	400	2800	2000	60.1	40.0	0.215*10 <sup>6</sup>	0.215*10 <sup>6</sup>	66.1	66.1
Tank Trucks	97.2	48.3	292	193	369	193	7.78	7.72	0.0654*10 <sup>6</sup>	0.0611*10 <sup>6</sup>	20.0	18.7

Transit Loss Emission Factor, L1

Use AP-42 equation (EPA, 1985a),

$$L1^* = 0.1 * P * W$$

Reformulated Gasoline Properties

Assume RVP = 9 psi,

P = True vapor pressure @ 55°F = 4.2 psi

W = Density of condensed vapors @ 60°F = 5.1 lb/gal

$$L1^* = 2.13 \text{ lb/week-1000gal}$$

Estimate time (weeks) travelled by tankers and barges:

Average haul length for domestic tankers = 2000 miles

Average haul length for domestic barges = 200 miles

Assumed haul length in U.S. waters for imported tankers = 200 mile

Average haul length for domestic tankers and barges

$$= (2000+200)/2 = 1100 \text{ miles}$$

Average speed for domestic and imported tankers = 16 mph (API, 1991)

Average speed for domestic barge = 8 mph (API, 1991)

Average speed for tankers and barges

$$= (16+8)/2 = 12 \text{ mph}$$

Total time for product transport by domestic tanker and barge

$$= 1100/12 = 92 \text{ hours} = 3.8 \text{ days} = 0.55 \text{ weeks}$$

Total time for product transport by imported tanker

$$= 200/16 = 12.5 \text{ hours} = 0.5 \text{ days} = 0.07 \text{ weeks}$$

Transit Loss Emission Factor  $L1 = L1^* * (\text{total time in transit})$

For domestic tankers and barges,  $L1 = 2.13 * 0.55 = 1.17 \text{ lb/1000gal}$

**Figure F-18. Evaporative VOC Calculations for Reformulated Gasoline Transport by Tanker and Barge**

Loading Loss Emission Factor, L2

Use AP-42 equation (EPA, 1985a),

$$L2^* = 1.84 * (0.44 * P - 0.42) * \left(\frac{M * 1.02}{T}\right) + C$$

Reformulated Gasoline Properties

Assume RVP = 9 psi,

P = True Vapor pressure @ 55°F = 4.2 psi

M = Molecular weight @ 60°F = 66.7 lb/lb-mole

T = Assumed crude oil temperature = 515°F

C = EPA arrival emission factor for cleaned or gas-freed cargo tanks from AP-42 = 0.53

Uncontrolled loading loss emission factor, L2\* = 0.88 lb/1000gal

Assume vapor control equipment for tanker and barge loading procedures:

Year 2000, 95% efficiency

Year 2010, 98% efficiency

Controlled loading loss emission factor, L2 = L2\* \* (vapor control efficiency)

For tankers and barges,

Year 2000, L2 = 0.88 \* (1-0.95) = 0.04 lb/1000gal

Year 2010, L2 = 0.88 \* (1-0.98) = 0.02 lb/1000gal

**Figure F-18. Evaporative VOC Calculations for Reformulated Gasoline by Tanker and Barge (Cont'd)**

Transit Loss Emission Factor, L1

From AP-42 (EPA, 1985a),

Average transit loss emission factor for tank trucks with 10 RVP gasoline:

$$L1 = (0.0 + 0.01)/2 = 0.005 \text{ lb/1000gal}$$

Assume L1 for crude is proportional to the true vapor pressures of reformulated gasoline,

True vapor pressure of 10 RVP gasoline @ 55°F = 4.7 psi

True vapor pressure of reformulated gasoline 55°F = 4.2 psi

For reformulated gasoline,

$$L1 = 0.005*(4.2/4.7) = 0.004 \text{ lb/1000gal in 2000 and 2010}$$

Loading Loss Emission Factor, L2

From AP-42 (EPA, 1985a),

$$L2^* = 12.46 * \frac{(S * P * M)}{T}$$

Reformulated Gasoline Properties

RVP = 9 psi

P = 4.2 psi @ 55°F

S = 0.60 dedicated normal service

M = 66.7 lb/lb-mole @ 60°F

T = 515°F

Uncontrolled loading loss emission factor, L2\*

$$L2^* = 4.07 \text{ lb/1000gal}$$

Assume vapor control equipment for tank truck loading procedures:

Year 2000, 95% efficiency

Year 2010, 98% efficiency

Assume vapor tight cargo tank control efficiency for loading procedures:

Years 2000 and 2010, 67% efficiency

Controlled loading loss emission factor, L2 = L2\* \* (vapor tight cargo and control efficiencies)

For tank trucks,

$$\text{Year 2000, } L2 = 4.07 * (1-0.67) * (1-0.95) = 0.07 \text{ lb/1000gal}$$

$$\text{Year 2010, } L2 = 4.07 * (1-0.67) * (1-0.98) = 0.03 \text{ lb/1000gal}$$

**Figure F-19. Evaporative VOC Calculation for Reformulated Gasoline Transport by Rail and Tank Truck**

### VOC Emissions from Gasoline Bulk Terminal Storage

#### Facility and Storage Tank Assumptions:

Each facility uses 4 internal floating roof tanks w/ welded seams

Storage tank capacity = 1.6 million gallons (each)

Tank dimensions = 95 ft. dia. x 30 ft. high

Facility throughput = 65 million gallons/year

Assume facility operates 260 days/year

Use AP-42 equation (1985a) for internal floating roof tanks.

Tank Breathing Loss:  $L_t = L_r + L_w + L_d + L_f$

where:  $L_t$  = Total loss

$L_r$  = rim seal loss =  $K_v V^n P^* D M_v K_c = 3569$  lbs./yr

where:

$K_v = 6.7$

$V$  (average assumed wind speed) = 10 mi/hr

$n = 0$

$P^* = 0.0837$  psi

$D = 95$  ft.

$M_v = 67$  lb/lb-mole

$K_c = 1.0$

$L_w$  = withdrawal loss =  $[(0.943) Q C W_L] / D [1 + (N_c F_c / D)]$   
= 35.5 lbs./yr

where:

$Q = 3.74 \times 10^5$  bbls/yr (each tank)

$C = 0.0015$

$W_L = 6.0$  lb/gal. (density of gasoline)

$D = 95$  ft. dia.

$N_c = 6$  (number of columns)

$F_c = 1.0$

$L_d$  = deck seam loss = 0 for welded tanks

$L_f$  = deck fitting loss =  $F_f P^* M_v K_c = 3365$  lb/yr

where:

$F_f = 600$  (for 95 ft. dia tank)

$P^* = 0.0837$  psi

$M_v = 67$  lb/lb-mole

$K_c = 1.0$  (for gasoline)

Gasoline Properties:

Assume RVP = 9.0

Gasoline density = 6.0 lb./gal

Gasoline energy content = 115,400 Btu/gal

True vapor pressure @ 55 F = 4.2 psi

#### Emission Factors:

Uncontrolled VOC emissions:  $L_t = 3569 + 35.5 + 3365 = 6,934$  lb/yr/tank

$L_t = 1679$  g/10<sup>9</sup> Btu throughput for facility

#### Year 2000

Assume 95% vapor recovery efficiency

Year 2000  $L_t = 84$  g/10<sup>9</sup> Btu throughput

#### Year 2010

Assume 98% vapor recovery efficiency

Year 2010  $L_t = 34$  g/10<sup>9</sup> Btu throughput

**Figure F-20. Evaporative VOC Calculation for Reformulated Gasoline Unloading and Storage at Pipeline and Marine Terminals**

### VOC Emissions from Gasoline Bulk Plant Storage

#### Facility and Storage Tank Assumptions:

Each facility uses 3 fixed roof storage tanks  
Storage tank capacity = 15,000 gallons (each)  
Tank dimensions = 10.5 ft. dia. x 23 ft. high  
Facility throughput = 1.7 million gallons/year  
Assume facility operates 260 days/year

Use AP-42 equation (1985a) for fixed roof tanks.

Tank Breathing Loss:  $L_t = L_b + L_w$

where:  $L_t$  = Total loss

$L_b$  = breathing loss  
 $= 2.26/100 M_v (P/P_s - P)^{0.68} D^{1.73} H_v^{0.51} \Delta T^{0.50} F_p C K_c = 369 \text{ lb/yr.}$   
where:

$P = 4.2 \text{ psi}$

$P_s = 14.7 \text{ psi}$

$M_v = 67 \text{ lb/lb-mole}$

$K_c = 1.0 \text{ (for gasoline)}$

$D = 10.5 \text{ ft.}$

$H_v = 11.5 \text{ ft.}$

$\Delta T = 20 \text{ degrees F}$

$F_p = 1.00 \text{ (assume white tank)}$

$C = 0.5$

$L_w$  = working loss =  $2.40 \times 10^{-5} M_v P V N K_N K_c = 2659 \text{ lbs./yr.}$

where:

$M_v = 67 \text{ lb/lb-mole}$

$P = 4.2 \text{ psi}$

$V = 15,000 \text{ gallons}$

$N = 37.5 \text{ turnovers/yr}$

$K_N = 0.7 \text{ (turnover factor)}$

$K_c = 1.0 \text{ (for gasoline)}$

#### Gasoline Properties:

Assume RVP = 9.0

Gasoline density = 6.0 lb/gal

Gasoline energy content = 115,400 Btu/gal

True vapor pressure @ 55 F = 4.2 psi

#### Emission Factors:

Uncontrolled VOC emissions:  $L_t = 369 + 2659 = 3028 \text{ lbs/yr/tank}$

$L_t = 21,244 \text{ g/10}^9 \text{ Btu throughput for facility}$

#### Year 2000 and 2010

Assume 95% vapor recovery efficiency

$L_t = 1062 \text{ g/10}^9 \text{ Btu throughput}$

**Figure F-21. Evaporative VOC Calculation for Reformulated Gasoline Unloading and Storage at Bulk Plants**

### Underground Storage Tank Filling

From AP-42 (EPA, 1985a),

$$L2^* = 12.46 * \frac{(S * P * M)}{T}$$

#### Reformulated Gasoline Properties

RVP = 9 psi

P = 4.2 psi @ 55°F

S = 0.60 dedicated normal service

M = 66.7 lb/lb-mole @ 60°F

T = 515°F

Uncontrolled loading loss emission factor, L2\*

L2\* = 4.07 lb/1000gal

Assume Stage I vapor control equipment for tank truck unloading procedures:

Years 2000 and 2010, 95% efficiency

Assume vapor tight tank control efficiency for underground tank filling procedures:

Years 2000 and 2010, 67% efficiency

Controlled loading loss emission factor, L2 = L2\* \* (vapor tight cargo and control efficiencies)

For underground storage tanks,

Years 2000 and 2010, L2 = 4.07 \* (1-0.67) \* (1-0.95) = 0.07 lb/1000gal

#### Underground Storage Tank Breathing Losses

Using AP-42 estimates:

Avg. Breathing Loss for a 10,000 gallon underground storage tank = 1.0 lb/10<sup>3</sup> gallon throughput

**Emission Factor:**

Assumed to be the same for the year 2000 and 2010.

Breathing Loss = (454g/1000 gal) x 1 gal/115,400 Btu) = 3934 g/10<sup>9</sup> Btu throughput

#### Vehicle Refueling Losses

from reference (20)

Refueling Vapor Loss (g/gal) = -5.909 - 0.0940ΔT + 0.084T<sub>D</sub> + 0.485(RVP)

where:

ΔT = fuel tank temperature - dispensed fuel temperature

fuel tank temperature = 52 F

(T<sub>D</sub>) dispensed fuel temperature = 55 F

Gasoline RVP = 9.0 psi

Gasoline energy content = 115,400 Btu/gal.

**Emission Factor:**

Assumed to be the same for 2000 and 2010.

Uncontrolled Emissions: Refueling Vapor Loss = 3.6 g/gal.

assuming 95% vapor recovery efficiency with Stage II controls in 2000 and 2010

Controlled Refueling Vapor Loss Emissions = 0.18 g/gal. = 1560 g/10<sup>9</sup> Btu throughput

**Figure F-22. Evaporative VOC Calculation for Reformulated Gasoline Unloading, Storage and Vehicle Refueling at Commercial Fleet and Retail Fueling Facilities**

technologies in place for each source in years 2000 and 2010 were assumed based on previously documented EPA estimates (EPA, 1989; EPA, 1988a; EPA, 1988b).

The evaporative VOC emission factors for each source of the reformulated gasoline distribution infrastructure are listed in Table F-82 for years 2000 and 2010. The most significant VOC emissions per Btu of reformulated gasoline throughput occur from tanker/barge transit, bulk plant unloading and storage, service station and commercial account underground storage tank breathing losses, and vehicle refueling. Evaporative

VOC emission factors for reformulated gasoline pipelines were generally assumed to be negligible; leaks from pipelines were assumed to be in the form of liquid spills. The evaporative VOC emissions produced from the reformulated gasoline distribution infrastructure are comprised of a large variety of compounds. EPA has compiled a listing of these compounds for seasonal grades of gasoline (EPA, 1991b). For summer gasoline, the following compounds have been determined to be some of the main constituents: isomers of hexanes, heptanes, octanes, nonanes, butenes and pentanes, ethane, propane, hexane, heptane, n- and iso-butananes, 1-pentene, n-pentane, and 3-methyl pentane.

### Liquid Spills

As mentioned previously, the other significant environmental emission from the reformulated gasoline distribution infrastructure is liquid spills. Liquid spills might originate from "normal operation" such as during loading and unloading episodes of transport modes at bulk facilities, or through pipeline system seals. For instance, a small amount of reformulated gasoline might be spilled upon hose disconnect during tank truck loading. Liquid spill data along the current gasoline distribution infrastructure for typical or "normal" operations were not available in the literature; it is assumed that these spills are typically very small and are unreported for this reason. Since spills resulting during normal reformulated gasoline distribution system operations are assumed to be small, such spills are not considered for this analysis.

However, data does exist for accidental spills of gasoline. These accidental spills tend to be very significant in size. U.S. Coast Guard data (NPC, 1991) was obtained for reported accidental crude oil and refined product spills in U.S. borders (200 miles (Demby, 1991)). The spill data encompassed 1983 to 1987 calendar years and covered various components of the gasoline distribution system. Based on this historical data, average yearly spill rates in gallons of petroleum products were calculated for the potential sources within the reformulated gasoline infrastructure on a national basis. Due to limitations in the data, equivalent spill rates were assumed for crude oil and gasoline. It was also assumed that these spill rates would apply to reformulated gasoline distribution in years 2000 and 2010, since source technology should not appreciably change to affect spill rates, and the frequency of spills is very uncertain in a given year.

**Table F-82.  
Reformulated Gasoline Distribution Infrastructure Evaporative  
VOC Emission Factors for 2000 and 2010**

SOURCE CATEGORY	VOC g/10 <sup>9</sup> Btu Throughput	
	2000	2010
<b>Refined Product Transport</b>		
- Pipeline		
- Tanker/Barge		
- Loading	157	78.7
- Transit	3850	3850
- Tank Truck		
- Loading	275	236
- Transit	14.5	14.5
<b>Pipeline Terminal Refined Product</b>		
- Unloading & Storage	84.0	34.0
<b>Marine Terminal Refined Product</b>		
- Unloading & Storage	84.0	34.0
<b>Bulk Plant Refined Product</b>		
- Unloading & Storage	1060	1060
<b>Commercial/Rural Accounts</b>		
- UG Storage Tank Filling	275	275
- UG Storage Tank Breathing	3930	3930
- Vehicle Refueling	1560	1560
<b>Retail Service Stations</b>		
- UG Storage Tank Filling	275	275
- UG Storage Tank Breathing	3930	3930
- Vehicle Refueling	1560	1560

To obtain liquid spill emission factors on a gram per billion Btu of reformulated gasoline throughput basis, NES reformulated gasoline consumption for 2000 and 2010 (DOE, 1991) were apportioned by national transport mode and bulk facility using national throughput estimates. These reformulated gasoline throughput values were then divided into the average liquid spill rates along with the fuel density to obtain the units required. Figure F-10 of section F.3 in this report provides a detailed description of the methodology behind the liquid spill rate calculations for reformulated gasoline. Refueling spill rates at retail and commercial outlets were obtained from previous project team work (EA Mueller, 1987).

The reformulated gasoline spill emission factor estimates are listed in Table F-83 for each source of the distribution infrastructure in years 2000 and 2010. Note that tankers, barges, and vehicle refueling were estimated to have the highest rates of reformulated gasoline spills.

### Weighted Emission Factors

Once each pollutant emission factor for the individual sources of the reformulated gasoline distribution infrastructure was determined, single weighted emission factors were calculated for each pollutant to represent the entire operation of the reformulated gasoline distribution infrastructure. When overall reformulated gasoline throughput over a specific period of time is applied to these overall weighted emission factor, the total mass of each pollutant emitted from reformulated gasoline distribution operations can be estimated for that same period of time.

The weighting of the individual emission factors was essentially performed based on the reformulated gasoline distribution infrastructure illustrated in Figure F-16. The reformulated gasoline distribution infrastructure is essentially divided into two separate legs. The first leg transports reformulated gasoline through pipeline terminals and onto the remaining segments of the infrastructure, while the other leg directs reformulated gasoline flow through marine terminals and then through the rest of distribution system. The percentage of current gasoline flow through each of these two legs was estimated (NPC, 1991). This same flow was assumed for reformulated gasoline since little shift in gasoline consumption sectors should occur in 2000 and 2010 relative to the present. Then using these percentages, the emission factors of the individual sources along each of these branches were weighted. Additional weighting was performed for those segments of the distribution system with multiple reformulated gasoline transport modes.

The weighted emission factors of each leg of the reformulated gasoline distribution system were then added together to obtain overall weighted reformulated gasoline distribution emission factors for each pollutant. Figure F-23 details the weighting procedure used for the emission factors of the reformulated gasoline distribution system. Tables F-84 and F-85 display the weighted emission factors for Exhaust, Evaporative

**Table F-83.  
Reformulated Gasoline Distribution Infrastructure Liquid Spill  
Emission Factors for 2000 and 2010**

SOURCE CATEGORY	Spills g/10 <sup>9</sup> Btu Throughput	
	2000	2010
<b>Refined Product Transport</b>		
- Pipeline	11.0	11.0
- Tanker/Barge	1060	1060
- Loading		
- Transit		
- Tank Truck	518	518
- Loading		
- Transit		
<b>Pipeline Terminal Refined Product</b>		
- Unloading & Storage	68.0	68.0
<b>Marine Terminal Refined Product</b>		
- Unloading & Storage	68.0	68.0
<b>Bulk Plant Refined Product</b>		
- Unloading & Storage	68.0	68.0
<b>Commercial/Rural Accounts</b>		
- UG Storage Tank Filling		
- UG Storage Tank Breathing		
- Vehicle Refueling	1990	1990
<b>Retail Service Stations</b>		
- UG Storage Tank Filling		
- UG Storage Tank Breathing		
- Vehicle Refueling	1990	1990

Emission factors for each source were weighted according to their location within the infrastructure. These weighted emission factors were then summed to obtain overall weighted emission factors representing the entire reformulated gasoline distribution system.

The weighting of the emission factors was essentially performed based on the percentage of current gasoline flow through each of the two legs of the assumed reformulated gasoline distribution system. Using these percentages, the emission factors of the individual sources along each of these branches were weighted. Additional weighting was performed for those segments of the distribution system with multiple reformulated gasoline transport modes.

The following equations were used to derive the weighted emission factors for the reformulated gasoline distribution system:

x2A = emission factor for tankers

x2B = emission factor for inland barges

x2D = emission factor for tank trucks

x2E = emission factor for pipelines

x5 = emission factor for electric pumps at pipeline terminals

x6 = emission factor for electric pumps at marine terminals

x7 = emission factor for electric pumps at bulk plants

x8 = emission factor for electric pumps at service stations

x9 = emission factor for electric pumps at commercial/rural facilities

y1A = percent of product moved by tankers = 22

y1B = percent of product moved by inland barges = 13

y1D = percent of product moved by tank trucks = 9

y1E = percent of product moved by pipelines = 56

Year 2000 and 2010

$$\text{WEF} = 0.84*(x2E+x5) + 0.16*(x2A*(y1A/(y1A+y1B))+x2B*(y1B/(y1A+y1B))+x6) + x2D + x7 + 0.95*(x2D+x8) + 0.05*(x2D+x9)$$

**Figure F-23. Method of Emission Factor Weighting for Reformulated Gasoline Distribution System**

**Table F-84.**  
**Overall Weighted Emission Factors for the Reformulated Gasoline Distribution Infrastructure in 2000**

TRANSPORT INFRASTRUCTURE	Weighted Emission Factors (g/10 <sup>9</sup> BTU)							
	Exhaust HC	CO	NO <sub>x</sub>	Part	CO <sub>2</sub>	SO <sub>2</sub>	Evap VOC	Liquid Spills
Reformulated Gasoline	454	1160	2150	81.5	0.318*10 <sup>6</sup>	95.97	8050	3340

**Table F-85.**  
**Overall Weighted Emission Factors for the Reformulated Gasoline Distribution Infrastructure in 2010**

TRANSPORT INFRASTRUCTURE	Weighted Emission Factors (g/10 <sup>9</sup> BTU)							
	Exhaust HC	CO	NO <sub>x</sub>	Part	CO <sub>2</sub>	SO <sub>2</sub>	Evap VOC	Liquid Spills
Reformulated Gasoline	312	784	2150	81.5	0.309*10 <sup>6</sup>	93.4	7920	3340

VOC, and Liquid Spills for the reformulated gasoline distribution infrastructure in years 2000 and 2010.

### F.5.5 Non-Process Requirements

Several other environmental issues for reformulated gasoline distribution are discussed below:

- **Air Quality:** Certain toxic compounds of exhaust emissions are associated with reformulated gasoline distribution operations. These compounds are toxic in terms of their mutagenic or carcinogenic properties. Compounds such as benzene, formaldehyde, and 1,3 butadiene representative of such emissions. While evaporative VOC emissions may contain some toxic compounds like benzene, their levels should be lower than those of current gasolines.
- **Water Resources:** Surface and groundwater resources have the potential to be affected by reformulated gasoline spills. Such effects may be may come in the form of bulk storage leaks, underground storage tank leaks, transportation mode transit and loading/unloading spills, and marine vessel ballasting practices. Although spills occurring during normal operations can result in significant contamination of surface and groundwater resources over time, the most detrimental impacts result from large accidental spills of reformulated gasoline. A more serious impact of surface and groundwater contamination with reformulated gasoline is the water affinity of oxygenates by which the oxygenate in the fuel separates out of the gasoline and mixes with water. Other than methanol, which is known to be toxic, the health effects of oxygenates in groundwater has not been determined with certainty.
- **Soils:** Similar to water resources, soils would be negatively impacted from reformulated gasoline spills. The most likely sources of soil contamination from the reformulated gasoline distribution would be bulk storage and underground storage tanks, and transit and loading/unloading spills.
- **Vegetation:** Vegetation is mainly affected from reformulated gasoline spills. Direct contamination with reformulated gasoline product or indirect impacts from groundwater contamination will negatively affect vegetation. Acid rain formation from certain types of electricity production for operating electric pumps in the reformulated gasoline distribution infrastructure also has a negative impact on vegetation growth.
- **Wildlife:** Direct exposure from reformulated gasoline spills is the most damaging and immediate effect of the distribution operations. Another indirect impact is the loss of indigenous vegetation due to spills and acid

rain. Both marine and land wildlife can be affected by reformulated gasoline distribution.

- **Land Utilization:** Due to minor changes in reformulated gasoline production levels and/or sites, modifications to land-based (pipeline and tank truck) reformulated gasoline distribution routes may be required. Additional land to lay pipeline and build highways may be necessary to accommodate route changes. Also, regional reformulated gasoline production level or site changes may require additional bulk terminals and plants and service stations.
- **Odors and Noise:** Odors and noise are proximity events. Odors and noise can result from the activities at bulk facilities and from transportation modes. Both will impact humans and wildlife which come into contact with their sources. Protection can be offered to most persons employed within the reformulated gasoline distribution infrastructure in terms of respiratory and hearing protection.
- **Other Concerns:** Other environmental concerns with the reformulated gasoline distribution infrastructure are very site-specific. Certain aspects of local environments may be more susceptible to potential damage from reformulated gasoline transport than those of other areas due to differences in geology and wildlife. It is beyond the scope of this study to identify such site-specific impacts.
- **Occupational Health and Safety:** The primary occupational and safety impact on reformulated gasoline distribution system workers is the extremely flammable properties of gasoline. Gasoline vapors can very readily form flammable mixtures when mixed with air.

Many compounds in reformulated gasolines are highly toxic substances. Inhalation of these substances can cause respiratory (e.g. pneumonitis) or even neurological problems. Prolonged inhalation can result in permanent respiratory damage. Skin exposure to reformulated gasoline could result in dermatitis and other skin-related problems. Finally, many compounds likely to be found in reformulated gasoline have been identified as carcinogens in laboratory animal experiments.

The Bureau of Labor Statistics reports the number of occupational injuries and illnesses associated with various industries (DOL, 1990). One statistic covering the petroleum-related transportation infrastructure was injury and illness incidence rate by transportation mode. Table F-86 displays the average employment and injury and illness incident rates for pipelines (except natural gas), railroad transportation, trucking (local and long

distances), water transportation, and the average private sector industry in 1988. Note that the trucking and water transportation industries exhibit higher injury and illness rates than those associated with pipelines and rail. Compared with the average private sector, only the trucking and water transportation industries had higher illness and injury rates; however, only the pipeline industry had a lower lost workday rate than the overall private sector industry average.

**Table F-86.  
Occupational Health and Safety Projection to 2000 and 2010 for Reformulated Gasoline  
Distribution System**

	SIC Code	Injury and Illness Rate per 100 Full-Time Workers	Lost Workdays Cases per 100 Full-Time Workers	Fatalities per 100,000 Full-Time Workers <sup>1</sup>
Pipeline, except natural gas	46	3.6	1.4	13.5
Railroad	40	6.9	4.9	13.5
Trucking, local and long distance	421	13.9	8.0	13.5
Water transportation	44	12.2	7.5	13.5
Average private Sector Industry		8.6	4.0	5.0

<sup>1</sup> Value based on overall transportation and public utilities

Fatality rates for the reformulated gasoline distribution system could also be estimated from Bureau of Labor data. Rates for each transport mode were assumed to be represented by the Bureau of Labor's estimate for overall transportation and public utilities. Based on this assumption, the fatality rate for the reformulated gasoline distribution modes is more than twice that of overall private industry.

## **F.5.6 Pre- and Post-Operational Phase of the Reformulated Gasoline Transportation Infrastructure**

As identified earlier in Section F.3.6 for the crude oil infrastructure, this section will identify the "inputs" and "outputs" of the reformulated gasoline infrastructure from both the pre-operational (before transport) and post-operational (after transport) perspective. This section provides a brief understanding of the possible environmental impacts from the outputs of both the pre- and post-operational phases. The discussion of the pre-operational phase of the reformulated gasoline infrastructure is divided into several segments: transportation of gasoline by pipeline, marine vessel, and tank truck, and the storage of gasoline on land. The inputs and outputs of each segment and their potential effects on the environment will be briefly discussed.

### **F.5.6.1 Pre-Operational Phase**

There are currently three methods used to transport gasoline in the U.S.; overland pipelines, marine vessels, and on-road tanker trucks. The environmental impacts of constructing overland pipelines and marine vessels were discussed earlier in Section F.3.6 and are not addressed here. The inputs required to construct gasoline tanker trucks will include materials (mostly steel), fuel (electricity), labor, and manufacturing equipment. Tanker trucks are usually manufactured at a facility specifically designed to produce this type of vehicle. The outputs associated with constructing tank trucks will be outputs emitted from the factory or facility that produces these vehicles. The outputs from these facilities will include solid waste in the form of scrap materials leftover from the vehicle manufacturing processes. Air outputs from the factory could include fossil fuel combustion emissions depending on the design of the factory, i.e. what equipment within the factory uses fossil fuel, and what equipment is electrically powered. Liquid emissions from the factory may include any solvents or chemicals used by the factory during the manufacturing process. The environmental impact as a result of tank truck factory emissions will depend on the geographic location of the factory and its age. Outputs from factories located near inland or coastal waterways could impact both the marine and land environment. Recently constructed manufacturing facilities are likely to be designed to minimize the possible environmental impacts to the factory's surroundings.

The storage segment of the current gasoline infrastructure includes pipeline and marine bulk terminals, bulk plants, retail outlets, and commercial/rural facilities. Each of the storage facility inputs required for the pre-operational phase will vary, but can be summarized as requiring land, materials, labor, and fuel. Constructing gasoline bulk terminals will require building storage tanks, piping, and tank truck loading racks which will require mostly concrete and steel. The heavy equipment used to construct the bulk terminals will most likely be diesel powered and will emit air emissions from the combustion of diesel fuel. The emissions and subsequent environmental impacts from diesel fuel combustion were described in earlier sections of this report. Bulk plant, retail outlet, and commercial/rural facility construction will require inputs similar to bulk terminals, with smaller amounts of land, labor,

materials and fuel required. Bulk plants will need storage tanks, piping and tank truck loading racks similar to bulk terminals, but on a smaller scale. It is expected that most of the commercial and rural facilities within the tertiary storage segment will employ underground storage tanks to store their gasoline inventory. In summary, the outputs of constructing the Secondary Distribution, and Tertiary Storage segments of the reformulated gasoline infrastructure will include air emissions from construction equipment operation, liquid emissions from fuel or chemical spills during construction, and solid waste in the form of scrap building materials leftover from the construction process. In general, the specific environmental impacts of constructing the Secondary Distribution, and Tertiary Storage of the reformulated gasoline infrastructure will vary based on the geographic location and the type of facility constructed.

#### **F.5.6.2 Post-Operational Phase**

The post operational phase of the reformulated gasoline infrastructure includes removing tanker trucks, overland pipelines, bulk terminals, bulk plants, retail outlets, and commercial/rural facilities from service. Taking these segments of the infrastructure out of service will require disassembling the tanker trucks, and bulk storage facilities etc.. After the disassembly is complete, recycling the materials or salvaging them for further use in other parts of the infrastructure are likely possibilities. In order to decommission the transport and storage segments of the reformulated gasoline infrastructure, several inputs will be needed. There will be inputs of fuel, labor, and land for the post-operational phase. It is expected that heavy equipment powered by diesel fuel will be used to disassemble the components described above. There will be possible air, liquid, and solid waste emissions from the clean-up operations, as well as land reclamation once all of the facility and equipment has been removed. In summary the environmental impacts of decommissioning each segment of the reformulated gasoline infrastructure will vary depending on the geographic location of the bulk terminal, bulk plant, retail outlet, or commercial/rural facility.

#### **F.5.7 Discussion and Summary**

For the reformulated gasoline distribution system analysis, reformulated gasoline was assumed to be moved 22 percent by tanker, 13 percent by barge, zero percent by rail, nine percent by tank truck, and 56 percent by pipeline for years 2000 and 2010. No imported gasoline was assumed to enter the reformulated gasoline distribution system. Reformulated gasoline flow from the refinery was assumed to reside along two primary paths or legs. The first leg was assumed to consist of route through a pipeline terminal and the rest of the distribution system, while the second leg was assumed to be comprised of a route through marine terminals and the rest of the system before its ultimate end-use vehicle consumption.

The inputs of the reformulated gasoline transport process were characterized as reformulated gasoline, No. 2 diesel fuel, No. 6 fuel oil, electricity, replacement parts, and labor. The output of the system consisted only of reformulated gasoline.

The main environmental impacts of the reformulated gasoline distribution infrastructure system were characterized as air and liquid spill emissions. The air emissions consist of both exhaust and evaporative emissions. The exhaust emissions result from the combustion of fuel for transporting the crude through the infrastructure to the refinery. Specific exhaust emission factors for HC, CO, NO<sub>x</sub>, particulates, and CO<sub>2</sub> were derived for the tank truck, ocean tanker, and inland barge crude oil transportation modes for years 2000 and 2010. Assessments were also made of the same exhaust emissions from electricity production required to operate reformulated gasoline pipelines.

Another important air emission from the reformulated gasoline distribution system is evaporative VOC emissions. Such emissions result from the vaporization of crude oil and the subsequent release of these vapors to the atmosphere. Evaporative VOC emissions could be released at a variety of points along the reformulated gasoline distribution infrastructure including during transit between facilities, during loading and unloading at facilities, and from bulk storage at facilities. Estimates of evaporative VOC emission factors for various transport modes and facilities of the reformulated gasoline distribution system were derived from EPA sources for years 2000 and 2010 assuming the application of various types of vapor control equipment for these modes and facilities in these years.

The other main environmental impact of reformulated gasoline transportation comes in the form of liquid spills. Such spills may originate from "normal" operations, such from loading hose disconnect, or from accidental occurrences. Industry data on "normal" operations was not available. It was also assumed that such spills would be small and insignificant relative to accidental spills. Therefore, emission factors for "normal" operational spills were not estimated.

However, historical data was available for current accidental spills for the transportation modes and bulk storage facilities of the current petroleum transportation system. Based on this data, estimates of annual accidental spill rates along the reformulated gasoline transportation infrastructure system were determined for years 2000 and 2010. These rates were placed on a throughput basis using NES reformulated gasoline consumption estimates for years 2000 and 2010.

After the exhaust, evaporative VOC, and liquid spill emission factors for individual components of the reformulated gasoline transportation system were derived, they were weighted based on total system throughput in order to estimate a single emission factor for each pollutant representing reformulated gasoline transport. The weighting was performed for the amount of reformulated gasoline assumed to flow through each leg of the reformulated gasoline distribution system assumed for this analysis. The percentage breakout for each leg in years 2000 and 2010 were assumed to be the same as the current percentage breakout for gasoline flow. Additional weighting was performed for those portions of the system in which multiple transport modes were used.

A summary of all reformulated gasoline distribution system inputs and outputs is provided in Table F-87. The annual estimates were derived by applying the NES estimates of reformulated gasoline production in years 2000 and 2010 to the weighted system inputs and outputs. It was assumed that reformulated gasoline production is equivalent to reformulated gasoline end-use consumption.

As shown in Table F-87, the majority of inputs and outputs for reformulated gasoline distribution in 2010 are lower than those in 2000. This results mainly from lower reformulated gasoline consumption (i.e. throughput) in 2010 as assumed by NES.

**Table F-87.**  
**Summary of Total Inputs and Outputs for the Reformulated Gasoline**  
**Distribution Infrastructure in 2000 and 2010.**

	2000		2010	
	per MMBTU	per Year	per MMBTU	per Year
<b>INPUTS</b>				
Reformulated Gasoline (bbl)	0.206	2,560*10 <sup>6</sup>	0.206	2,300*10 <sup>6</sup>
No. 2 Diesel Fuel (bbl)	0.000334	4,140,000	0.000319	3,550,000
No. 6 Fuel Oil (bbl)	0.000370	4,580,000	0.000370	4,120,000
Electricity (kWh)	5.68	70.3*10 <sup>9</sup>	5.68	63.3*10 <sup>9</sup>
Labor (persons)	0.000063	780,000	0.000063	702,000
Replacement Parts	N/A	N/A	N/A	N/A
<b>OUTPUTS</b>				
Reformulated Gasoline (bbl)	0.206	2,560*10 <sup>6</sup>	0.206	2,300*10 <sup>6</sup>
<b>Air Emissions (lbs,tons)</b>				
HC	0.000999	6,190	0.000687	3,830
CO	0.00255	15,800	0.00173	9,630
NO <sub>x</sub>	0.00475	29,400	0.00303	16,900
Particulates	0.000180	1110	0.000131	729
SO <sub>2</sub>	0.000212	1310	0.000206	1150
CO <sub>2</sub>	0.701	4,340,000	0.682	3,800,000
Total Evaporative VOC	0.0178	110,000	0.0174	97,200
Liquid Spill Emissions (lbs,tons)	0.00736	45,600	0.00736	41,000

<sup>1</sup> N/A = Not Available

## **F.5.8 References**

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