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Background Documents for the Cost and Economic Impact Analysis of Listing Four Petroleum Refining Wastes as Hazardous under RCRA Subtitle C

PRLF-S0008

BACKGROUND DOCUMENTS
FOR THE
COST AND ECONOMIC IMPACT ANALYSIS
OF LISTING FOUR PETROLEUM REFINING WASTES
AS HAZARDOUS UNDER RCRA SUBTITLE C

Prepared for:

Office of Solid Waste
Economics, Methods and Risk Assessment Division
U.S. Environmental Protection Agency
Washington, D.C. 20460

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January 10, 1998

PRLF-S0008.A

DOCUMENT 1

COST AND ECONOMIC IMPACT ANALYSIS OF LISTING HAZARDOUS WASTES FROM THE PETROLEUM REFINING INDUSTRY

September 21, 1995

INDEX

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September 21, 1995

Mr. Andrew Wittner
U.S. Environmental Protection Agency
Office of Solid Waste, Regulatory Analysis Branch
Room S-256
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Washington, D.C. 20460

RE: Contract No. 68-W3-0008
Work Assignment No. 208
Revised Draft Final Report, Cost and Economic Impact Analysis of Listing Hazardous Wastes from the Petroleum Refining Industry

Dear Andy:

Enclosed please find three copies (two bound and one unbound) of the revised Draft Final Report for the Cost and Economic Impact Analysis of Listing Hazardous Wastes from the Petroleum Refining Industry. The report incorporates the revised methodology for estimating additional waste quantities and the corresponding revisions to the cost estimates.

Please do not hesitate to call me at (612) 227-6500 if you have any questions or need additional assistance.

Sincerely,

Dave Gustafson

Dave Gustafson
Associate Engineer

Enclosure

cc: Bill Moody, ICF
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DRAFT FINAL REPORT

COST AND ECONOMIC IMPACT ANALYSIS OF LISTING HAZARDOUS WASTES FROM THE PETROLEUM REFINING INDUSTRY

Prepared for:

Office of Solid Waste
Regulatory Analysis Branch
U.S. Environmental Protection Agency
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ACKNOWLEDGEMENT

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

EXECUTIVE SUMMARY

Pursuant to the provisions of the Hazardous and Solid Waste Amendments of 1984 (HSWA), the Environmental Protection Agency (EPA) is listing, as hazardous wastes, certain waste streams generated by the petroleum refining industry. This action is expected to require changes in the current waste management practices of firms within this industry and thereby compel them to incur additional costs associated to comply with EPA's hazardous waste regulations. This report assesses the likely changes in waste management practices brought on by this waste listings determination and analyzes the costs and economic impacts associated with these changes at the facility level. This Cost and Economic Impact Analysis was possible at the facility-specific level because substantial plant-specific data were available from EPA's 1992 RCRA Section 3007 Survey responses and engineering site visits.

Executive Order No. 12866 requires that regulatory agencies determine whether a new regulation constitutes a significant regulatory action. A significant regulatory action is defined as an action likely to result in a rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities;

- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in Executive Order 12866.

EPA estimated the costs and potential economic impacts of this listing of petroleum refining wastes to determine if it is a significant regulatory action as defined by the Executive Order.

ES.1 Cost Impacts

This listing has determined that four petroleum refining residuals (crude oil sludges, clarified slurry oil (CSO) sludges, hydrotreating catalysts, and hydrorefining catalysts) are hazardous wastes and subject to RCRA Subtitle C regulation. These four petroleum refining wastes are currently being generated and managed in non-RCRA Subtitle C management units at 162 refineries which are owned and operated by 80 companies. The quantity of waste at the point of generation ranges from 91,600 to 177,900 metric tons per year, with an expected value of approximately 134,800 metric tons per year. Approximately 36 percent of this expected affected quantity was reported by the industry in the 1992 RCRA 3007 Survey. The remaining 64 percent was added by EPA as estimates for non-reported quantities.

Three scenarios are evaluated in this Cost and Economic Impact Analysis. The first scenario, Listing Scenario, assesses the costs incurred by the petroleum refining industry to comply with Subtitle C regulation excluding Land Disposal Restriction (LDR) regulations. The Listing Scenario assumes an end disposal management of Subtitle C landfilling or continued combustion of wastes, where indicated as the baseline management practice, in a Subtitle C incinerator/BIF. The second scenario, LDR Scenario, expands on the Listing Scenario by adding in cost impacts attributable to LDR regulations. Two options are assessed for the LDR Scenario. In Option 1, the upper bound estimate, the oil-based sludges are combusted in off-site Subtitle C incinerators and the metal catalysts are combusted in off-site incinerators followed by vitrification and Subtitle C landfill of the ash. In Option 2, the lower bound estimate, oil-based sludges are assumed to be managed in on-site Subtitle C incinerators for those refineries generating sufficient quantities and are currently in the RCRA permitting program (thereby, avoiding potential corrective action costs). Metal catalysts are assumed to be regenerated/reclaimed in RCRA-exempt off-site metal recovery units. The third scenario, Contingent Management Scenario, expands on the LDR Scenario, Option 2, by allowing contingent management for the oil-based sludges in Subtitle D units. Contingent management means that the wastes will no longer be regulated as hazardous if they are placed in these Subtitle D units. The wastes are still subject to Subtitle C storage and transportation requirements prior to placement in these units. Two options are assessed for the Contingent Management Scenario. In Option 1, CSO sludges are contingently managed in either Subtitle D land treatment units with run-on/run-off controls or Subtitle D landfills. Crude oil sludges are managed in on-/off-site Subtitle C incinerators and metal catalysts are regenerated/reclaimed in off-site metal recovery units. In Option 2, crude oil tank sludges also are contingently managed in Subtitle D land treatment units with run-on/run-off controls. The compliance management practices for the other waste streams are the same as in Option 1.

The total incremental cost of the listings under the Listing Scenario, on a before-tax basis, is estimated to be between $4 and $16 million per year with an expected value of $8 million per year.

The total incremental cost of the listings under the LDR Scenario is estimated to range from $21 to $101 million per year. The expected value is $41 million per year. This expected value represents incineration management of the two oil-based sludges on site when it is economically feasible and off-site reclamation/regeneration of the two metal catalysts.

The total incremental cost of the listings under the Contingent Management Scenario is estimated to range from $3 to $42 million per year. If contingent management regulations are promulgated for CSO sludges alone the expected value is $24 million per year. If contingent management regulations are promulgated for both crude oil tank sludges and CSO sludges the expected value is $6 million per year. Results of the cost impact analysis are summarized in Table ES.1.

All of the above cost estimates under each scenario reflect implementation of a waste minimization opportunity for filtering "oily" crude oil tank sludges and CSO sludges and recycling the oil filtrate back into process units. Revenues from the recycled oil are estimated at $1.3 million per year.

The petroleum refining industry is expected to incur no corrective action costs as a result of the listings determination. The RCRA Corrective Action Program is triggered when a facility seeks a RCRA Part B permit. EPA assumes that unpermitted facilities will avoid potential corrective action costs by shipping wastes off site for management and thereby no constructing and permitting new waste management units. EPA estimates that two unpermitted facilities generate sufficient waste to economically construct an on-site incinerator if they choose. Potential corrective action costs range from $0 to $7.2 million per year with a cost of zero representing the expected value.

ES.2 Industry Profile

The entities affected by this listings determination are classified in SIC 2911, Petroleum Refining. As of January 1, 1995, there are 173 refineries owned/operated by 84 companies in the United States. Based on data obtained from the 1992 RCRA 3007 Survey, 162 refineries owned/operated by 80 companies generate wastes affected by this listings determination. Companies that operate petroleum refineries are characterized as vertically integrated if they own and operate segments responsible for both exploration and production of crude oil and for marketing the finished petroleum products after refining occurs. The crude capacity of the major, vertically integrated companies in the petroleum refining industry represented 69 percent of nationwide production in 1994. The Small Business Administration defines petroleum companies with crude capacity less than or equal to 75,000 barrels per calendar day (b/cd) as a small entity. Based on this cutoff, 45 of the 80 companies affected by this listings determination, or 56 percent, are considered small entities.

ES.3 Economic Impacts

Partial equilibrium analysis is used to evaluate economic impacts of the listings on the petroleum refining industry in an effort to specify market demand and supply, estimate the post-control shift in market supply, predict the change in market equilibrium (price and quantity), and estimate plant closures. Petroleum refineries produce several hundred products. The economic impacts analysis evaluates the impact of the listings based on ten petroleum products (i.e., ethane/ethylene, butane/butylene, normal butane/butylene, isobutane/isobutylene, finished motor gasoline, jet fuel, distillate and residual fuel oil, asphalt, and petroleum coke), which represents 91 percent of domestically refined petroleum products in 1992. Because compliance costs for the hazardous waste listings cannot be allocated to any specific products, output in the partial equilibrium model is defined as a composite, bundled good equal to the sum of price multiplied by the weighted production volumes of all ten products.

A bounding analysis was conducted to evaluate the potential economic impacts of this listings determination. The Listing Scenario, lower bound option, assumes an end disposal management method of Subtitle C landfilling or continued combustion of wastes, where indicated as the baseline management practice, in a Subtitle C incinerator/BIF. The LDR Scenario management assumptions and quantity estimates for the crude oil tank sludge and CSO tank sludge used in the economic impact analysis differ from the cost impact analysis assumptions due to late revisions in the designation of LDR management practices and quantity estimation methodology. The total before-tax incremental costs for the LDR management assumptions described below range from $16 to $70 million compared to the range of $21 million to $101 million presented in the cost impact analysis. The LDR Scenario, upper bound option, assumes a pretreatment management method of solidification prior to Subtitle C landfill for metal-based wastes and combustion in a Subtitle C incinerator/BIF for organic-based wastes. The lower bound LDR Scenario, assumes a pretreatment management method of solidification prior to Subtitle C landfill for metal-based wastes and combustion in a Subtitle C incinerator/BIF for organic-based wastes for those refineries generating sufficient quantities to warrant on-site incineration. This regulatory option represents the most cost-effective option for compliance with the listings and LDRs. The results of the economic impacts analysis are summarized in Table ES.2.

Predicted price increases and reductions in domestic output are less than 1 percent for the ten products evaluated under both the Listing and LDR compliance scenarios. Projected price increase for the ten products combined range from 0.03 to 0.76 percent under the low and high cost scenarios, respectively. Under the low and high cost scenarios, production is expected to decrease ranging from 1.3 to 30.9 million barrels per year, representing a 0.02 to 0.59 percent decrease in annual production, respectively. The value of shipments or revenues for domestic producers are expected to increase for the ten products combined ranging from $9.0 to $213 million annually for the low and high cost scenarios, respectively. This revenue increase results given that the percent increase in price exceeds the percent decrease in quantity for goods with inelastic demand. The model estimates that up to two refineries may close as a result of the predicted decrease in production, under both regulatory scenarios. Those refineries with the highest per unit control costs are assumed to be marginal in the post-control market. No significant regional impacts are anticipated from implementation of the listings since only up to two facilities are anticipated to close and impacts overall are estimated to be minimal.

Under the low and high cost scenarios, the number of workers employed by firms in SIC 2911 are estimated to decrease ranging from 12 to 282 workers annually, representing a 0.03 and 0.59 percent decrease in total employment, respectively. The small magnitude of predicted job loss directly results from the relatively small decrease in production anticipated and the relatively low labor intensity in the industry. An estimated decrease in energy use ranging from $1.02 to $24.32 million annually is expected for the industry, under the low and high cost scenarios, respectively. As production decreases, the amount of energy input utilized by the refining industry also declines. The change in energy use does not consider the increased energy use associated with operating and maintaining the regulatory control equipment due to the lack of available data. Finally, imposition of the listings will further increase the negative balance of trade. Under the low and high cost scenarios, net exports are anticipated to decline ranging from 0.2 to 4.7 million barrels annually, representing a 0.1 and 2.8 percent decline, respectively. The dollar value of the total decline in net exports ranges from $6.35 to $152.6 million ($1992) annually. Given the magnitude of the estimated compliance costs, refineries are expected to incur minimal economic impacts.

Economic impacts may be over-estimated as a result of the following model assumptions:

- the model assumes that all refineries compete in a national market. In reality, some refineries are protected from market fluctuations by regional or local trade barriers and may therefore be less likely to close;

- the total cost of compliance is assigned exclusively to ten petroleum products, rather than the entire product slate for each refinery;

- some refineries may find it profitable to expand production in the post-control market. This would occur when a firm found its post-control incremental unit cost to be smaller than the post-control market price. Expansion by these firms would result in a smaller decrease in output and increase in price than otherwise would occur;

- the economic analysis was based on the listing of five waste streams including unleaded gasoline sludge, which has since been removed from the list of wastes included in this listing determination. Compliance costs associated with unleaded gasoline sludge represent 11 to 14 percent of the total compliance cost used in the evaluation of economic impacts under the lower and upper bound scenarios, respectively. As a result, economic impacts for the 98 facilities generating unleaded gasoline sludge will be overestimated;

- the regulatory options used to evaluate economic impacts differ slightly from those that were used to calculate the cost of compliance. This difference does not affect the total cost of compliance for the Listing Scenario or the lower bound LDR Scenario, but does have an impact on the upper bound LDR Scenario, such that costs were understated by $8 million. As a result, economic impacts may be underestimated for the upper bound LDR Scenario; and

• the economic analysis was based on a lower estimate for crude oil tank sludge quantities, each having 9,000 MT/yr managed in final management practices. These quantities were revised to 14,600 and 13,100 MT/yr, respectively. As a result, impacts for facilities generating these sludges are understated for all scenarios presented in Table ES.2.

ES.4 Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 (RFA) requires agencies to assess the effect of regulations on small entities and to examine regulatory alternatives to alleviate any adverse economic effects on this group. Section 603 of the RFA requires an Initial Regulatory Flexibility Analysis (IRFA) to be performed to determine whether small entities will be affected by the regulation. If affected small entities are identified, regulatory alternatives that mitigate the potential impacts must be considered.

For SIC 2911, Petroleum Refining, the Small Business Administration defines small entities as those companies with refinery capacity less than or equal to 75,000 barrels of crude per calendar day. Based on this criterion, approximately 56% or 45 of the 80 companies affected by the listing determination are considered to be small.

Even under the highest cost scenario, the estimated impacts of the listing determination are minimal. Predicted price increases and reductions in domestic output are less than 1 percent for the ten products evaluated. The small magnitude of predicted job loss directly results from the relatively small decrease in production anticipated and the relatively low labor intensity in the industry.

Under the Agency's Revised Guidelines for Implementing the Regulatory Flexibility Act, the Agency is committed to considering regulatory alternatives in rulemakings when there are any estimated economic impacts on small entities. Despite the high percentage of small entities in the population of refineries affected by the listing determination, anticipated impacts as a result of implementation of the listing are minimal, with only up to two plant closures predicted under each of the scenarios evaluated. Because economic impacts are estimated to be minimal, no small entity exemptions or options were judged to be necessary in an effort to reduce economic impacts on small entities.

TABLE ES.1

Summary of Cost of Compliance ($ millions per year)[1]

Waste Stream	Listing Scenario Subtitle C Landfill of Sludges and Catalysts	LDR Scenario Option 1 Off-Site Incineration of Sludges and Off-Site Incineration and Vitrification of Catalysts	LDR Scenario Option 2 On-/Off-Site Incineration of Sludges and Regen./Reclam. of Catalysts	Contingent Management Scenario Option 1 Subtitle D Landfill and Land Treatment (w/ contr.) of CSO Sludges, On-/Off-Site Incineration of Crude Oil Sludges and Regen./Reclam. of Catalysts	Contingent Management Scenario Option 2 Subtitle D Landfill and Land Treatment (w/ contr.) of CSO Sludges, Sub. D Land Treatment (w/ contr.) of Crude Oil Sludges and Regen./Reclam. of Catalysts
Crude Oil Tank Sludge	2.2 [1.0 - 3.9]	21.6 [9.3 - 38.8]	16.7 [8.1 - 28.3]	17.5 [8.5 - 29.8]	(0.5) [(0.2) - (1.0)]
Clarified Slurry Oil Sludge	2.8 [1.4 - 4.8]	22.5 [11.2 - 37.6]	16.8 [9.4 - 26.5]	(0.5) [(0.3) - (0.8)]	(0.5) [(0.3) - (0.8)]
Hydrotreating Catalyst	1.3 [0.8 - 2.9]	5.0 [3.5 - 7.6]	2.3 [1.2 - 4.5]	2.3 [1.2 - 4.5]	2.3 [1.2 - 4.5]
Hydrorefining Catalyst	1.5 [0.7 - 3.8]	11.6 [8.3 - 16.5]	3.9 [1.9 - 7.9]	3.9 [1.9 - 7.9]	3.9 [1.9 - 7.9]
RCRA Administrative Costs	0.5 [0.4 - 0.6]	0.5 [0.4 - 0.7]	0.8 [0.6 - 1.0]	0.6 [0.5 - 0.8]	0.5 [0.3 - 0.6]
TOTAL	8.3 [4.3 - 16.0]	61.3 [32.7 - 101.2]	40.6 [21.3 - 68.3]	23.8 [11.8 - 42.2]	5.6 [3.1 - 11.2]

[1] Costs are presented as the average cost followed by the range of costs from low to high in brackets. Parentheses indicate negative values, credits.

TABLE ES.2

Summary of Economic Impacts

Economic Impacts	Listing Scenario Lower Bound[1]	LDR Scenario Lower Bound[2]	LDR Scenario Upper Bound[3]
PRIMARY ECONOMIC IMPACTS[4]			
Average Price Increase Over All Products	0.03%	0.08%	0.76%
Annual Production Decrease			
Amount (MMbbl)	(1.3)	(3.27)	(30.93)
Percentage Change	(0.03%)	(0.06%)	(0.59%)
Annual Value of Shipments			
Amount (MM$92)	$9.0	$22.59	$213.34
Percentage Change	0.01%	0.02%	0.16%
Number of Plant Closures	0-2	0-2	0-2
SECONDARY ECONOMIC IMPACTS[3]			
Annual Job Loss			
Number	(12)	(30)	(282)
Percentage Change	(0.03%)	(0.06%)	(0.59%)
Annual Decrease In Energy Use			
Amount (MM$92)	($1.02)	($2.57)	($24.32)
Percentage Change	(0.03%)	(0.06%)	(0.59%)
Annual Net Foreign Trade Loss			
Amount (MMbbl)	(0.20)	(0.49)	(4.70)
Percentage Change	(0.12%)	(0.3%)	(2.8%)
Dollar Value ($/MMbbl)	($6.35)	($15.96)	($152.60)

1 assumes an end disposal management method of Subtitle C landfilling or continued combustion of wastes, where indicated as the baseline management practice in a Subtitle C incinerator/BIF.

2 assumes a pretreatment management method of solidification prior to Subtitle C landfill for metal-based wastes and combustion in an on-site Subtitle C incinerator/BIF for organic-based wastes for those refineries generating sufficient quantities to warrant on-site incineration.

3 assumes a pretreatment management method of solidification prior to Subtitle C landfill for metal-based wastes and combustion in an off-site Subtitle C incinerator/BIF for organic-based wastes.

4 brackets indicate decreases or negative values.

1. INTRODUCTION

This report presents a cost and economic impact analysis corresponding to the listings determination for four additional hazardous wastes from the petroleum refining industry by the U.S. Environmental Protection Agency (EPA). These waste listings are pursuant to the Hazardous and Solid Waste Amendments of 1984 (HSWA) and a proposed consent decree between the Environmental Defense Fund (EDF) and EPA in which EPA agreed to promulgate a final listing determination for petroleum refining wastes on or before October 31, 1996 (EDF v. EPA, DC DC, No.89-0598, 6/18/91). The expected effects of this listings determination involve increased costs for treatment and disposal of newly listed hazardous wastes and capital investment expenditures to manage and reduce these wastes compared to current management practices by most firms in the affected industries.

Executive Order No. 12866 (FR V. 58 No. 170, 51735, October 4, 1993) requires that regulatory agencies determine whether a new regulation constitutes a significant regulatory action. A significant regulatory action is defined as an action likely to result in a rule that may:

- Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or tribal governments or communities;
- Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;
- Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in Executive Order 12866.

EPA estimated the costs and potential economic impacts of the listings determination of petroleum refining wastes to determine if it is a significant regulatory action as defined by the Executive Order.

The Regulatory Flexibility Act of 1980 requires federal agencies to assess the effects of regulations on small entities and to examine regulatory alternatives that may bring about any adverse effects on these small entities. EPA conducted a regulatory flexibility screening analysis. The results of this analysis are presented in Chapter 4.

1.1 Purpose

Four additional waste streams, referenced as K169 through K172, are being listed as hazardous in the petroleum refining industry. This report presents the cost and economic impact analysis that was performed for these waste listings.

This analysis estimates how facilities in the petroleum refining industry may be economically impacted by the regulation, as well as how the aggregate industry may be affected. Best estimates of the cost effects of the listings were determined and then compared to the value of production on both a facility-specific and industry-wide basis.

1.2 Scope of Study

The scope of the study involves the petroleum refining industry, for which hazardous waste listings under Part 261 of RCRA are being promulgated. This industry produces petroleum products made from petroleum crude oil and natural gas. Petroleum products made from crude oil include still gas, liquified gas, motor gasoline, aviation gasoline, jet fuel, kerosene, special naphtha, petrochemical feeds, distillates, lubricants, waxes, coke, asphalt/road oil, residuals, and other miscellaneous products.

A total of 172 of the 173 petroleum refining facilities submitted 1992 RCRA 3007 Surveys on their petroleum refining products manufactured on site, manufacturing and waste management practices, and other supporting information. Of the 172 facilities that responded to the survey, one facility is closed, and nine do not generate the listed wastes or manage them in non-exempt waste management units. This study addresses the cost of compliance and economic impacts for the 162 facilities affected by the listings determination.

A total of two sludges and two spent catalysts waste streams are currently being listed as hazardous wastes. The wastes are briefly described in the following table (see Chapter 3 for further details).

TABLE 1.1. NEWLY LISTED HAZARDOUS WASTES

WASTE STREAM	NEWLY LISTED HAZARDOUS WASTE
K169	Crude oil storage tank sludge
K170	Clarified slurry oil sludge from catalytic cracking
K171	Catalyst from catalytic hydrotreating
K172	Catalyst from catalytic hydrorefining

1.3 Organization of the Report

The remainder of this report is divided into three main chapters. Chapter 2 presents an economic profile for the petroleum refining industry. For this industry, available economic profile data are developed including products manufactured, number and location of facilities, production capacity and utilization, market structure and industry concentration, supply and demand conditions, and industry trends and market outlook.

Chapter 3 profiles the hazardous waste streams to be listed, their generation rates, and current and alternative compliance hazardous waste management practices. Unit costs and prices for the current and alternative compliance hazardous waste management practices are presented in this chapter as well as a summary of the regulatory costs.

Chapter 4 documents the economic impacts of the hazardous waste listings determination.

2.0 INDUSTRY PROFILE

This section presents a profile of the petroleum refining industry, which is the subject of this listings determination. Refining is the process which converts crude oil into useful fuels and other products for consumers and industrial users. All affected facilities are classified under SIC 2911, Petroleum Refining.

Sections 2.1 and 2.2 present an overview of industry products and processes and the population of affected facilities, respectively. The petroleum refining market structure including market supply, demand characteristics, and industry trends are described in Sections 2.3 through 2.6.

2.1 Overview of Products and Processes[1]

2.1.1 General Product Descriptions

Petroleum products are made from petroleum crude oil and natural gas. Synthetic products, while similar, differ in that they are made from other raw materials such as coal, peat, lignite, shale oil and tar sands. The principal classes of products made from crude oil include still gas, liquified gas, motor gasoline, aviation gasoline, jet fuel, kerosene, special naphtha, petrochemical feeds, distillates, lubricants, waxes, coke, asphalt/road oil, residuals, and miscellaneous.

Three major classes of petroleum products include fuels, building materials, and chemicals. Fuels include gases, liquids, and semisolids. Common fuel uses include burning in furnaces to produce heat, aspirating into internal combustion engines to supply mechanical power, and injecting into jet engines to create thrust. Building materials made from petroleum products include petroleum asphalt used for roofing and road coverings, petroleum waxes used for waterproofing, and plastics, elastomers, and other resins used for various construction purposes. Chemicals derived from petroleum, often referred to as petrochemicals, have numerous uses including adhesives, cleaners, drugs, fungicides, inks, paints, and solvents.[2]

The economic analysis for this listings determination is based on the evaluation of ten primary petroleum products including motor gasoline, jet fuel, distillate fuel, residual fuel, liquified petroleum gases (4), asphalt, and petroleum coke. Based on 1992 production data

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[1] Process information in this section is from "OSW Listing Determination for the Petroleum Refining Industry, Waste Characterization Part III", Science Applications International Corporation, September 15, 1994.

[2] Petroleum Processing Handbook, Chapter 1, "Petroleum Products," by Harold L. Hoffman, 1992.

reported in the RCRA 3007 Survey, these products account for approximately 91 percent of domestically refined petroleum products.[3]

Motor gasoline is defined as a complex mixture of relatively volatile hydrocarbons that has been blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline includes reformulated gasoline, oxygenated gasoline, and other finished gasoline. Jet fuel is a low freezing distillate of the kerosene type used primarily for turbojet and turboprop aircraft engines. Distillate fuel oil is a general classification for one of the petroleum fractions produced in conventional distillation operations. It is used primarily for space heating, on-and-off-highway diesel engine fuel, and electric power generation. Residual fuel oil is a heavy oil that remains after the distillate fuel oils and lighter hydrocarbons (e.g., ethane/ethylene, propane/propylene) are distilled away in refinery operations. Primary uses include commercial and industrial heating, electricity generation, and to power ships. Liquified petroleum gases (LPG) include ethane/ ethylene, propane/propylene, normal butane/butylene, and isobutane/isobutylene. Asphalt includes crude asphalt as well as other finished products including cements, fluxes, emulsions, and petroleum distillates blended with asphalt to make cutback asphalts. Petroleum coke is a residue, the final product of the condensation process in cracking. Marketable coke includes those grades of coke produced in delayed or fluid cokers, which may be recovered as relatively pure carbon.

2.1.2 General Process Descriptions

The refining process transforms crude oil into a wide range of petroleum products which have a variety of applications. Refined products include liquified petroleum gases such as ethane/ethylene, propane/propylene, normal butane/butylene, and isobutane; finished motor gasoline, unleaded and leaded; finished aviation gasoline; jet fuel; distillate fuel oil; residual fuel oil; special naphthas; lubricants; waxes; asphalt and road oil; coke; petrochemical feedstocks; sulfur; and hydrogen. The output of each refinery is a function of its crude oil feedstock and its preferred petroleum product slate. These products are produced using the processes described in the following subsections.

Catalytic Cracking

Cracking is the process in which long-chained hydrocarbon oil molecules are decomposed (broken-down) into shorter-chained hydrocarbons, low-boiling molecules. Catalytic cracking breaks heavy gas oils and residual oils into simpler and lighter hydrocarbons using high heat and catalyst to promote the decomposition reactions. It is an effective process for increasing the yield of products ranging from naphtha to reduced crude oil. The silica alumina catalyst used in this process has a small particle size and moves through the reactor as a fluid and is commonly called fluid catalytic cracking. Coke (i.e., solid carbon) forms on the catalyst

[3] RCRA 3007 Survey and U.S. Department of Energy, Energy Information Administration, Petroleum Supply Annual 1993, DOE/EIA-0340(93)/1.

causing it to lose its reactivity and become spent. Metals such as vanadium and nickel from the crude oil also deposit on the catalyst, reducing activity. The catalyst is continuously sent to a regenerator where the coke is burned off and the catalyst is recycled to the catalytic reactor. To control metal formation on the catalyst and maintain reactivity, catalyst is continuously withdrawn from the regenerator and replaced with fresh catalyst. Catalyst fines also become entrained in the flue gas and can be removed in an electrostatic precipitator or a wet gas scrubber or can be sent to a stack (depending on air permits). Clarified slurry from residual oils also may be stored temporarily in tanks. Relatively infrequently (every 10 to 20 years), these storage tanks require sludge removal due to maintenance, inspection, or sludge buildup. Clarified slurry oil sludges which may be generated during this process are not limited to "tank sludges." For this residual, sludges are generated from tank storage and, more rarely, filtration prior to tank storage.

Catalytic Hydrotreating and Hydrorefining

Catalytic hydrotreating and hydrorefining are used to improve the quality of a process feed stream. These processes remove sulfur from a process feed stream by converting mercaptans[4] to a carbon-based structure and hydrogen sulfide gas, which is fractionated. These processes may also remove nitrogen, asphaltene, and metal contaminates. The catalyst used in these processes is typically cobalt or nickel and molybdenum or alumina. Catalyst lifetime is approximately 1 to 5 years, after which the catalyst is replaced. Catalyst activity losses occur because of poisons from the crude, coke deposits, and structural breakdown from severe operating conditions in the hydrotreating and hydrorefining processes.

Catalytic Reforming

Catalytic reforming increases the octane of gasoline by dehydrogenation[5] and molecular rearrangement of naphthas. This process uses a precious metal catalyst. Fixed bed reforming is semi-regenerative and cyclic and generates a relatively large quantity of catalyst on an infrequent basis. Continuous reforming generates a relatively small quantity of catalyst on a continuous basis.

Thermal Processes

A thermal process is any refining process that utilizes heat without the aid of a catalyst. In the delayed coking process, residuum is heated to the point of cracking and is charged to a coke drum. In the coke drum, the residuum cracks, forming a wide range of products and coke (a solid hydrocarbon residue poor in hydrogen). The gaseous products are recovered in a fractionator and the coke deposits are recovered in a drum. Once the drum is full, the

[4] Mercaptan is the common name for a thiol, which is a chemical functional group containing sulfur.

[5] Dehydrogenation is the removal of hydrogen from a chemical compound.

coke is hydraulically drilled out and dropped to a concrete pad. Delayed coking is the most common thermal process. Other types of thermal processes include fluid coking, visbreaking, Dubbs units, and thermal cracking. The drilling process produces coke fines that are entrained in the decoking water. This water is filtered to remove the fines and is recycled to a decoking water surge drum. The fines are typically placed on the coke pile.

Liquid Treating

Caustic treating removes impurities such as mercaptans and naphthalenes from light hydrocarbons (e.g., kerosene and lighter hydrocarbon products). A slip stream of caustic is continuously removed from this process. All spent caustics are corrosive. Caustic regeneration is sometimes used in this process.

Sulfur Complex and H_2S Removal

Sulfur-containing compounds are removed as hydrogen sulfide (H_2S) gas at many points in the refinery and are sent to an H_2S removal system where the gas is contacted with an aqueous amine in an absorption column. The sulfur laden amine is routed to a desorber where it is heated, causing the H_2S gas to come out of solution. The H_2S is then sent for sulfur recovery. The sulfur-free amine solution is returned to the absorption column. A slip stream of sulfur-free amine from the desorber is filtered to remove any corrosion products. The filters are changed monthly. The Claus Unit is the most common unit used for the production of sulfur from hydrogen sulfide. It converts H_2S into elemental sulfur through the use of heat and an alumina catalyst. Sulfur dioxide in the off-gas (i.e., tail gas) is further converted to H_2S and sour water using another catalyst. The H_2S is recycled to the Claus unit. Sulfur production uses an alumina catalyst, which is changed every two to three years.

H_2SO_4 Alkylation

Alkylation is the formation of complex saturated[6] molecules by the combination of a saturated and an unsaturated molecule. Olefin[7] and isobutane gases are contacted over concentrated sulfuric acid (H_2SO_4) catalyst to synthesize alkylates for octane boosting in motor and aviation fuels. The reaction products are separated by distillation and are scrubbed with caustic (see Liquid Treating). A portion of the acid catalyst is continuously bled and replaced with a fresh acid to maintain reactor concentrations around 90 percent. Sludge is generated in a neutralization pit. Sludge may also be generated in process line junction boxes, in the spent H_2SO_4 holding tank, and during turnarounds.

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[6] A saturated hydrocarbon contains no double or triple bonds.

[7] An olefin is an open-chain hydrocarbon having one or more double bonds per molecule.

HF Alkylation

Olefin and isobutane gases are also contacted over concentrated hydrofluoric (HF) acid catalyst to synthesize alkylates for octane boosting in motor and aviation fuel. The reaction products are separated by distillation and are scrubbed with caustic. The volume and type of sludge generated are dependent on the types of influents to the neutralization pit [e.g., acid soluble oil (ASO), and potassium hydroxide scrubber water from air pollution control equipment] and the type of neutralizing agent used (e.g., sodium, calcium, or potassium ions). Neutralizing controls fluoride levels to the wastewater treatment plant. Some facilities discharge acid soluble oil to their HF neutralization pit, where it becomes part of the HF sludge.

Storage

Nearly all refineries store feed and products in tanks. Relatively infrequently (every 10 to 20 years), tanks require sludge removal due to maintenance, inspection, or sludge buildup. Crude oil tank sludge consists of heavy hydrocarbons, basic sediment and water, and entrapped oil that settles to the bottom of the tank. When removed, the oil is recovered while the solids are collected and discarded as a waste. Unleaded gasoline tank sludge consists of tank scale and rust. A typical cleaning procedure is to wash the tank with water (to decrease benzene levels for occupational health safety reasons), send the water to the sewer, and sweep or scrape the remaining solids for drumming and disposal. Sometimes there are no solids.

2.2 Profile of Affected Facilities

This section describes the products and processes of the refining industry and identifies the companies and refineries that generate the four wastestreams associated with this listings determination.

The 1992 Petroleum Supply Annual, reports the number of operable refineries as of January 1, 1993 at 187, of which 175 were operating and 12 were idle. In support of these listings, the 1992 RCRA 3007 Survey was submitted to 173 petroleum refining facilities to obtain information on manufacturing and waste management practices and quantities of petroleum refining products manufactured. Of the 173 facilities surveyed, one facility did not respond, one facility is closed, and nine do not generate wastes included in this listings determination. The 162 facilities that generated wastes included in this listings determination are owned/operated by 80 companies. A summary of refineries (by company) affected by this listings determination and their 1992 capacity from the RCRA 3007 Survey is presented in Table 2.1.

TABLE 2.1

List of Refineries Affected by the Listing Determination

Parent Company/Plant Name	Plant State	Crude Capacity (Mb/sd)
AGE REFINING, INC.		
Age Refining, Inc.	TX	5
AMERADA HESS CORPORATION		
Port Reading Refining Facility	NJ	54
Hess Oil Virgin Island Corp.	VI	545
AMOCO CORPORATION		
Amoco Oil Co.- Mandan Refinery	ND	60
Salt Lake City	UT	40
Amoco Yorktown Refinery	VA	56
Amoco Whiting Refinery	IN	440
Texas City Refinery	TX	440
ANCHOR GASOLINE		
Canal Refinery	LA	12
ASHLAND OIL, INC.		
Ashland Petroleum Refinery No.4	OH	66
Ashland Pet. Catlettsburg Refinery	KY	245
St. Paul Park Refinery	MN	67
ASPHALT MATERIALS, INC.		
Laketon Refining Corporation	IN	9.5
Calumet Lubricants Company	LA	6.5
ATLANTIC RICHFIELD COMPANY		
Cherry Point Refinery	WA	190

TABLE 2.1

List of Refineries Affected by the Listing Determination

PARENT COMPANY/PLANT NAME	PLANT STATE	CRUDE CAPACITY (Mb/sd)
Arco Los Angeles Refinery	CA	242
BARRETT REFINING CORPORATION		
Barrett Refining Corp.	OK	10.5
BHP PETROLEUM AMERICAS, INC.		
BHP Petroleum Americas Refining, Inc.	HI	95
BP EXPLORATION & OIL, INC.		
Toledo Refinery	OH	130
Lima Refinery	OH	155
BP Oil Co. Ferndale Refinery	WA	95
Alliance Refinery	LA	228.5
Marcus Hook Refinery	PA	186
CHEMOIL REFINING CORPORATION		
Chemoil	CA	16
CHEVRON CORPORATION		
Pascagoula Refinery	MS	291
Hawaii Refinery	HI	58
El Segundo Refinery	CA	263
Richmond Refinery	CA	240
Richmond Beach Asphalt Refinery	WA	5
Salt Lake Refinery	UT	49
Philadelphia Refinery	PA	180
Chevron El Paso Refinery	TX	194
Willbridge Asphalt Refinery	OR	15

TABLE 2.1

List of Refineries Affected by the Listing Determination

Parent Company/Plant Name	Plant State	Crude Capacity (Mb/sd)
Port Arthur Refinery	TX	194
CITGO PETROLEUM CORPORATION		
Citgo Corpus Christi Refinery	TX	140
CLARK REFINING & MARKETING CORP.		
Clark Refining & Marketing Corp.	IL	70.7
THE COASTAL CORPORATION		
Coastal Eagle Point Oil Refinery	NJ	125
Coastal Refining - Augusta	KS	20.8
Coastal Refining & Marketing - Wichita	KS	27
Coastal Refining & Marketing Inc.	TX	79
COUNTRYMARK COOPERATIVE, INC.		
Countymark Cooperative, Inc.	IN	22.6
CROSS OIL & REFINING CO., INC.		
Cross Oil & Refining Co., Inc.	AR	7
CROWN CENTRAL PETROLEUM CORP		
Crown Central Petroleum Corp	TX	105
La Gloria Oil and Gas Company	TX	60
CRYSEN CORPORATION		
Crysen Refining, Inc	UT	9.5
Sound Refining, Inc	WA	11.1
DIAMOND SHAMROCK, INC.		
Three Rivers Refinery	TX	57
McKee Plants	TX	120

TABLE 2.1

List of Refineries Affected by the Listing Determination

PARENT COMPANY/PLANT NAME	PLANT STATE	CRUDE CAPACITY (Mb/sd)
E.I. DUPONT DE NEMOURS & CO (CONOCO)		
Billings Refinery	MT	52
Lake Charles Refinery	LA	179
Denver Refinery	CO	42.7
Ponca City Refinery	OK	138.1
ERGON, INC.		
Ergon Refining, Inc.	MS	12
EXXON CORPORATION		
Exxon Co USA Billings Refinery	MT	44
Baton Rouge Refinery	LA	438
Exxon Baytown Refinery	TX	418
Benicia Refinery	CA	132
FARMERS UNION CENTRAL EXCHANGE		
Cenex, Laurel Refinery	MT	42.5
FARMLAND INDUSTRIES		
Coffeyville Refinery	KS	62
FINA OIL & CHEMICAL COMPANY		
Port Arthur	TX	134.7
Big Spring	TX	60
FIRST OIL INTERNATIONAL		
Caribbean Petroleum Corp. Inc.	PR	40.4
FLYING J INC.		
Flying J	UT	14

TABLE 2.1

List of Refineries Affected by the Listing Determination

PARENT COMPANY/PLANT NAME	PLANT STATE	CRUDE CAPACITY (Mb/sd)
FRONTIER OIL CORPORATION		
Frontier Cheyenne Refinery	WY	38.9
GARY-WILLIAMS ENERGY CORP.		
Bloomfield Refining Co.	NM	20
GENERAL PARTNER-CASTLE ENERGY CORP.		
Indian Refining Limited Partnership	IL	69
GIANT INDUSTRIES, INC.		
Ciniza Refinery	NM	20.8
GOLD LINE REFINING, LTD.		
Gold Line Refining	LA	11.4
HOLLY CORPORATION		
Artesia Refinery	NM	34
HORSHAM CORPORATION		
Clark Hartford Refinery	IL	61.2
HOWELL CORPORATION		
Howell Hydrocarbons & Chemicals, Inc.	TX	1.9
HUNT CAPITAL CORPORATION		
Tuscaloosa Refinery	AL	44
HUNTWAY PARTNERS, L.P.		
Huntway Refining Company	CA	5.5
Huntway Refining Company	CA	8.4
Sunbelt Refining Company	AZ	8.5
KERR MCGEE REFINING CORPORATION		

TABLE 2.1

List of Refineries Affected by the Listing Determination

PARENT COMPANY/PLANT NAME	PLANT STATE	CRUDE CAPACITY (Mb/sd)
Kerr McGee Wynnewood Refinery	OK	45
Cotton Valley Facility	LA	8.5
Southwestern Refining Company	TX	104
Bakersfield	CA	23
KOCH INDUSTRIES, INC.		
Koch Refining Company	MN	255
Koch Refining Company	TX	135
LION OIL COMPANY		
Lion Oil Refinery	AR	50
LOUISIANA LAND & EXPLORATION, INC.		
LL&E Petroleum - Mobile Refinery	AL	74
LYONDELL-CITGO REFINING CO. LTD		
Lyondell-Citgo Refining Co. Ltd	TX	283
MAPCO PETROLEUM, INC.		
Mapco Alaska Petroleum, Inc., North Pole Refinery	AK	118
Mapco Petroleum, Inc.	TN	78
MOBIL CORPORATION		
Torrance Refinery	CA	135.4
Mobil Paulsboro Refinery	NJ	110.1
Beaumont Refinery	TX	275
Mobil Chalmette Refinery	LA	167
Joliet Refinery	IL	173.7
MURPHY OIL CORPORATION		

TABLE 2.1

List of Refineries Affected by the Listing Determination

Parent Company/Plant Name	Plant State	Crude Capacity (Mb/sd)
Meraux Refinery	LA	100
Superior Refinery	WI	35
NATIONAL COOP. REF. ASSOC.		
McPherson Refinery	KS	80
NAVAJO NORTHERN, INC.		
Montana Refining Company	MT	7.2
PACIFIC REFINING COMPANY		
Pacific Refining Company	CA	52.1
PARAMOUNT PETROLEUM CORPORATION		
Paramount Petroleum Corporation	CA	46.5
PENNZOIL COMPANY		
Atlas Processing Company	LA	41
Pennzoil Products Co., Roosevelt Refinery	UT	8
Rouseville	PA	16.5
PETROLEOS DE VENEZUELA, S.A. (PDVSA)		
Citgo Lake Charles Refinery	LA	320
PETRO SOURCE REFINING PARTNERS		
Eagle Springs	NV	6.1
PHILLIPS PETROLEUM COMPANY		
Sweeny Refinery & Petrochemical Complex	TX	190
Phillips 66 Co., Borger Complex	TX	111
Phillips 66 Co., Woods Cross Refinery	UT	26
Phillips Puerto Rico Corp, Inc.	PR	44.1

TABLE 2.1

List of Refineries Affected by the Listing Determination

Parent Company/Plant Name	Plant State	Crude Capacity (Mb/sd)
PLACID REFINING COMPANY		
Placid Refining Company	LA	48.5
PRIDE COMPANIES, L.P.		
Pride Refining, Inc.	TX	45
QUAKER STATE CORPORATION		
Congo Refinery	WV	12
SAN JOAQUIN REFINING COMPANY		
San Joaquin Refining Company (SJR)	CA	21
SAUDI REFINING, INC. (STAR ENTERPRISE)		
Star Enterprise Delaware City Refinery	DE	152
Port Arthur Plant	TX	246.8
Louisiana Plant	LA	242
SHELL OIL COMPANY		
Deer Park Manufacturing Complex	TX	225
Shell Oil Co., Norco Refinery	LA	215
Odessa Refinery	TX	29.5
Anacortes Refinery	WA	94.2
Wood River Manufacturing Complex	IL	286
Martinez Manufacturing Complex	CA	130
SINCLAIR OIL CORPORATION		
Sinclair, Wyoming Refinery	WY	54
Tulsa Refinery	OK	62
Little America Refining Company	WY	24.5

TABLE 2.1

List of Refineries Affected by the Listing Determination

PARENT COMPANY/PLANT NAME	PLANT STATE	CRUDE CAPACITY (Mb/sd)
SOLOMON, INC (PHIBRO ENERGY USA, INC.)		
Houston Refinery	TX	71
Krotz Springs	LA	70
Texas City Refinery	TX	139.8
SOMERSET OIL, INC.		
The Somerset Refinery, Inc.	KY	5.5
SOUTHLAND OIL CO.		
Southland-Lumberton Refinery	MS	5
Rogerslacy - Sandersville	MS	10
SUN COMPANY, INC.		
Sun Company, Inc.	PA	157.1
Yabucoa Refinery	PR	85
Toledo Refinery	OH	125
Sun Philadelphia Refinery	PA	130
Sun Co., Inc. (R&M) - Tulsa Refinery	OK	90
TENBY, INC.		
Tenby, Inc.	CA	4
TESORO PETROLEUM CORPORATION		
Tesoro Alaska Petroleum Co. - Kenai Refinery	AK	80
TEXACO, INC		
Eldorado Plant	KS	88.3
Texaco Refining and Marketing - Areas 1 and 2	CA	49.5
Los Angeles Plant	CA	95

TABLE 2.1

List of Refineries Affected by the Listing Determination

Parent Company/Plant Name	Plant State	Crude Capacity (Mb/sd)
Texaco Puget Sound Plant	WA	134
TOSCO CORPORATION		
Bayway Refinery	NJ	200
Avon Refinery	CA	160
TOTAL PETROLEUM, INC.		
Ardmore Refinery	OK	70
Alma Refinery	MI	44.8
Colorado Refining Company	CO	28
Arkansas City Refinery	KS	60
TRANSWORLD OIL, USA, INC.		
Calcasieu Refining Co.	LA	13.5
U.S. OIL & REFINING CO		
U.S. Oil & Refining Co.	WA	37
ULTRAMAR CORPORATION		
Wilmington Refinery	CA	71
UNO-VEN COMPANY		
UNO-VEN Refinery	IL	153
UNOCAL		
LA Refinery, Wilmington Plant	CA	65
Santa Maria Refinery	CA	44.4
San Francisco Refinery	CA	77
USX (MARATHON OIL COMPANY)		
Marathon Oil Co., Texas Refining Division	TX	74

TABLE 2.1

List of Refineries Affected by the Listing Determination

PARENT COMPANY/PLANT NAME	PLANT STATE	CRUDE CAPACITY (Mb/sd)
Illinois Refining Division - Robinson Refinery	IL	175
Indiana Refining Division	IN	52
Louisiana Refinery Division (Garyville)	LA	263
Marathon Oil Co., Michigan Refining Division	MI	75.9
VALERO ENERGY CORPORATION		
Valero Refinery Co.	TX	28
WITCO CORPORATION		
Kendall Refining Co.	PA	10
Golden Bear Products	CA	10
WORLD OIL CORPORATION		
Lunday-Thagard	CA	2.3
YOUNG REFINING CORP.		
Young Refining Corp.	GA	2.6

Mb/sd = thousand barrels of crude oil per stream day

2.2.1 Refinery Capacity and Utilization

Refinery capacity is the characteristic most often used to measure petroleum production and output. In recent years, refining capacity has been falling even though product demand has been rising. Trade industry reports indicate that marginally profitable refineries found new environmental compliance requirements prohibitively costly, and capacity was reduced.[8] As demand increases, the need for additional refining capacity will intensify.

Table 2.2 presents refinery capacity and utilization for the period 1984 through 1993. These data indicate that operable capacity has remained relatively constant over the past 10 years, while capacity utilization has been increasing. This suggests that existing refineries are operating closer to full capacity and will have limited opportunity to enhance production by increasing utilization. In 1995, refining capacity is expected to decease slightly to 15.13 millions of barrels per calendar day (MMb/cd) from 15.14 MMb/cd in 1994, which will further increase the utilization rate from 92.6 percent in 1994 to 93.3 percent in 1995.[9]

2.2.2 Large and Small Refineries

The Small Business Administration defines petroleum companies with crude capacity less than or equal to 75,000 barrels per calendar day (b/cd) as a small entity. Capacity data reported in barrels per stream day (b/sd) was converted to barrels per calendar day (b/cd) using the conversion factor 0.95, for the purpose of determining small entities. Based on this cutoff, 45 of the 80 companies affected by this listings determination, or 56 percent, are considered small entities. Table 2.3 presents a listing of companies with reported capacity less than or equal to 75,000 b/cd (or 78,947 b/sd).[10]

2.2.3 Refinery Complexity

Complexity is a measure of the different processes used in refineries. More complex refineries have process units such as cracking, alkylation, reforming, isomerization, hydrotreating and lubricant processing, which produce a wide range of products including gasolines, low-sulfur fuel oils, lubricants, petrochemicals, and petrochemical feedstocks. The level of complexity generally correlates to the types of products the refinery is capable of producing. Higher complexity denotes a greater ability to enhance or diversify product output, to improve yields of preferred products, and to process lower quality crude oil. In theory, more complex refineries are more adaptable to change and are therefore potentially less affected by regulation relative to less complex facilities.

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[8] Robert J. Beck, "Economic Growth, Low Prices to Lift U.S. Oil And Gas Demand In 1995," Oil & Gas Journal, Vol.93, No.5, January 30, 1995, pp.51-68.

[9] ibid.

[10] Capacity data obtained from the 1992 RCRA 3007 Survey.

TABLE 2.2

Refinery Capacity and Utilization, 1984-1993[11]

Year	Number of Refineries	Capacity (MMb/cd)	Gross Input to Distillation Units (MMb/cd)	Utilization (percent)
1984	247	16.14	12.22	76.2
1985	223	15.66	12.17	77.6
1986	216	15.46	12.83	82.9
1987	219	15.57	13.00	83.1
1988	213	15.92	13.45	84.7
1989	204	15.65	13.65	86.6
1990	205	15.57	13.61	87.1
1991	202	15.68	13.51	88.0
1992	199	15.70	13.60	87.9
1993	187	15.12	13.86	91.4

Notes:

MMb/cd = Million barrels of crude oil per calendar day

Utilization is derived by averaging reported monthly utilization.

[11] U.S. Department of Energy, Energy Information Administration, Annual Energy Review 1993, Table 5.9 Refinery Capacity and Utilization, 1949-1993.

TABLE 2.3

List of Small Entities

Parent Company	Number of Refineries	Total Crude Capacity (Mb/sd)
Age Refining, Inc.	1	5.0
Anchor Gasoline	1	12.0
Asphalt Materials, Inc.	2	16.0
Barrett Refining Corp.	2	10.5
Chemoil	1	16.0
Clark Refining & Marketing Corp.	1	70.7
Countrymark Cooperative, Inc.	1	22.6
Cross Oil & Refining Co., Inc.	1	7.0
Crysen Corporation	1	20.6
Ergon, Inc.	1	12.0
Farmers Union Central Exchange	1	42.5
Farmland Industries	1	62.0
First Oil International	1	40.4
Flying J Inc.	1	14.0
Frontier Oil Corporation	1	38.9
Gary-Williams Energy Corp.	1	20.0
General Partner-Castle Energy Corp.	1	69.0
Giant Industries, Inc.	1	20.8
Gold Line Refining, Ltd.	1	11.4
Holly Corporation	1	34.0
Horsham Corporation	1	61.2
Howell Corporation	1	1.9
Hunt Capital Corporation	1	44.0

TABLE 2.3

List of Small Entities

Parent Company	Number of Refineries	Total Crude Capacity (Mb/sd)
Huntway Partners, L.P.	3	22.4
Lion Oil Company	1	50.0
Louisiana Land & Exploration, Inc.	1	74.0
Navajo Northern, Inc.	1	7.2
Pacific Refining Company	1	52.1
Paramount Petroleum Corporation	1	46.5
Pennzoil Company	3	65.5
Petro Source Refining Partners	1	6.1
Placid Refining Company	1	48.5
Pride Companies, L.P.	1	45.0
Quaker State Corporation	1	12.0
San Joaquin Refining Company	1	21.0
Somerset Oil, Inc.	1	5.5
Southland Oil Co.	2	15.0
Tenby, Inc.	1	4.0
Transworld Oil, USA, Inc.	1	13.5
U.S. Oil and Refining Co.	1	37.0
Ultramar Corporation	1	71.0
Valero Energy Corporation	1	28.0
Witco Corporation	2	20.0
World Oil Corporation	1	2.3
Young Refining Corp.	1	2.6

Mb/sd = thousand barrels of crude oil per stream day

2.3 Market Structure

This section describes the petroleum market and industry concentration. Data are presented on the largest petroleum refining companies and their market share.

The U.S. petroleum product supply, demand and logistics system is a complex set of facilities that supply petroleum products to meet regional demands. The markets for refined petroleum products vary by geographic location. Regional markets may differ due to the quality of crude supplied or the local product demand. Some smaller refineries that produce only one product have single, local markets, while larger, more complex refineries have extensive distribution systems and sell their output in several different regional markets.

In addition to differences in regional markets, each of the ten product categories in this analysis possesses its own individual market segment, satisfying demand among different end-use sectors. Each of the ten products, in and of themselves, are homogenous by nature. As a result, product differentiation does not play a major role in the competitiveness among refineries. However, if for example, the production of one refined product were to become less costly after regulation, production of this product may increase at the expense of a product with a more costly refining process.

2.3.1 Market Concentration

Market concentration is a measure of the output of the largest firms in the industry, expressed as a percentage of total national output. A market concentration of 100 percent would indicate monopoly control of the industry by one firm. Conversely, a concentration of one percent would indicate the industry was comprised of numerous small firms.

Table 2.4 shows U.S. refining companies with more than 200,000 b/cd crude capacity as of December 1994. Historically, the top four refining companies have comprised over 30 percent of the market share; however, market concentration ratios have been declining in recent years. Based on reported total U.S. crude capacity of 15.3 MMb/cd for 1994, the top four companies comprise 26 percent of the market share. Chevron Corporation remains the largest U.S. refiner with 1.02 MMb/cd crude capacity, followed by Amoco Oil Co. and Exxon Co. USA with 0.998 MMb/cd and 0.992 MMb/cd crude capacity, respectively. Shell Oil Co. represents the fourth largest refiner with 0.964 MMb/cd crude capacity.

TABLE 2.4

Companies With 200,000 b/cd or Greater of Crude Capacity[12]

Rank	Company	Number of Refineries	Crude Capacity (Mb/cd)
1	Chevron Corporation	9	1,021
2	Amoco Corporation	5	998
3	Exxon Corporation	4	992
4	Shell Oil Company	6	964
5	Mobil Corporation	5	900
6	BP Exploration & Oil, Inc.	4	705
7	Sun Company, Inc.	5	687
8	Saudi Refining, Inc. (Star Enterprise)	3	600
9	USX (Marathon Oil Company)	5	579
10	Citgo Petroleum Corporation	4	545
11	Atlantic Richfield Company	4	450
12	Tosco Corporation	3	437
13	E.I. DuPont De Nemours & Co. (Conoco)	4	435
14	Koch Industries, Inc.	2	420
15	Texaco, Inc.	4	393
16	Ashland Oil, Inc.	3	347
17	Phillips Petroleum Company	3	311
18	Clark Refining & Marketing Corp.	3	309
19	Solomon, Inc. (Phibro Energy USA, Inc.)	4	283
20	Lyondell-Citgo Refining Co. Ltd.	1	265
21	The Coastal Corporation	3	235
22	Unocal	2	222
23	Mapco Petroleum, Inc.	2	220
24	Fina Oil & Chemical Company	2	220
	Total	90	12,536

Mb/cd = thousand barrels of crude oil per calendar day.

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12 Anne K. Rhodes, "World Crude Capacity, Conversion Capability Inch Upward," Oil & Gas Journal, Vol.92, No.51, December 19, 1994, pp.45-52.

U.S. refineries number 173, with a total reported crude capacity of 15,319 Mb/cd as of January 1, 1995.[13] In the past year, the number of companies with crude capacity of 200,000 b/cd or greater increased from 22 to 24 and the number of refineries increased from 87 to 90. These 90 refineries have a total crude capacity of 12.5 MMb/cd, representing 82 percent of the total domestic crude capacity. The number of companies with a crude capacity of less than 200,000 b/cd decreased from 84 to 71 in the past year. The number of refineries associated with these companies also declined from 91 to 83. These 83 refineries have a total crude capacity of 2.78 MMb/cd, representing 18 percent of the total domestic crude capacity.

2.3.2 Industry Concentration

Vertical integration exists when the same firm supplies input for several stages of the production and marketing process. Firms that are responsible for the exploration and production of crude oil as well as for marketing the finished petroleum products are vertically integrated. Within the petroleum refining industry, firms are classified as major or independent. Generally, major firms are vertically integrated.

The Department of Energy (DOE) defines major refiners as "companies with a total refinery capacity in the U.S. and its possessions of greater than or equal to 275,000 barrels per day as of January 1, 1982".[14] DOE's current list of major refiners are presented in Table 2.5. The crude capacity of the major, vertically integrated firms represents approximately 69 percent of total domestic crude capacity.

Horizontal integration refers to the operation of multiple refineries. As shown in Table 2.4, the major oil companies operate several refineries, which are often distributed around the country. Chevron operates nine domestic refineries, the largest number of refineries operated by a major oil company. Together, the major refiners operate 74 of the 173 operating refineries, representing 43 percent of the total number of refineries.

2.4 Market Supply Characteristics

This section summarizes the factors affecting the supply side of the petroleum refining industry. Historical production data are presented as well as discussions regarding supply determinates and the role of exports.

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[13] ibid.

[14] U.S. Department of Energy, Energy Information Administration, Petroleum Marketing Annual 1993, DOE/EIA-0487(93).

TABLE 2.5

Major Refineries and Crude Capacity[15]

Major Refiners	Crude Capacity (Mb/cd)	Percent of Domestic Crude Capacity (%)
Amerada Hess Corporation[1]	--	--
Amoco Corporation	998	6.51
Ashland Oil, Inc.	347	2.26
Atlantic Richfield Company	450	2.94
BP Exploration & Oil, Inc.	705	4.60
Champlin Refinery[2]	na	na
Chevron Corporation	1,021	6.67
Citgo Petroleum Corporation	545	3.55
Conoco	435	2.84
Exxon Corporation	992	6.48
Lyondell-Citgo Refining Co.	265	1.73
Marathon Oil Company	579	3.78
Mobil Corporation	900	5.88
Phillips Petroleum Company	311	2.03
Shell Oil Company	964	6.29
Southland Oil Company	17	0.11
Star Enterprise	600	3.92
Sun Company, Inc.	687	4.48
Texaco, Inc.	393	2.57
Unocal	222	1.45
Uno-Ven Company	145	0.95
Total	10,575	69.04

Mb/cd = thousand barrels of crude oil per calendar day
[1] refinery shutdown 1/1/94
[2] data not available

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[15] Anne K. Rhodes, "World Crude Capacity, Conversion Capability Inch Upward," Oil & Gas Journal, Vol.92, No.51, December 19, 1994, p.48.

2.4.1 Past and Present Production

Table 2.6 presents data on the domestic supply of petroleum products over the past 14 years. Domestic refinery production decreased in the early 1980s followed by a period of steady increase from 1984 through 1989. Production decreased in the first two years of the 1990s, as a result of warmer winter temperatures, economic slowdown, and higher prices resulting from the Gulf War and has been increasing since 1992, as a result of a growing economy.

All major petroleum products showed a net increase in supply over the past 14 years, with the exception of residual fuel. This decrease in residual fuel demand reflects a move in the industry away from heavier fuels toward lighter, more refined ones. This trend is expected to continue as a result of increasing efforts to reduce air emissions. Motor gasoline represents the largest component of total petroleum product supplied, representing 43 percent of total petroleum product supplied in 1993. Supply of motor gasoline has increased steadily since 1980, peaking at 7.48 MMb/d in 1993. Distillate fuel, the second largest component of total petroleum product supplied, historically has represented approximately 17 to 18 percent of total petroleum product supplied, peaking at 3.16 MMb/d in 1989. Supply of jet fuel peaked in 1990, at 1.52 MMb/d, representing an increase of 50 percent from product supplied levels in the early 1980s.

2.4.2 Supply Determinations

As previously discussed, the complexity of a refinery determines the product slate the refinery is capable of producing. The decision as to how much crude oil to allocate to the production of each product is for the most part a function of the marginal cost of producing each product. The price of crude oil, the primary input to the refining process, and the profit margin associated with alternative refined product drive the decision regarding product slate.

2.4.3 Exports of Petroleum Products

Table 2.7 presents export levels and domestic refinery output for the past decade. Exports as a percentage of domestic refinery output steadily increased from 1984 to 1991, fell slightly in 1992 and increased to approximately 5.8 percent in 1993. Petroleum coke and distillate and residual fuels oils are exported in the highest volumes, averaging 75 percent of total refined product exports over the past 10 years. Although exports as a percentage of domestic refinery output have, for the most part, increased over time, they represent a small fraction of total domestic output.

TABLE 2.6

Petroleum Products Supplied to the U.S. Market by Type[16]
(millions of barrels per day)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel	Residual Fuel	LPGs	Other	Total
1980	6.58	1.07	2.87	2.51	1.47	2.57	17.07
1981	6.59	1.01	2.83	2.09	1.47	2.08	16.07
1982	6.54	1.01	2.67	1.72	1.50	1.86	15.30
1983	6.62	1.05	2.69	1.42	1.51	1.94	15.23
1984	6.69	1.18	2.85	1.37	1.57	2.07	15.73
1985	6.83	1.22	2.87	1.20	1.60	1.95	15.73
1986	7.03	1.31	2.91	1.41	1.51	2.05	16.28
1987	7.21	1.39	2.98	1.26	1.61	2.19	16.67
1988	7.34	1.45	3.12	1.38	1.66	2.30	17.28
1989	7.33	1.49	3.16	1.37	1.67	2.29	17.33
1990	7.24	1.52	3.02	1.23	1.56	2.40	16.99
1991	7.19	1.47	2.92	1.16	1.69	2.27	16.71
1992	7.27	1.45	2.98	1.09	1.76	2.47	17.03
1993	7.48	1.47	3.04	1.08	1.73	2.43	17.24

16 U.S. Department of Energy, Energy Information Administration, Petroleum Supply Annual 1993, DOE/EIA-0340(93)/1, Tables S4-S10.

TABLE 2.7

Exports and Domestic Refinery Production[17]
(millions of barrels per day)

Year	Exports	Domestic Refinery Production	Exports as a Percentage of Production (%)
1984	0.54	13.68	4.0
1985	0.58	13.75	4.2
1986	0.63	14.52	4.3
1987	0.61	14.63	4.2
1988	0.66	15.02	4.4
1989	0.72	15.17	4.7
1990	0.75	15.26	4.9
1991	0.89	15.20	5.9
1992	0.86	15.30	5.6
1993	0.90	15.50	5.8

[17] U.S. Department of Energy, Energy Information Administration, Petroleum Supply Annual 1993, DOE/EIA-0340(93)/1, Tables S1-2, and S4-S10.

2.5 Market Demand Characteristics

This section summarizes the characteristics of the demand side of the petroleum refining industry. Information is presented on past and present consumption and the effect price and exports have on domestic demand.

2.5.1 Demand Determinants

The demand for refined petroleum products is a function of economic growth, price, and the price of competing substitutes. Demand for petroleum products generally tracts the growth or decline of the economy. The degree to which price influences quantity demanded is referred to as price elasticity of demand, which is a measure of the sensitivity of buyers of a product to a change in the price of the product. Further discussion of price elasticity is presented in Section 4.3.

In some markets, economic growth is the more important factor affecting demand, whereas price is salient in others. For example, the demand for jet fuel is a function of the overall health of the airline industry, as well as price. In contrast, the demand for distillate fuel, for residential heating, is less influenced by economic growth. Price, as well as climate and mean temperature are the primary determinants of distillate fuel demand. Whereas climate and temperature are exogenous factors, which will determine heating needs regardless of price, high prices affect use of substitute fuels, conservation measures (e.g., adjusting thermostats), and other energy-efficient behaviors (e.g., purchase of energy-efficient appliances). Significantly higher prices for heating fuel in relation to substitute fuels create incentives for consumers to switch from oil to natural gas or electric heat.

In the industrial sector, fuel oil competes with natural gas and coal for the boiler-feed market. High prices relative to other fuels will encourage fuel-switching, especially at electric utilities and in industrial plants having dual-fired boilers. In the early 1980s, most new boilers in the utility sector were coal-fired. Today, oil is becoming more competitive as environmental regulations require the use of low-sulfur fuels and reduced air emissions.

2.5.2 Past and Present Consumption

Table 2.8 presents petroleum product supplied (i.e., consumption) by product type for the U.S. market.[18] Consumption of all types of petroleum products has primarily increased over the past ten years, with the exception of residual fuel, which has decreased approximately 21 percent since 1984. Since 1984, the largest percentage increase in consumption,

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[18] DOE uses the term "product supplied" as a proxy for consumption. It is calculated by adding refinery production, natural gas liquids production, supply of other liquids, imports, and stock withdrawals, and subtracting stock additions, refinery inputs, and exports.

TABLE 2.8

Petroleum Products Supplied to the U.S. Market by Type[19]
(millions of barrels per day)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel	Residual Fuel	LPGs	Other	Total
1984	6.69	1.18	2.85	1.37	1.57	2.07	15.73
1985	6.83	1.22	2.87	1.20	1.60	1.95	15.73
1986	7.03	1.31	2.91	1.41	1.51	2.05	16.28
1987	7.21	1.39	2.98	1.26	1.61	2.19	16.67
1988	7:34	1.45	3.12	1.38	1.66	2.30	17.28
1989	7.33	1.49	3.16	1.37	1.67	2.29	17.33
1990	7.24	1.52	3.02	1.23	1.56	2.40	16.99
1991	7.19	1.47	2.92	1.16	1.69	2.27	16.71
1992	7.27	1.45	2.98	1.09	1.76	2.47	17.03
1993	7.48	1.47	3.04	1.08	1.73	2.43	17.24

[19] U.S. Department of Energy, Energy Information Administration, Petroleum Supply Annual 1993, DOE/EIA-0340(93)/1, Tables S4-S10.

24.5 percent, is associated with jet fuel, followed by "other"[20] and motor gasoline for a percentage increase of 17 and 12 percent, respectively. Residual fuel represents the only fuel to show a decline in use and is expected to continue in the future as a result of increasing air emissions regulations.

All major petroleum products showed lower demand in 1991 and 1992 in comparison to 1990 levels, with the exception of LPGs. Total consumption increased in 1993 for all fuels in comparison to 1990 levels, with the exception of jet and residual fuels.

Over the past 10 years, demand for motor gasoline increased from 6.69 MMb/d in 1984 to a high of 7.48 MMb/d in 1993. In 1993, motor gasoline consumption represented approximately 43 percent of total product supplied, followed by jet fuel, representing 18 percent of total consumption. Demand for jet fuel increased from 1.18 MMb/d in 1984 to a high of 1.52 MMb/d in 1990. Changes in demand for distillate fuel oil are similar, whereby consumption increased from 2.85 MMb/d in 1984 to a high of 3.16 MMb/d in 1989. Currently, distillate fuel oil represents approximately 6.7 percent of total product supplied. Residual fuel demand, in response to lower-priced natural gas and air emissions concerns, decreased from a high of 1.41 MMb/d in 1986 to a low of 1.08 MMb/d in 1993. As evidenced by these data, consumption of all petroleum products primarily increased over the past 10 years, with the exception of residual fuel.

Overall, changes in consumption of petroleum products are attributed to dramatic price increases and supply disruptions as a result of political upheaval and wars. Variation among fuels is more related to changes in the price of petroleum products relative to other fuels, as well as other energy sources.

2.5.3 Product Pricing

Table 2.9 presents average prices of petroleum products to end users. Prices for petroleum products have shown volatility over the past two decades, with large increases in the early 1980s followed by substantial declines by the end of the decade. Prices increased slightly in 1990 and have continued to decline to the present. The volatility of prices for petroleum products is primarily due to fluctuations in the global market for crude oil and the inelastic demand for petroleum products. Inelastic demand allows refiners to pass crude oil price increases on to consumers due to the homogeneity of products and limited ability to switch easily to alternative fuels.

2.5.4 Imports of Refined Petroleum Products

Imports of refined petroleum products ranged from a high of 2.30 MMb/d in 1988 to a low

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[20] Other petroleum products include pentanes plus other hydrocarbons and oxygenates, unfinished oils, gasoline blending components and all finished petroleum products except finished motor gasoline, distillate fuel oil, residual fuel oil, jet fuel, and liquefied petroleum gases.

TABLE 2.9

Prices of Petroleum Products to End Users[21]
(cents per gallon, excluding taxes)

Petroleum Product	Average Price in 1978	Average Price in 1993	Highest Average Price Between Years of 1978 to 1993
Motor Gasoline	48.4	75.9	114.7 (1981)
Aviation Gasoline	51.6	99.0	131.2 (1982)
Kerosene-Type Jet Fuel	38.7	57.9	102.4 (1981)
Propane (Consumer Grade)	33.5	67.4	74.5 (1986, 1990)
Kerosene	42.1	75.5	112.3 (1981)
No. 1 Distillate	41.0	66.5	103.9 (1981)
No. 2 Distillate			
No. 2 Diesel Fuel	37.7	60.2	99.5 (1981)
No. 2 Fuel Oil	40.0	60.2	91.4 (1981)
Average	39.6	60.2	95.8 (1981)
No. 4 Fuel Oil/Diesel Fuel	31.1	50.2	79.7 (1981)
Residual Fuel Oil	29.8	33.7	75.6 (1981)

21 U.S. Department of Energy, Energy Information Administration, Petroleum Marketing Annual 1993, DOE/EIA-0487(93), Table 2.

of 1.80 MMb/d in 1992 over the past ten years. Table 2-10 presents import levels of refir. petroleum products and domestic consumption over the past decade. Imports as a percent of domestic consumption reached a high of 13.3 percent in 1988 and have declined, for the most part, thereafter. Imports as a percent of domestic consumption for 1993 are roughly the same as in 1982.

2.6 Industry Trends and Market Outlook

This section presents an overview of selected environmental regulations affecting the petroleum refining industry and the supply and demand outlook in the near future.

2.6.1 Environmental Regulations

Passage of the Clean Air Act Amendments of 1990 prompted U.S. refiners to install new processes and equipment to comply with stricter specifications for gasoline and diesel fuel. Investment in "clean fuels" projects are mandatory in order for many refineries to stay in business, but do little to increase capacity or provide return on investment. Trade journal reports indicate that the cost of compliance led to some facility shutdown of plants too economically marginal to support the debt required for modernization.[22] Refiners' costs are estimated to increase 2-3 cents/gallon for reformulated gasoline and 12-17 cents/gallon for gasoline meeting California Air Resources Board specifications.

The impact of environmental regulations vary based on a refinery's location, complexity, market position, and corporate structure (i.e., major or independent). As a result, refiners in rural areas, with less stringent regulation, may not need to secure as much capital as refiners in congested or highly regulated areas. Obtaining capital for refinery upgrades generally is harder for independents than for majors. Refinery shutdowns are based less on size than on marketing position. Highly competitive markets where refinery margins are weak, and regulations stringent, will tend to experience greater economic impacts and facility closures. Refineries that can process a wide variety of crude oils will have an advantage in that they have greater flexibility in modifying their product slate in an effort to reduce the impact of environmental regulations.

2.6.2 Demand Outlook

Economic improvement in the past several years led to marginal increases in energy and petroleum consumption in 1992 and more significant increases in 1993 and 1994. Demand for petroleum products is expected to increase further in 1995.

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[22] Ralph Ragsdale, Bechtel Corporation, "U.S. Refiners Choosing Variety of Routes to Produce Clean Fuels," Oil and Gas Journal, March 21, 1993, Vol.92, No.12, pp.52-58.

TABLE 2.10

Imports and Domestic Consumption of Refined Petroleum Products[23]
(millions of barrels per day)

Year	Imports	Domestic Consumption	Imports as a Percent of Consumption (%)
1984	2.01	15.73	12.8
1985	1.87	15.73	11.9
1986	2.05	16.28	12.6
1987	2.00	16.67	12.0
1988	2.30	17.28	13.3
1989	2.22	17.33	12.8
1990	2.12	16.99	12.5
1991	1.84	16.71	12.8
1992	1.81	17.03	11.0
1993	1.83	17.24	10.6

[23] U.S. Department of Energy, Energy Information Administration, Petroleum Supply Annual 1993, DOE/EIA-0340(93)/1, Table S1.

The clean fuels requirements of the Clean Air Act Amendments created increased demand for oxygenated fuels. The reformulated gasoline program is mandatory in areas noncompliant with atmospheric ozone or carbon monoxide limits. Although regions not classified as "noncompliant" can opt out of the reformulated program, some states are taking the initiative to join the program creating increased demand for oxygenated fuels.[24]

2.6.3 Supply Outlook (Production and Capacity)

Economic growth and low prices are expected to increase oil demand in the next year. Despite modest improvement in oil prices, trade journal reports predict a decline in U.S. crude oil output of 2.4 percent for 1995, following a decline of 3 percent in 1994.[25] U.S. production has been falling since 1985, except for a modest increase in 1991, when prices rose in the wake of Iraq's invasion of Kuwait. U.S. crude oil production has been falling at an average rate of 260,000 barrels per day since 1985. Falling U.S. production and rising demand mean increased petroleum imports again in 1995. Trade journals report that there are potential problems in U.S. product supply because refining capacity is being stretched as product demand moves up and capacity expansion remains limited by environmental regulations and costs.[26] Increased production costs as a result of environmental regulation could further reduce U.S. output and increase imports of petroleum products from abroad.

In recent years, refining capacity has been falling even though product demand has been rising. Trade journal reports indicate that marginally profitable refineries found the new environmental compliance requirements prohibitively costly and capacity was reduced due to plant modifications.[27] A major issue in the near future will be the need for additional refining capacity to meet rising demand. In 1994, U.S. refiners processed more crude domestically but also boosted product imports. When the required domestic refining capacity is not available, then product imports are used to fill the gap. If additional environmental regulations result in the shutdown of more facilities, the import of petroleum products may increase further.

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[24] Ralph Ragsdale, Bechtel Corporation, "U.S. Refiners Choosing Variety of Routes to Produce Clean Fuels," Oil and Gas Journal, March 21, 1993, Vol.92, No.12, pp.52-58.

[25] Robert J. Beck, "Economic Growth, Low Prices To Lift U.S. Oil And Gas Demand In 1995," Oil & Gas Journal, January 30, 1995, Vol.93, No.5, pp.51-68.

[26] ibid.

[27] ibid.

3.0 COST IMPACT ANALYSIS

A total of four wastes generated during petroleum refining are being listing as hazardous under RCRA. This chapter examines the four wastes, the quantity of each generated, their current management practices, compliance management practices available after listing, the unit costs and prices of managing these wastes, and the total incremental compliance costs. Information on quantities of waste generated, waste management costs, and current management practices are based on the 1992 RCRA 3007 Survey of the Petroleum Refining Industry. The 162 facilities affected by the listings determination (i.e., facilities that manage these four listed wastes in non-exempt waste management units) are owned and operated by 80 companies.

3.1 Hazardous Wastes[1]

The newly listed wastes generated in the petroleum refining industry are as follows:

- K169 - Crude oil storage tank sludge;
- K170 - Clarified slurry oil sludge from catalytic cracking;
- K171 - Catalyst from catalytic hydrotreating; and
- K172 - Catalyst from catalytic hydrorefining.

Figure 3.1 illustrates the points of origin for the newly listed wastes associated with the petroleum refining industry. This is an illustrative facility diagram and does not necessarily represent a specific plant. These wastes and selected characteristics for each are described below.

1. <u>K169 - Crude oil storage tank sludge</u>

Nearly all refineries store feedstock materials and products in tanks. Every 10 to 20 years crude oil storage tanks require sludge removal due to maintenance, inspection, or sludge buildup. Crude oil tank sludge consists of heavy hydrocarbons, basic sediment and water, and entrapped oil that settles to the bottom of the tank. When removed, the oil is recovered while the solids are collected and discarded as a waste (see K169, Figure 3.1).

2. <u>K170 - Clarified slurry oil sludge from catalytic cracking</u>

Nearly all refineries store feedstock materials and products in tanks. Every 5 to 10 years clarified slurry oil tanks require sludge removal due to maintenance, inspection, or sludge buildup. Clarified slurry oil is the lowest boiling fraction from the catalytic cracking main fractionator. It contains some catalyst and catalyst fines. Clarified slurry oil sludges are not

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[1] Process information in this section is taken from "OSW Listing Determination for the Petroleum Refining Industry - Waste Characterization Part III", Science Applications International Corporation, September 15, 1994.

limited to "tank sludges." For this residual, sludges are generated from tank storage and, more rarely, filtration prior to tank storage (see K170, Figure 3.1 and Figure 3.2).

3. <u>K171 - Catalyst from catalytic hydrotreating</u>

Catalytic hydrotreating removes sulfur by converting mercaptans to H_2S, which is fractionated. The catalyst is typically cobalt or nickel and molybdenum on alumina. Catalyst lifetime is approximately 1 to 5 years, after which the catalyst is replaced (see K171, Figure 3.1 and Figure 3.3). Catalyst "activity" losses occur because of poisons from the crude, coke deposits, and structural breakdown from severe operating conditions.

4. <u>K172 - Catalyst from catalytic hydrorefining</u>

Catalytic hydrorefining removes sulfur by converting mercaptans to H_2S, which is fractionated. The catalyst is typically cobalt or nickel and molybdenum on alumina. Catalyst lifetime is approximately 1 to 5 years, after which the catalyst is replaced (see K172, Figure 3.1 and Figure 3.3). Catalyst "activity" losses occur because of poisons from the crude, coke deposits, and structural breakdown from severe operating conditions.

FIGURE 3.1

Typical Petroleum Refining Process Flow Diagram

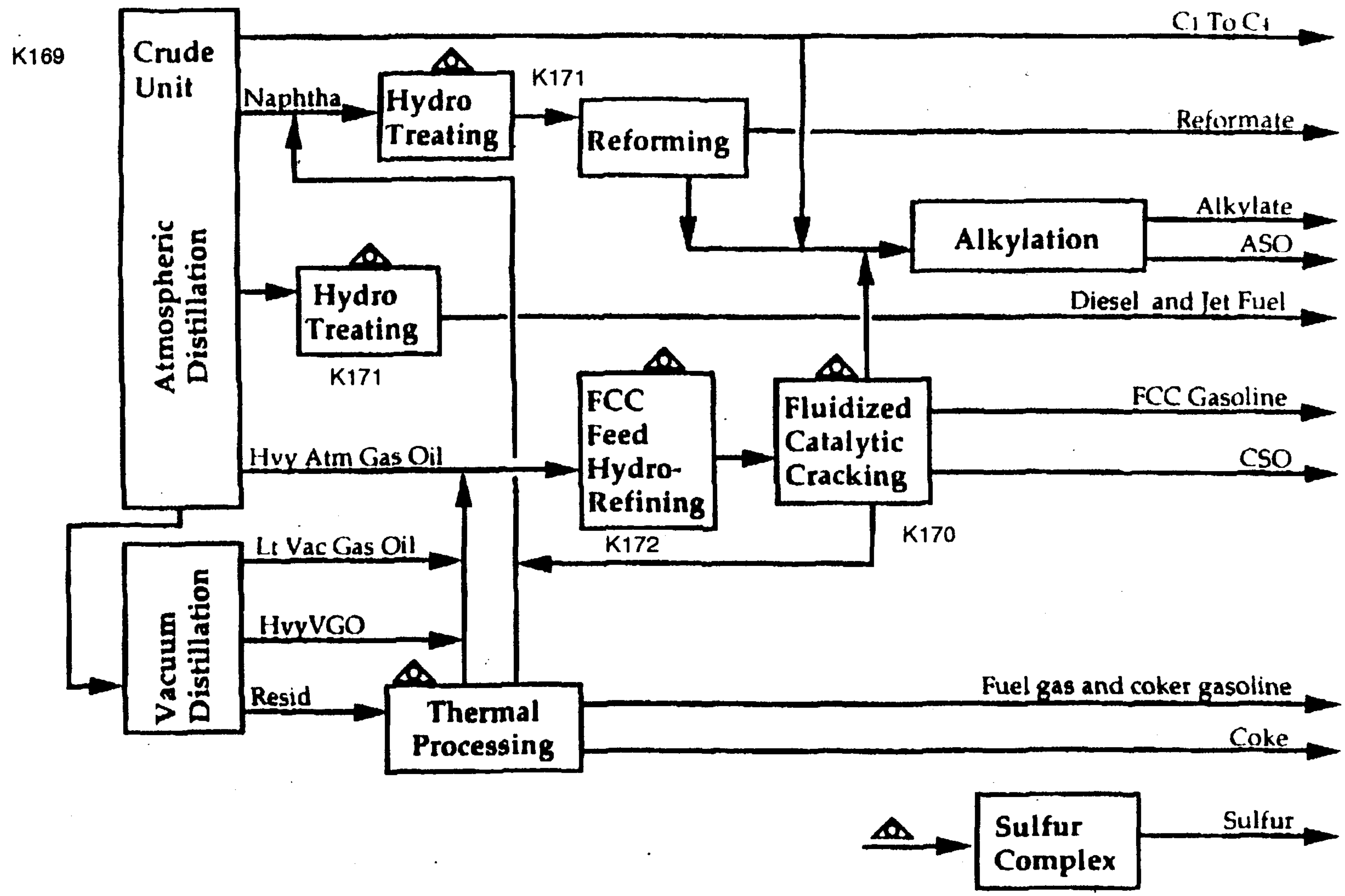


FIGURE 3.2

Fluid Catalytic Cracking

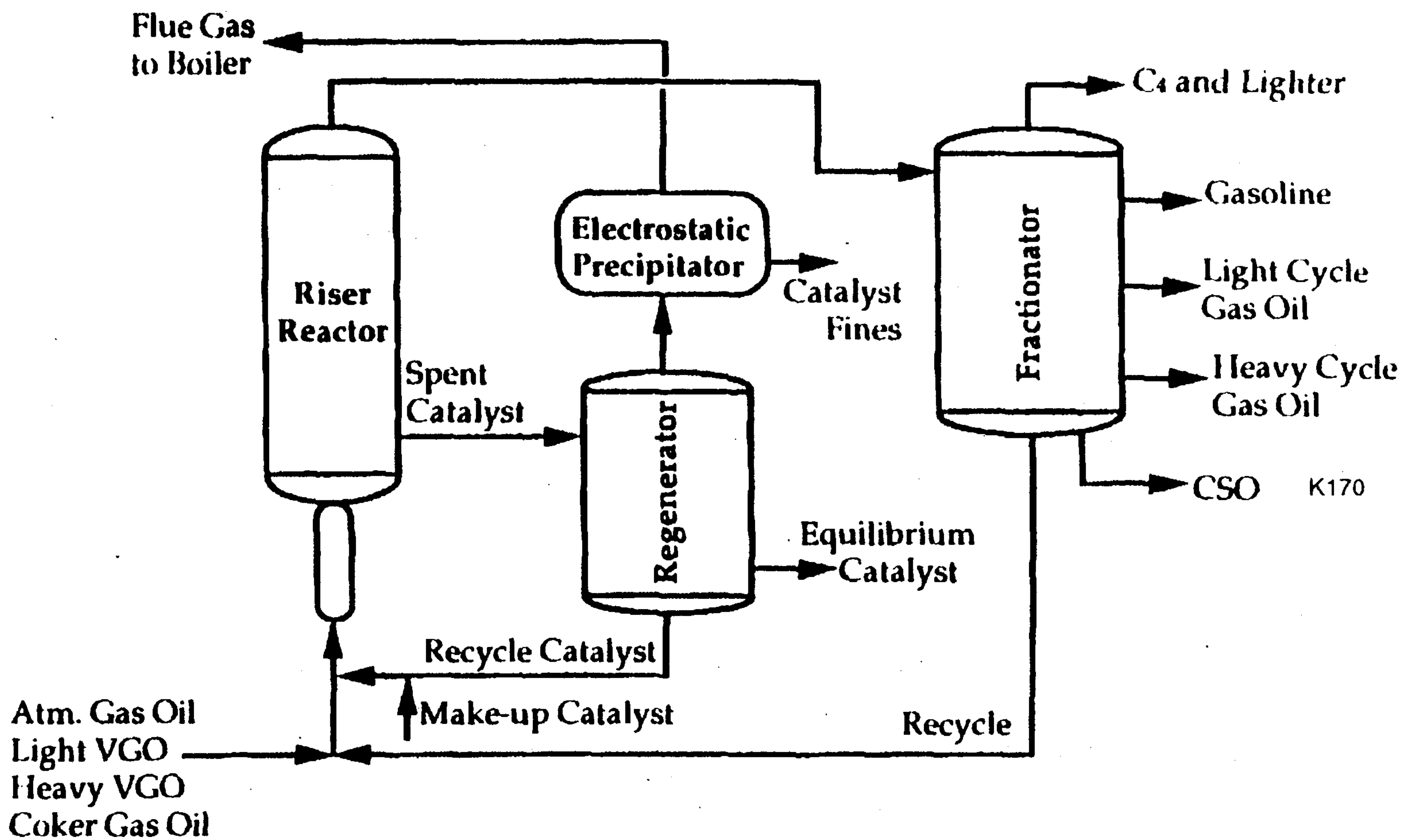
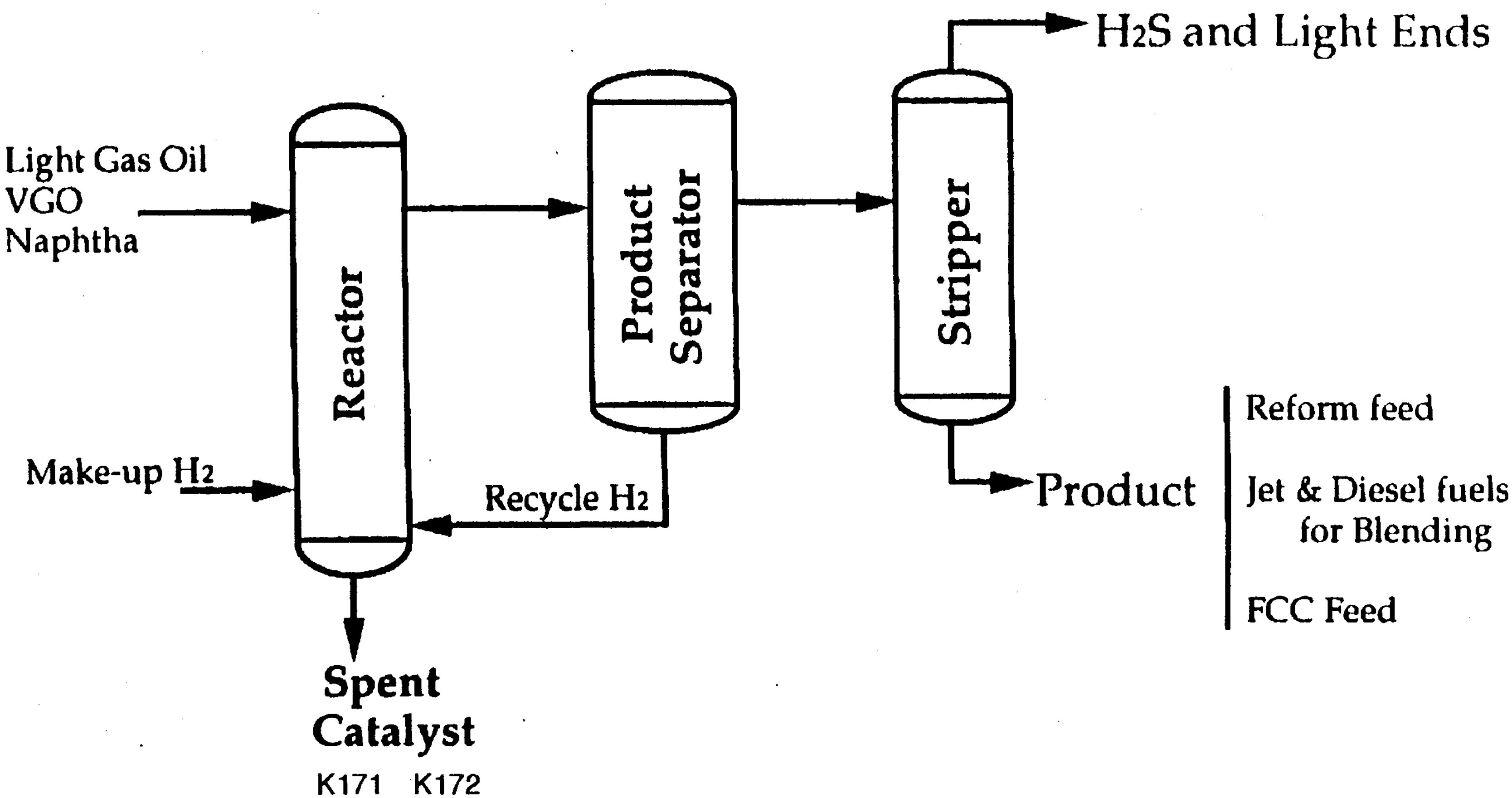


FIGURE 3.3

Hydrotreating/Hydrorefining



3.2 Annual Hazardous Waste Quantities

Annual hazardous waste quantities were developed on a plant specific level for each newly listed waste. This section describes the development of the annual hazardous waste quantities considered in the analysis.

3.2.1 Methodology

The methodology for developing annual hazardous waste questions is divided into three parts. The first part presents the methodology for estimating annual generation quantities for facilities reporting generating wastes in the 1992 RCRA 3007 Survey. The second part presents the methodology for predicting annual generation quantities for facilities which did not report generating wastes in the Survey. The third part discusses how contaminated soil and debris quantities were addressed.

Reporting Facilities

Most of the wastes reported by facilities through the 1992 RCRA 3007 Survey were generated less than once per year. In order to evaluate the cost and economic impact of this listing on each facility, wastes generated less than once per year were annualized. For example, if a facility had five storage tanks which were cleaned once every ten years, EPA assumed that one tank would be cleaned at an even-year interval rather than several tanks in the same year. To obtain a yearly average cost of cleaning these tanks which can be applied to the economic analysis for the year 1992, the quantity of waste generated in the cleaning of each of the five tanks was divided by the generation frequency of ten years. The final quantity of this waste used in the analysis is the sum of the annualized generation quantities for the five tanks. For those wastes with reported quantities and generation frequencies, EPA used this procedure to annualize the quantities.

If the generation frequency of a waste was not reported, EPA assumed the frequency to be the same as that of similar wastes generated at the facility. When this assumption was not possible, EPA assumed the average generation frequency of all facilities reporting that waste. The average generation frequency for each waste stream is as follows:

Average Waste Stream Generation Frequency

Waste Stream	Average Generation Frequency (years)
K169	10.5
K170	9
K171	3.5
K172	2.5

The RCRA 3007 Survey only required the reporting of crude oil and CSO tank sludge quantities that were generated during a two-year period (1991 and 1992). The catalyst residuals were not limited to this two-year reporting period. Because of the two-year reporting period, tank sludge quantities needed to be estimated for tanks which were not cleaned out during this period. The RCRA 3007 Survey captured cleanout quantities from approximately 21 percent of the existing crude oil tanks and 56 percent of the existing CSO tanks.

As noted above, on average crude oil tanks are cleaned out once every 10.5 years and CSO tanks are cleaned out once every 9 years. Also, on average there are approximately 8 crude oil tanks per refinery and 3.4 CSO tanks per refinery. Based on the average number of tanks per facility and the clean-out frequency, crude oil sludge is generated every 1.3 years at a facility and CSO sludge is generated every 2.6 years.

For facilities reporting generating tank sludges in the 3007 Survey, EPA estimated quantities for the other tanks not cleaned out during the two-year reporting period by assigning the average reported quantity generated per tank at that facility. These assigned quantities were then annualized using the facility-specific or industry-average frequency of generation.

Some facilities reported generating a waste(s) but did not report a waste quantity. When possible, EPA estimated missing quantities based on the average of other similar wastes at the same facility. EPA estimated quantities for the remaining facilities based on industry waste generation to daily crude rate relationships. Waste generation estimates were based on the daily throughput rate of crude oil rather than products because the wastes cannot be directly related to particular products. Statistical tests proved a correlation exists between the rate of sludge and catalyst residual generation and daily crude oil rate. To estimate missing quantities, EPA estimated waste generation using regression techniques to predict sludge and catalyst generation quantities.

EPA used regression methods to determine the relationship (i.e., line) that is the best predictor of annual waste generation quantities. EPA's procedure was to plot the data and the annual crude rate and annual waste quantity data, graph the regression line, and identify the points that lie outside the 95 percent prediction interval of the regression equation for this line. These points were assumed to be "outliers" and not representative of the population of data points as a whole. Linear regression equations were recalculated on the remaining data points. The "r-values" (a statistical parameter that predicts correlation between two sets of data) indicated that there was statistical correlation between the annual generation quantities for each sludge and catalyst residual and annual crude oil rates and therefore, inferences can be drawn from these regression relationships. The "r-squared values" were low for all the linear regression equations. This means that there is high variability in the Y-values (annual waste quantities) explained by the regression line.

The regression equations for each waste stream are presented in the table below. EPA ran sensitivity analyses on the cost and economic impact analyses because of the high variability of the annual waste quantities explained by the regression line. See Section 3.2.2 for a discussion on data limitations.

Linear Regression Equations
(Annual Waste Quantities are in MT/yr;
Daily Crude Oil Rates are in Mb/cd)

Waste Stream	Linear Regression Equation
K169	Annual Waste Quantity = 0.000856 * (Daily Crude Oil Rate * 365)$^{1.1623}$
K170	Annual Waste Quantity (MT) = 0.0163 * (Daily Crude Oil Rate * 365)$^{0.83047}$
K171	Annual Waste Quantity (MT) = 3.3573 + 0.00115 * (Daily Crude Oil Rate * 365)
K172	Annual Waste Quantity (MT) = exp [3.6624 + 1.714 x 10^{-5} * (Daily Crude Oil Rate * 365)]

These linear regression equations were applied to units at facilities which did not report waste generation quantities. For each unit with an unknown quantity, the daily crude rates were entered into the linear regression equations to estimate sludge and catalyst waste quantities. These total waste stream quantities, which represents the generation of that waste for the entire facility, were divided by the number of units at the facility which generate that waste. For example, if a facility had three crude oil storage tanks, the daily crude rate was inserted into the crude oil tank sludge linear regression equation. This annual crude oil sludge quantity was then divided by three to estimate the sludge quantity generated from each tank.

A few facilities reported generating a quantity of zero for various wastes. EPA used best engineering judgement to determine whether or not this zero quantity was feasible. If it was determined unlikely that the particular management method would not generate a waste, a quantity was estimated. For example, a facility reporting a zero waste quantity from a filtration unit followed by disposal in a landfill was assumed to be incorrect unless the facility noted otherwise.

A few facilities provided generation and disposal quantities, but did not provide quantities involved with intermediate treatment steps. For example, a facility may have provided a quantity entering a treatment step such as pressure filtration, but the quantity of sludge leaving this step was not reported. As presented below, EPA determined average ratios of the quantity leaving the step to quantity entering the step based on quantity data reported by other facilities. The appropriate ratio was multiplied by the quantity reported entering the step to estimate the quantity leaving the step.

Treatment Method	Average Quantity Leaving/Quantity Entering
Washing with Water	0.9
Sludge De-watering	0.6
Pressure Filtration/Centrifuging	0.4
On-site Stabilization	1.6

Non-Reporting Facilities

The regression equations presented previously also were used to estimate waste generation quantities for facilities EPA believes generate specific waste residuals but did not report quantities in the 1992 RCRA 3007 Survey. EPA made the following assumptions when identifying those facilities with non-reported waste residuals (and quantities):

1. All facilities with existing crude oil storage tanks or clarified slurry oil storage tanks generate crude oil storage tank sludges (K169) or clarified slurry oil tank sludges (K170) unless it has been specifically stated in a cover letter or communication that the residual is not generated.

2. All facilities with hydrotreating or hydrorefining units generate hydrotreating catalyst residuals (K171) or hydrorefining catalyst residuals (K172).

Contaminated Soil and Debris

Approximately 600,000 cubic yards of contaminated soil and debris were reported by 33 facilities in the 1992 RCRA 3007 Survey. Almost all of this quantity was generated by 7 out of the 33 facilities. This quantity was not included in the analysis because (1) these 1992 one-time quantities have likely already been managed, (2) management of soil and debris exhibiting TC characteristic hazard (e.g., benzene) are already regulated under RCRA Subtitle C due to the TC listings and the Phase II LDR regulations, and (3) refineries will likely manage non-hazardous soil and debris under current regulations (RCRA Subtitle D) prior to final listing of the newly listed wastes included in this analysis.

3.2.2 Data Limitations

Many facilities did not report waste quantities. Estimates for these quantities were based on generation in other units at the same facility, generation at other reporting facilities, and on the daily crude throughput rate. The waste generation regression analyses determined a statistical correlation between the annual waste quantity and daily crude rate data sets, but, the regression equations had low "r-squared" values indicating high variability in the prediction of annual waste generation quantities. Also, the generation of many wastes cannot be directly related to the production of single products. Therefore, regression equations were derived as tools for estimating annual waste generation. Because of the low "r-squared values", sensitivity analyses of the cost and economic impacts have been conducted which evaluate impacts using annual waste generation estimates that are 50 percent smaller (lower-bound estimate of waste generation quantity) and 50 percent higher (upper-bound estimate of waste generation quantity) than the amount predicted by the regression equations.

Some of the facilities with missing quantities are not "typical" refineries. These facilities do not generate the same variety of products as the majority of the facilities. For example, an asphalt facility will generally produce only heavy products such as asphalt and possibly heavy residual fuel oil. Very few of these facilities reported all waste quantities, therefore, a separate average waste to crude ratio for these "non-typical" refineries cannot be determined. As a result, all available data from both "typical" and "non-typical" refineries were used to develop the average ratios to be applied to all facilities.

3.2.3 Waste Summaries

The following subsections summarize the waste quantities for each newly listed waste. Waste quantities were based on 1992 data from the RCRA 3007 Survey. Table 3.1 presents the total waste quantity generated for each waste stream listing. The total reported waste quantity and total annualized waste quantity (including estimates for non-reported quantities) affected by this listing are presented. These quantities represent the amount of waste generated at the point of generation (e.g., tank cleanout) prior to any type of treatment or disposal.

1. <u>K169 - Crude oil storage tank sludge</u>

Petroleum refineries produce between 45,900 and 114,700 Mton/year with a typical value of approximately 80,300 Mton/year of crude oil storage tank sludge (K169) affected by this listing. EPA estimates that 145 facilities generate this waste. Eighty-five of the 93 facilities reporting generating this waste did not report quantity for cleaning out all of their tanks. Fifteen of the 93 facilities did not provide a quantity. EPA also estimated that an additional 52 facilities did not report generating this waste. Waste quantities for these non-reported quantities were estimated using the methodology described in Section 3.2.1. These estimates account for approximately 86 percent of the typical annual quantity.

2. K170 - Clarified slurry oil sludge from catalytic cracking

Petroleum refineries produce between 18,300 and 35,400 Mton/year with a typical value of approximately 26,800 Mton/year of clarified slurry oil sludge from catalytic cracking (K170) affected by this listing. EPA estimates that 101 facilities generate this waste. Thirty-seven of the 54 facilities reporting generating this was did not report quantities for cleaning out all of their tanks. Six of the 54 facilities did not provide a quantity. EPA also estimated that an additional 47 facilities did not report generating this waste. Waste quantities for these non-reported quantities were estimated using the methodology described in Section 3.2.1. These estimates account for approximately 64 percent of the typical annual quantity.

3. K171 - Catalyst from catalytic hydrotreating

Petroleum refineries produce between 6,700 and 6,900 Mton/year with a typical value of approximately 6,800 Mton/year of catalyst from catalytic hydrotreating (K171) affected by this listing. EPA estimates that 130 facilities generate this waste. Fourteen of the 127 facilities reporting this waste did not provide a quantity. EPA also estimated that an additional 3 facilities did not report generating this waste. Waste quantities for these non-reported quantities were estimated using the methodology described in Section 3.2.1. These estimates account for approximately 3 percent of the typical annual quantity.

4. K172 - Catalyst from catalytic hydrorefining

Petroleum refineries produce between 20,700 and 20,900 Mton/year with a typical value of approximately 20,800 Mton/year of catalyst from catalytic cracking (K172) affected by this listing. EPA estimates that 55 facilities generate this waste. EPA also estimated that an additional 2 facilities did not report generating this waste. Waste quantities for these non-reported quantities were estimated using the methodology described in Section 3.2.1. These estimates account for approximately 1 percent of the typical annual quantity.

TABLE 3.1

TOTAL WASTE QUANTITIES BY WASTE STREAM LISTING

Waste Stream	No. of Fac. w/ Non-Exempt Waste Mgmt.	No. of Non-Reporting Fac.[a]	Reported Point of Generation Waste Quantity (All Years) (MT/yr)	Annualized Reported Point of Generation Waste Quantity (All Years) (MT/yr)	Added Unreported Annualized Point of Generation Quantities (MT/yr) Average [Low - High]			Annualized Point of Generation Waste Quantity (MT/Yr)[e]
					Additional Tank Quantities for Reporting Facilities[b]	Non-Quantified Wastes for Reporting Facilities[c]	Total Tank Quantities for Non-Reporting Facilities[d]	
K169	145	52	136,000	11,400	63,900 [31,900 - 95,800]	900 [400 - 1,300]	4,100 [2,100 - 6,200]	80,300 [45,900 - 114,700]
K170	101	47	60,600	9,700	11,600 [5,800 - 17,400]	700 [300 - 1,000]	4,900 [2,400 - 7,300]	26,800 [18,300 - 35,400]
K171	130	3	13,500	6,600	0 [0 - 0]	200 [100 - 300]	0 [0 - 100]	6,800 [6,700 - 6,900]
K172	55	2	26,400	20,600	0 [0 - 0]	0 [0-0]	100 [100 - 200]	20,800 [20,700 - 20,900]
Total[f]	162	---	236,500	48,300	75,500 [37,700 - 113,200]	1,800 [900 - 2,600]	9,200 [4,600 - 13,800]	134,800 [91,600 - 177,900]

[a] The number of facilities assumed to be generating this waste stream but did not report any quantities in the Survey.
[b] The estimated additional quantity of waste generated from all other tanks at facilities that did not report quantities for all existing tanks.
[c] The estimated quantity of waste for waste streams which were reported being generated but were not quantified.
[d] The estimated quantity of waste generated from all tanks at facilities assumed to be generating this waste stream but did not report any quantities in the Survey.
[e] The total includes an added annualized unreported point of generation waste quantity of 86,500 MT/yr (64%).
[f] Totals may not sum due to rounding.

3.2.4 Comparison of 1992 RCRA Section 3007 Survey Quantities and Annual Hazardous Waste Quantities

A comparison of the 1992 RCRA 3007 Survey quantities and the annual waste quantities used in the cost and economic impact analysis is presented here to demonstrate how the data was derived from those numbers that may be presented in other EPA analyses supporting this listings determination. Costs are directly related to the quantity of the waste being managed and costs may be incurred at several steps from the point of generation, through intermediate storage and treatment steps, and at the point of final management (disposal). The cost model spreadsheet supporting this analysis tracks the waste quantities and costs for each step of the waste treatment train on a waste-by-waste and refinery-by-refinery basis.

Table 3.2 presents the waste quantities that have been presented in other EPA analyses. This table presents the waste quantities reported in the 1992 RCRA 3007 Survey as being disposed (i.e., quantities reaching the end of the waste management train) in 1992 only, ignoring all quantities reported being disposed in previous and later years.

Reported and predicted waste generation quantities (i.e., quantities entering the waste treatment train) for all years (1992, 1993, 1994, etc.) were annualized based on the reported generation frequencies. This annualization methodology "smooths out" the peaks and valleys associated with these infrequently generated (i.e., not generated annually) wastes over time. EPA chose to annualize all reported waste quantities in order to assign quantity and costs attributable to the listings determination to all refineries impacted by the listing and utilize a larger set of responses reported in the 3007 RCRA Survey. This approach also enabled EPA to estimate unreported quantities without having to predict the year of generation. Table 3.3 presents the "typical" annualized generation and final management waste quantities used in the cost analysis. The annualized generation quantity is higher or lower depending on the waste than the quantity reported being generated in the year 1992 (comparison of column 4 in Table 3.2 with column 6 in Table 3.3). As a note, the Table 3.3 annual final management quantities for crude oil tank sludges and clarified slurry oil sludge have been decreased because EPA assumes that all refineries who are currently not filtering oily sludges will install a filtration unit to recycle the oil back into process units as a cost-effective waste minimization practice (see discussion in Section 3.3.1). If the waste minimization practice is not implemented the totals would be 17,400 and 18,000 MT/yr, respectively. In Table 3.3, Column 5 presents the annual quantity entering waste management trains (i.e., point of generation), Column 6 presents the "non-process recycled" annual quantities reaching the end of the waste management train (i.e., final management), and Column 10 presents the annual quantities reaching the end of the waste management train that incur an additional cost in the final management step.

TABLE 3.2
Reported and Adjusted 1992 RCRA 3007 Survey Quantities in Metric Tons[1]

(1) Waste Stream	(2) Reported Final Management Quantity[2]	(3) Exempted Final Mgmt. Quantities Based on the Definition of Solid Waste[3]	(4) Final Management Quantity Excluding DSW Exemptions[4]	(5) Exempted Final Mgmt. Quantities Assoc. w/ Metal Reclamation Units[5]	(6) Final Mgmt. Quantities Associated with Headwaters Exemption	(7) Final Management Quantities Currently in Compliance	(8) Adjusted Final Management Quantity[6]
Crude Oil Tank Sludge	22,017	9,826	12,191	0	2,118	4,019	6,054
Clarified Slurry Oil Sludge	24,010	581	23,429	0	250	3,564	19,615
Hydrotreating Catalyst	5,640	133	5,507	4,274	0	639	594
Hydrorefining Catalyst	18,634	0	18,634	15,388	0	198	3,048
TOTAL	70,301	10,540	59,761	19,662	2,368	8,420	29,311

[1] U.S. EPA, Office of Solid Waste, "Listing Background Document for the 1992-1996 Petroleum Refining Listing Determination," Draft Final, prepared by SAIC, August 31, 1995.

[2] Total includes quantities where the final management practice (disposition) is landfill, land treatment, incineration, industrial furnace, recycling, recovery, reclamation, reuse, wastewater discharges, off-site stabilization, and storage. It excludes on-site intermediate storage and treatment (e.g., water washing, stabilization, and filtering) management practices.

[3] Based on the definition of solid waste (DSW), all oil-bearing residuals reinserted into petroleum refining processes or used directly as effective substitutes are exempted from the listing.

[4] Equals Col. 2 - Col. 3.

[5] Metal reclamation units (including catalyst regeneration) are included under the exemption for "smelting, melting, and refining furnaces that process hazardous wastes solely for metal recovery."

[6] Equals Col. 4 - Col. 5 - Col. 6 - Col. 7. These totals are lower than the totals used for costing in that costs requiring compliance management may be incurred at various points in the management process.

TABLE 3.3
LISTING DETERMINATION ANNUALIZED GENERATION AND FINAL MANAGEMENT QUANTITIES IN METRIC TONS[1,11]

(1) Waste Stream	(2) Reported Point of Generation Quantity[2]	(3) Annual Reported Point of Generation Quantity[3]	(4) Added Annual Unreported Generation Quantities[4]	(5) Annual Total Point of Generation Quantity[5]	(6) Annual Final Mgmt. Quantity[6]	(7) Final Mgmt. Headwaters Exemption Quantity[7]	(8) Final Mgmt. Quantities Currently in Compliance[8]	(9) Final Mgmt. Quantity w/ No Incr. Compl. Cost[9]	(10) Listing Annual Final Mgmt. Quantity[10]
Crude Oil Tank Sludge	136,000	11,400	68,900	80,300	14,600	2,700	1,300	1,400	9,200
Clarified Slurry Oil Sludge	60,600	9,700	17,200	26,800	13,100	500	2,000	900	9,700
Hydrotreating Catalyst	13,500	6,600	200	6,800	6,600	0	200	0	6,400
Hydrorefining Catalyst	26,400	20,600	100	20,800	20,100	0	100	0	20,000
TOTAL	236,500	48,300	86,500	134,800	54,400	3,200	3,600	2,300	45,300

1 Source: DPRA Cost Model derived from Petroleum Refining Database (1992 RCRA 3007 Survey).
2 Total includes quantities at the point of generation prior to any treatment or disposal. Total only includes waste streams having a potential associated incremental cost of compliance. In many cases (unless filtration is required) oil-bearing residuals exempted under the definition of solid waste have no associated incremental compliance cost and therefore, are not included.
3 Total reported generation quantity is annualized to represent an average quantity of waste generated per year.
4 Estimate of additional waste generated by facilities that reported generating a waste but did not report a quantity, and estimates for facilities that did not report generating a waste when it should have been generated, annualized to represent an average quantity of waste generated per year.
5 Total reported and unreported generation quantity is annualized to represent an average quantity of waste generated per year.
6 Total final management quantity is annualized to represent an average quantity of waste managed per year.
7 Total amount of the annualized final management quantity exempt because of the wastewater treatment headwaters exemption.
8 Total amount of the annualized final management quantity already managed in units that comply with RCRA Subtitle C regulations.
9 Total amount of the annualized final management quantity with no incremental compliance cost due to the benefits (recycled oil value) obtained from adding a filtration unit as a waste minimization practice.
10 Total includes exempt metal reclamation quantities because the "metals reclamation unit exemption" does not apply to RCRA Subtitle C storage requirements. No incremental compliance costs are incurred for the metal reclamation unit itself. Col. 10 = Col. 6 - Col. 7 - Col. 8 - Col. 9
11 Costs are incurred at various points in the management of these wastes, beginning with the point of generation (Col. 4) and ending with the final management (Col. 10).

3.3 Waste Management Practices and Compliance Costs

This section describes the current (baseline) waste management practices for each newly listed waste and the alternative waste management practices assumed after listing.

3.3.1 Current (Baseline) and Compliance Waste Management Practices

Current waste management practices were provided in the 1992 RCRA 3007 Survey by facilities in the petroleum refining industry. When a reported waste management train seemed incomplete, EPA made the following assumptions:

- Where a facility reported a final waste management practice of storage, washing, or filtration, EPA assigned the most common final waste management practice reported by other facilities as the ultimate disposition of the waste.

- Where a facility reported a final waste management practice of off-site management (e.g., landfill or incineration) with no prior on-site storage (e.g., container or tank) indicated, EPA assigned the most common waste storage practice reported by other facilities as the storage mechanism prior to off-site management.

Compliance waste management practices were developed to address the RCRA Subtitle C requirements imposed by the waste listings. It should be noted that frequently several individual waste management methods make up the components of the waste management practice (i.e., waste management train). Because of the number of waste management trains, baseline and compliance costs were developed for the individual components of each waste management train. Then the costs for each of the components was summed together to develop baseline and compliance cost estimates for the complete waste management train.

Compliance management practices were assumed under three different scenarios, compliance due to the listing alone, compliance due to land disposal restriction (LDR) and listing regulations combined, and compliance due to contingent management, LDR, and listing regulations combined. The scenarios are defined as follows:

- The Listing Scenario assumes an end disposal management method of Subtitle C landfill or continued combustion of wastes, where indicated as the baseline management practice, in a Subtitle C incinerator/BIF.

- The LDR Scenario assumes two options. In the first option, the metal-based wastes are combusted in a Subtitle C incineration followed by vitrification and Subtitle C landfill of the ash and the organic-based wastes are combusted in off-site Subtitle C incinerator/BIF units. This option reflects the highest cost situation. Other technologies may be applicable (e.g., solvent extraction instead of incineration or solidification instead of vitrification for metal-based wastes) to meet LDR standards, but these are lower cost options and will not provide an upper-bound to the cost and economic analysis. In the second option, the metal-based catalyst residuals are reclaimed/recovered to take advantage of the exclusion from RCRA Subtitle C regulation. The oil-based wastes are combusted in either an on- or off-site Subtitle C incinerator/BIF depending on the economic feasibility of constructing on-site incinerator units. If a facility does not currently have a RCRA Part B permit, EPA assumed the facility would choose not to construct an on-site incinerator in order to avoid incurring costs under the RCRA corrective action program (see Section 3.3.6 for discussion of corrective action costs). This option reflects the most likely cost to the petroleum refining industry (excluding corrective action costs) due to the listing and LDR regulations if the Contingent Management Scenario is not proposed as an alternative management option.

- The Contingent Management Scenario expands the second option of the LDR Scenario. Instead of combusting the oil-based wastes in an on- or off-site Subtitle C incinerator/BIF, the wastes can be excluded from RCRA Subtitle C regulation under the definition of a solid waste if managed in certain Subtitle D management units. Crude oil tank sludges are excluded if contingently managed in Subtitle D land treatment units having run-on/run-off controls. The contingent management exclusion does not allow exclusion from Subtitle C storage and transportation requirements prior to the contingent management practice. CSO sludges are excluded if contingently managed in Subtitle D land treatment units with run-on/run-off controls or Subtitle D landfills. Option 1 of the Contingent Management Scenario assumes that Contingent Management Scenarios are proposed for both the crude oil and CSO sludges. Option 2 assumes that contingent management only is proposed for the CSO sludge.

The following list summarizes the compliance management practices assumed for the listing, LDR, and contingent regulatory options:

- Storage and treatment of wastes are performed in accumulation tanks or containers (i.e., meeting the 40 CFR 262.34 requirements, therefore, a permit is not required). Existing tank systems and container storage areas are retrofitted with secondary containment systems. In addition, the current management practices which use treatment impoundments in the wastewater treatment system incur no incremental compliance cost of upgrading to a tank system because of the "headwaters exemption" granted to tank residuals (flushing waters) discharged to on-site wastewater treatment facilities at petroleum refineries.

- Closure of non-compliance land disposal units is required if the existing accumulated/disposed wastes are physically disturbed (see 54 FR 36597 regarding retroactive application of Subtitle C requirements). EPA assumes, because of retrofitting economics and LDR requirements, that non-compliance disposal surface impoundments and waste piles (i.e., drying on pad) will be dredged and cleared of any newly listed wastes prior to final listing instead of constructing new Subtitle C units. These units will be recommissioned for uses other than management of the newly listed wastes. The compliance management practice for the newly listed oil-based sludges is filtration followed by disposal in a Subtitle C landfill (Listing Scenario), Subtitle C incineration (LDR Scenario), or Subtitle D landfill/land treatment (Contingent Management Scenario).

- For the Listing and LDR Scenarios, non-RCRA land treatment units will be abandoned because acceptance of other nonhazardous wastes (i.e., wastes not covered by this listing) will disturb the contained newly listed wastes. For those units currently accepting other nonhazardous wastes (not newly listed), costs could not be estimated for alternative management of those wastes due to closure of the unit because waste quantity data is unavailable. Many facilities responded in the 1992 RCRA 3007 Survey that their land treatment units are permitted under RCRA. EPA's RCRIS database confirmed the permitted status of these units. However, LDR regulations currently exist for hazardous wastes that would likely have been disposed in these permitted units by refineries (e.g., D001, D018, F037, F038, and soil and debris wastes). EPA assumes that "no-migration" variances have not been granted for most, if not all, of these units. Therefore, EPA assumes that due to new LDR regulations promulgated since 1992, none of the newly listed wastes are currently managed in RCRA permitted land treatment units, but, have been switched over to non-RCRA land treatment units. Also, all newly listed wastes that are currently characteristically hazardous and reported being managed in land treatment units in 1992 are assumed now to be in compliance with all applicable Subtitle C regulations. EPA also assumes that management of these characteristically hazardous wastes under LDRs will be the same, therefore, no incremental compliance costs will be incurred. For the Contingent Management Scenario, Subtitle D land treatment units will continue to be allowed management practices for oil-based wastes if they have proper run-on/run-off controls.

- For the Listing and LDR Scenarios, because new wastes accumulated/disposed prior to the final listing will not be disturbed in a landfill, EPA assumes that these units will not have to be closed or abandoned. For landfills, use of the particular cells containing the newly listed wastes will be discontinued prior to final listing. The remaining portion of the landfill will continue to be used. For the Contingent Management Scenario, Subtitle D landfill units will continue to be allowed as a management practice for CSO sludges only.

- Recycling/recovery/regeneration/reclamation is frequently reported as a current management practice. Some recycling practices and residuals that are recycled are exempt from RCRA under either the §261.2 definition of materials that are not solid waste when recycled (e.g., reused as ingredients in an industrial process to make a product, such as a distillation unit, coker, and catalytic cracker or direct use as effective substitutes for commercial product, such as transfer with coke product or other refinery product) or the §266.100 exemption for "smelting, melting, and refining furnaces that process hazardous waste solely for metal recovery." It should be noted that residuals from certain metal reclamation and regeneration processes are not exempt from RCRA Subtitle C storage, transportation, and/or management requirements when they are used to produce or contained in products that are applied to or placed on land, involve speculative accumulation of metals, or partial reclamation of metals.

- For newly listed waste streams for which recycling/recovery/regeneration/reclamation is not an option, the disposal options consist of Subtitle C landfill under the Listing Scenario and Subtitle C incineration followed by vitrification prior to Subtitle C landfill under the LDR Scenario. Other LDR options possibly could include solvent extraction instead of incineration and solidification instead of vitrification.

Table 3.4 summarizes baseline and compliance waste management practices for wastes impacted by the listing. Table 3.5 summarizes compliance waste management practices for listed wastes impacted by LDR regulations. Table 3.6 summarizes compliance waste management practices for listed wastes impacted by contingent management regulations. The following narratives also detail how each listed waste is managed under baseline practices and what the assumed compliance practices will be for that waste after listing.

1. K169 - Crude oil storage tank sludge

The most common residual disposal method for crude oil storage tank sludge is disposal in an off-site Subtitle D or C landfill. Pressure filtration/centrifuging is a common residual treatment method. Other treatment methods include thermal treatment, off-site incineration, washing with distillate or water, sludge thickening or de-watering, settling, filtration, chemical or thermal emulsion breaking, land treatment, discharge to on-site wastewater treatment facility, drying on a pad, and stabilization. Other disposal methods include discharge to surface water under NPDES, disposal in an on-site Subtitle C landfill, and disposal in an on-site surface impoundment.

For the Listing Scenario, the assumed compliance practice is disposal in an on-/off-site Subtitle C landfill. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Discharge of flushing waters to on-site wastewater treatment systems will be continued because of a "headwater exemption" provided for waste-derived sludges from wastewater treatment systems that are not already hazardous due to a previous listing. The practice of disposing this waste in land treatment and disposal surface impoundment units will be abandoned.

For the LDR Scenario, the assumed compliance practice is disposal in an on-/off-site Subtitle C incinerator. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Discharge of flushing waters to on-site wastewater treatment systems will be continued because of a "headwater exemption" provided for waste-derived sludges from wastewater treatment systems that are not already hazardous due to a previous listing. The practice of disposing this waste in land treatment and disposal surface impoundment units will be abandoned.

For the Contingent Management Scenario, the assumed compliance practice is disposal in a Subtitle D land treatment unit with run-on/run-off controls. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Discharge of flushing waters to on-site wastewater treatment systems will be continued because of a "headwater exemption" provided for waste-derived sludges from wastewater treatment systems that are not already hazardous due to a previous listing. The practice of disposing this waste in disposal surface impoundment units will be abandoned.

2. K170 - Clarified slurry oil sludge from catalytic cracking

The most common residual disposal method for clarified slurry oil sludge from catalytic cracking is disposal in an off-site Subtitle D or C landfill. Pressure filtration/centrifuging is a common residual treatment method. Other treatment methods include on-site industrial flare, washing with distillate, sludge thickening or de-watering, settling, filtration, thermal emulsion breaking, land treatment, discharge to on-site wastewater treatment facility, drying on a pad, and stabilization. Other disposal methods include disposal in an on-site Subtitle D landfill.

For the Listing Scenario, the assumed compliance practice is disposal in an on-/off-site Subtitle C landfill. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Discharge of flushing waters to on-site wastewater treatment systems will be continued because of a "headwater exemption" provided for waste-derived sludges from wastewater treatment systems that are not already hazardous due to a previous listing. The practice of disposing this waste in land treatment and on-site Subtitle D landfill units will be abandoned.

For the LDR Scenario, the assumed compliance practice is disposal in an on-/off-site Subtitle C incinerator. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Discharge of flushing waters to on-site wastewater treatment systems will be continued because of a "headwater exemption" provided for waste-derived sludges from wastewater treatment systems that are not already hazardous due to a previous listing. The practice of disposing this waste in land treatment and on-site Subtitle D landfill units will be abandoned.

TABLE 3.4
SUMMARY OF BASELINE AND LISTING COMPLIANCE WASTE MANAGEMENT PRACTICES FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Compliance Management Practice [b]
RESIDUAL STORAGE METHODS			
Tank	01-A	K169, K170, K171, K172	Upgrade to Subtitle C accumulation storage tank
Container (e.g., drum)	01-B	K169, K170, K171, K172	Upgrade to Subtitle C accumulation container storage area
Pile	01-C	K169, K170, K172	Clear waste pile and recommission for non-hazardous waste use and replace with Subtitle C accumulation roll-on/roll-off bin storage area
Roll-on/Roll-off Bin	01-E	K169, K170, K171, K172	Upgrade to Subtitle C accumulation roll-on/roll-off bin storage area
Other	01-F	K169, K170, K171, K172	Assumed similar to roll-on/roll-off bin storage practice; upgrade to Subtitle C accumulation roll-on/roll-off bin storage area
RESIDUAL TREATMENT METHODS			
On-site Industrial Furnace	02-E	K170	Ship off site to Subtitle C BIF
Other On-site Thermal Treatment	02-F	K169	Ship off site to Subtitle C BIF
Off-site Incineration	03-A	K169, K171	Ship off site to Subtitle C incinerator
Washing with Distillate	04-C	K169, K170	Upgrade to Subtitle C accumulation treatment tank
Washing with Water	04-D	K169	Upgrade to Subtitle C accumulation treatment tank
Other Cleaning/Extraction	04-E	K171, K172	Upgrade to Subtitle C accumulation treatment tank
Sludge Thickening	05-A	K169, K170	Upgrade to Subtitle C accumulation treatment tank

TABLE 3.4 (CONTINUED)
SUMMARY OF BASELINE AND LISTING COMPLIANCE WASTE MANAGEMENT PRACTICES
FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Compliance Management Practice [b]
Sludge De-watering	05-B	K169, K170	Upgrade to Subtitle C accumulation treatment tank
Settling	05-C	K169, K170	Upgrade to Subtitle C accumulation treatment tank
Filtration	05-D	K169, K170	Upgrade to Subtitle C accumulation treatment tank
Pressure Filtration/Centrifuging	05-E	K169, K170	Upgrade to Subtitle C accumulation treatment tank
Chemical Emulsion Break	05-F	K169	Upgrade to Subtitle C accumulation treatment tank
Thermal Emulsion Break	05-G	K169, K170	Upgrade to Subtitle C accumulation treatment tank
Other Phase Separation	05-J	K169, K171, K172	Upgrade to Subtitle C accumulation treatment tank
On-site Land Treatment	06-A	K169, K170, K171	Abandon land treatment unit; ship off site to Subtitle C landfill
Off-site Land Treatment	06-B	K169, K170	Ship off site to Subtitle C landfill
Discharge to On-site WWT Facility	07	K169, K170	Same as baseline if conducted in wastewater treatment tank system discharging to NPDES outfall or POTW because of "headwaters exemption;" upgrade to Subtitle C accumulation treatment tanks discharging to on-site injection well or on-site disposal impoundment
Drying on a Pad	08	K169, K170	Clear drying pad and recommission for non-hazardous waste use and replace with Subtitle C accumulation treatment tank
On-site Oxidation of Pyrophoric Material	10	K171, K172	Upgrade to Subtitle C accumulation treatment tank
On-site Stabilization	11-A	K169, K170, K171, K172	Upgrade to Subtitle C accumulation treatment tank

TABLE 3.4 (CONTINUED)
SUMMARY OF BASELINE AND LISTING COMPLIANCE WASTE MANAGEMENT PRACTICES
FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Compliance Management Practice [b]
Off-site Stabilization	11-B	K171	Ship off site to Subtitle C stabilization
Other Treatment	13	K169	Upgrade to Subtitle C accumulation treatment tank
RESIDUAL RECYCLE METHODS			
On-site Coker	14-A	K169, K170	Oil-bearing residuals that are generated at petroleum refineries and are reinserted into petroleum refining processes are exempt from Subtitle C storage, transportation, and management regulation.
On-site Catalytic Cracker	14-B	K169, K170	Oil-bearing residuals that are generated at petroleum refineries and are reinserted into petroleum refining processes are exempt from Subtitle C storage, transportation, and management regulation.
On-site Distillation	14-C	K169, K170	Oil-bearing residuals that are generated at petroleum refineries and are reinserted into petroleum refining processes are exempt from Subtitle C storage, transportation, and management regulation.
On-site Asphalt Production Unit	14-D	K169, K170	Ship off site to Subtitle C BIF
On-site Replacement Catalyst for Another Unit	14-E	K171	Catalyst residuals that are generated at petroleum refineries and are reinserted into petroleum refining processes are exempt from Subtitle C storage, transportation, and management regulation.
On-site Nonprecious Metal Catalyst Reclamation/Regeneration	14-G	K171	Catalyst residuals that are generated at petroleum refineries and are reinserted into petroleum refining processes are exempt from Subtitle C storage, transportation, and management regulation. Spent catalyst residuals that can no longer be regenerated are shipped off site to Subtitle C landfill.

TABLE 3.4 (CONTINUED)
SUMMARY OF BASELINE AND LISTING COMPLIANCE WASTE MANAGEMENT PRACTICES
FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Compliance Management Practice [b]
Other On-site Recovery	14-I	K171	If description provided, assigned most similar recycling practice listed above. If no description provided, assigned most frequently reported recycling practice for that waste stream.
Other On-site or Off-site Recycling/Reclamation/Reuse	15	K169, K170, K171, K172	If description provided, assigned most similar recycling practice listed above. If no description provided, assigned most frequently reported recycling practice for that waste stream
RESIDUAL TRANSFER METHODS			
Transfer of Off-site Precious or Nonprecious Metal Catalysts for Reclamation/Regeneration	16-A	K171, K172	Metal recovery management practices are exempt. Residuals from these reclamation/regeneration practices are "waste-derived" and not exempt from RCRA Subtitle C storage, transportation, and/or management when they are used to produce or contained in products that are applied to or placed on land, involve speculative accumulation of metals, or partial reclamation of metals.
Transfer For Off-site Direct Use as a Fuel or to Make a Fuel	16-B	K169, K170	Ship off site to Subtitle C BIF
Transfer with Coke Product or Other Refinery Product	16-C	K169, K170	Residuals are assumed to be product materials and exempt from Subtitle C storage, transportation, and management requirements.
Transfer for Use as Ingredient in Products that are Placed on the Land	16-E	K169	Ship off site to Subtitle C BIF

TABLE 3.4 (CONTINUED)
SUMMARY OF BASELINE AND LISTING COMPLIANCE WASTE MANAGEMENT PRACTICES FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Compliance Management Practice [b]
Transfer to Other Off-site Entity	16-G	K169, K171	Assigned the most commonly reported transfer practice listed above for that waste stream.
RESIDUAL DISPOSAL METHODS			
NPDES	17-A	K169	Same as baseline
Off-site Municipal Subtitle D Landfill	17-D	K169, K170, K171	Ship off site to Subtitle C landfill
Off-site Industrial Subtitle D Landfill	17-E	K169, K170, K171, K172	Ship off site to Subtitle C landfill
Off-site Subtitle C Landfill	17-F	K169, K170, K171, K172	Same as baseline
On-site Subtitle D Landfill	18-A	K170, K171, K172	Ship off site to Subtitle C landfill
On-site Subtitle C Landfill	18-B	K169, K171, K172	Same as baseline
On-site Surface Impoundment	18-D	K169	Discontinue practice of discharging these sludges to a disposal surface impoundment; Dredge impoundment and recommission for non-hazardous waste use; Construct on site Subtitle C filtration unit and ship sludge residuals to off site Subtitle C landfill

[a] Management code corresponds to the coding system used in the 1992 RCRA Section 3007 Survey.
[b] If the baseline management practice is already permitted under RCRA Subtitle C regulations, then the compliance management practice does not apply.

TABLE 3.5
SUMMARY OF BASELINE AND LDR COMPLIANCE WASTE MANAGEMENT PRACTICES FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	LDR Compliance Management Practice
RESIDUAL STORAGE METHODS			
Waste Pile	01-C	K169, K170, K172	Assumed, because of economics, the waste pile was abandoned in anticipation of LDR regulations under the listing compliance management practice; Same as listing compliance management practice
Other	01-F	K169, K170, K171, K172	Assumed practice conducted in tanks, no LDR impact
RESIDUAL TREATMENT METHODS			
On-site Land Treatment	06-A	K169, K170, K171	Assumed, because of economics, the land treatment unit was abandoned in anticipation of LDR regulations under the listing compliance management practice; Oil-based wastes will require combustion in an incinerator/BIF; Metal-based wastes will require Subtitle C incineration followed by vitrification and Subtitle C landfill of ash or will be reclaimed in metals reclamation/regeneration units
Off-site Land Treatment	06-B	K169, K170	Oil-based wastes will require combustion in an incinerator/BIF
Discharge to On-site WWT Facility	07	K169, K170	A "headwaters exemption" has been granted for oil-based sludges (flushing waters) discharged to on-site wastewater treatment system; no LDR impact
Drying on a Pad	08	K169, K170	Assumed, because of economics, the drying pad was cleared and recommissioned for non-hazardous waste use in anticipation of LDR regulations under the listing compliance management practice; Same as listing compliance management practice
Other Treatment	13	K169	Assumed conducted in tanks; no LDR impact

TABLE 3.5 (CONTINUED)
SUMMARY OF BASELINE AND LDR COMPLIANCE WASTE MANAGEMENT PRACTICES
FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	LDR Compliance Management Practice
RESIDUAL DISPOSAL METHODS			
Off-site Municipal Subtitle D Landfill	17-D	K169, K170, K171	Oil-based wastes will require combustion in an incinerator/BIF; Metal-based wastes will require Subtitle C incineration followed by vitrification and Subtitle C landfill of ash or will be reclaimed in metals reclamation/regeneration units
Off-site Industrial Subtitle D Landfill	17-E	K169, K170, K171, K172	Oil-based wastes will require combustion in an incinerator/BIF; Metal-based wastes will require Subtitle C incineration followed by vitrification and Subtitle C landfill of ash or will be reclaimed in metals reclamation/regeneration units
Off-site Subtitle C Landfill	17-F	K169, K170, K171, K172	Oil-based wastes will require combustion in an incinerator/BIF; Metal-based wastes will require Subtitle C incineration followed by vitrification and Subtitle C landfill of ash or will be reclaimed in metals reclamation/regeneration units
On-site Subtitle D Landfill	18-A	K170, K171, K172	Oil-based wastes will require combustion in an incinerator/BIF; Metal-based wastes will require Subtitle C incineration followed by vitrification and Subtitle C landfill of ash or will be reclaimed in metals reclamation/regeneration units
On-site Subtitle C Landfill	18-B	K169, K171, K172	Oil-based wastes will require combustion in an incinerator/BIF; Metal-based wastes will require Subtitle C incineration followed by vitrification and Subtitle C landfill of ash or will be reclaimed in metals reclamation/regeneration units
On-site Surface Impoundment	18-D	K169	Oil-based wastes will require combustion in an incinerator/BIF

[a] Management code corresponds to the coding system used in the 1992 RCRA Section 3007 Survey.

TABLE 3.6
SUMMARY OF BASELINE AND CONTINGENT MANAGEMENT COMPLIANCE WASTE MANAGEMENT PRACTICES FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Contingent Management Compliance Management Practice
RESIDUAL STORAGE METHODS			
Waste Pile	01-C	K169, K170, K172	Assumed, because of economics, the waste pile was abandoned in anticipation of LDR regulations under the listing compliance management practice; Crude oil sludges will be disposed in Subtitle D land treatment units with run-on/run-off controls; CSO sludges will be disposed in Subtitle D land treatment units with run-on/run-off controls or Subtitle D landfill units; Metal-based wastes will be reclaimed in metal catalyst reclamation/regeneration units
Other	01-F	K169, K170, K171, K172	Assumed practice conducted in tanks, no contingent management impact
RESIDUAL TREATMENT METHODS			
On-site Land Treatment	06-A	K169, K170, K171	Crude oil sludges and CSO sludges will be disposed in Subtitle D land treatment units with run-on/run-off controls; Metal-based wastes will be reclaimed in metal catalyst reclamation/regeneration units; For metal-based wastes, because of economics, the land treatment unit was abandoned in anticipation of LDR regulations under the listing compliance management practice;
Off-site Land Treatment	06-B	K169, K170	Crude oil sludges and CSO sludges will be disposed in Subtitle D land treatment units with run-on/run-off controls;
Discharge to On-site WWT Facility	07	K169, K170	A "headwaters exemption" has been granted for oil-based sludges (flushing waters) discharged to on-site wastewater treatment system; No contingent management impact

TABLE 3.6 (CONTINUED)
SUMMARY OF BASELINE AND CONTINGENT MANAGEMENT COMPLIANCE WASTE MANAGEMENT PRACTICES FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Contingent Management Compliance Management Practice
Drying on a Pad	08	K169, K170	Assumed, because of economics, the drying pad was cleared and recommissioned for non-hazardous waste use in anticipation of LDR regulations under the listing compliance management practice; Same as listing compliance management practice
Other Treatment	13	K169	Assumed conducted in tanks; no contingent management impact
RESIDUAL DISPOSAL METHODS			
Off-site Municipal Subtitle D Landfill	17-D	K169, K170, K171	Crude oil sludges will be disposed in Subtitle D land treatment units with run-on/run-off controls; CSO sludges will be disposed in Subtitle D landfill units; Metal-based wastes will be reclaimed in metal catalyst reclamation/regeneration units
Off-site Industrial Subtitle D Landfill	17-E	K169, K170, K171, K172	Crude oil sludges will be disposed in Subtitle D land treatment units with run-on/run-off controls; CSO sludges will be disposed in Subtitle D landfill units; Metal-based wastes will be reclaimed in metal catalyst reclamation/regeneration units
Off-site Subtitle C Landfill	17-F	K169, K170, K171, K172	Crude oil sludges will be disposed in Subtitle D land treatment units with run-on/run-off controls; CSO sludges will continue to be disposed in Subtitle C landfill units; Metal-based wastes will be reclaimed in metal catalyst reclamation/regeneration units
On-site Subtitle D Landfill	18-A	K170, K171, K172	CSO sludges will be disposed in Subtitle D landfill units; Metal-based wastes will be reclaimed in metal catalyst reclamation/regeneration units

TABLE 3.6 (CONTINUED)
SUMMARY OF BASELINE AND CONTINGENT MANAGEMENT COMPLIANCE WASTE MANAGEMENT PRACTICES
FOR THE PETROLEUM REFINING INDUSTRY

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Contingent Management Compliance Management Practice
On-site Subtitle C Landfill	18-B	K169, K171, K172	Crude oil sludges will be disposed in Subtitle D land treatment units with run-on/run-off controls; Metal-based wastes will be reclaimed in metal catalyst reclamation/regeneration units
On-site Surface Impoundment	18-D	K169	Crude oil sludges will be disposed in Subtitle D land treatment units with run-on/run-off controls

[a] Management code corresponds to the coding system used in the 1992 RCRA Section 3007 Survey.

For the Contingent Management Scenario, the assumed compliance practice is disposal in a Subtitle D land treatment unit with run-on/run-off controls or landfill. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Discharge of flushing waters to on-site wastewater treatment systems will be continued because of a "headwater exemption" provided for waste-derived sludges from wastewater treatment systems that are not already hazardous due to a previous listing.

3. K171 - Catalyst from catalytic hydrotreating

The most common residual disposal method for catalyst from catalytic hydrotreating is disposal in an off-site Subtitle D or C landfill. Residual treatment methods include off-site incineration, other cleaning/extraction, other phase separation, on-site land treatment, on-site oxidation of pyrophoric material, and stabilization. Other disposal methods include disposal in a on-site Subtitle D or C landfill.

For the Listing Scenario, the assumed compliance practice is disposal in an on-/off-site Subtitle C landfill. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Off-site combustion practices will be transferred to Subtitle C incineration units. The practice of disposing this waste in on-site land treatment and Subtitle D landfill units will be abandoned.

For the LDR Scenario, the assumed compliance practice is either disposal in an off-site Subtitle C incinerator followed by vitrification and Subtitle C landfill of the ash or metal catalyst reclamation/regeneration. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Off-site combustion practices will be transferred to Subtitle C incineration units. The practice of disposing this waste in on-site land treatment and Subtitle D landfill units will be abandoned.

For the Contingent Management Scenario, the assumed compliance practice is metal catalyst reclamation/regeneration. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Off-site combustion practices will be transferred to metal catalyst reclamation/regeneration units. The practice of disposing this waste in on-site land treatment and Subtitle D landfill units will be abandoned.

4. K172 - Catalyst from catalytic hydrorefining

The most common residual disposal method for catalyst from catalytic hydrorefining is disposal in an off-site Subtitle D or C landfill. Residual treatment methods include other cleaning/extraction, other phase separation, on-site oxidation of pyrophoric material, and stabilization. Other disposal methods include disposal in an on-site Subtitle D or C landfill.

For the Listing Scenario, the assumed compliance practice is disposal in an on-/off-site Subtitle C landfill. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. The practice of disposing this waste in on-site Subtitle D landfill units will be abandoned.

For the LDR Scenario, the assumed compliance practice is either disposal in an off-site Subtitle C incinerator followed by vitrification and Subtitle C landfill of the ash or metal catalyst reclamation/regeneration. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. The practice of disposing this waste in on-site Subtitle D landfill units will be abandoned.

For the Contingent Management Scenario, the assumed compliance practice is metal catalyst reclamation/regeneration. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. The practice of disposing this waste in on-site Subtitle D landfill units will be abandoned.

3.3.2 Current (Baseline) and Compliance Waste Management Costs

Frequently, several individual waste management methods make up the components of the waste management practice (i.e., waste management train) for storing, treating, recycling, and disposing a waste stream. Because of the significant number of waste management trains reported by the petroleum refining industry, current (baseline) and compliance management costs were developed for the individual components of each waste management train. The incremental difference in cost between the baseline and compliance management costs for each individual component of the waste management train were summed together to develop incremental compliance cost estimates for the complete waste management practice.

For example, Petroleum Refinery X generates 100 metric tons per year of crude oil tank sludge. The current waste management train is to filter the oily sludge, recycling 60 metric tons (MT) of oil filtrate back to the distillation unit, and storing 40 MT of filter sludge in roll-on/roll-off bins within an accumulation container storage area prior to spreading the sludge in an on-site Subtitle D land treatment unit. To comply with Subtitle C accumulation treatment tank regulations, the filtration operation will require the construction and maintenance of a secondary containment system underneath the filtration unit ($2,500/yr). The cost for operating and maintaining the filtration unit will not change and a new filtration unit will not need to be purchased ($0/yr). The 60 MT of oil filtrate recycled back to the distillation unit is exempt from regulation under the "definition of solid waste". A recycled oil credit is applied to the oil filtrate if the facility has not been de-oiling its sludges as a baseline management practice ($110/MT credit; see Section 3.3.7 for waste minimization discussion). To comply with Subtitle C accumulation container storage area regulations, a new accumulation container storage area will need to be constructed and maintained ($4,800/yr). To comply with Subtitle C disposal regulations, the refinery will abandon the on-site land treatment unit ($87/MT), choose not to construct an on-site Subtitle C land treatment unit in anticipation of future LDR regulations that will mandate the closure of such a unit, and transport and dispose the waste in an off-site Subtitle C landfill ($73/MT for transport and $233/MT for Subtitle C landfill). Under the LDR Scenario, off-site Subtitle C incineration ($92/MT for transport and $1,867/MT for Subtitle C incineration) will be the required disposal method.

The following table (Table 3.7) demonstrates how the incremental compliance cost was derived for the management of this waste stream. Incremental management costs for other waste streams (e.g., CSO sludge and hydrotreating and hydrorefining catalysts) generated by this refinery were calculated in a similar manner with compliance management practices dependent upon the current waste management trains reported in the RCRA 3007 Survey for these wastes. These waste stream-specific incremental compliance costs were then aggregated into a total for the refinery. Incremental RCRA administrative compliance costs (e.g., manifest system implementation, contingency plan and emergency procedures, and permit applications) were added to the facility total.

TABLE 3.7
DERIVATION OF INCREMENTAL COMPLIANCE COSTS

Baseline Management	Compliance Cost (A)	Baseline Cost (B)	Incremental Compliance Cost (A-B)
Filtration Unit	Construct Subtitle C Filtration Unit Secondary Containment: $2,500/yr	No Subtitle C Secondary Containment Exists: $0/yr	$2,500/yr
Accumulation Container Storage Area	Construct Subtitle C Accumulation Container Storage Area: $4,800/yr	No Subtitle C Accumulation Storage Area Exists: $0/yr	$4,800/yr
Recycle Oil Filtrate to Distillation Unit	Recycled Oil Credit: $110/MT * 60 MT.	Not Applicable (Oily Sludge)	($6,600/yr)
Disposal of Filtration Sludge	Transport to Off-Site Subtitle C Landfill: ($73/MT + $233/MT) * 40 MT Transport to Off-Site Subtitle C Incineration: ($92/MT + $1,867/MT) * 40 MT	On-Site Land Treatment: $87/MT * 40 MT	Listing Scenario: $8,760/yr LDR and Listing Scenario: $74,880/yr
Total Incremental Compliance Management Cost			Listing Scenario: $9,460/yr LDR and Listing Scenario: $75,580/yr

Current Management Practices

Current waste management practice unit costs were provided in the 1992 RCRA 3007 Survey by facilities in the petroleum refining industry. Where a facility did not report a unit cost, an average cost was derived from the unit costs provided by other facilities using similar management practices. If data were not available to derive an industry-based average unit cost, EPA estimated a unit cost for the management practice.

- Statistical tests were conducted on the reported industry unit costs for each baseline management practice to identify outlier or extreme values. These outliers were assumed to be reporting errors since they are significantly different (using a 95 percent confidence interval) from the unit costs provided by other facilities. Twenty management unit costs unit costs provided by industry were not used because they were determined to be statistical outliers for a given baseline management practice. Costs reported by facilities as flat fees were not included in the average since these expenses do not represent unit costs.

- From the remaining list of industry-reported unit costs, average industry unit costs were developed for the following baseline management practices:

  - Off-site incineration
  - On-site land treatment
  - Off-site land treatment
  - Off-site municipal Subtitle D landfill
  - Off-site industrial Subtitle D landfill
  - Off-site Subtitle C landfill
  - On-site Subtitle D landfill
  - On-site Subtitle C landfill
  - Transfer of metal catalysts for reclamation/regeneration
  - Transfer for use as a fuel or to make a fuel

  All unit costs are in 1992 dollars. These average industry unit costs were assigned to facility-specific waste streams using these baseline management practices that had no reported unit cost or had a reported unit cost which was identified as an outlier.

- For all other baseline management practices, unless unit costs were reported, EPA estimated unit costs. EPA estimated unit costs for the following baseline management practices:

  - On-site industrial furnace
  - Off-site stabilization
  - On-site disposal surface impoundment
  - Transfer for use as an ingredient in products that are placed on the land

Table 3.8 presents the unit costs for each baseline management practice. The table is organized by management practice, management code, and wastes managed. The cost information in the table is labeled estimated or industry average.

The following list summarizes the major baseline waste management assumptions that EPA used in developing the costs for the current waste management practices.

- Wastes reported as being managed in an "invalid" baseline management method were assumed, when possible, to be managed in the same way as other similar wastes at the same facility. When this was not possible, the waste was assumed to be managed in the most frequently used disposal or recycling method for that waste based on other reporting facilities. If process recycling/metal catalyst reclamation was assumed, that unit of the facility was removed from the analysis and no cost impact was included due to its exemption from RCRA Subtitle C requirements under the definition of solid waste.

- Wastes reported as being managed in an "other" baseline management practice were assumed to be managed by the most frequent method used by other reporting facilities. For example, if "other on-site thermal treatment" was reported, the most frequently used on-site thermal treatment was assumed. If "other treatment" was reported, the most frequent of all types of treatment was assumed.

TABLE 3.8
SUMMARY OF BASELINE MANAGEMENT UNIT COSTS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost[b]
RESIDUAL STORAGE METHODS			
Tank	01-A	K169, K170, K171, K172	Same as compliance, therefore, no incremental cost (c).
Container (e.g., drum)	01-B	K169, K170, K171, K172	Same as compliance, therefore, no incremental cost (c).
Pile	01-C	K169, K170, K172	Same as compliance, therefore, no incremental cost (c).
Roll-on/Roll-off Bin	01-E	K169, K170, K171, K172	Same as compliance, therefore, no incremental cost (c).
Other	01-F	K169, K170, K171, K172	Same as compliance, therefore, no incremental cost (c).
RESIDUAL TREATMENT METHODS			
On-site Industrial Furnace	02-E	K170	Facilities Reporting Cost: 0 Facilities Not Reporting Cost: 1 Estimated: $50/MT
Other On-site Thermal Treatment	02-F	K169	Facilities Reporting Cost: 1 Facilities Not Reporting Cost: 0
Off-site Incineration	03-A	K169, K171	Facilities Reporting Cost: 25 Facilities Not Reporting Cost: 6 Industry Average: $1,867/MT
Washing with Distillate	04-C	K169, K170	Same as compliance, therefore, no incremental cost (c).
Washing with Water	04-D	K169	Same as compliance, therefore, no incremental cost (c).

TABLE 3.8 (CONTINUED)
SUMMARY OF BASELINE MANAGEMENT UNIT COSTS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost[b]
Other Cleaning/Extraction	04-E	K171, K172	Same as compliance, therefore, no incremental cost (c).
Sludge Thickening	05-A	K169, K170	Same as compliance, therefore, no incremental cost (c).
Sludge De-watering	05-B	K169, K170	Same as compliance, therefore, no incremental cost (c).
Settling	05-C	K169, K170	Same as compliance, therefore, no incremental cost (c).
Filtration	05-D	K169, K170	Same as compliance, therefore, no incremental cost (c).
Pressure Filtration/Centrifuging	05-E	K169, K170	Same as compliance, therefore, no incremental cost (c).
Chemical Emulsion Break	05-F	K169	Same as compliance, therefore, no incremental cost (c).
Thermal Emulsion Break	05-G	K169, K170	Same as compliance, therefore, no incremental cost (c).
Other Phase Separation	05-J	K169, K171, K172	Same as compliance, therefore, no incremental cost (c).
On-site Land Treatment	06-A	K169, K170, K171	Facilities Reporting Cost: 12 Facilities Not Reporting Cost: 13 Industry Average: $87/MT
Off-site Land Treatment	06-B	K169, K170	Facilities Reporting Cost: 11 Facilities Not Reporting Cost: 1 Industry Average: $78/MT
Discharge to On-site WWT Facility	07	K169, K170	Same as compliance, therefore, no incremental cost.

TABLE 3.8 (CONTINUED)
SUMMARY OF BASELINE MANAGEMENT UNIT COSTS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost[b]
Drying on a Pad	08	K169, K170	Same as compliance, therefore, no incremental cost (c).
On-site Oxidation of Pyrophoric Material	10	K171, K172	Same as compliance, therefore, no incremental cost (c).
On-site Stabilization	11-A	K169, K170, K171, K172	Same as compliance, therefore, no incremental cost (c).
Off-site Stabilization	11-B	K171	Facilities Reporting Cost: 1 Facilities Not Reporting Cost: 3 Estimated: $82/MT
Other Treatment	13	K169	Estimated or industry average of the industry's most frequent management method for the same waste managed.
RESIDUAL TRANSFER METHODS			
Transfer of Precious or Nonprecious Metal Catalysts for Reclamation/Regeneration	16-A	K171, K172	Facilities Reporting Cost: 86 Facilities Not Reporting Cost: 28 Industry Average: $725/MT
Transfer for Off-site Direct Use as a Fuel or to Make Fuel	16-B	K169, K170	Facilities Reporting Cost: 13 Facilities Not Reporting Cost: 6 Industry Average: $752/MT
Transfer for Use as an Ingredient in Products that are Placed on the Land	16-E	K169	Facilities Reporting Cost: 2 Facilities Not Reporting Cost: 1 Estimated: $50/MT

TABLE 3.8 (CONTINUED)
SUMMARY OF BASELINE MANAGEMENT UNIT COSTS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost[b]
Transfer to Off-site Entity	16-G	K169, K171	Estimated or industry average of the industry's most frequent transfer method for the same waste managed.
RESIDUAL DISPOSAL METHODS			
NPDES	17-A	K169	Same as compliance, therefore, no incremental cost.
Off-site Municipal Subtitle D Landfill	17-D	K169, K170, K171	Facilities Reporting Cost: 24 Facilities Not Reporting Cost: 12 Industry Average: $52/MT
Off-site Industrial Subtitle D Landfill	17-E	K169, K170, K171, K172	Facilities Reporting Cost: 59 Facilities Not Reporting Cost: 20 Industry Average: $58/MT
Off-site Subtitle C Landfill	17-F	K169, K170, K171, K172	Facilities Reporting Cost: 60 Facilities Not Reporting Cost: 22 Industry Average: $233/MT
On-site Subtitle D Landfill	18-A	K170, K171, K172	Facilities Reporting Cost: 13 Facilities Not Reporting Cost: 5 Industry Average: $49/MT

TABLE 3.8 (CONTINUED)
SUMMARY OF BASELINE MANAGEMENT UNIT COSTS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost[b]
On-site Subtitle C Landfill	18-B	K169, K171, K172	Facilities Reporting Cost: 4 Facilities Not Reporting Cost: 3 Industry Average: $43/MT
On-site Surface Impoundment	18-D	K169	Facilities Reporting Cost: 1 Facilities Not Reporting Cost: 2 Estimated: $10/MT

[a] Management code corresponds to the coding system used in the 1992 RCRA Section 3007 Survey.
[b] EPA used the unit costs reported by facilities except when unit costs were determined to be statistical outliers for that practice. When unit costs were not provided by the facility, EPA calculated an industry average based on unit costs reported by facilities, excluding outliers, where applicable or estimated unit costs and cost equations. Unit costs that are industry averages or are estimated by EPA are identified in the table as industry average and estimated, respectively.
[c] Management costs (i.e., operation and maintenance costs) for baseline and compliance are the same for this management method. Secondary containment is not included in the baseline cost for all facilities. Secondary containment costs are the compliance costs for the facilities where required.

Listing Management Practices

Unit costs, unit prices, and cost equations were developed to determine annualized costs for alternative compliance waste management practices for each waste listing on a facility specific basis. Costs, prices, and cost equations were obtained from the industry averages derived from the 1992 RCRA 3007 Survey, previous listing determinations and land disposal restrictions analyses. When necessary, cost estimates were developed specifically for this rule using cost data from engineering cost documents.

Table 3.9 presents the unit costs for the compliance waste management practices. The information in the table is organized similarly to Table 3.8. Incremental compliance costs can be determined for each management practice by subtracting the baseline management cost in Table 3.8 from the compliance management cost in Table 3.9. For example, the incremental compliance cost for wastes currently managed in off-site municipal Subtitle D landfills is \$181/MT (\$233/MT - \$52/MT).

The following list summarizes the major waste management assumptions that EPA used in developing the costs for the compliance waste management practices.

- EPA-derived 1992 cost estimates were annualized assuming an interest rate of 7 percent over 20 years on a before-tax cost basis.

- Existing disposal impoundments do not meet Subtitle C surface impoundment minimum technological requirements and are, therefore, dredged with the sludges being transported and disposed to an on-/off-site Subtitle D Landfill prior to the date of final listing, and recommissioned for non-hazardous wastes use. The disposal impoundments are replaced with on-site filtration and off-site Subtitle C landfill.

- Facilities need to upgrade their storage areas to meet the Subtitle C container accumulation (i.e., <90 day storage) requirements. Because wastes are stored for <90 days, these storage areas do not need permits. Costs for container accumulation areas are estimated using the cumulative waste generation amount within one year (i.e., periodically generated wastes were not annualized) to reflect peak demand conditions.

- Facilities need to upgrade their storage/treatment tanks to meet the Subtitle C accumulation (i.e., <90 day storage) tank requirements. Because wastes are stored/treated for <90 days, these tanks do not need permits. Costs for accumulation tanks are estimated using the cumulative waste generation amount within one year (i.e., periodically generated wastes were not annualized) to reflect peak demand conditions.

TABLE 3.9
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]	
RESIDUAL STORAGE METHODS				
Tank	01-A	K169, K170, K171, K172	Upgrade to Subtitle C accumulation tank system:[c]	
			0-350 MT/yr	$2,500/yr
			350-1,040 MT/yr	$2,700/yr
			1,040-2,420 MT/yr	$3,100/yr
			2,420-5,180 MT/yr	$3,600/yr
			5,180-8,640 MT/yr	$4,100/yr
			8,640-12,100 MT/yr	$4,600/yr
			12,100-16,730 MT/yr	$5,000/yr
Container (e.g., drum)	01-B	K169, K170, K171, K172	Upgrade to Subtitle C accumulation container storage area:[c]	
			0-20 MT/yr	$3,300/yr
			20-70 MT/yr	$4,600/yr
			70-4,680 MT/yr	$4,800/yr
			4,680-9,360 MT/yr	$6,100/yr

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]	
Pile	01-C	K169, K170, K172	Construct new Subtitle C accumulation tank storage system:[d]	
			0-350 MT/yr	$3,800/yr
			350-1,040 MT/yr	$4,400/yr
			1,040-2,420 MT/yr	$5,600/yr
			2,420-5,180 MT/yr	$7,400/yr
			5,180-8,640 MT/yr	$8,900/yr
			8,640-12,100 MT/yr	$10,300/yr
			12,100-16,730 MT/yr	$11,400/yr
			16,730-19,010 MT/yr	$12,400/yr
			19,010-27,650 MT/yr	$13,700/yr
			27,650-43,200 MT/yr	$17,100/yr
			43,200-69,130 MT/yr	$20,500/yr
Roll-on/Roll-off Bin	01-E	K169, K170, K171, K172	Upgrade to Subtitle C accumulation container storage area:[c]	
			0-20 MT/yr	$3,300/yr
			20-70 MT/yr	$4,600/yr
			70-4,680 MT/yr	$4,800/yr
			4,680-9,360 MT/yr	$6,100/yr
Other	01-F	K169, K170, K171, K172	Assume most common storage type reported by the industry for that waste type.	

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
RESIDUAL TREATMENT METHODS			
On-site Industrial Furnace	02-E	K170	Listing or LDR Scenarios: Estimated: $100/MT plus RCRA Part 264 and 270 administrative costs to permit Contingent Management Scenario: See Management Code 06-A
Other On-site Thermal Treatment	02-F	K169	See Management Code 02-E

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
Off-site Incineration	03-A	K169, K171	Listing and LDR Scenarios: Off-site Subtitle C industry average: $1,867/MT LDR Scenario: Construct new on-site Subtitle C incinerator: 0-35 MT/yr $640,000/yr 35-75 MT/yr $659,000/yr 75-125 MT/yr $686,000/yr 125-175 MT/yr $708,000/yr 175-225 MT/yr $728,000/yr 225-325 MT/yr $745,000/yr 325-750 MT/yr $820,000/yr 750-1,250 MT/yr $938,000/yr 1,250-1,750 MT/yr $1,039,000/yr 1,750 and over MT/yr $1,131,000/yr Contingent Management Scenario: K169 - See Management Code 06-A K171 - See Management Code 16-A
Washing with Distillate	04-C	K169, K170	See Management Code 01-A
Washing with Water	04-D	K169	See Management Code 01-A
Other Cleaning/Extraction	04-E	K171, K172	See Management Code 01-A

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
Sludge Thickening	05-A	K169, K170	See Management Code 01-A
Sludge De-watering	05-B	K169, K170	See Management Code 01-A
Settling	05-C	K169, K170	See Management Code 01-A
Filtration	05-D	K169, K170	See Management Code 01-A
Pressure Filtration/Centrifuging	05-E	K169, K170	See Management Code 01-A for existing units Waste Minimization Opportunity for Oily Sludges (see Section 3.3.7): Construct new on-site Subtitle C pressure filtration/centrifuge unit: 0 - 350 MT/yr $3,300/yr 350 - 1,040 MT/yr $3,600/yr 1,040 - 2,420 MT/yr $4,200/yr 2,420 - 5,180 MT/yr $4,900/yr
Chemical Emulsion Break	05-F	K169	See Management Code 01-A
Thermal Emulsion Break	05-G	K169, K170	See Management Code 01-A
Other Phase Separation	05-J	K169, K171, K172	See Management Code 01-A

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
On-site Land Treatment	06-A	K169, K170, K171	Listing Scenario: Abandon on-site land treatment unit and dispose waste in on-/off-site Subtitle C Landfill (see Management Code 17-F for costs) LDR Scenario: K169, K170 - See Management Code 03-A K171 - Option 1 -- See Management Code 03-A for incinerator costs; Estimated vitrification cost is $240/MT; Option 2 -- See Management Code 16-A Contingent Management Scenario: K169, K170 - For existing units, no increase in cost due to compliance if run-on/run-off controls exist; For new units, construct on-site Subtitle D land treatment unit with run-on/run-off controls: Estimated: $21/MT for on-site land treatment plus $2,200/yr for run-on/run-off controls (size < 750 MT/yr) or $2,600/yr for controls (size 750 - 1,500 MT/yr) K171 - See Management Code 16-A

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
Off-site Land Treatment	06-B	K169, K170	Listing Scenario: Ship to off-site Subtitle C landfill (see Management Code 17-F for costs) LDR Scenario: Ship to off-site Subtitle C incinerator (see Management Code 03-A) Contingent Management Scenario: No increase in cost due to compliance
Discharge to On-site WWT Facility	07	K169, K170	The headwaters exemption results in no increase in cost due to compliance for wastewaters discharged to NPDES or POTW; If wastewater is discharged into on-site disposal impoundment then wastewater treatment system tanks require upgrading to Subtitle C accumulation tank systems (see Management Code 01-A for costs)
Drying on a Pad	08	K169, K170	See Management Code 01-C
On-site Oxidation of Pyrophoric Material	10	K171, K172	See Management Code 01-A
On-site Stabilization	11-A	K169, K170, K171, K172	See Management Code 01-A
Off-site Stabilization	11-B	K171	Estimated: $75/MT
Other Treatment	13	K169	See Management Code 01-A

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
RESIDUAL TRANSFER METHODS			
Transfer of Precious or Nonprecious Metal Catalysts for Reclamation/Regeneration	16-A	K171, K172	Assume a 5 percent increase in the baseline price passed back to refiners for increased Subtitle C storage, transportation, and management costs incurred from waste-derived residuals at metal reclamation/regeneration facilities.
Transfer to Non-Petroleum Refinery for Direct Use as a Fuel or to Make a Fuel	16-B	K169, K170	Estimated: $180/MT
Transfer for Use as an Ingredient in Products that are Placed on the Land	16-E	K169	Estimated: $180/MT
Transfer to Other Off-site Entity	16-G	K169, K171	Assume most common reported transfer method reported by industry for each waste type.
RESIDUAL DISPOSAL METHODS			
NPDES	17-A	K169	No increase in cost due to compliance
Off-site Municipal Subtitle D Landfill	17-D	K169, K170, K171	See Management Code 18-A
Off-site Industrial Subtitle D Landfill	17-E	K169, K170, K171, K172	See Management Code 18-A

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
Off-site Subtitle C Landfill	17-F	K169, K170, K171, K172	Listing Scenario: Off-site Subtitle C Industry Average: $233/MT LDR Scenario: K169, K170 - See Management Code 03-A K171, K172 - Option 1 -- See Management Code 03-A for incinerator costs; Estimated vitrification cost is $240/MT; Option 2 -- See Management Code 16-A Contingent Management Scenario: K169 - See Management Code 06-A K170 - No increase in cost due to compliance K171 - See Management Code 16-A

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
On-site Subtitle D Landfill	18-A	K170, K171, K172	Listing Scenario: See Management Code 17-F LDR Scenario: K169, K170 - See Management Code 03-A K171, K172 - Option 1 -- See Management Code 03-A for incinerator costs; Estimated vitrification cost is $240/MT; Option 2 -- See Management Code 16-A Contingent Management Scenario: K169 - See Management Code 06-A K170 - No increase in cost due to compliance K171, K172 - See Management Code 16-A

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
On-site Subtitle C Landfill	18-B	K169, K171, K172	Listing Scenario: No increase in cost due to compliance LDR Scenario: K169 - See Management Code 03-A K171, K172 - Option 1 -- See Management Code 03-A for incinerator costs; Estimated vitrification cost is $240/MT; Option 2 -- See Management Code 16-A Contingent Management Scenario: K169 - See Management Code 06-A K171, K172 - See Management Code 16-A

TABLE 3.9 (CONTINUED)
SUMMARY OF COMPLIANCE MANAGEMENT UNIT COSTS AND COST EQUATIONS
(1992 Dollars)

Baseline Management Practice	Mgmt Code[a]	Wastes Managed	Unit Cost or Cost Equation [b]
On-site Surface Impoundment	18-D	K169	One-time dredging of impoundment sludge and disposal in off-site Subtitle D Landfill at $90/MT prior to final listing and then recommission impoundment for non-hazardous waste use; Manage sludge using upgrade of existing on-site filtration system (see Management Code 01-A for costs) Listing Scenario: Dispose in off-site Subtitle C landfill (see Management Code 17-F for costs). LDR Scenario: See Management Code 03-A Contingent Management Scenario: See Management Code 06-A

[a] Management code corresponds to the coding system used in the 1992 RCRA Section 3007 Survey.
[b] EPA used the unit costs reported by facilities except when unit costs were determined to be statistical outliers for that practice. When unit costs were not provided by the facility, EPA calculated an industry average based on unit costs reported by facilities, excluding outliers, where applicable or estimated unit costs and cost equations. Unit costs that are industry averages or are estimated by EPA are identified in the table as industry average and estimated, respectively.
[c] Management costs (i.e., operation and maintenance costs) for baseline and compliance are the same for this management method. Secondary containment is not included in the baseline cost for all facilities. Secondary containment costs are the compliance costs for the facilities where required.
[d] Management costs (i.e., O&M costs) for baseline and compliance are the same for this management method. Secondary containment is not included in the baseline cost for all facilities. The compliance cost will involve closure of the drying pad and construction of a drying tank system with secondary containment.

- Sludges and spent catalysts are managed by Subtitle C landfill. The two options for Subtitle C landfill are 1) off-site (i.e., commercial transport and disposal) and 2) on-site landfill. EPA assumed the industry average of $233/MT for off-site Subtitle C landfill reported by the petroleum refining industry and $73/MT for transport by truck with dumpsters. On-site landfilling is economical only for those facilities generating $\geq$2,300 Mton/year of metal-based residuals (i.e., spent catalysts) only, assuming that LDR regulations will require incineration of oil-based residuals. In the Listing Scenario, which allows landfill as an option for oil-based residuals, no facilities generate enough waste to construct an on-site landfill.

- There are no additional compliance costs, only additional revenues for facilities currently recycling residuals back into their process units. For some metal catalyst regeneration/reclamation processes, waste-derived residuals are not exempt from RCRA Subtitle C storage, transportation, and/or management requirements.

Appendix A presents the annual before-tax incremental compliance costs for the Listing Scenario. Incremental compliance costs range from $4 million to $16 million per year. The expected value for the listing option is $8 million per year.

LDR Management Practices

Table 3.9 presents the unit costs for the LDR compliance waste management practices.

The following list summarizes the major waste management assumptions that EPA used in developing the costs for the LDR compliance waste management practices.

- EPA-derived 1992 cost estimates were annualized assuming an interest rate of 7 percent over 20 years on a before-tax cost basis.

- Oil-based residuals (crude and CSO tank sludges) are managed by Subtitle C incineration. The two options for Subtitle C incineration are 1) off-site (i.e., commercial transportation and incineration) and 2) on-site incineration. EPA assumed the industry average of $1,867/MT for off-site incineration reported by the petroleum refining industry and $163/MT for truck transport of drummed wastes. On-site incineration is economical only for those facilities generating $\geq$415 Mton/year of waste. Eight facilities, which are currently in the RCRA program, generate enough waste to construct new on-site incinerators. Two facilities will permit an existing on-site incinerator. Two facilities have existing permitted on-site incinerators. Two facilities that generate enough waste, which are not in the RCRA program and do not have existing on-site incinerators are assumed to ship their waste to an off-site incinerator. EPA assumes that these two facilities will choose to avoid potential corrective action costs which are triggered when a facility applies for a RCRA Part B permit.

- Metal-based residuals (spent catalysts) are managed by Subtitle C incineration followed by vitrification and Subtitle C landfill of the ash or are managed in metal catalyst reclamation/regeneration units. The two options for are 1) off-site Subtitle C incineration followed by Subtitle C vitrification and Subtitle C landfill of the ash and 2) metal catalyst reclamation/regeneration. EPA assumed the industry average of $1,867/MT for off-site Subtitle C incineration and ash disposal reported by the petroleum refining industry and $163/MT for truck transport of drummed wastes, and $240/MT for Subtitle C vitrification. EPA assumed an industry average of $725/MT for off-site transfer of precious or nonprecious metal catalysts for reclamation/regeneration.

Appendix B presents the before-tax incremental compliance costs for the combined affect of the listing and LDR waste management practices (LDR Scenario) for high-cost and low-cost options. The high-cost LDR option assumes all affected oil-based sludge residuals will be incinerated off site and all metal catalyst residuals will be combusted in a Subtitle C incinerator followed by Subtitle C vitrification and Subtitle C landfill of the ash off site. The low-cost LDR option assumes on- and off-site incineration of oil-based sludge residuals depending on the economic viability of constructing a unit on site and off-site reclamation/regeneration of metal catalyst residuals. Incremental compliance costs range from $21 million to $101 million per year. The expected value for the high-cost LDR option is $61 million per year and for the low-cost option it is $41 million per year.

<u>Contingent Management Practices</u>

Table 3.9 presents the unit costs for the compliance waste management practices.

The following list summarizes the major waste management assumptions that EPA used in developing the costs for the contingent compliance management waste management practices.

- For CSO sludges, if the waste is currently managed in a Subtitle D landfill it will continued to be managed in this unit. Otherwise, the waste will be managed in an existing or newly constructed on-site land treatment unit with run-on/run-off controls unless the waste is currently managed in an off-site land treatment unit, where the practice is assumed to be continued.

- Under the second option, crude oil sludges will be managed in an existing or newly constructed on-site land treatment unit with run-on/run-off controls unless the waste is currently managed in an off-site land treatment unit, where the practice is assumed to be continued. Cost savings (benefits - approximately $200,000 in annual savings) result from the switch from Subtitle D and C landfill practices to Subtitle D land treatment units with run-on/run-off controls.

Appendix C presents the before-tax incremental compliance costs for the Contingent Management Scenario for the high-cost and low-cost options. The high-cost contingent management option assumes that crude oil sludges will be incinerated on or off site depending on the economic viability of constructing an incinerator on site. CSO sludges are managed in either a Subtitle D land treatment unit with run-on/run-off controls or a Subtitle D landfill. The low-cost option assumes crude oil sludges are managed in Subtitle D land treatment units with run-on/run-off controls. Metal catalysts are reclaimed/regenerated off site under both options. Incremental compliance costs range from $3 million to $42 million per year. The expected value for the high-cost contingent management option is $24 million per year and for the low-cost option it is $6 million per year.

3.3.3 Current (Baseline) and Compliance Waste Transportation Costs

Current waste transportation practice unit costs were provided in the 1992 RCRA 3007 Survey by facilities in the petroleum refining industry. Where a facility did not report a unit cost, an average cost was derived from the unit costs provided by other facilities using similar transportation practices. If data were not available to derive an industry-based average unit cost, EPA estimated a unit cost for the transportation practice. These unit costs also were used for compliance cost estimates. For example, incremental compliance costs for wastes currently transported by truck in drums to a Subtitle D landfill, which now will be managed in a Subtitle C landfill, are $189/MT ($224/MT-$45/MT). Note that these industry-average unit costs reflect the average distance the industry is transporting their wastes.

- Statistical tests were conducted on the reported industry unit costs for each baseline transportation practice to identify outlier or extreme values. These outliers were assumed to be reporting errors since they are significantly different (using a 95 percent confidence interval) from the unit costs provided by other facilities. Eight transportation unit costs provided by industry were not used because they were determined to be statistical outliers for a given baseline transportation practice. Costs reported by facilities as flat fees were not included in the average since these expenses do not represent unit costs.

- From the remaining list of industry-reported unit costs, average industry unit costs were developed for the following baseline transportation practices:

  - Truck with drums to Subtitle D landfill
  - Truck with dumpsters to Subtitle D landfill
  - Truck with a bed to Subtitle D landfill
  - Tanker truck to Subtitle D landfill
  - Truck with other container to Subtitle D landfill
  - Truck with drums to Subtitle C landfill
  - Truck with dumpsters to Subtitle C landfill
  - Truck with a bed to Subtitle C landfill

- Tanker truck to Subtitle C landfill
- Truck with other container to Subtitle C landfill
- Truck with drums to incinerator
- Truck with dumpsters to incinerator
- Truck to facility for direct use as a fuel or to make a fuel
- Truck with drums to catalyst regenerator
- Truck with dumpsters to catalyst regenerator

All unit costs are in 1992 dollars. These average industry unit costs were assigned to those facilities using these baseline transportation practices that had no reported unit cost or had a reported unit cost which was identified as an outlier.

- For all other baseline transportation practices, unless unit costs were reported, EPA estimated unit costs. EPA estimated unit costs for the following baseline transportation practices:

  - Truck to industrial furnace
  - Barge
  - Pipeline

- No additional transportation practices are assumed for compliance. Applicable baseline transportation costs also were used for compliance transportation costs.

Table 3.10 presents the unit costs for each baseline and compliance transportation practice. The table is organized by transportation practice, transportation code, and wastes managed. The cost information in the table is labeled estimated or industry average.

The following list summarizes the major baseline waste transportation assumptions that EPA used in developing the costs for the current waste transportation practices.

- Wastes reported as being transported in an "invalid" baseline transportation method were assumed, when possible, to be transported in the same way as other similar wastes with similar management methods at the same facility. When this was not possible, the waste was assumed to be transported in the most frequently used transportation method for that waste based on other reporting facilities.

- Wastes reported as being transported in an "other" baseline transportation method were assumed to be transported by the most frequent method used by other reporting facilities.

TABLE 3.10
SUMMARY OF BASELINE/COMPLIANCE TRANSPORTATION UNIT COSTS
FOR THE PETROLEUM REFINING INDUSTRY
(1992 Dollars)

Baseline Transportation Practice	Tran. Code	Wastes Managed	Unit Cost
Truck	TR-2	K169, K170, K171, K172	Subtitle D landfill Facilities Reporting Cost: 82 Facilities Not Reporting Cost: 76 Industry Average: Truck with drums: $45/MT Truck with dumpsters: $27/MT Truck with bed: $17/MT Tanker truck: $55/MT Truck with other container: $72/MT Subtitle C landfill Facilities Reporting Cost: 62 Facilities Not Reporting Cost: 18 Industry Average: Truck with drums: $224/MT Truck with dumpsters: $73/MT Truck with bed: $47/MT Tanker truck: $123/MT Truck with other container: $178/MT

TABLE 3.10 (CONTINUED)
SUMMARY OF BASELINE/COMPLIANCE TRANSPORTATION UNIT COSTS
FOR THE PETROLEUM REFINING INDUSTRY
(1992 Dollars)[b]

Baseline Transportation Practice	Tran. Code	Wastes Managed	Unit Cost
Truck (con't)	TR-2		<u>Incineration</u> Facilities Reporting Cost: 17 Facilities Not Reporting Cost: 4 Industry Average: Truck with drums: \$163/MT Truck with dumpster: \$92/MT <u>Industrial furnace</u> Facilities Reporting Cost: 2 Facilities Not Reporting Cost: 0 Estimate: (Truck) \$47/MT <u>Reclamation/Regeneration</u> Facilities Reporting Cost: 84 Facilities Not Reporting Cost: 37 Industry Average: Truck with drums: \$95-\$167/MT Truck with dumpster: \$74/MT Truck with other container: \$80 \$129/MT <u>Direct Use as Fuel or to Make a Fuel</u> Facilities Reporting Cost: 13 Facilities Not Reporting Cost: 4 Industry Average: \$102/MT <u>Use as an Ingredient in Product Land Applied</u> Facilities Reporting a Cost: 5 Facilities Not Reporting a Cost: 1 Industry Average: \$34/MT

TABLE 3.10 (CONTINUED)
SUMMARY OF BASELINE/COMPLIANCE TRANSPORTATION UNIT COSTS
FOR THE PETROLEUM REFINING INDUSTRY
(1992 Dollars)[b]

Baseline Transportation Practice	Tran. Code	Wastes Managed	Unit Cost
Barge	TR-3	K171	Facilities Reporting Cost: 2 Facilities Not Reporting Cost: 1 Estimated: $300/MT
Ship	TR-4	K169	Facilities Reporting Cost: 3 Facilities Not Reporting Cost: 0
Pipeline	TR-5	K169	Facilities Reporting Cost: 1 Facilities Not Reporting Cost: 9 Estimate: $0/MT

[a] Management code corresponds to the coding system used in the 1992 RCRA Section 3007 Survey.
[b] EPA used the unit costs reported by facilities except when unit costs were determined to be statistical outliers for that practice. When unit costs were not provided by the facility, EPA calculated an industry average based on unit costs reported by facilities, excluding outliers, where applicable or estimated unit costs and cost equations. Unit costs that are industry averages or are estimated by EPA are identified in the table as industry average and estimated, respectively.

3.3.4 RCRA Administrative Compliance Costs

Facilities generating and managing listed hazardous wastes are subject to Parts 262, 264, 266, and 270 of RCRA. RCRA administrative compliance activities for each of these parts are briefly described below.

RCRA Part 262 standards regulate generators of hazardous waste. All facilities producing a newly listed waste are subject to this part. There are four subparts to the Part 262 standards. First, those facilities generating hazardous waste must obtain an EPA identification number. Second, an approved manifest system must be established for those facilities shipping wastes off site. Third, before transporting hazardous waste off site, a series of pre-transport requirements must be satisfied such as labeling, marking, and placarding. Fourth, specified recordkeeping and reporting requirements are applicable.

RCRA Part 264 standards apply to owners/operators of hazardous waste treatment, storage, and disposal facilities. Facilities seeking compliance after listing through use of a new on-site Subtitle C landfill or incinerator will be subject to this part. Part 264 has six applicable subparts which address general facility standards (Subpart B); preparedness and prevention (Subpart C); contingency plan and emergency procedures (Subpart D); manifest systems, recordkeeping, and reporting (Subpart E); closure (Subpart G); and financial requirements (Subpart H).

RCRA part 266 includes standards for the management of specific hazardous wastes and specific types of hazardous waste management facilities. Facilities seeking compliance after listing through the use of on-site boilers and industrial furnaces (BIFs) will be subject to this part. The requirements for BIFs are the same as those described for Part 264 above.

RCRA Part 270 standards address RCRA permitting requirements for facilities that treat, store, or dispose of hazardous wastes. Facilities seeking compliance after listing through use of a Subtitle C landfill, incinerator, or BIF will be subject to this part. Part 270 requires a facility to submit a RCRA Part B permit application and obtain a RCRA permit. RCRA Part B permits for incinerators and BIFs include trial burn requirements to assure proper combustion of the newly listed wastes.

The listings RCRA administrative and on-going compliance costs were based on engineering estimates for activities required by 40 CFR Parts 262, 264, 266, and 270. The basis for these costs are for five to six waste listings[2]. These estimates appear to be reasonable compared to more detailed cost estimates in the September 1994 document entitled "Economic Benefits of RCRA Noncompliance (EBN)". The basis for the EBN costs varied from four to nine waste streams, with six being typical, so that approximate costs per waste

[2] These costs were developed based on the assumption that five to six of the original number of residuals being considered would be listed. Since only four wastes are being listed, the RCRA administrative costs are estimated to be too high by approximately 20 to 30 percent overall.

stream were used in the comparison. For permitting costs, the EBN document itself was used for cost estimating. For BIFs, no EBN costs have been published, so no comparison was possible. The EBN costs themselves were compared to EPA Information Collection Request (ICR) cost data and were generally higher due to the increased level of detail of costs for required activities in the EBN document.

Table 3.11 summarizes the RCRA administrative costs associated with each of the RCRA Parts described above.

TABLE 3.11
RCRA ADMINISTRATIVE COSTS
(1992 Dollars)

RCRA Part	Activity	Initial Items	Initial Cost	Periodic Items	Periodic Cost
262	Generator Requirements: New listing (i.e., facility currently a hazardous waste generator) and new wastes managed off-site	Assess current waste generation and management practices, evaluate regulations listing the new wastes, review procedures for packaging and labeling, personnel training, and contingency plan and local emergency arrangements	$2,300 if permitted TSDF/BIF facility total costs are $900	Additional time for completing manifest for newly listed wastes, packaging and marking, annual portion of biennial report, personnel training, and contingency plan and local emergency arrangements	$3,200/yr if permitted TSDF/BIF facility total costs are $1,600
262	Generator Requirements: New listing and all new wastes managed on-site	Assess current waste generation and management practices, evaluate regulations listing the new wastes, personnel training, and contingency plan and local emergency arrangements	$2,000 if permitted TSDF/BIF facility total costs are $700	Additional time for annual portion of biennial report, personnel training and contingency plan and local emergency arrangements	$400/yr if permitted TSDF/BIF facility total costs are $100
262	Generator Requirements: First listing (i.e., facility not currently a hazardous waste generator) and new wastes managed off-site	Become aware of and understand responsibilities under regulations, assess current waste generation and management practices, obtain EPA ID number, review and determine applicable DOT requirements, develop procedures for manifesting, packaging, and labeling, and purchase file cabinet for storing manifests and reports, personnel training, and contingency plan and local emergency arrangements	$9,800 if permitted TSDF/BIF facility total costs are $2,200	Complete manifest, packaging and labeling of hazardous waste for off-site shipment, annual portion of biennial report, filing exception report, personnel training, and contingency plan and local emergency arrangements	$6,700/yr if permitted TSDF/BIF facility total costs are $2,800

TABLE 3.11 (CONTINUED)
RCRA ADMINISTRATIVE COSTS
(1992 Dollars)

RCRA Part	Activity	Initial Items	Initial Cost	Periodic Items	Periodic Cost
262	Generator Requirements: First listing and all new wastes managed on-site	Become aware of and understand responsibilities under regulations, assess current waste generation and management practices, and obtain EPA ID number, personnel training, and contingency plan and local emergency arrangements	$7,900 if permitted TSDF/BIF facility total costs are $1,300	Annual portion of biennial report, personnel training, and contingency plan and local emergency arrangements	$2,400/yr if permitted TSDF/BIF facility total costs are $600
264, Parts A-H	TSDF Requirements (if landfill and/or incinerator): Not currently a TSDF	Prepare waste analysis plan, conduct waste analysis on newly listed wastes, personnel training, inspection schedule, personnel training, purchase required preparedness and prevention equipment, make arrangements with local authorities, prepare contingency plan, record waste analyses results in operating record, prepare closure plan and closure cost estimate, select financial assurance mechanisms for closure and third party liability, submit Part A application, and corrective action scheduling	$53,000 (a) $84,000 (b)	Review waste analysis plan and contingency plan, conduct and record inspections, personnel training review, test and maintain preparedness and prevention equipment, maintain operating record, and review closure plans and cost estimates, financial assurance, and corrective action schedule	$11,000/yr (a) $16,000/yr (b)

TABLE 3.11 (CONTINUED)
RCRA ADMINISTRATIVE COSTS
(1992 Dollars)

RCRA Part	Activity	Initial Items	Initial Cost	Periodic Items	Periodic Cost
264, Parts A-H	TSDF Requirements (if landfill and/or incinerator): Currently a TSDF	Conduct waste analysis on newly listed wastes; modify waste analysis plan, inspection schedule, personnel training, contingency plan, closure plan, closure cost estimate, financial assurance mechanism for closure, and Part A application; and record waste analyses results in operating record, and corrective action scheduling	$41,000 (a) $69,000 (b)	Review waste analysis plan and contingency plan, conduct and record inspections, personnel training, maintain operating record, and review closure plans and cost estimates, financial assurance, and corrective action schedule	$6,500/yr (a) $11,000/yr (b)
266	Boiler and Industrial Furnace (BIF) Requirements: Not currently a TSDF	Same as Part 264	$53,000	Same as Part 264	$11,000/yr
266	Boiler and Industrial Furnace (BIF) Requirements: Currently a TSDF	Same as Part 264	$41,000	Same as Part 264	$6,500/yr

TABLE 3.11 (CONTINUED)
RCRA ADMINISTRATIVE COSTS
(1992 Dollars)

RCRA Part	Activity	Initial Items	Initial Cost	Periodic Items	Periodic Cost
266	Boiler and Industrial Furnace (BIF) Requirements: Small quantity exempt (i.e., facility burns <330 gallons/month, which is estimated to be <15 Mton/yr based on stack height of 50 meters)	Submit written notification to EPA	$100	Document compliance with the hazardous waste quantity, firing rate, and heating value per calendar month	$300/yr
270	Part A Requirements Not Currently Permitted	Part A application	$2,400 (a) $3,500 (b)		$0/yr
	Part A Requirements Currently Permitted	Modify Part A application	$600 (a) $900 (b)		$0/yr
270	Part B Permit Requirements - BIF: Not currently permitted	Part B permit application consisting of the following requirements: general information, SWMU, and BIF (including trial burns)	$117,000	Permit renewal every 10 years	$43,000/10 yr
270	Part B Permit Requirements - BIF: Currently permitted	Modify Part B permit for BIF (including trial burns)	$108,000	Permit renewal every 10 years	$39,000/10 yr

TABLE 3.11 (CONTINUED)
RCRA ADMINISTRATIVE COSTS
(1992 Dollars)

RCRA Part	Activity	Initial Items	Initial Cost	Periodic Items	Periodic Cost
270	Part B Permit Requirements - Incineration: Not currently permitted	Part B permit application consisting of the following requirements: general information, SWMU, and incineration (including trial burns)	$268,000	Permit renewal every 10 years	$99,000/10 yr
270	Part B Permit Requirements - Incineration: Currently permitted	Modify Part B permit for incineration (including trial burns)	$255,000	Permit renewal every 10 years	$95,000/10 yr

(a) TSDF administrative costs if one new unit
(b) TSDF administrative costs if two new units

3.3.5 Corrective Action Compliance Costs

Incremental corrective action costs associated with unpermitted facilities include the cost to conduct a RCRA Facility Investigation (RFI), a Corrective Measures Study (CMS), and remediate solid waste management units (SWMUs) and areas of concern (AOCs). Because of the petroleum refinery waste listings, some of the 97 unpermitted refineries of the 162 affected by the listings determination may be brought into the RCRA permitting program. A certain number of the currently unpermitted facilities will seek a RCRA Part B permit for incinerators or BIFs. RCRA corrective action is typically triggered by facilities seeking a RCRA permit. RCRA Facility Assessments (RFAs) will be conducted at these facilities to determine the need for corrective action (RFI, CMS, and remediation) prior to issuing a permit. Currently, permitted facilities will likely have already gone through this process, therefore, corrective action costs have already been incurred or assessed under the Corrective Action rulemaking. EPA assumed that industry will avoid triggering the corrective action process by not constructing on-site Subtitle C units requiring permits unless the facility already has a RCRA Part B permit for other types of on-site treatment, storage, and disposal units. However, if this assumption is incorrect, corrective action cost estimates were derived as follows.

The following probabilities of facilities incurring corrective action costs were assumed:[3]

- There is a 75 percent probability that corrective action investigation (RFI and CMS) and remediation will be conducted at a facility.

- Separating the two activities, there is a 66 percent probability that both corrective action investigations and remediations will be conducted at a facility and a 9 percent probability that only corrective action investigations will be conducted.

The Draft Final Rule Corrective Action RIA presents corrective action costs expressed as a present value using a seven percent discount rate in 1992 dollars. The Draft Final Rule Corrective Action RIA does not provide detailed information on how the discounting was applied (i.e., what costs occurred in what year). The following corrective action cost estimates, which reflect a 7 percent before-tax discount rate, were derived based on the Proposed Rule and Final Rule Corrective Action RIAs.

- The weighted average correction action remediation (only) cost per "triggered" facility is $600,000/yr with a range from $2,000/yr to $17.0 million/yr.

[3] Estimates of probabilities that corrective action is triggered at a facility and corrective action costs were obtained from the U.S. EPA, "Draft Regulatory Impact Analysis for the Final Rulemaking on Corrective Action for Solid Waste Management Units," Office of Solid Waste, March 1993, and the U.S. EPA, "Regulatory Impact Analysis for the Proposed Rulemaking on Corrective Action for Solid Waste Management Units," Office of Solid Waste, June 25, 1990.

- Approximately 15 percent of the triggered facilities incur corrective action investigation and remediation costs greater than $900,000/yr.

- Approximately 60 percent of the triggered facilities incur corrective action investigation and remediation costs between $90,000/yr and $900,000/yr.

- Approximately 25 percent of the triggered facilities incur corrective action investigation and remediation costs less than $90,000/yr.

- Typical investigation costs are $33,800/yr for an RFI and $9,800/yr for a CMS.

Using the above estimates, the following assumptions were used in the bounding analysis for corrective action compliance costs:

- Listing Scenario:

  No unpermitted facilities would need a RCRA permit. Three facilities will be seeking to permit existing units (i.e., on-site incinerators/BIFs), but, these facilities already <u>have RCRA Part B permits</u>.

- LDR Scenario, Option 1 - Off-site Subtitle C Incineration:

  No unpermitted facilities would need a RCRA permit. Three facilities will be seeking to permit existing units (i.e., on-site incinerators/BIFs), but, these facilities already <u>have RCRA Part B permits</u>. Two facilities already have permitted on-site incinerators.

- LDR Scenario, Option 2 - On-Site Subtitle C Incineration:

  EPA assumed that no unpermitted facilities will construct an on-site incinerator. However, two unpermitted facilities generate enough waste to construct and permit an on-site incinerator. Eight permitted facilities will seek to construct and permit an on-site incinerator under their current permit. Two permitted facilities will be seeking to permit existing units under their current permit. Two facilities already have permitted on-site incinerators.

- Contingent Management Scenario, Option 1 - On-Site Subtitle C Incineration of Crude Oil Tank Sludges and Subtitle D Management of CSO Sludges:

  EPA assumed that no unpermitted facilities will construct an on-site incinerator. However, one unpermitted facility generates enough waste to construct and permit an on-site incinerator. Three permitted facilities will seek to construct and permit an on-site incinerator under their current permit. Two permitted facilities will be seeking to permit existing units under their current permit. Two facilities already have permitted on-site incinerators.

- Contingent Management Scenario, Option 2 - Subtitle D Management of Oil-Based Sludges:

  No unpermitted facilities will need a RCRA permit. One facility already has a permitted on-site landfill.

Corrective action incremental compliance costs may be incurred under the LDR Scenario (Option 2) and the Contingent Management Scenario (Option 1) when it is economically feasible to construct new on-site incinerators at unpermitted facilities. EPA assumed that unpermitted facilities will not seek to construct and permit a new on-site incinerator because of the corrective action implications. Therefore, corrective action costs are zero for all scenarios. However, if facilities do choose to construct on-site incinerators, the corrective action incremental compliance costs would range from \$2.0 million (Best Case) to \$7.2 million (Worst Case) annually for Option 2 of the LDR Scenario, and from \$0.7 million (Best Case) to \$2.7 million (Worst Case) annually for Option 1 of the Contingent Management Scenario. Corrective action costs may be incurred because facilities will be applying for RCRA Part B permits if the facility is currently unpermitted. No incremental corrective action costs are incurred under the Listing Scenario, Option 1 of LDR Scenario when off-site incineration management is assumed, and Option 2 of the Contingent Management Scenario when Subtitle D management of oil-based sludges is assumed.

The corrective action cost results are summarized as follows:

- LDR Scenario, Option 2 - On-site Subtitle C Incineration:

  Possibly two unpermitted facilities may incur total corrective action costs ranging from \$ 0.3 million/yr under the best case, \$0.9 million/yr under the expected case, to \$1.8 million/yr under the worst case.

- Contingent Management Scenario, Option 1 - Subtitle D Management of Oil-Based Sludges:

  Possibly one unpermitted facility may incur total corrective action costs ranging from \$0.2 million/yr under the best case, \$0.4 million/yr under the expected case, to \$0.9 million/yr under the worst case.

The following assumptions were used in preparing the worst, expected, and best cases:

Worst Case:

- Assume 100 percent of the facilities are triggered for corrective action.

- Assume corrective action investigation and remediation costs are $900,000/yr. This value represents the 85th percentile of the estimated corrective action costs in the Draft Final Rule Corrective Action RIA.

Expected Case:

- Assume 75 percent of the facilities will incur corrective action investigation costs of $43,600/yr. This value assumes costs of $33,800/yr to conduct an RFI and $9,800/yr to conduct a CMS.

- Assume 66 percent of the facilities will incur corrective action remediation costs of $600,000/yr. This value represents the weighted average corrective action remediation cost estimated in the Draft Final Rule Corrective Action RIA.

Best Case:

- Assume 50 percent of the facilities will incur corrective action investigation costs of $43,600/yr. At a minimum, some percentage of the facilities will be investigated. The Draft Final Rule Corrective Action RIA indicates that of the 5,800 facilities subject to corrective action, 3,500 (60 percent) will require an RFI. EPA assumed for a "best case" analysis that the percentage would be lower than 60 percent and assumed that only 1 in every 2 facilities (50 percent) will be investigated.

- Assume 37 percent of the facilities will incur corrective action remediation costs of $600,000/yr. The Draft Final Rule Corrective Action RIA indicates that of the 5,800 facilities subject to corrective action, only 2,600 facilities (45 percent) will require remediation. EPA assumed for a "best case" analysis that the percentage would be lower than 45 percent and assumed that a proportionate number (74 percent; 2,600/3,500) of the facilities requiring corrective action investigation will require remediation in the "best case" analysis.

3.3.6 Data Limitations

Many facilities did not report unit treatment, transportation, recycling, and disposal costs in the 1992 RCRA 3007 Survey. Estimates for these unit costs were based on the average derived from other reporting facilities. Where not enough data were provided, EPA estimated unit costs. Because of the potential for over or underestimating incremental compliance costs using industry averages and cost estimates as surrogates to facility-specific costs, sensitivity analyses on the cost and economic impacts have been conducted using industry average and estimated unit costs that are 25 percent lower (lower-bound estimate of incremental cost of compliance) and 25 percent higher (upper-bound estimate of incremental cost of compliance) to bound uncertainties within the cost estimates.

3.3.7 Waste Minimization Opportunities

Regulatory compliance costs for the petroleum refining industry can be lowered through use of waste minimization practices. De-oiling (i.e., using a filtration unit) of crude oil storage tank and clarified slurry oil (CSO) tank sludges is a common management practice within the industry. EPA assumed that facilities will implement filtration of oily crude oil and CSO sludges as a cost-effective waste minimization practice. The cost of installing and operating a filtration unit was added to those facilities that did not report filtration of their oily sludge wastes. Based on data reported by those facilities currently filtering their sludges, 60 percent of the waste stream becomes oil filtrate that is recycled back to a process unit on site. Only 40 percent remains as a filtration sludge requiring further management. When estimating revenues gained from substituting the oil filtrate for crude oil feedstock, EPA assumed that 90 percent of the filtrate is oil with an assumed value (credit) equal to 90 percent of crude oil. Revenues from the oily sludge filtration were estimated to be approximately $1.3 million per year.

3.4 Regulatory Compliance Costs

Under Executive Order 12866, EPA must determine whether a regulation constitutes a "significant regulatory action." One of the criteria for defining a significant regulatory action, as defined under the Executive Order, is if the rule has an annual effect on the economy of $100 million or more. To determine whether the listing is a significant regulatory action under this criteria, all costs are annualized on a before-tax basis assuming a seven percent real rate of return. The savings attributable to corporate tax deductions or depreciation on capital expenditures for pollution control equipment are not considered in calculating before-tax costs.

3.4.1 Annualization of Before-Tax Compliance Costs

A facility-by-facility annualized before-tax cost analysis was conducted for 162 facilities, in the petroleum refining industry, which generate wastes affected by the listings determination. The 162 facilities are owned and operated by 80 manufacturers. Several facilities submitted incomplete information to EPA regarding waste generation. However, average data from the other petroleum refining facilities were used as proxy values for the plants without waste generation data to avoid understating industry regulatory compliance cost impacts. Nine facilities do not generate any of the new waste stream listings, one facility is closed, and one facility did not respond to the survey; consequently, these facilities were excluded from this compliance cost impact analysis of the petroleum refining industry.

Annual before-tax baseline and compliance costs were estimated for each facility and each waste listing using the unit costs, prices, and waste quantities discussed previously. Before-tax compliance costs were used because they represent a resource or social cost of the listings determination, measured before any business expense tax deductions available to affected companies. In reformulating the social costs of compliance, EPA used a discount rate of seven percent, assumed a 20-year borrowing period, a 20-year operating life for tanks, secondary containment systems, container storage areas, and incinerators, and a 10-year operating life for filtration units for annualizing capital costs.

The following formula was used to determine the before-tax annualized costs:

Annual Before-Tax Costs =

(Capital and One-Time Initial Costs)(CRF_{20}) + (10-YR Capital Costs/1.07^{10})(CRF_{20}) + (Annual O&M Costs) + [(5-YR O&M Costs/1.07^{5}) + (5-YR O&M Costs/1.07^{10}) + (5-YR O&M Costs/1.07^{15})](CRF_{20}) + (10-YR O&M Costs/1.07^{10})(CRF_{20}) + (Closure Costs/1.07^{21})(CRF_{20})

Where: CRF_n = Capital recovery factor (i.e., the amount of each future annuity payment required to accumulate a given present value) based on a 7 percent real rate of return (i) and a 20-year borrowing period (n) as follows:

$$\frac{(1+i)^n(i)}{(1+i)^n-1} = 0.09439 \quad \text{when } n = 20$$

The compliance costs are engineering cost estimates that are specific to each waste stream. These costs include capital costs for items such as less than 90-day container storage areas, treatment tanks, incinerators and O&M costs for management of hazardous wastes (i.e., transportation and landfill disposal): In addition, plants will incur 40 CFR Part 262 (first and new listing notification), 264 (treatment tanks, container storage areas, and on-site incinerator), 266 (on-site boiler or industrial furnace), and 270 (on-site boiler or industrial furnace, and on-site incinerator Part B permit) administrative costs. Corrective action costs are assumed to be zero for this listings determination. At a maximum, they may reach $1.8 million per year.

3.4.2 Annualized Compliance Costs

A summary of the annual incremental before-tax compliance costs for each waste due to the listing and the listing including LDR regulations is presented in Table 3.12. A similar summary of the annual incremental before-tax compliance costs for the Contingent Management Scenario is presented in Table 3.13. More detailed summaries, including the baseline and compliance cost totals, are presented in Appendices A, B, and C. Appendices A, B, and C present the before-tax incremental compliance costs due to the listing (Listing

Scenario), the listing including LDR regulations (LDR Scenario), and the listing with contingent management options (Contingent Management Scenario). In the Listing Scenario, EPA assumed all affected oil-based sludge residuals and metal catalyst residuals will be disposed in off-site Subtitle C units corresponding to their current Subtitle D units (e.g., landfill, incinerator, or BIF), except for land treatment which will shift to Subtitle C landfill. The shift to Subtitle C landfill is a major portion of the total incremental compliance cost. An assessment was made of the economic viability of constructing a landfill unit on-site, however, none of the refineries generate enough of the affected wastes to find construction of on-site landfill units to be cost-effective. Incremental compliance costs range from $4 million to $16 million per year with an expected value of $8 million per year.

EPA assumed Subtitle C incineration/BIF of all oil-based residuals and Subtitle C incineration followed by Subtitle C vitrification and Subtitle C landfill of the ash of metal catalyst residuals under the LDR Scenario (Option 1). The shift to Subtitle C incineration of the oil-based residuals is a major portion of the total incremental compliance cost. An assessment also was made of the economic viability of constructing an incineration unit on site. A few of the refineries generate enough of the affected wastes for construction of on-site incineration units to be cost-effective (Option 2). EPA assumed under Option 2 that facilities will ship metal catalyst residuals to off-site metal catalyst regeneration/reclamation operations to take advantage of the exemption from RCRA Subtitle C regulation for metals recovery. Incremental compliance costs range from $33 million to $101 million per year with an expected value of $61 million per year for Option 1, and from $21 million to $68 million per year with an expected value of $41 million per year for Option 2.

EPA assumed on-/off-site Subtitle C incineration/BIF of crude oil tank sludges depending on the economic viability, disposal of CSO sludges in Subtitle D land treatment units with run-on/run-off controls or Subtitle D landfills, and reclamation/regeneration of metal catalyst residuals under the Contingent Management Scenario (Option 1). Option 2 allows the contingent management alternative of crude oil tank sludges being disposed in Subtitle D land treatment units with run-on/run-off controls. Incremental compliance costs range from $12 million to $42 million per year with an expected value of $24 million per year for Option 1, and from $3 million to $11 million per year with an expected value of $6 million per year for Option 2.

The estimated annual before-tax costs are not greater than the $100 million significant regulatory action criteria. The significant regulatory action criteria of adverse impacts on the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities is evaluated in Chapter 4.

TABLE 3.12
ANNUALIZED COSTS FOR THE PETROLEUM REFINING HAZARDOUS WASTE LISTINGS[1]
LISTING AND LDR SCENARIOS
($ MILLIONS)

(1) Waste Stream	(2) Listing Scenario Average Cost (Low-High)	(3) LDR Scenario, Option 1 Off-Site Incineration of Sludges and Off-Site Incineration and Vitrification of Catalysts Average Cost (Low-High)	(4) LDR Scenario, Option 2 On-/Off-Site Incineration of Sludges and Regeneration/Reclamation of Catalysts[2] Average Cost (Low-High)
Crude Oil Tank Sludge	2.2 [1.0 - 3.9]	21.6 [9.3 - 38.8]	16.7 [8.1 - 28.3]
Clarified Slurry Oil Sludge	2.8 [1.4 - 4.8]	22.5 [11.2 - 37.6]	16.8 [9.4 - 26.5]
Hydrotreating Catalyst	1.3 [0.8 - 2.9]	5.0 [3.5 - 7.6]	2.3 [1.2 - 4.5]
Hydrorefining Catalyst	1.5 [0.7 - 3.8]	11.6 [8.3 - 16.5]	3.9 [1.9 - 7.9]
RCRA Administrative Costs	0.5 [0.4 - 0.6]	0.5 [0.4 - 0.7]	0.8 [0.6 - 1.0]
TOTAL	8.3 [4.3 - 16.0]	61.3 [32.7 - 101.2]	40.6 [21.3 - 68.3]

[1] Cost uncertainty (Low-High) is estimated using a +/- 50% adjustment of any estimated quantities and a +/- 25% adjustment of any estimated costs. Current management practice and transportation unit costs were provided in the 1992 RCRA 3007 Survey. If unit costs were not reported, an industry-based average unit cost was used. If data were not available to derive an industry-based average, EPA estimated a unit cost for the management practice based on previous listing determinations, land disposal restrictions analyses, and engineering cost documents. Compliance management practice, transportation, and RCRA administrative unit costs, prices, and cost equations were obtained from industry-based averages derived from the 1992 RCRA 3007 Survey, previous listing determinations and land disposal restrictions analyses, and engineering cost documents.

[2] On-site incinerators are assumed only for those facilities that manage a large enough quantity of waste so that an on-site incinerator is more economical for the facility and which are currently in the RCRA program. All other facilities are assumed to continue managing wastes off site.

TABLE 3.13
ANNUALIZED COSTS FOR THE PETROLEUM REFINING HAZARDOUS WASTE LISTINGS[1]
CONTINGENT MANAGEMENT SCENARIO
($ MILLIONS)

(1) Waste Stream	(2) Contingent Management Scenario, Option 1 Subtitle D Landfill and Land Treatment (w/ controls) of CSO Sludge, On-/Off-Site Incineration of Crude Oil Tank Sludges and Regeneration/Reclamation of Catalysts Average Cost (Low-High)	(3) Contingent Management Scenario, Option 2 Subtitle D Landfill and Land Treatment (w/ controls) of CSO Sludge, Subtitle D Land Treatment (w/ controls) of Crude Oil Tank Sludges and Regeneration/Reclamation of Catalysts Average Cost (Low-High)
Crude Oil Tank Sludge	17.5 [8.5 - 29.8]	(0.5) [(0.2) - (1.0)]
Clarified Slurry Oil Sludge	(0.5) [(0.3) - (0.8)]	(0.5) [(0.3) - (0.8)]
Hydrotreating Catalyst	2.3 [1.2 - 4.5]	2.3 [1.2 - 4.5]
Hydrorefining Catalyst	3.9 [1.9 - 7.9]	3.9 [1.9 - 7.9]
RCRA Administrative Costs	0.6 [0.5 - 0.8]	0.5 [0.3 - 0.6]
TOTAL	23.8 [11.8 - 42.2]	5.6 [3.1 - 11.2]

[1] Cost uncertainty (Low-High) is estimated using a +/- 50% adjustment of any estimated quantities and a +/- 25% adjustment of any estimated costs. Current management practice and transportation unit costs were provided in the 1992 RCRA 3007 Survey. If unit costs were not reported, an industry-based average unit cost was used. If data were not available to derive an industry-based average, EPA estimated a unit cost for the management practice based on previous listing determinations, land disposal restrictions analyses, and engineering cost documents. Compliance management practice, transportation, and RCRA administrative unit costs, prices, and cost equations were obtained from industry-based averages derived from the 1992 RCRA 3007 Survey, previous listing determinations and land disposal restrictions analyses, and engineering cost documents.

[2] On-site incinerators are assumed only for those facilities that manage a large enough quantity of waste so that an on-site incinerator is more economical for the facility and which are currently in the RCRA program. All other facilities are assumed to continue managing wastes off site.

4.0 ECONOMIC IMPACTS OF NEWLY LISTED WASTES

This section presents the estimated economic impacts of this listings determination for selected petroleum refining wastes. A facility-by-facility economic analysis was conducted for 163 facilities in the petroleum refining industry that generate wastes affected by this listings determination.[1] Partial equilibrium analysis is used to specify the baseline market supply and demand, estimate the post-control shift in market supply, estimate the change in equilibrium price and quantity, and predict plant closures.

The remainder of this section is organized as follows: The economic impacts methodology and data sources and limitations are discussed in Section 4.1. Sections 4.2 and 4.3 present the industry economic impacts and limitations of the analysis, respectively. The regulatory flexibility analysis is presented in Section 4.4.

4.1 Economic Impacts Methodology

Economic effects are defined as the difference between the projections of the likely effects on facilities that result from regulatory compliance and the industrial activity likely in the absence of regulation (i.e., baseline conditions). Imposition of regulatory requirements may have an adverse economic effect on industry since expenditures must be made that do not necessarily contribute directly to improved operating efficiency measured in terms of economic return on investment. The difference between the baseline and post-regulatory costs is equal to the incremental cost of compliance on which economic impacts are evaluated.

Economic impacts were evaluated for two regulatory scenarios-- the Listing Scenario and the Listing and LDR Scenario, which reflects compliance with both the listings and land disposal restrictions (LDRs). The Listing Scenario assumes an end disposal management method of Subtitle C landfilling, continued combustion of wastes (where indicated as the baseline management practice) in a Subtitle C incinerator/BIF, or continued metals reclamation/recovery. The combined Listing and LDR Scenario adds a pretreatment management method of solidification prior to Subtitle C landfill for metal-based wastes and assumes combustion in a Subtitle C incinerator/BIF for organic-based wastes. For the lower bound Listing and LDR Scenario, on-site incineration is assumed for those entities generating sufficient quantities of waste, whereby the economics favors on-site incineration. This scenario represents the most cost-effective alternative for compliance with the listing as well as LDRs.

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[1] The economic analysis is based on the listing of five wastestreams including unleaded gasoline sludge, which has since been removed from the list of wastes included in this listings determination. Also, the economic analysis is based on a lower estimate for crude oil tank sludge and CSO tank sludge quantities, each having 9,000 MT/yr managed in final management practices. These quantities have since been revised to 14,600 and 13,100 MT/yr, respectively.

4.1.1 Partial Equilibrium Analysis

Partial equilibrium analysis is used to estimate primary and secondary economic impacts resulting from implementation of the listings. Primary economic impacts include changes in the market equilibrium price and output levels, changes in the value of shipments or revenues to domestic producers, and plant closures. Secondary impacts include changes in employment, use of energy inputs, balance of trade, and regional refinery distribution.

The baseline or pre-control petroleum refining market is defined by a domestic market demand equation, a domestic market supply equation, and a foreign market supply equation.[2] The purchase of regulatory control equipment results in an upward shift in the domestic supply curve for refined petroleum products. The height of the shift is determined by the after-tax cash flow required by refineries to offset the per unit increase in production cost as a result of the listings determination. The partial equilibrium model assumes that refineries will seek to increase the price of the product they sell by an amount that recovers the capital and operating costs of the regulatory control requirements over the useful life of the equipment.

Petroleum refineries produce several hundred products. The economic impacts analysis evaluates the impact of the listings on ten petroleum products (i.e., ethane/ethylene, butane/butylene, normal butane/butylene, isobutane/isobutylene, finished motor gasoline, jet fuel, distillate and residual fuel oil, asphalt, and petroleum coke) which represent 91 percent of the 1992 domestically produced petroleum products. Because compliance costs for the hazardous waste listings cannot be allocated to any specific products, output in the partial equilibrium model is defined as a composite, bundled good equal to the sum of price multiplied by the weighted production volumes of each of the ten products.

<u>Primary Economic Impacts</u> - The impact of the listings on market equilibrium price and output is derived by solving for the post-control market equilibrium and comparing the new equilibrium price and quantity to the pre-control equilibrium. Trade impacts are reported as the change in both the volume and dollar value of net imports (exports minus imports). It is assumed that a refinery will close if its post-control supply price exceeds the post-control market equilibrium price.

<u>Secondary Economic Impacts</u> - The estimates of the labor and energy market impacts associated with the listings are based on input-output ratios and estimated changes in domestic production. The labor market impacts are measured as the number of jobs lost due to domestic output reductions. The estimated number of job losses are a function of the change in level of production that is anticipated to occur as a result of

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[2] See Appendix D for a detailed discussion of the economic impacts methodology and the partial equilibrium model algorithms.

the listings. The reduction in energy inputs associated with the listings results from the reduction in expenditures for energy inputs due to production decreases.

Foreign supply is assumed to have the same price elasticity of supply as domestic supply. The U.S. had a negative trade balance in 1992 for each of the refined products, with the exception of distillate fuel oil, which had a slightly positive trade balance of $1.1 million. Therefore, net exports are negative for all products except distillate fuel oil in the baseline model. Foreign and domestic post-control supply are added together to form the total post-control market supply. The intersection of this post-control supply with market demand determines the new market equilibrium price and quantity. Post-control domestic output is derived by deducting post-control imports from the post-control output.

Economic Welfare Impacts - Regulatory control requirements will result in changes in the market equilibrium price and quantity of petroleum products produced and sold. These changes in the market equilibrium price and quantity will affect the welfare of consumers of petroleum products, producers of petroleum products, and society as a whole. The total economic cost of the listings is equal to the sum of the changes in consumer surplus, producer surplus, and the residual surplus and represents the value that society places on goods and services not produced as a result of resources being diverted to increased waste management and disposal under this listings determination.

Consumer Surplus - The change in consumer surplus includes losses of surplus incurred by both foreign consumers (of U.S. exports) and domestic consumers. The partial equilibrium model assumes that the consumer surplus change is allocable to foreign and domestic consumers in the same ratio as sales are divided between foreign and domestic consumers in the pre-control market. Consumers, in total, will experience a loss or gain in economic welfare depending on the magnitude of the changes in post-control price and quantity.

Producer Surplus - The change in producer surplus is composed of two elements. The first element relates to output eliminated as a result of regulatory controls on the treatment and disposal of listed wastes. The second element is associated with the change in price and cost of production for the new market equilibrium quantity. The total change in producer surplus is the sum of these two components. Output eliminated as a result of control costs causes producers to suffer a welfare loss in producer surplus. Refineries remaining in operation after regulatory controls are implemented realize a welfare gain of the post-control equilibrium price minus the pre-control equilibrium price on each unit of production for the incremental increase in the price and, in addition, realize a decrease in welfare per unit for the capital and operating cost of implementing the required control equipment.

Residual Surplus - The changes in economic surplus, as measured by the changes in consumer and producer surplus must be adjusted to reflect the true change in social welfare as a result of this listings determination. The adjustments are necessary due to tax effects differences and to the difference between the private and social discount rates. Two adjustments to economic surplus are necessary to account for tax effects. The first relates to the per unit control cost that reflects after-tax control costs and is used to predict the post-control market equilibrium. A second tax-related adjustment is required because changes in producer surplus have been reduced by a factor of (1-t) to reflect the after-tax welfare impacts of regulatory treatment and disposal requirement costs on affected refineries. Economic surplus must also be adjusted because of the difference between private and social discount rates. The private discount rate is used to shift the supply curve of refineries in the industry since this rate reflects the marginal cost of capital to affected refineries. The economic costs of the regulation, however, must consider the social cost of capital. This rate reflects the social opportunity cost of resources displaced by investments in regulatory treatment and disposal equipment. Together, the adjustment for the two tax effects and the social cost of capital equal the residual change in economic surplus.

Additional detail regarding the calculation of changes in economic welfare is provided in Appendix D (see Changes in Economic Welfare). The results of the economic impact analysis for each regulatory scenario evaluated are presented in Section 4.2.

4.1.2 Data Sources and Limitations

The partial equilibrium model described above requires baseline values for variables and parameters that characterize the petroleum refining market. Table 4.1 lists the variable and parameter inputs to the model that vary for the ten petroleum products evaluated. Table 4.2 lists variables and parameters that are assumed to be the same for all petroleum products.

Data on production volumes were obtained from the 1992 RCRA 3007 Survey. Facilities were asked to report 1992 product yields for all finished products produced at the refinery. Quantity (i.e., refinery output) data are reported in millions of barrels. Imports and exports (1992) of the ten petroleum products evaluated were obtained from the Petroleum Supply Annual, 1992. The baseline market prices ($1992) were obtained from the Petroleum Market Annual, 1993. Prices are stated in barrels per gallon excluding taxes. Other sources for baseline market prices ($1992) include Platts Oil Gram for prices on liquified petroleum gases; Pace Consultants for petroleum coke; and the Asphalt Institute for prices on asphalt. A marginal tax rate of 34 percent, private discount rate of 10 percent, and social discount rate of 7 percent are assumed in the economic analysis. An equipment life of 20 years is assumed for treatment/disposal units including tanks and incinerators and 10 years for filtration units. The number of workers per unit of output, labor, and the energy expenditures per value of shipments were derived from the U.S. Department of Commerce, Annual Survey of Manufactures (ASM), 1991. Data from the ASM used to derive these estimates include the 1991 annual values for total number of workers employed, total expenditures on energy, and the value of shipments for SIC 2911.

A bounding analysis was conducted for two regulatory scenarios to account for uncertainty in reporting quantities and cost estimates. The lower bound analysis assumes a 50 percent reduction in any estimated quantity (non-reported) and a 25 percent reduction in any estimated cost. The upper bound analysis assumes a 50 percent increase in any estimated quantity (non-reported) and a 25 percent increase in any estimated cost. Additionally, the economic analysis was based on the listing of five wastestreams including unleaded gasoline sludge, which has since been removed from the wastes to be listed under this listings determination. Compliance costs associated with unleaded gasoline sludge represent 11 and 14 percent of the total compliance cost used in the evaluation of economic impacts under the lower and upper bound regulatory scenarios, respectively. As a result, economic impacts for the 98 facilities generating unleaded gasoline sludge will be overestimated. Finally, the regulatory options used to evaluate economic impacts differ slightly from those that were used to calculate the cost of compliance. This difference does not affect the total cost of compliance for the Listing Scenario or the lower bound Listing and LDR Scenario, but does have an impact on the upper bound Listing and LDR Scenario, such that costs are understated by $8 million. As a result, economic impacts may be underestimated for the upper bound Listing and LDR Scenario.

4.2 Estimated Industry Impacts

For purposes of presentation, the results of the economic impacts analysis are presented as a bounding analysis whereby the Listing Scenario, lower bound, represents the least costly compliance option. The Listing and LDR Scenario, off-site incineration, represents the worst case or most costly compliance option. The Listing and LDR Scenario, on-site incineration, assumes on-site incineration for those refineries generating sufficient quantities of wastes, whereby the economics favors on-site incineration. This scenario represents the most cost-effective regulatory alternative assuming compliance with both the listings and LDRs. Results are presented on an aggregate basis to protect the confidentiality of facilities affected by this listings determination.

The partial equilibrium model is used to analyze the market outcome of this listings determination. The purchase of regulatory compliance equipment will result in an upward shift in the domestic supply curve for refined petroleum products. The height of the shift is determined by the after-tax cash flow required to offset the per unit increase in production costs. Since the control costs vary for each of the domestic refineries, the post-control supply curve is segmented, or a step function. Underlying production costs for each refinery are unknown; therefore, a worst case scenario is assumed. The plants with the highest control costs per unit of production are assumed to also have the highest pre-control per unit

TABLE 4.1

Baseline 1992 Domestic Production and Price

Variable/Products	Domestic Production[1] (million bbls)	Price[2] ($1992)
Ethane/Ethylene	19.4	8.53
Propane/Propylene	176.3	12.90
Normal Butane/Butylene	90.1	15.19
Isobutane	15.8	18.61
Finished Motor Gasoline	2,565.1	28.43
Kerosene-Type Jet Fuel	529.3	25.41
Distillate Fuel Oil	1,070.1	25.51
Residual Fuel Oil	378.1	12.94
Asphalt and Road Oil	129.3	30.80
Coke	154.2	1.36

[1] As reported in the 1992 RCRA 3007 Survey

[2] Sources: U.S. Department of Energy, Energy Information Administration, Petroleum Marketing Annual, 1993, Table 4, U.S. Refiner Prices of Petroleum Products for Resale; Platts Oil Gram Spot Price Assessment (Average of March 6, June 4, October 2, 1992) for ethane/ethylene, propane/propylene, normal butane/butylene, and isobutane; Pace Consultants for Coke; and the Asphalt Institute for Asphalt.

TABLE 4.2

Baseline Inputs for the Petroleum Refining Industry

Variable/Inputs	Value
Demand Elasticity (ϵ)	-0.646
Supply Elasticity (γ)	1.24
Tax Rate (t)	0.34
Private Discount Rate (r)	0.10
Social Discount Rate	0.07
Equipment Life (T)[1]	20/10 years
Labor (L_0)[2]	9.12 Workers
Energy (E_0)[3]	\$0.03
Import Ratio[4]	0.07
Export Ratio[5]	0.02
Number of Operating Petroleum Refineries	173

[1] 20-year life assumed for treatment tanks and incinerators and a 10-year life assumed for filtration units.
[2] Production workers per million barrels produced per year.
[3] Energy expenditures per dollar value of shipments.
[4] Value of imports divided by value of domestic production, computed from Table 2, Petroleum Supply Annual, 1992, DOE/EIA.
[5] Value of exports divided by value of domestic production, computed from Table 2, Petroleum Supply Annual, 1992, DOE/EIA.

cost of production. Thus, firms with the highest per unit cost of regulatory control are assumed to be marginal in the post-control market.

4.2.1 Listing Scenario

The lower bound regulatory option, Listing Scenario, assumes an end disposal management method of Subtitle C landfilling or continued combustion of wastes, where indicated as the baseline management practice, in a Subtitle C incinerator/BIF. Table 4.3 presents the economic impacts predicted by the partial equilibrium model.

<u>Primary Economic Impacts</u> - Under this scenario, the average price for all ten products combined is estimated to increase 0.03 percent. Domestic production is expected to decrease by 1.3 million barrels per year, representing a 0.03 percent decrease in annual production. The value of shipments or revenues for domestic producers are expected to increase for the ten products combined by approximately $9.0 million annually. This revenue increase results given that the percent increase in price exceeds the percent decrease in quantity for goods with inelastic demand.

The model estimates that up to two refineries may close as a result of the predicted decrease in production. Those refineries with the highest per unit control costs are assumed to be marginal in the post-control market. Refineries that have post-control supply prices that exceed the market equilibrium price are assumed to close. This assumption is consistent with the theory of perfect competition, which presumes all firms in the industry are price takers. Firms with the highest per unit regulatory compliance costs may not have the highest underlying cost of production. As a result, this assumption may overstate the number of plant closures and other adverse effects of the listing. In addition, a single national market for a homogeneous product is assumed in the partial equilibrium analysis. There are some regional trade barriers, however, that would protect individual refineries from closure.

The estimated primary impacts reported depend on the set of parameters used in the partial equilibrium model. One of the parameters, the price of elasticity of demand, consists of a range for the ten products evaluated.[3] The midpoint of the weighted average of price elasticities associated with the ten products evaluated was used to estimate the reported economic impacts. Sensitivity analyses were performed for the low and high weighted average elasticities. In general, the sensitivity analysis shows that the estimated primary impacts are relatively insensitive to reasonable changes of price elasticity of demand estimates.

<u>Secondary Economic Impacts</u> - Implementation of the listings will have an impact on secondary markets including the labor and energy markets, foreign trade, and regional

[3] See Appendix D, Table D.3 for product-specific price elasticities.

TABLE 4.3

Summary of Economic Impacts

Economic Impacts	Listing Scenario Lower Bound[1]	Listing and LDR Scenario Lower Bound[2]	Listing and LDR Scenario Upper Bound[3]
PRIMARY ECONOMIC IMPACTS[4]			
Average Price Increase Over All Products	0.03%	0.08%	0.76%
Annual Production Decrease Amount (MMbbl) Percentage Change	 (1.3) (0.03%)	 (3.27) (0.06%)	 (30.93) (0.59%)
Annual Value of Shipments Amount (MM$92) Percentage Change	 $9.0 0.01%	 $22.59 0.02%	 $213.34 0.16%
Number of Plant Closures	0-2	0-2	0-2
SECONDARY ECONOMIC IMPACTS[3]			
Annual Job Loss Number Percentage Change	 (12) (0.03%)	 (30) (0.06%)	 (282) (0.59%)
Annual Decrease In Energy Use Amount (MM$92) Percentage Change	 ($1.02) (0.03%)	 ($2.57) (0.06%)	 ($24.32) (0.59%)
Annual Net Foreign Trade Loss Amount (MMbbl) Percentage Change Dollar Value ($/MMbbl)	 (0.20) (0.12%) ($6.35)	 (0.49) (0.3%) ($15.96)	 (4.70) (2.8%) ($152.60)

1 assumes an end disposal management method of Subtitle C landfilling or continued combustion of wastes, where indicated as the baseline management practice in a Subtitle C incinerator/BIF.

2 assumes a pretreatment management method of solidification prior to Subtitle C landfill for metal-based wastes and combustion in an on-site Subtitle C incinerator/BIF for organic-based wastes for those refineries generating sufficient quantities to warrant on-site incineration.

3 assumes a pretreatment management method of solidification prior to Subtitle C landfill for metal-based wastes and combustion in an off-site Subtitle C incinerator/BIF for organic-based wastes.

4 brackets indicate decreases or negative values.

effects. Under this scenario, the number of workers employed by firms in SIC 2911 is estimated to decrease by 12 workers annually, representing a 0.03 percent decrease in total employment. The estimated decrease in employment reflects only direct employment losses due to reductions in domestic production of refined petroleum products. Gains in employment anticipated to result from operation and maintenance of regulatory control equipment have not been included in the analysis due to the lack of available data. An estimated decrease in energy use of $1.02 million annually is expected for the industry. As production decreases, the amount of energy input utilized by the refining industry also declines. The change in energy use does not consider the increased energy use associated with operating and maintaining the regulatory control equipment due to the lack of available data. For this reason, energy impacts may be overstated.

Implementation of the listings will increase the cost of production for domestic refineries relative to foreign refineries, all other factors held constant. This change in the relative price of imports will cause domestic imports of refined petroleum products to increase and domestic exports to decrease. The balance of trade overall for refined petroleum products is currently negative (i.e., imports exceed exports). Imposition of the listings will further increase the negative balance of trade. Net exports are anticipated to decline by 0.20 million barrels annually, representing a 0.12 percent decline. The dollar value of the total decline in net exports is estimated at $6.35 million ($1992) annually. No significant regional impacts are anticipated from implementation of the listings since only up to two facilities are anticipated to close and impacts overall are minimal.

Economic Welfare Impacts - Regulatory controls affect society's economic well-being by causing a reallocation of productive resources within the economy. Resources are allocated away from the production of goods and services (i.e., refined petroleum products) to waste management and disposal. By definition, the economic costs of pollution control are the opportunity costs incurred by society for productive resources reallocated in the economy to regulatory control. The economic cost of this listings determination can be measured as the value that society places on goods and services not produced as a result of resources being diverted to increased waste management and disposal.[4]

The sum of the change in consumer surplus, producer surplus, and residual surplus to society constitutes the economic cost of the regulation. Under this scenario, there is a welfare gain to producers of $24.71 million annually and a welfare loss to consumers of $43.36 million annually. The residual surplus, which accounts for tax effects and differences between the private and social discount rates, is estimated at a gain of

[4] See Appendix D, Changes in Economic Welfare, for a discussion of measures of consumer, producer, and residual surplus.

$14.02 million annually for a net economic cost or opportunity loss to society of $4.63 million annually (i.e., [(24.71 + 14.02) - 43.36 = -4.63]). This would suggest that the loss to society in terms of goods and services not produced, as a result of resources being diverted to increased waste management and disposal, is valued at $4.63 million annually.

4.2.2 Listing and LDR Scenario, Lower Bound Regulatory Option

The lower bound regulatory option, Listing and LDR Scenario, assumes a pretreatment management method of solidification prior to Subtitle C landfill for metal-based wastes and combustion in a Subtitle C incinerator/BIF for organic-based wastes for those refineries generating sufficient quantities to warrant on-site incineration. This scenario represents the most cost-effective option for compliance with the listings and LDRs.

Primary Economic Impacts - Under this scenario, the average price for all ten products combined is estimated to increase 0.08 percent. Domestic production is expected to decrease by 3.27 million barrels per year, representing a 0.06 percent decrease in annual production. The value of shipments or revenues for domestic producers are expected to increase for the ten products combined by approximately $22.6 million annually. Similar to the Listing Scenario, it is estimated that up to two refineries may close as a result of the decrease in production predicted by the model.

Secondary Economic Impacts - Under this scenario, the number of workers employed by firms in SIC 2911 is estimated to decrease by 30 workers annually, representing a 0.06 percent decrease in total employment. The estimated decrease in employment reflects only direct employment losses due to reductions in domestic production of refined petroleum products. An estimated decrease in energy use of $2.57 million annually is expected for the industry. Imposition of the listings will further increase the negative balance of trade. Net exports are anticipated to decline 0.49 million barrels annually, representing a 0.3 percent decline. The dollar value of the total decline in net exports is estimated at $15.96 million ($1992) annually. No significant regional impacts are anticipated from implementation of the listing, since only up to two refineries are anticipated to close and impacts overall are minimal.

Economic Welfare Impacts - The sum of the change in consumer surplus, producer surplus, and residual surplus to society constitutes the economic cost of this listings determination. Under this regulatory option, there is a welfare gain to producers of $57.7 million annually and a welfare loss to consumers of $108.9 million annually. The residual surplus, which accounts for tax effects and differences between the private and social discount rates, is estimated at a gain of $30.9 million annually for a net economic cost or opportunity loss to society of $20.3 million annually (i.e., [(57.7 + 30.9) - 108.9 = -20.3]). This would suggest that the loss to society in terms of goods and services not produced, as a result of resources being diverted to increased waste management and disposal, is valued at $20.3 million annually.

4.2.3 Listing and LDR Scenario, Upper Bound Regulatory Option

The upper bound regulatory option, Listing and LDR Scenario, assumes a pretreatment management method of solidification prior to Subtitle C landfill for metal-based wastes and combustion in a Subtitle C incinerator/BIF for organic-based wastes.

Primary Economic Impacts - Under this scenario, the average price for all ten products combined is estimated to increase 0.76 percent. Domestic production is expected to decrease by 30.9 million barrels per year, representing a 0.59 percent decrease in annual production. The value of shipments or revenues for domestic producers are expected to increase for the ten products combined by approximately $213 million annually. Similar to the Listing Scenario, it is estimated that up to two refineries may close as a result of the decrease in production predicted by the model.

Secondary Economic Impacts - Under this scenario, the number of workers employed by firms in SIC 2911 is estimated to decrease by 282 workers annually, representing a 0.59 percent decrease in total employment. The estimated decrease in employment reflects only direct employment losses due to reductions in domestic production of refined petroleum products. An estimated decrease in energy use of $24.32 million annually is expected for the industry. Imposition of the listings will further increase the negative balance of trade. Net exports are anticipated to decline 4.7 million barrels annually, representing a 2.8 percent decline. The dollar value of the total decline in net exports is estimated at $152.6 million ($1992) annually. No significant regional impacts are anticipated from implementation of the listing, since only up to two refineries are anticipated to close and impacts overall are minimal.

Economic Welfare Impacts - The sum of the change in consumer surplus, producer surplus, and residual surplus to society constitutes the economic cost of this listings determination. Under the Listing and LDR Scenario, there is a welfare gain to producers of $616.8 million annually and a welfare loss to consumers of $1,033.75 million annually. The residual surplus, which accounts for tax effects and differences between the private and social discount rates, is estimated at a gain of $318.58 million annually for a net economic cost or opportunity loss to society of $98.37 million annually (i.e., [(616.8 + 318.58) - 1033.75 = -98.37]). This would suggest that the loss to society in terms of goods and services not produced, as a result of resources being diverted to increased waste management and disposal, is valued at $98.37 million annually.

4.3 Limitations of the Analysis

Limitations associated with the partial equilibrium model are as follows: First, a single national market for a homogeneous product is assumed in the partial equilibrium analysis. There are some regional trade barriers, however, that would protect individual refineries.

The analysis also assumes that the refineries with the highest control costs are marginal in the post-control market. Refineries that are marginal in the post-control market have per unit control costs that significantly exceed the average. In addition, the cost allocation methodology assigns all of the control costs to the ten petroleum products evaluated in the analysis rather than the entire product slate for each refinery. As a result, impacts may be overestimated for the predicted post-control market equilibrium price and quantity, revenues, and plant closures. Furthermore, some refineries may find it profitable to expand production in the post-control market. This would occur when a firm found its post-control incremental unit cost to be smaller than the post-control market price. Expansion by these firms would result in a smaller decrease in output and increase in price than otherwise would occur. Additionally, the economic analysis was based on the listing of five wastestreams including unleaded gasoline sludge, which has since been removed from the list of wastes to be listed under this listings determination. As a result, economic impacts for the 98 facilities generating unleaded gasoline sludge are overestimated. Also, quantity estimates have been increased for the facilities generating crude oil tank sludge and CSO tank sludge. These revised quantity estimates and resulting cost of compliance estimates are not accounted for in the economic analysis. As a result, economic impacts for facilities generating these sludges are underestimated for the scenarios presented in Table 4.3. Finally, because the regulatory options used to evaluate economic impacts differ slightly from those that were used to calculate the cost of compliance, economic impacts may be underestimated for the upper bound Listing and LDR Scenario.

4.4 Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 requires agencies to assess the effect of regulations on small entities and to examine regulatory alternatives that alleviate any adverse economic effects on this group. Section 603 of the Regulatory Flexibility Act (RFA) requires an Initial Regulatory Flexibility Analysis (IRFA) to be performed to determine whether small entities will be affected by the regulation. If affected small entities are identified, regulatory alternatives that mitigate the potential impacts must be considered. Small entities as described in the Act are only those "businesses, organizations, and governmental jurisdictions subject to regulation."

4.4.1 Criteria and Methodology

The analysis described in this section examines whether the listing determination will affect small entities. EPA sets guidelines and criteria for identifying and evaluating whether a regulation will have an economic impact on small entities.[5] The guidelines address the following procedures:

[5] "EPA Guidelines for Implementing the Regulatory Flexibility Act," Office of Regulatory Management and Evaluation, Office of Policy, Planning and Evaluation, Revised April 1992.

- Identify the small entities affected by the rule;

- Determine if small entities are affected by the rule; and

- Determine whether the operating statute allows the Agency to consider regulatory alternatives to minimize the rule's impacts on small entities.

The Act specifies that the term "small entity" shall be defined as including small businesses, small organizations, and small government jurisdictions. The Regulatory Flexibility Act defines small businesses as those firms that satisfy the criteria established under Section 3 of the Small Business Act. The Agency may use an alternative definition of "small business" after consultation with the Small Business Administration (SBA) and public comment. Similarly, alternative definitions of small organizations and small government jurisdictions are allowed after public comment. The SBA criteria apply to <u>firm size</u>, whereas the economic impact analysis for this rule is conducted at the <u>facility level</u> (i.e., refinery level). For single-plant firms, the SBA criteria can be applied directly. For firms (i.e., companies) owning more than one refinery, crude capacity is aggregated for all plants (i.e., refineries) to determine the overall size of the company.

For all identified small entities, EPA guidelines suggest four criteria be applied to evaluate the severity of impacts on small businesses:

- Compare total annual compliance cost (i.e., capital, operating, reporting, etc.) to operating characteristics of the firm, such as: annual sales, annual operating expenditures, net profits, cash flow, working capital, and net worth.

- Compare capital compliance costs to operating characteristics of the firm, such as net worth and working capital.

- Compare administrative costs to operating characteristics of the firm, such as net profits, labor costs, working expenditures, and cash flow.

- Examine administrative requirements in comparison with supply of personnel and resources, training requirements, technical capabilities, and workload demands placed on existing employees.

4.4.2 Screening Analysis: Small Entity Impacts

For SIC 2911, Petroleum Refining, the Small Business Administration defines small entities as those companies with refinery capacity less than or equal to 75,000 barrels of crude per calendar day.[6] Based on this criterion, approximately 56 percent or 45 of the 80 companies affected by the listing determination are considered to be small.

Even under the highest cost scenario, the estimated impacts of this listings determination are minimal. Predicted price increases and reductions in domestic output are less than 1 percent for the products evaluated. The small magnitude of predicted job loss directly results from the relatively small decrease in production anticipated and the relatively low labor intensity in the industry. Given the magnitude of the estimated compliance costs, refineries are expected to incur minimal economic impacts.

Under the Agency's Revised Guidelines for Implementing the Regulatory Flexibility Act, the Agency is committed to considering regulatory alternatives in rulemakings when there are any estimated economic impacts on small entities. Despite the high percentage of small entities in the population affected by this listings determination, anticipated impacts as a result of implementation of the listings are minimal, with only up to two plant closures predicted under each of the scenarios evaluated. Because economic impacts are estimated to be minimal, no small entity exemptions or options were judged to be necessary in an effort to reduce economic impacts on small entities.

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6 "EPA Guidelines for Implementing the Regulatory Flexibility Act," Office of Regulatory Management and Evaluation, and Office of Policy, Planning and Evaluation, Appendix C, 13 CFR, Part 121, Revised April 1992.

APPENDIX A

ANNUALIZED INCREMENTAL COMPLIANCE COSTS FOR THE PETROLEUM REFINING HAZARDOUS WASTE LISTINGS LISTING SCENARIO ($ millions)

Waste Stream	Number of Facilities with Non-Exempt Waste Management Trains	Total Annualized Waste Quantity (Metric Tons)* Average (Low-High)	Total Annual Baseline Cost Average (Low-High)	Total Annual Compliance Cost Average (Low-High)	Total Annual Incremental Cost of Compliance Average (Low-High)
K169	145	80,300 [45,900 - 114,700]	$2.8 [$1.6 - $4.0]	$3.8 [$1.9 - $6.4]	$2.2 [$1.0 - $3.9]
K170	101	26,800 [18,300 - 35,400]	$2.1 [$1.5 - $2.8]	$3.9 [$2.1 - $6.2]	$2.8 [$1.4 - $4.8]
K171	130	6,800 [6,700 - 6,900]	$4.8 [$4.5 - $5.2]	$5.8 [$4.1 - $7.7]	$1.3 [$0.8 - $2.9]
K172	55	20,800 [20,700 - 20,900]	$8.4 [$7.9 - $8.9]	$9.1 [$6.5 - $12.0]	$1.5 [$0.7 - $3.8]
RCRA	162	NA	$0.0 [$0.0 - $0.0]	$0.5 [$0.4 - $0.6]	$0.5 [$0.4 - $0.6]
TOTALS		134,800 [91,600 - 177,900]			$8.3 [$4.3 - $16.0]

* Average quantity generated to daily crude rate ratios of similar waste streams at reporting facilities were applied to non-reporting facilities.

APPENDIX B

ANNUALIZED INCREMENTAL COMPLIANCE COSTS FOR THE PETROLEUM REFINING HAZARDOUS WASTE LISTINGS LAND DISPOSAL RESTRICTIONS SCENARIO ($ millions)

Waste Stream	Number of Facilities with Non-Exempt Waste Management Trains	Total Annualized Waste Quantity (Metric Tons)* Average (Low-High)	Total Annual Baseline Cost Average (Low-High)	LDR Scenario, Option 1 Off-Site Incineration of Sludges and Off-Site Incineration and Vitrification of Catalysts		LDR Scenario, Option 2 On-/Off-Site Incineration of Sludges and Regeneration/Reclamation of Catalysts	
				Total Annual Compliance Cost Average (Low-High)	Total Annual Incremental Cost of Compliance Average (Low-High)	Total Annual Compliance Cost Average (Low-High)	Total Annual Incremental Cost of Compliance Average (Low-High)
K169	145	80,300 [45,900 - 114,700]	$2.8 [$1.6 - $4.0]	$23.8 [$10.5 - $42.0]	$21.6 [$9.3 - $38.8]	$18.9 [$9.3 - $31.6]	$16.7 [$8.1 - $28.3]
K170	101	26,800 [18,300 - 35,400]	$2.1 [$1.5 - $2.8]	$24.2 [$12.3 - $39.8]	$22.5 [$11.2 - $37.6]	$18.4 [$10.5 - $28.5]	$16.8 [$9.4 - $26.5]
K171	130	6,800 [6,700 - 6,900]	$4.8 [$4.5 - $5.2]	$9.6 [$6.9 - $12.6]	$5.1 [$3.5 - $7.6]	$6.9 [$4.6 - $9.5]	$2.3 [$1.2 - $4.5]
K172	55	20,800 [20,700 - 20,900]	$8.4 [$7.9 - $8.9]	$19.5 [$14.3 - $25.0]	$11.6 [$8.3 - $16.5]	$11.8 [$8.0 - $16.3]	$3.9 [$1.9 - $7.9]
RCRA	162	NA	$0.0 [$0.0 - $0.0]	$0.5 [$0.4 - $0.7]	$0.5 [$0.4 - $0.7]	$0.8 [$0.6 - $1.0]	$0.8 [$0.6 - $1.0]
TOTALS		134,800 [91,600 - 177,900]			$61.3 [$32.7 - $101.2]		$40.6 [$21.3 - $68.3]

* Average quantity generated to daily crude rate ratios of similar waste streams at reporting facilities were applied to non-reporting facilities.

APPENDIX C

ANNUALIZED INCREMENTAL COMPLIANCE COSTS FOR THE PETROLEUM REFINING HAZARDOUS WASTE LISTINGS CONTINGENT MANAGEMENT SCENARIO ($ millions)

Waste Stream	Number of Facilities with Non-Exempt Waste Management Trains	Total Annualized Waste Quantity (Metric Tons)* Average (Low-High)	Total Annual Baseline Cost Average (Low-High)	Contingent Management Scenario, Option 1 Subtitle D Landfill and Land Treatment (w/ controls) of CSO Sludge, On-/Off-Site Incineration of Crude Oil Tank Sludges and Regeneration/Reclamation of Catalysts		Contingent Management Scenario, Option 2 Subtitle D Landfill and Land Treatment (w/ controls) of CSO Sludge, Subtitle D Land Treatment (w/ controls) of Crude Oil Tank Sludges and Regeneration/Reclamation of Catalysts	
				Total Annual Compliance Cost Average (Low-High)	Total Annual Incremental Cost of Compliance Average (Low-High)	Total Annual Compliance Cost Average (Low-High)	Total Annual Incremental Cost of Compliance Average (Low-High)
K169	145	80,300 [45,900 - 114,700]	$2.8 [$1.6 - $4.0]	$19.7 [$9.7 - $33.0]	$17.5 [$8.5 - $29.8]	$1.0 [$0.7 - $1.2]	($0.5) [($0.2) - ($1.0)]
K170	101	26,800 [18,300 - 35,400]	$2.1 [$1.5 - $2.8]	($0.5) [($0.3) - (<$0.1)]	($0.5) [($0.3) - ($0.8)]	($0.5) [($0.3) - (<$0.1)]	($0.5) [($0.3) - ($0.8)]
K171	130	6,800 [6,700 - 6,900]	$4.8 [$4.5 - $5.2]	$6.9 [$4.6 - $9.5]	$2.3 [$1.2 - $4.5]	$6.9 [$4.6 - $9.5]	$2.3 [$1.2 - $4.5]
K172	55	20,800 [20,700 - 20,900]	$8.4 [$7.9 - $8.9]	$11.8 [$8.0 - $16.3]	$3.9 [$1.9 - $7.9]	$11.8 [$8.0 - $16.3]	$3.9 [$1.9 - $7.9]
RCRA	162	NA	$0.0 [$0.0 - $0.0]	$0.6 [$0.5 - $0.8]	$0.6 [$0.5 - $0.8]	$0.5 [$0.3 - $0.6]	$0.5 [$0.3 - $0.6]
TOTALS		134,800 [91,600 - 177,900]			$23.8 [$11.8 - $42.2]		$5.6 [$3.1 - $11.2]

* Average quantity generated to daily crude rate ratios of similar waste streams at reporting facilities were applied to non-reporting facilities.

APPENDIX D

ECONOMIC METHODOLOGY[1]

This appendix presents details of the economic methodology and algorithms used to calculate economic impacts. The first and second sections present an overview of partial equilibrium analysis and the algorithms used in the model. The calculation of market demand and supply elasticities is discussed in the third section.

Introduction

The economic methodology used in this analysis is outlined in this section. The following subsections present the baseline values used in the partial equilibrium analysis and describe the analytical methods used to conduct each of the following analyses:

- Partial equilibrium analysis
- Impact of control costs on market price and quantity
- Trade impacts and plant closures
- Economic surplus changes
- Labor and energy impacts

Market Model

Partial Equilibrium Analysis

A partial equilibrium model is used by economists to evaluate a single market for a commodity, in this case, petroleum products, in isolation. Given fixed prices of all other commodities, the conditions for equilibrium in a single market can be examined. The economic analysis uses a partial equilibrium model to evaluate economic impacts of the listing determination on the petroleum refining industry in an effort to specify market demand and supply, estimate the post-control shift in market supply, predict the change in market equilibrium (price and quantity), and estimate plant closures.

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[1] This appendix was prepared with the assistance of MathTech, Inc. and information contained in "Economic Impact Analysis For the Petroleum Refinery NESHAP," Revised Draft, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, NC, EPA Contract No. 68-D1-0144, March 15, 1994.

Market Demand and Supply

The baseline or pre-control petroleum refining market is defined by a domestic market demand equation, a domestic market supply equation, and a foreign market supply equation. The following equations identify the market demand, supply, and equilibrium conditions:

$$Q_d = \alpha P^{\epsilon} \tag{EQ-1}$$

$$Q_s^d = \beta P^{\gamma} \tag{EQ-2}$$

$$Q_s^f = \rho P^{\gamma} \tag{EQ-3}$$

$$Q_d = Q_s^d + Q_s^f = Q \tag{EQ-4}$$

where,

Q	=	annual output or quantity of petroleum products purchased in the U.S.
Q_d	=	annual quantity of the petroleum products domestically demanded
Q_s^d	=	annual quantity of the products produced by domestic suppliers
Q_s^f	=	annual quantity of the products supplied by foreign producers to the domestic economy
P	=	price of the petroleum product

Superscripts ϵ and γ reference price elasticity of demand and price elasticity of supply, respectively.

The constants α, β and ρ are computed such that the baseline equilibrium price is normalized to one. The market specification assumes that domestic and foreign supply elasticities are the same. This assumption was necessary because data were not readily available to estimate the price elasticity of supply for foreign suppliers.

Market Supply Shift

The domestic supply equation shown above may be solved for the price of the petroleum product, P, to derive an inverse supply function that will serve as the baseline supply function for the industry. The inverse domestic supply equation for the industry is as follows:

$$P = (Q_s^d/\beta)^{1/\gamma} \tag{EQ-5}$$

A rational profit maximizing firm will be willing to supply the baseline (pre-control) output if the price of the product it sells increases by an amount that recovers the capital and operating costs of the regulatory control requirements over the useful life of the equipment. This relationship is identified in the following equation:

$$\frac{[(C * Q) - (V+D)](1-t)+D}{S} = K+V^{1} \qquad \text{(EQ-6)}$$

where,

C	=	increase in the supply price
Q	=	annual output
V	=	measure of annual operating and maintenance costs of controls
t	=	marginal corporate income tax rate
S	=	capital recovery factor
D	=	annual depreciation (straight-line depreciation is assumed)
K	=	the present value of the investment cost of control and closure equipment
V^1	=	the present value of periodic operating and maintenance costs of controls

Solving for C yields the following expression:

$$C = \frac{(K+V^{1})S-D}{Q(1-t)} + \frac{V+D}{Q} \qquad \text{(EQ-7)}$$

Estimates of the annual operation and maintenance control costs and of the investment costs for treatment and disposal (V, V^1 and K, respectively) were obtained from industry averages derived from the 1992 RCRA 3007 Survey, previous listings documents including the land disposal restrictions RIAs, and engineering studies.

Values for K are computed as:

$$K = \sum_k K_k * f_k \qquad \text{(EQ-8)}$$

where the subscript k references the timing (in years) of up front and future capital costs, where

$$f_k = 1/(1 + r)^k$$

Similarly, we compute V^1 as

$$V^1 = \sum_v V_v * f_v \qquad \text{(EQ-9)}$$

where the subscript v references the timing of up front and periodic (non-annual) operating and maintenance costs and

$$f_v = 1/(1 + r)^v$$

Depreciation (D) and the capital recovery factory (S) are computed as follows:

$$D = 1/T \sum_k K_k * f_k \qquad \text{(EQ-10)}$$

$$S = r(1+r)^T/[(1+r)^T-1] \qquad \text{(EQ-11)}$$

where, r equals the discount rate or cost of capital faced by producers and is assumed to be a rate of 10 percent and T is the life of the post-control treatment equipment.

Regulatory control costs will raise the supply price for each refinery by an amount equivalent to the per unit cost of the annual recovery of investment costs and annual and periodic operating costs of the regulatory control equipment or C_i (where i denotes domestic refinery 1 through 168). The aggregate domestic market supply curve does not identify the supply price for individual plants. Therefore, we adopt a worse-case assumption that marginal plants (highest cost producers) in the post-control market also face the highest compliance cost (per unit of output). Based on this assumption, the post-control supply function becomes the following:

$$P = (Q_s^d/\beta)^{1/\gamma} + C(C_i, q_i) \qquad \text{(EQ-12)}$$

where,

$C(C_i, q_i)$ = a function that shifts the post-control supply function

C_i = vertical shift that occurs in the supply curve for the ith refinery to reflect post-control costs, sorted by per unit control costs

q_i = quantity produced by the ith refinery

This shift in the supply curve is illustrated in Figure D-1.

Impact of Supply Shift on Market Price and Quantity

The impact of the listing determination on market equilibrium price and output is derived by solving for the post-control market equilibrium and comparing the new equilibrium price and quantity to the pre-control equilibrium. Since the post-control domestic supply is segmented, a special algorithm was developed to solve for post-control market equilibrium. The algorithm first searches for the segment in the post-control supply function at which equilibrium occurs and then solves for the post-control market price that clears the market.

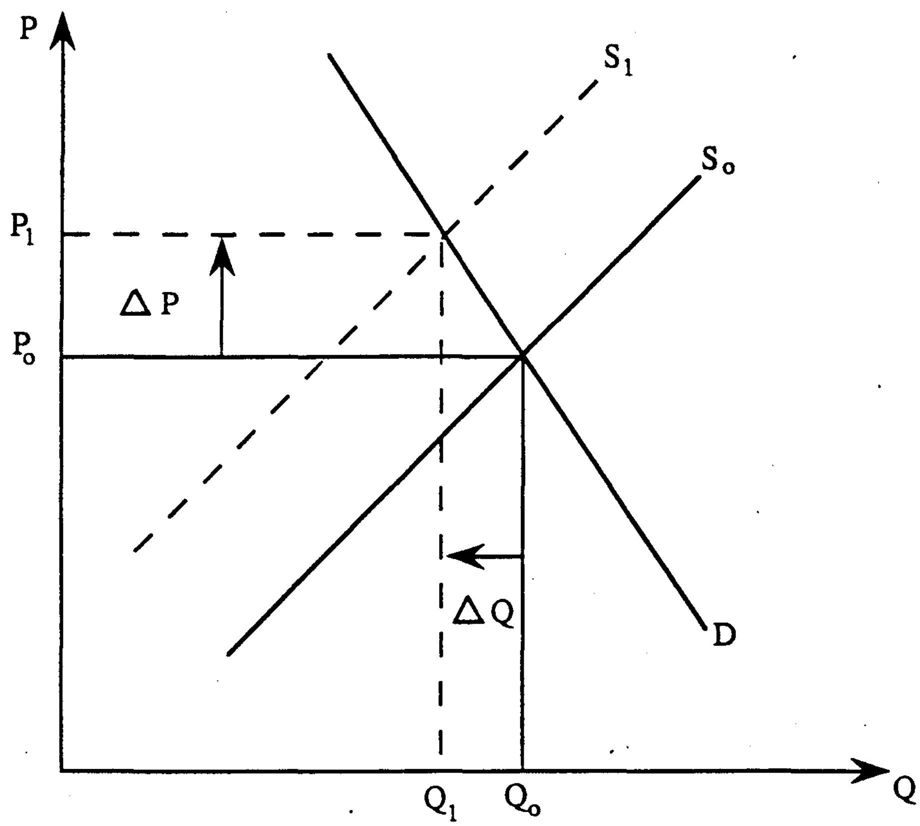
Since the market clearing price occurs where demand equals post-control domestic supply plus foreign supply, the algorithm simultaneously solves for the following post-control variables:

- equilibrium market price
- equilibrium market quantity
- change in the value of domestic production or revenues to producers
- quantity supplied by domestic producers
- quantity supplied by foreign producers

The market impacts of control costs are assessed by comparing baseline equilibrium values with post-control equilibrium values for each of the variables listed above.

FIGURE D-1

Post-Control Shift in the Supply Curve
(Not Drawn to Scale)



S_o = Pre-Control Industry Supply Curve

S_1 = Post-Control Industry Supply Curve

P_o = Pre-Control Equilibrium Price

P_1 = Post-Control Equilibrium Price

Trade Impacts

Trade impacts are reported as the change in both the volume and dollar value of net imports (exports minus imports). It is assumed that exports comprise an equivalent percentage of domestic production in the pre- and post-control markets. The supply elasticities in the domesticand foreign markets have also been assumed to be equal. As the volume of imports rises and the volume of exports falls, the volume of net exports will decline. However, the dollar value of net exports might rise when demand is inelastic, as is the case for the petroleum products of interest. The dollar value of imports will increase since both the price and quantity of imports increase. Alternatively, the quantity of exports will decline, while the price of the product will increase. Price increases for products with inelastic demand result in revenue increases for the producer. Consequently, the dollar value of exports is anticipated to increase. Since the dollar value of imports and exports rise, the resulting change in the value of net exports will depend on the magnitude of the changes for imports relative to exports.

The following algorithms are used to compute the trade impacts:

$$
\begin{aligned}
\Delta Q^{s_f} &= Q_1^{s_f} - Q_0^{s_f} \\
\Delta VIM &= (P_1 \cdot Q_1^{s_f}) - (P_0 \cdot Q_0^{s_f}) \\
\Delta Q_x^{s_d} &= \frac{Q_x^{s_d}}{Q_0^{s_d}} (Q_1^{s_d} - Q_0^{s_d}) \\
\Delta VX &= P_1 (\Delta Q_x^{s_d} + Q_x^{s_d}) - P_0 \times Q_x^{s_d}
\end{aligned}
\qquad \text{(EQ-13)}
$$

where,

ΔQ^{sf}	=	the change in volume of imports
ΔVIM	=	the change in the dollar value of imports
ΔQ_x^{sf}	=	the change in the volume of exports
ΔVX	=	the change in the dollar value of exports
Q_x^{sd}	=	the quantity of exports by domestic producers in the pre-control market

Subscripts 0 and 1 refer to the pre- and post-control equilibrium values, respectively. All other terms have been previously defined.

The change in the quantity of net exports (ΔNX) is simply the difference between the change in the volume of imports, expressed as ΔQ^{x}_{sd} - ΔQ^{sf}. The reported change in the dollar value of net exports (ΔVNX) is the difference between the equations for change in the value of exports and the change in the value of imports, or ΔVX - ΔVIM.

Plant Closures

It is assumed that a refinery will close if its post-control supply price exceeds the post-control market equilibrium price. Post-control supply prices for the individual refinery are computed as described in Industry Supply and Demand Elasticities.

Changes in Economic Welfare

Regulatory control requirements will result in changes in the market equilibrium, price and quantity of petroleum products produced and sold. These changes in the market equilibrium price and quantity will affect the welfare of consumers of petroleum products, producers of petroleum products, and society as a whole. The procedure for estimating the welfare change for each group is presented below in the following subsections.

Change in Consumer Surplus. The change in consumer surplus includes losses of surplus incurred by both foreign consumers (of U.S. exports) and domestic consumers. Although the change in domestic consumer surplus is the object of interest, no method is available to distinguish the marginal consumer as domestic or foreign. Therefore, an assumption is made that the consumer surplus change is allocable to the foreign and the domestic consumer in the same ratio as sales are divided between foreign and domestic consumers in the pre-control market. The change in domestic surplus (ΔCS_d) becomes the following:

$$\Delta CS_d = [1 - \left(\frac{Q_x^{s_d}}{Q_0} \right)] \, \Delta CS \qquad \text{(EQ-14)}$$

where

$$\Delta CS = \int_{Q_1}^{Q_0} (Q/\alpha)^{1/\varepsilon} - P_0Q_0 + P_1Q_1 \qquad \text{(EQ-15)}$$

ΔCS_d represents the change in domestic consumer surplus that results from the change in market equilibrium price and quantity resulting from the imposition of regulatory controls. While ΔCS includes foreign consumer surplus losses due to purchases of U.S. exports, ΔCS_d is the change in consumer surplus relevant to the domestic economy.

Change in Producer Surplus. The change in producer surplus is composed of two elements. The first element relates to surplus losses on output eliminated as a result of reduced post-control equilibrium quantity. The second element is associated with the change in price and higher costs of production due to compliance with the regulation. The total change in producer surplus is the sum of these two components. After-tax measures of surplus changes are required to estimate the impacts of controls on producers' welfare. The after-tax surplus change is computed by multiplying the pre-tax surplus change by a factor of 1 minus the tax rate, (1-t), where t is the marginal tax rate.

Output eliminated as a result of control costs causes producers to suffer a welfare loss in producer surplus. The post-control welfare loss on eliminated output is given by:

$$\left[P_0(Q_{s_0}^d - Q_{s_1}^d) - \int_{Q_{s_1}^d}^{Q_{s_0}^d} (Q/\beta)^{1/\gamma}\, dQ \right] (1-t) \qquad \text{(EQ-16)}$$

Refineries remaining in operation after regulatory controls are implemented realize a welfare gain of $P_1 - P_0$ on each unit of production for the incremental increase in the price and realize a decrease in welfare per unit for the capital and operating cost of implementing the required control equipment of C_i. The post-control loss in producer surplus for refineries remaining in the market is specified by the following equation:

$$\left[(P_0 - P_1) Q_{s_1}^d + \sum_{i=1}^{m} C_i q_i \right] (1-t) \qquad \text{(EQ-17)}$$

The total post-control loss in producer surplus, ΔPS, is given by the sum of (EQ-16) and (EQ-17). Specifically,

$$\Delta PS = \left[P_0 Q_{s_0}^d - P_1 Q_{s_1}^d - \int_{Q_{s_1}^d}^{Q_{s_0}^d} (Q/\beta)^{1/\gamma}\, dQ + \sum_{i=1}^{m} C_i q_i \right] (1-t) \qquad \text{(EQ-18)}$$

Since domestic surplus changes are the subject of interest, the welfare gain experienced by foreign producers due to higher prices is not considered. This procedure treats higher prices paid for imports as a dead-weight loss in consumer surplus. From a world economy perspective, higher prices paid to foreign producers represent a transfer of surplus from the United States to other countries. The higher prices paid for imports represent a welfare loss from the perspective of the domestic economy.

Residual Effect on Society. The changes in economic surplus, as measured by the changes in consumer and producer surplus, previously discussed must be adjusted to reflect the true change in social welfare as a result of regulation. The adjustments are necessary due to tax effects differences and to the difference between the private and social discounts rates.

Two adjustments to economic surplus are necessary to account for tax effects. The first relates to the per unit control cost C_i that reflects after-tax control costs and is used to predict the post-control market equilibrium. The true cost of regulatory treatment and disposal requirements must be measured on a pre-tax basis.

A second tax-related adjustment is required because changes in producer surplus have been reduced by a factor of (1-t) to reflect the after-tax welfare impacts of regulatory treatment and disposal requirement costs on affected refineries. As noted previously, a dollar loss in pre-tax producer surplus imposes an after-tax burden on the affected refinery of (1-t) dollars. In turn, a one dollar loss in after-tax producer surplus causes a complimentary loss of t/(1-t) dollars in tax revenues.

Economic surplus must also be adjusted because of the difference between private and social discount rates. The private discount rate is used to shift the supply curve of refineries in the industry since this rate reflects the marginal cost of capital to affected refineries. The economic costs of the regulation, however, must consider the social cost of capital. This rate reflects the social opportunity cost of resources displaced by investments in regulatory treatment and disposal equipment.

The adjustment for the two tax effects and the social cost of capital are referred to as the residual change in economic surplus, ΔRS. This adjustment is given by the following equation:

$$\Delta RS = -\sum_{i=1}^{m} (C_i - pc_i)q_i + \Delta PS * [t/(1-t)] \qquad \text{(EQ-19)}$$

where, pc_i equals the per unit cost of controls for each refinery with the tax rate assumed to be zero, the discount rate assumed to be the social discount rate of 7 percent.

Total Economic Costs. The total economic costs of the listings, EC, are the sum of the losses in consumer surplus, producer surplus, and the residual surplus. This relationship is defined in the following equation:

$$EC = \Delta CS + \Delta PS + \Delta RS \qquad \text{(EQ-20)}$$

Labor and Energy Impacts

The estimates of the labor and energy market impacts associated with this listing determination are based on input-output ratios and estimated changes in domestic production. The methodologies used to estimate each impact are described below in the following subsections.

Labor Impacts. The labor market impacts are measured as the number of jobs lost due to domestic output reductions. The estimated number of job losses are a function of the change in level of production that is anticipated to occur as a result of this listing determination. The change in employment is computed as follows:

$$\Delta L = \left(L_0/Q_{s_0}^{d}\right) * \left(Q_{s_0}^{d}-Q_{s_1}^{d}\right) \qquad \text{(EQ-21)}$$

where, ΔL equals the change in employment and L_0 equals the baseline employment level. All other variables have previously been defined.

Energy Impacts. The reduction in energy inputs associated with the listing determination results from the reduction in expenditures for energy inputs due to production decreases. The expected change in use of energy inputs is calculated as follows:

$$\Delta E = \left(E_0/Q_{s_0}^{d}\right) * \left(Q_{s_0}^{d}-Q_{s_1}^{d}\right) \qquad \text{(EQ-22)}$$

where, ΔE equals the change in expenditures on energy inputs and E_0 is the baseline expenditure on energy inputs per dollar of refined petroleum output. All other variables have previously been defined.

Baseline Inputs

The partial equilibrium model described above requires baseline values for variables and parameters that characterize the petroleum refining market. Table D.1 lists baseline prices and production volumes for the petroleum products. Table D.2 lists variables and parameters that are assumed to be the same for all petroleum products.

The baseline conditions in the petroleum refining industry are characterized by the baseline parameters and variables in the tables. The baseline market prices ($1992) were obtained from the Petroleum Market Annual, 1993. Prices are stated in cents per gallon excluding taxes. Quantities of petroleum products produced (1992) were obtained from the 1992 RCRA 3007 Survey. Quantity (i.e., refinery output) data are reported in millions of barrels per stream day. Imports and exports of the ten petroleum products of interest (1992) were obtained from the Petroleum Supply Annual, 1992. Sources for the price elasticity of supply and demand are discussed in the following section, Industry Supply and Demand Elascities. A marginal tax rate of 34 percent, private discount rate of 10 percent, and social discount rate of 7 percent are assumed in the economic analysis. An equipment life of 20 years was assumed for treatment/disposal units including tanks and incinerators and 10 years for filtration units. The number of workers per unit of output (L) and the energy expenditures per value of shipments (E) were derived from the U.S. Department of Commerce, Annual Survey of Manufactures (ASM), 1991. Data from the ASM used to derive these estimates include the 1991 annual values for total number of workers employed, total expenditures on energy, and the value of shipments for SIC 2911.

Data inputs also include the number of domestic refineries operating in 1992 and annual production per refinery. The number of operating refineries and annual production per refinery were obtained from the 1992 RCRA 3007 Survey.

As Table D.1 indicates, petroleum refineries produce several products. However, compliance costs for the hazardous waste listing cannot be allocated to any specific products. Accordingly, output in the partial equilibrium model is defined as a composite, bundled good equal to the sum of price multiplied by the weighted production volumes of each product. Specifically, we define Q_i, the composite production level for refinery i, as follows:

$$Q_i = \sum_w P_w * Q_{wi} \qquad \text{(EQ-23)}$$

where, P equals product prices and the subscript w references the various products listed in Table D.1. The baseline price of the composite product is normalized to unity (i.e., one dollar). Given these definitions, the partial equilibrium model predicts percentage changes in price and output levels.

In some cases, impacts are reported in barrels rather than in units of the composite good for ease of interpretation. Production measures are converted to barrels by dividing production of the composite good by the weighted average refined product price, where the average is computed across industry-wide production.

Industry Supply and Demand Elasticities

Demand and supply elasticities are crucial components of the partial equilibrium model that is used to quantify the economic impact of regulatory control cost measures on the petroleum refinery industry. This section discusses the price elasticities of demand and supply used as inputs to the partial equilibrium analysis. Estimates of price elasticities of demand for several refined products were available from the economic literature. The price elasticity of supply used for this analysis was estimated by Pechan and Mathtech (1993).

Price Elasticity of Demand

The price elasticity of demand, or own-price elasticity of demand, is a measure of the sensitivity of buyers of a product to a change in price of the product. The price elasticity of demand represents the percentage change in the quantity demanded resulting from each 1 percent change in the price of the product.

Petroleum products represent a very important energy source for the United States. Many studies have been conducted which estimate the price elasticity of demand for some or all of the petroleum products of interest. Over one hundred studies of the demand for motor gasoline alone have been conducted (see Dahl and Stern for a survey of these model results). Numerous published sources of the price elasticity of demand for petroleum products exist and are discussed in detail in the *Industry Profile for the Petroleum Refinery NESHAP* (Pechan, 1993). Ranges in estimates of own-price elasticities of demand for several refined products are listed in Table D.3.

As noted earlier, refinery production is defined as a bundled, composite good of products refined at domestic plants. As a result, the partial equilibrium model requires a corresponding composite price elasticity. We compute the composite demand elasticity as the weighted average of the mid-points of the range reported in Table D.3. Specifically, we compute the composite demand elasticity, ϵ, as

$$\epsilon = \sum_{w} \bar{\epsilon}_w * Q_w / \sum_{w} Q_w \qquad \text{(EQ-24)}$$

where, the subscript w references the refined products listed in Table D.3, the ϵ are the mid-points of the ranges listed in Table D.3, and the Q are industry-wide production levels of refined products.

The demand elasticity estimates for the individual products that are components of the composite elasticity are close in magnitude. As Table D.3 indicates, the lower and upper ranges of the estimates for seven of the ten products are bounded by -0.50 and -1.00. While the estimate for jet fuel, -0.15, falls outside this range, it is more inelastic, meaning that using the composite elasticity will overstate somewhat the adverse impacts for this product.

Price Elasticity of Supply

The price elasticity of supply or own-price elasticity of supply, is a measure of the responsiveness of producers to changes in the price of a product. The price elasticity of supply indicates the percentage change in the quantity supplied of a product resulting from each 1 percent change in the price of the product.

Few estimates of the price elasticity of supply are available in the economic literature. Two studies estimate the price elasticity of supply for gasoline to be 1.96[2] and 1.47[3], respectively. However, both studies use data covering time periods during the decade of 1979 and, accordingly, are somewhat dated. This analysis uses the estimate reported by Pechan and Mathtech (1993). This study estimates a supply elasticity of 1.24 for the composite of refined products listed in Table D.3. As a result, it is consistent with the composite demand elasticity used in this analysis.

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[2] Zarate, Marco, Letter from Marco A. Zarate to James Durham, U.S. Environmental Protection Agency, Chemical and Petroleum Branch, November 30, 1993.

[3] Murphy, Patrick, Letter from Patrick Murphy, Radian to James Durham, U.S. Environmental Protection Agency, Chemical and Petroleum Branch, December 3, 1993.

TABLE D.1

Baseline 1992 Domestic Production and Prices

Variable/Products	Domestic Production[1] (millions bbls)	Price[2] (1992 $)
Ethane/Ethylene	19.4	8.53
Propane/Propylene	176.3	12.90
Normal Butane/Butylene	90.1	15.19
Isobutane	15.8	18.61
Motor Gasoline	2,565.1	28.43
Kerosene-Type Jet Fuel	529.3	25.41
Distillate Fuel Oil	1,070.1	25.51
Residual Fuel Oil	378.1	12.94
Asphalt and Road Oil	129.3	30.80
Coke	154.2	1.36

[1] As reported in the 1992 RCRA 3007 Survey

[2] Sources: U.S. Department of Energy, Energy Information Administration, Petroleum Marketing Annual, 1993, Table 4, U.S. Refiner prices of Petroleum Products for Resale; Platt's Oil Gram Spot Price Assessment (Average of March 6, June 4, October 2, 1992) for ethane/ethylene, propane/propylene, normal butane/butylene, and isobutane; Pace Consultants for Coke; and the Asphalt Institute for Asphalt.

TABLE D.2

Baseline Inputs for the Petroleum Refining Industry

Variable/Inputs	Value
Demand Elasticity (ϵ)	-0.646
Supply Elasticity (γ)	1.24
Tax Rate (t)	0.34
Private Discount Rate (r)	0.10
Social Discount Rate	0.07
Equipment Life (T)	20 years
Labor (L_0)[1]	9.12 Workers
Energy (E_0)[2]	$0.03
Import Ratio[3]	0.07
Export Ratio[4]	0.02
Number of operating petroleum refineries	175

[1] Production workers per million barrels produced per year.

[2] Energy expenditures per dollar value of shipments.

[3] Value of imports divided by value of domestic production, computed from Table 2, Petroleum Supply Annual, 1992, DOE/EIA.

[4] Value of exports divided by value of domestic production, computed from Table 2, Petroleum Supply Annual, 1992, DOE/EIA.

TABLE D.3

Estimates of Price Elasticity of Demand[1]

Fuel Type	Long-Run Elasticity
Motor Gasoline	-0.55 to -0.82
Jet Fuel	-0.15
Residual Fuel Oil	-0.61 to -0.74
Distillate Fuel Oil	-0.50 to -0.99
Liquified Petroleum Gases[2]	-0.60 to -1.0

[1] Elasticities were not available for coke and asphalt.

[2] Represents the elasticity for the following products-- ethane/ethylene, propane/propylene, normal butane/butylene, and isobutane/isobutylene.

PRLF-S0008.B

DOCUMENT 2

"OTHER BENEFITS" FROM RECOVERY OF OIL IN COKER PROCESSING UNITS

August 24, 1995

MEMORANDUM

TO: Andy Wittner, EPA/OSW/RAB

FROM: Dave Gustafson and Chris Lough, DPRA Incorporated

DATE: August 24, 1995

SUBJ: "Other Benefits" from Recovery of Oil in Coker Processing Units

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This memorandum presents our current understanding of the "coker exemption" and its potential benefits to the petroleum refining industry based on a conversation with you, Max Diaz and a review of the draft preamble language.

Policy Decision

EPA is including cokers under the definition of a petroleum refining process (e.g., distillation unit, catalytic cracker, and fractionation unit). Therefore, all oil-bearing residuals that are generated at petroleum refineries and reinserted into the petroleum refining process are excluded from regulation under the definition of solid waste.

As a result, previously listed wastes for the petroleum refining industry may now be recycled back to cokers and no longer be defined as a hazardous waste. It is up to the industry to prove that these wastes are oil-bearing. The wastes include the following:

F037 - primary separation sludge;
F038 - secondary separation sludge;
K048 - dissolved air floatation (DAF) float;
K049 - slop oil emulsion solids; and
K051 - API separator sludge.

Also note, cokers are viewed as process units under the Clean Air Act and are subject to regulations under the National Emission Standards for Hazardous Air Pollutants from petroleum refineries.

Background

The primary purpose of a petroleum coker is to upgrade lower value hydrocarbons into light ends that are used to produce more valuable product fuels. While coke is being produced, the coker thermally converts longer-chained (heavy) hydrocarbons to middle-chained and short-chained (light end) hydrocarbons that are used to produce high grade fuels (e.g., gasoline, kerosene, jet fuel, etc.). A typical coker yields about 30% petroleum coke and

70% light hydrocarbons. The light hydrocarbons are returned to the refining process to produce high grade fuels.

Some facilities are already recycling previously listed wastes ("unofficially") back to the coker. The listed wastes are transferred from wastewater treatment tanks to the coker via a closed system. The wastes are conveyed via hard pipe or tank trucks to stationary tanks or containers where oil is recovered and/or secondary materials are prepared for insertion into the coker.

Because of the high water content, these wastes are being used in the quench (i.e., cooling) process. When the coke product is ready it is quenched with water because the coker operates at approximately 900 degrees Fahrenheit. The recycled wastes are fed into the coker as a slug ahead of the quench water. Most of the oil fraction (70 percent) is volatilized with the off gases and recovered in the light hydrocarbon product stream. The remaining heavy fraction (30 percent) is converted into coke. At the same time, because of the low heating value (high water content) of the waste, the coke will begin to be cooled (quenched). After the waste has been fed into the coker, quench water is fed into the coker unit to complete the cooling process.

The facility has a couple of limitations to consider when feeding the wastes into the coker. If the solids content is too high, the injection nozzles may clog. If too much water is added the system may "vapor lock." DPRA assumes that vapor lock means that too much water vapor and hydrocarbon gases are generated too quickly to be handled through the stack, causing a pressure build-up which either triggers system shut-down; or if cokers have an open-burner (i.e., flame), similar to incinerators, it may be extinguished causing system failure. DPRA would need to research coker process systems to clarify how these wastes can cause process upsets, but, that is beyond the scope of our immediate needs. If the waste has too high of an ash content, the value of the petroleum coke may be reduced. Finally, cokers can be continuous processes. If the coker shuts down, refinery processes linked to the coker will need to be altered or shut down. Therefore, it appears that the coker operators have some incentives to maintain proper coker operation. Once again, we do not truly know how much leeway operators have in the "quality" of their coker feed streams.

Waste Stream Characteristics

The following table presents estimates of the waste stream characteristics for the previously listed wastes. Characterization data was obtained from the "Regulatory Impact Analysis for the Listings of Primary and Secondary Oil/Water/Solids Separation Sludges from the Treatment of Petroleum Refinery Wastewaters" (October 1990) and "Background Document for Capacity Analysis for F037 and F038 Petroleum Refining Wastes to Support 40 CFR 268 Land Disposal Restrictions" (December 1991).

DPRA
E-1500 First National Bank Building St. Paul. Minnesota 55101-1314 Telephone 612-227-6500 FAX 612-227-5522

April 9, 1997

Mr. Andrew Wittner
U.S. Environmental Protection Agency, Crystal Station
Office of Solid Waste
Economics, Methods and Risk Assessment Division
2800 Crystal Drive
Arlington, Virginia 22202

RE: Cost Impact Analysis of the Definition of Solid Waste Headworks Exemption for the Proposed Listings of Three Petroleum Refining Industry Wastes;
DPRA WA No. 3825.202

Dear Andy:

Attached is the final draft report of the Cost Impact Analysis of the Definition of Solid Waste Headworks Exemption for the Proposed Listings of Three Petroleum Refining Industry Wastes. If no headworks exemption or conditional exemption are granted, the cost for off-site management of tank and reactor wastewaters (wash waters), at an expected value of \$11.4 million, will be almost twice the cost associated with the management of the sludges and catalysts, at approximately \$5.9 million under the Listing Scenario.

Please call me with any questions or comments at 612/227-6500.

Sincerely,

Dave Gustafson
Senior Associate

cc: Gwen Di Pietro, SAIC
John Vierow, SAIC
Chris Lough, DPRA

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COST IMPACT ANALYSIS
OF THE DEFINITION OF SOLID WASTE HEADWORKS EXEMPTION
FOR THE PROPOSED LISTINGS OF
THREE PETROLEUM REFINING INDUSTRY WASTES

This report presents a cost impact analysis of the definition of solid waste headworks exemption for the proposed listing of three petroleum refining residuals (clarified slurry oil (CSO) sludge, hydrotreating catalyst, and hydrorefining catalyst) as hazardous wastes. These residuals will be subject to RCRA Subtitle C regulation.

ISSUES

Under the proposed listing, a headworks exemption was provided for CSO sludge under the definition of solid waste for wastewaters discharged to an oil-recovery system before primary oil/water/solids separation in the wastewater treatment system. In contrast, a headwaters exemption was not provided for hydrotreating and hydrorefining catalysts under the definition of solid waste for wastewaters discharged to the wastewater treatment system. This analysis evaluates two separate issues:

1.) If CSO sludge wastewaters are not granted a headwaters exemption under the definition of solid wastes, what will be the cost impacts to the petroleum refining industry?

2.) If hydrotreating or hydrorefining catalyst wastewaters are not granted a headwaters exemption under the definition of solid waste, what will be the cost impacts to the petroleum refining industry?

PUBLIC COMMENTS

EPA has received public comment on the proposed Petroleum Refining Waste Listings (60 FR 57747, November 20, 1995) regarding the need to exempt from RCRA regulation the disposal of wastewater from hydrotreating and hydrorefining catalyst reactor removal practices. The industry commenters suggested that the exemption should be similar to the "headworks exemption" proposed for wastewater generated from CSO sludge tank removal practices. For catalysts, this reactor cleanout activity is referred to as "wet dumping." The headwaters exemption is a regulatory option because the wash waters associated with the removal of these catalysts will be managed in existing wastewater treatment units subject to regulation under the Clean Water Act and some existing treatment impoundments subject to RCRA Minimum Technology and Land Disposal Restriction regulation.

CSO Sludge Headworks Exemption Comments

John H. Medley, Mobil Corporation's Environmental Health and Safety Issues Coordinator, provided information on the volume of water typically routed to the wastewater treatment system during water washing/hydroblasting activities when CSO tanks are cleaned to recover useful hydrocarbon and sediment and prepared for tank inspection. Two Mobil Oil Corporation refineries had data on CSO tank cleanout wastewater volumes. At one refinery, approximately 3,000 barrels of water were used to water wash/hydroblast the tank in preparation for inspection. This water wash is conducted after the tank has been first cleaned using a diesel or kerosene wash; thus, the wastewater should contain small quantities of sediment. The other refinery estimated a volume range of 2,000 to 5,000 barrels of water. The wash water is typically pumped via a temporary pump and flexible connector to the nearest sewer grate, where it can flow to the primary oil/water separation at the front of the wastewater treatment plant.[1]

John H. Medley also contacted Conoco and provided volume data from their experiences. Conoco estimates it generates approximately 1,000 barrels per year for its four refineries. These numbers have been annualized, whereas Mobil's numbers are episodic volume estimates.[2]

Hydrotreating and Hydrorefining Catalyst Headworks Exemption Comments

Philip T. Cavanaugh, Chevron Companies, Vice President and General Manager Federal Relations, provided comments on the impacts of Subtitle C regulation of wash water from hydrotreating and hydrorefining catalyst reactor cleanout activities. He believes that this wash water should be granted the same exemption from the definition of solid waste as CSO sludge. As the proposed regulation now stands, catalyst wash waters are hazardous because of the derived-from listed hazardous waste rule.[3]

Chevron states that it uses significant amounts of water for the safe removal of catalyst in order to minimize its risks due to self-heating tendencies (i.e., pyrophoric material). At one of Chevron's refineries, over 7,000 MT/yr of hydrotreating catalyst is wet dumped and sent to metal reclamation. Wet dumping involves filling the reactor with water ("drill water") to

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[1] John H. Medley, Mobil Corporation, letter to Max Diaz, U.S. EPA, regarding Docket No. F-95-PRLP-FFFFF; Clarified Slurry Oil Sediment Headworks Exemption - Supplemental, September 25, 1996.

[2] John H. Medley, Mobil Corporation, facsimile to Max Diaz, U.S. EPA, regarding data on CSO headworks exemption, September 25, 1996.

[3] Philip T. Cavanaugh, Chevron Companies, Vice President and General Manager Federal Relations, letter to EPA RCRA Docket Clerk (530SW), U.S. EPA, regarding hazardous waste management system, identification and listing of hazardous waste, petroleum refining process wastes, Land Disposal Restrictions for newly identified wastes, and CERCLA hazardous substance designation and reportable quantities, March 21, 1996 (Docket No. F-95-PRLP-FFFF).

mitigate the pyrophoric nature of the catalyst. The slurry is drained from the reactor into a special "spiral" classifier (manufactured by Wemco) to minimize water shipped in the storage containers. The catalyst is then taken to a covered RCRA permitted oxidation pad and carefully spread to allow the catalyst to continue to oxidize. Drill water continues to drain from the catalyst on the oxidation pad and is collected and returned to the wet dump storage tank. The catalyst is typically sent to metals reclamation. At another refinery, the catalyst is mixed with cement and sent to disposal instead of utilizing an oxidation pad.

According to Chevron, the advantages of wet dumping catalyst is that it is rapid, the catalyst is nonpyrophoric when wet, wet catalyst can be handled in air, and reactor cool down time is reduced. One Chevron refinery uses 400,000 gallons (approximately 1,500 MT) of water in its wet dumping process. The water is stored, reused, and eventually fed to the headworks of the refinery wastewater treatment system. This volume comprises a small fraction of the overall wastewater treatment volume.

One Chevron refinery has a two-stage reverse osmosis treatment unit installed prior to the headworks to meet NPDES permit requirements for removing nickel. This process treats two million gallons per year (approximately 7,600 MT/yr) which comprises less than one-tenth of one percent of the total effluent treatment system volume of eight million gallons per day. According to Chevron, if this wastewater is listed, the complete volume would be considered hazardous under the mixture rule.

Chevron is concerned about the following cost issues relating to wet dumping:

- Listing of these materials will increase disposal, reclamation, and transportation costs;
- The listing would result in less cost incentives to remove or reduce hazardous characteristics prior to shipment to avoid RCRA Subtitle C regulation;
- Higher incentive to shorten the downtime of the reactor (between 18 and 36 hours) increasing production and resulting in higher concentrations of organics in the residual (and higher hazard characteristics);
- Cheaper RCRA Subtitle C disposal practices will be preferred over RCRA-exempt (non-hazardous) reclamation practices;
- Hazardous waste manifests, LDR forms, etc.;
- HAZWOPER training and annual certification for all personnel involved in the wet dump including operators, maintenance, and contractors;
- Disposal of decontamination water and contaminated coveralls, cartridge respirators, scaffolding, gaskets, etc, will require hazardous waste disposal;
- Reactor internals could be considered hazardous debris upon replacement; and
- Catalyst samples pulled during the run of the unit could be considered hazardous waste.

RCRA 3007 SURVEY

EPA conducted an assessment of the RCRA 3007 Survey database to determine the number of refineries that generate CSO tank sludge and hydrotreating and hydrorefining catalyst wastes. These data are presented in Table 1.

Because of the 1992 RCRA 3007 Survey format and infrequent generation (e.g., CSO tanks are cleaned out on average once every nine years), EPA believes that not all facilities that generate specific waste residuals reported the activity and its associated quantities in the 1992 RCRA 3007 Survey. EPA made the following assumptions when identifying those facilities with non-reported waste residuals (and quantities):

1. All facilities with existing clarified slurry oil storage tanks generate clarified slurry oil tank sludges unless it has been specifically stated in a cover letter or communication that the residual is not generated.

2. All facilities with hydrotreating or hydrorefining units generate hydrotreating catalyst residuals or hydrorefining catalyst residuals.

The totals in Table 1 will not exactly match those in Tables 2 through 4 because of variances in survey responses in different sections of the RCRA 3007 Survey.

Table 2 presents the reported cleanout activities for CSO tanks in the RCRA 3007 Survey. Eighteen (18%) of the 103 facilities reporting CSO sludge generation clearly generate wastewater during their tank cleanout activities.

Table 3 presents the reported cleanout activities for hydrotreating and hydrorefining reactors in the RCRA 3007 Survey. Twenty-seven (20%) of the 134 facilities reporting hydrotreating and/or hydrorefining catalyst generation clearly generate wastewater during their tank cleanout activities.

Table 1. Number of Facilities Generating Waste

Waste	No. of Facilities Reporting Waste Generation and Waste Quantity	No. of Facilities Reporting Waste Generation and No Waste Quantity	Estimated No. of Facilities Misreporting not Generating Waste	Total Estimated No. of Facilities Generating Waste
CSO Sludge	48	6	47	101
Hydrotreating Catalyst	113	14	3	130
Hydrorefining Catalyst	53	0	2	55

Source: U.S. EPA, Draft Final Report: Cost and Economic Impact Analysis of Listing Hazardous Wastes from the Petroleum Refining Industry, September 21, 1995.

Table 2. Number of Facilities Conducting CSO Tank Cleanout Activities

Tank Cleanout Activity	No. of Facilities Reporting Cleanout Activity	Percentage of Facilities
Non-Water Generating Cleanout Activities: Diesel/Gas Oil/Kerosene/Solvent Wash, Installed Mixer, Proprietary Tank Cleaning, Centrifuge	21	20
Water Generating Cleanout Activities: Water Wash, Steam Stripping, Wastewater Treatment Plant Discharge	18	18
Cleanout Activities Not Reported: None, Invalid, Not Reported	64	62
TOTAL	103	100

Table 3. Number of Facilities Conducting Hydrotreating and/or Hydrorefining Reactor Cleanout Activities

Reactor Cleanout Activity	No. of Facilities Reporting Cleanout Activity	Percentage of Facilities
Large Volume Water Generating Cleanout Activities: Water Wash, Wet Dump, Water Fill, Soda Ash Wash, Diesel Wash	12	11
Small Volume Water Generating Cleanout Activities: Steam Stripping	15	9
Cleanout Activities that May Generate a Small Volume of Water: Hydrogen Sweep, Nitrogen Sweep, Evacuation, Oxidation, Reduction, Neutralization, Sulfiding	87	65
Cleanout Activities Not Reported: None, Invalid, Not Reported	20	15
TOTAL	134	100

SURVEY CLARIFICATION AND WASTEWATER GENERATION ESTIMATES

The RCRA 3007 Survey does not capture wash water volumes. Only one facility reported a discharge volume to a wastewater treatment system in 1992 (i.e., 250 MT for the episodic event or an annual rate of 100 MT/yr).

EPA contacted nine corporations which provided data on 12 petroleum refineries to clarify their RCRA 3007 Survey responses. Refinery personnel were asked to clarify whether their tank/reactor cleanout activities generate wastewaters. If so, they were asked to estimate the wash water generation volume and describe how these wash waters are managed (both pre-treatment and final management).

Initially, 22 refineries were selected for potential contact. These sites were selected to provide a good mix of large and small refineries, represent different corporate practices (i.e., these 22 sites reflect 22 different corporations), and possible regional differences (i.e., midwest, east, south, and west).

Enough data were gathered to conduct the analysis after having attempted to contact 14 of the 22 refineries. Of the 14 refineries contacted, nine responded (i.e., provided data), three did not return telephone calls, and two have had their telephone numbers changed since the 1992 RCRA Survey and were not tracked further. The nine responders represent nine different corporations and provided data for 12 refineries. These 12 refineries represent eight large an four small refineries with one located in the midwest, two in the east, four in the south, and five in the west.

Clarified Slurry Oil Sludge

EPA contacted eight corporations which generate CSO sludge to obtain wastewater data. Based on these contacts, wastewater data were obtained for ten facilities (note that one corporation provided data for four facilities). One facility was not able to estimate wastewater volumes. EPA also used wastewater data provided in writing to EPA by Mobil and Conoco. Mobil provided data for two facilities and Conoco provided average data for its four facilities.

Additional CSO tank wash water generation volume data were provided through public comments. Data were available for two additional corporations, representing six refineries. Two of these refineries are small and four are large. Two are located in the south, two are located in the west, and two have unknown locations.

The CSO tank cleanout method affects the potential to generate CSO sludge wastewater. Based on facility contacts and professional judgement, EPA assumes that the following CSO tank cleanout methods reported in the RCRA 3007 Survey <u>will</u> generate CSO sludge wastewater: water wash, discharge to WWTP, and steam stripping. EPA assumes that the following cleanout methods <u>will not</u> generate CSO sludge wastewater when they are not combined with any methods that will generate wastewater: diesel (or other similar solvent) wash, proprietary tank cleaning, centrifuge, and mixer. EPA also assumes that facilities reporting no cleanout method <u>may</u> generate CSO sludge wastewater. Based on these categories, 18 facilities will generate wastewater, 21 facilities will not generate wastewater, and 64 facilities may generate wastewater.

EPA used reported or estimated wastewater generation volumes for the 82 of the 103 facilities that have a potential to generate CSO sludge wastewaters. Actual reported data were available for 14 of the 103 facilities. Four of the 14 facilities do not generate wastewater. Six unique average wash volumes were provided by the remaining 10 facilities: 2,750; 2,800; 14,000; 16,333; 17,500; and 20,000 gallons per CSO tank cleanout. EPA was not able to assign the actual data provided for the two Mobil facilities because the specific facilities generating these wastewaters could not be determined. However, these two volumes were included in the determination of the average wastewater (wash water) generation estimate of 12,230 gallons per year per CSO tank. The average annualized wastewater generation per CSO tank estimate was determined by averaging all non-zero annualized wastewater volumes available on a per tank basis. This volume estimate was applied to all facilities with unknown wastewater volumes conducting tank cleanout methods with potential to generate CSO sludge wastewaters.

To determine the total annualized CSO sludge wastewater volume for each facility that will or may generate this wastewater, EPA applied the known or average volume estimate, as appropriate. The average volume estimate is on an annualized per tank basis. Therefore, EPA multiplied this average volume per tank by the number of CSO tanks at each facility. For those facilities not reporting the number of CSO tanks. EPA used the average of 3.8 CSO tanks per facility. The total annualized CSO sludge wastewater volume for those facilities which provided estimates is 190,300 gallons per year. The total annualized CSO sludge wastewater volume for those facilities that will generate wastewater, but have the average volume estimate applied, is 330,200 gallons per year. The total annualized CSO sludge wastewater volume for those facilities that may generate wastewater and have the average volume estimate applied is 2,878,900 gallons per year. EPA assumed an expected wastewater volume of 50 percent of this total volume for the 64 facilities that may generate wastewater, resulting in an expected wastewater generation volume of 1,439,500 gallons per year. The total expected CSO sludge wastewater volume for all facilities is 1,960,000 gallons per year (190,300 + 330,200 + 1,439,500).

A range of CSO sludge wastewater volumes also was determined. The minimum annualized total volume estimate was based on actual reported data. The minimum reported volume was assigned to the remaining facilities that will or may generate wastewater, and includes 50 percent of the volume of those facilities that may generate wastewater. The minimum annualized total wastewater volume estimate for all facilities was 588,300 gallons per year. The maximum annualized total volume estimate was based on actual reported data. The maximum reported volume was assigned to the remaining facilities that will or may generate wastewater, and includes 100 percent of the volume of those facilities that may generate wastewater. The maximum annualized total wastewater volume estimate for all facilities was 5,438,300 gallons per year. Table 4 presents a summary of the total wastewater volumes estimates for CSO tank cleanouts.

Table 4. CSO Tank Cleanout Wastewater Volumes[1]

Category	Number of Affected Facilities[2]	Annualized Total CSO Wastewater Volume (gallons per year)
Facilities Reporting Wastewater Volumes	10	190,300
Facilities Generating Wastewater but Did Not Report Volumes	8	330,200 [74,300 - 540,000]
Facilities that May Generate Wastewater and Did Not Report Volumes	32 [32 - 64][3]	1,439,500 [323,700 - 4,708,000]
TOTAL	50 [50 - 82]	1,960,000 [588,300 - 5,438,300]

[1] Quantities are presented as the average followed by the range from low to high in brackets.
[2] Does not include facilities that do not generate wastewater.
[3] Based on facility contacts, EPA assumes that a minimum of 50 percent of the facilities will be affected.

Hydrotreating and Hydrorefining Catalysts

EPA contacted nine corporations which generate these catalysts to obtain wastewater data. Based on these contacts, wastewater data were obtained for nine facilities (note that one corporation provided data for four facilities). The three remaining facilities were not able to estimate wastewater volumes.

The reactor cleanout method affects the potential to generate reactor cleanout wastewater. Based on facility contacts and professional judgement, EPA determined that the following reactor cleanout methods will generate a "large" amount of wastewater: water wash, wet dump, water fill, soda ash wash, and diesel wash. EPA determined that steam stripping will generate a "small" amount of wastewater. EPA assumed that all other reported cleanout methods may generate a "small" amount of wastewater when they are not combined with any methods that will generate a "large" amount of wastewater. EPA assumed that facilities reporting no cleanout method may generate wastewater. Based on these categories, 12 facilities will generate a "large" amount of wastewater, 15 facilities will generate a "small" amount of wastewater, and 87 facilities may generate wastewater. An additional 20 facilities which did not report a cleanout method may generate wastewater.

Based on telephone communications and public comments, EPA used or estimated wastewater generation volumes for 132 of the 134 facilities that have a potential to generate reactor cleanout wastewaters (two facilities reported no wastewater generation). Actual reported data were used for nine of the 134 facilities. Two of the nine facilities do not generate wastewater. Six of the nine facilities generate "large" volumes of wastewater. Three unique volume estimates were provided by these six facilities: 53,125; 240,000; and 500,000 gallons per year. An average annualized wastewater generation estimate per refinery of 264,400 gallons per year was determined by averaging these annualized wastewater volumes. Only one facility with a cleanout method categorized as "small" reported a non-zero wastewater volume. This volume was approximately 15 times smaller than the "large" volume average. Therefore, the average "small" wastewater generation volume has been assumed to be 15 times less than the "large" volume. These volume estimates were applied, as appropriate, to all facilities with unknown wastewater volumes with the potential to generate reactor cleanout wastewaters.

To determine the total annualized reactor cleanout wastewater volume for each facility that will or may generate this wastewater, EPA applied known or the average "large" or "small" volume estimates, as appropriate. The average volume estimates are on an annualized basis for all hydrotreating and hydrorefining reactors at the facilities. The total annualized reactor cleanout wastewater volume for those facilities which provided estimates is 969,200 gallons per year. The total annualized reactor cleanout wastewater volume for those facilities generating a "large" amount of wastewater and have the average volume applied is 1,586,400 gallons per year. The total annualized reactor cleanout wastewater volume for those facilities generating a "small" amount of wastewater and have the average volume estimate applied is 264,000 gallons per year. The total annualized reactor cleanout wastewater volume for those facilities that may generate a "small" amount of wastewater and have the average volume estimate applied is 739,200 gallons per year, assuming an expected generation of 50 percent of the maximum for this volume category. Based on the 113 facilities reporting reactor cleanout methods in the RCRA 3007 Survey, 12 (11 %) will generate a "large" amount of wastewater, 16 (14%) will generate a "small" amount of wastewater, and 84 (75%) may generate a "small" amount of wastewater. EPA assumes an expected volume of 50 percent of the maximum for the "may generate a small amount" category. Applying these percentages to the 20 facilities that may generate wastewater results in an expected wastewater generation volume of 762,000 gallons per year. The total expected reactor cleanout wastewater volume for all facilities is 4,320,800 gallons per year (969,200 + 1,586,400 + 264,000 + 739,200 + 762,000).

A range of reactor cleanout wastewater volumes also was determined. The minimum annualized total volume estimate includes actual data for those facilities providing it, applies the minimum reported volume to the remaining facilities that will or may generate wastewater, and includes 50 percent of the volume of those facilities that may generate wastewater. The minimum annualized total wastewater volume estimate for all facilities is 1,639,400 gallons per year. The maximum annualized total volume estimate includes actual data for those facilities providing it, applies the maximum reported volume to the remaining facilities that will or may generate wastewater, and includes 100 percent of the volume of those facilities that may generate wastewater. The maximum annualized total wastewater volume estimate for all facilities is 7,559,300 gallons per year. Table 5 presents a summary of the total wastewater volume estimates for reactor cleanouts.

Table 5. Hydrotreating and Hydrorefining Reactor Cleanout Wastewater Volumes[1]

Category	Number of Affected Facilities[2]	Annualized Total Hydrotreating and Hydrorefining Reactor Wastewater Volume (gallons per year)
Facilities Reporting Wastewater Volumes	7[3]	969,200
Facilities Generating Large Wastewater Volumes but Did Not Report Volumes	6	1,586,400 [318,700 - 3,000,000]
Facilities Generating Small Wastewater Volumes but Did Not Report Volumes	15	264,000 [52,500 - 499,500]
Facilities that May Generate Small Wastewater Volumes and Did Not Report Volumes	42 [21 - 84]	739,200 [147,000 - 1,398,600]
Facilities that May Generate Large or Small Wastewater Volumes and Did Not Report Volumes	12 [9 - 20]	762,000 [152,000 - 1,692,000]
TOTAL	82 [58 - 132]	4,320,800 [1,639,400 - 7,559,300]

[1] Quantities are presented as the average followed by the range from low to high in brackets.
[2] Does not include facilities that do not generate wastewater.
[3] Six facilities are "large" and one facility is "small.".

COST IMPACT ANALYSIS

Two risk reduction alternatives are evaluated for use in EPA cost-benefit and cost-risk reduction decision analyses. These risk reduction alternatives relate to the management of wash waters from clarified slurry oil (CSO) tank and hydrotreating and hydrorefining reactor cleanout activities at petroleum refineries.

The first risk reduction alternative is the granting of a headworks exemption (Risk Reduction Alternative 1). Under this alternative, wastewaters generated from CSO tank and catalyst reactor cleanouts will be granted an exclusion from RCRA under the definition of a hazardous waste (40 CFR 261.3(a)(2)(iv)) by not being defined as a hazardous waste.

The second risk reduction alternative is that no headworks exemption is granted for either CSO sludge or catalyst wastewaters (Risk Reduction Alternative 2). Under this alternative four cost options are evaluated.

Risk Reduction Alternative 1: Headwaters Exemption Granted for CSO Tank and Hydrotreating and Hydrorefining Catalyst Reactor Wash Waters

Under the definition of hazardous waste, EPA has proposed to exempt CSO tank wash waters and is considering a proposal to exempt hydrotreating and hydrorefining catalyst reactor wash waters only if refineries dispose the wash waters at the front of the headworks. By granting this exemption, the residuals will not be listed as hazardous wastes and downstream wastewaters and sludges (i.e., biological treatment wastewater and sludges) to be derived from or mixed with these wastes will not become listed hazardous wastes under CFR 261.3(a)(2)(iv).

If this risk alternative is selected by EPA, zero incremental compliance costs will be incurred. However, for analytical/decision purposes, by granting this exemption EPA has reduced the RCRA compliance costs and regulatory burden for petroleum refineries. The "avoided" compliance costs are quantified under Alternative 2.

Risk Reduction Alternative 2: No Headwaters Exemption Granted; Wastewater Treatment Tank Exemption Applies; and Land Disposal Restrictions Apply to Wastewater Treatment Impoundments

This risk reduction alternative reflects the potential cost of CSO tank and hydrotreating and hydrorefining reactor wash water management if a headwaters exemption is <u>not</u> granted. The potential risk is from wash water sediments and wastewaters reaching downstream biological treatment surface impoundments (i.e., non-RCRA regulated) and tanks in the refinery's on-site wastewater treatment system or a commercial TSD's off-site wastewater treatment system. The following four cost options are evaluated.

The first two cost options assess the incremental compliance costs if a "conditional exemption" was granted by EPA instead of a "headworks exemption." Costs associated with a conditional exemption (details are provided below) are evaluated because this would have been EPA's second regulatory relief option (after a headworks exemption) to avoid expensive impoundment redesign and sludge management costs. The conditional exemption options provide equivalent risk reduction to RCRA Subtitle C impoundment redesign and sludge management, but, at lower cost if additional risk management is deemed necessary by EPA. A conditional exemption will exempt downstream biological treatment impoundments and tanks from RCRA design, operation, and permitting requirements (i.e., Minimum Technology Requirements, 40 CFR 264, and Land Disposal Restrictions, 40 CFR 268) and exempt their derived biological treatment sludges, which will become hazardous under the mixture rule, from RCRA management requirements. If the headworks exemption or conditional exemption are not granted, biological treatment impoundments and tanks may be managing sludges that are being mixed with hazardous waste sediments, in addition to wastewaters, from the CSO tank and catalyst reactor wash waters. The mixture may be considered a listed hazardous waste under the mixture rule.

A conditional exemption, as well as a headworks exemption, allows refineries to avoid the full RCRA Subtitle C compliance cost for those owners who choose to manage wash waters on site. These costs will be significantly higher than any of the cost options evaluated in this analysis. Biological treatment surface impoundments, under Land Disposal Restrictions 40 CFR 268.4, must meet RCRA sampling, dredging, sludge management, design, and monitoring requirements. Under Minimum Technology Requirements, 40 CFR 264, impoundments must meet RCRA design and operation requirements. In addition, RCRA permits will be required for impoundments under 40 CFR 270. Biological treatment tanks will remain exempt from RCRA design and operation requirements under the wastewater treatment tank exemption. The biological treatment sludges from these units will become hazardous under the mixture rule and subject to RCRA Subtitle C regulation. Significant incremental compliance costs will be avoided if a conditional exemption (or headworks exemption) is granted.

Under the conditional exemption (Cost Options 1 and 2), incremental compliance costs depend on the sediment characteristics of the wash water. Dissolved air flotation (DAF) and API oil-water separators exist at the front end of all existing wastewater treatment plants in the petroleum refining industry. These wastewater treatment tank units should adequately separate out the oils of these wash waters since these separation methods have been approved for previous petroleum refining listings. The dissolved organic constituents that remain will be treated in subsequent biological treatment units, which could be surface impoundment units. Once again, given their common acceptance and use, EPA believes that biological treatment methods will adequately treat refinery watewaters with dilute organic constituent concentrations, unless data can be provided otherwise. Based on telephone communications with the petroleum refining industry, EPA believes that dissolved metal constituents are not an issue with these wash waters, but, suspended metals are. The concern is whether the DAF/API separators will adequately remove suspended sediments (e.g., catalyst fines -- low-density metal particles) in the wash waters. If suspended sediments are adequately removed by DAF/API separators, no incremental compliance costs will be incurred by the petroleum refineries if a conditional exemption is granted. However, EPA has doubt (but no data) that the existing DAF/API separators (i.e., wastewater treatment tanks) will adequately remove these sediments, since it is unlikely that these separators operate at 100 percent efficiency. As a result, hazardous ("listed") sediments will become mixed with the biological treatment sludges generated by the downstream biological treatment tanks and surface impoundments, causing these sludges to become hazardous under the mixture rule and require management under RCRA Subtitle C regulations. As a result, a filtration system is proposed for Cost Options 1 and 2 to remove these hazardous sediments prior to their introduction to downstream treatment units.

Over half (38 out of 72 respondents from API's survey entitled "Management of Residual Materials: 1994 - Petroleum Refining Performance," from September 1996) of the petroleum refineries likely operate surface impoundments downstream of their oil-water separation units. Approximately 40 percent (16 out of the 38 respondents) of those refineries with surface impoundments have obtained RCRA permits for them. Therefore, approximately 30 percent (22 out of 72 respondents) operate wastewater treatment systems containing surface impoundments which will incur large compliance costs if the headworks exemption or conditional exemption is not granted. To avoid these compliance costs, a conditional exemption may be granted if the wastewaters are adequately treated prior to reaching the downstream biological treatment units. The incremental compliance costs associated with the conditional exemption are discussed below.

Cost Option 1 - Conditional Exemption, In-line Filtration System

Install a filtration system (e.g., sand filter) within the existing wastewater treatment system to collect sediments prior to discharge to a biological treatment impoundment or treatment tank. All plant wastewaters would be filtered.

Cost Option 2 - Conditional Exemption, Redundant API Separator/DAF/Filtration System

Install a small-scale, batch-operated, redundant DAF/API separator system adjacent to the existing wastewater treatment units with a small-scale filtration system for dedicated treatment of wash waters only. Discharge treated wash water into the headworks of the existing wastewater treatment system.

The third cost option under Risk Reduction Alternative 2 is to manage the wash waters off-site at a RCRA permitted treatment facility. If both exemptions are granted, this cost option may be the most cost effective for some refineries. However, if neither exemption is granted, this cost option is the most cost effective, given the intermittent nature of when these cleanout activities are conducted, compared to the costs for retrofitting downstream impoundments and managing biological treatment sludges under RCRA Subtitle C.

Cost Option 3 - Off-site RCRA Subtitle C Treatment

Transport wash waters to a commercial, off-site RCRA permitted treatment facility. EPA assumed the off-site RCRA treatment facilities will typically be composed of all tank systems.

The fourth cost option reflects the most cost effective cost option for refinery operators of the above three options if the conditional exemption is granted.

Cost Option 4 - Conditional Exemption, Cost Effective Treatment Option

Under Cost Option 4, EPA assigned the minimum cost from the previous three cost options for each refinery to reflect the most cost effective solution if a conditional exemption is granted.

Cost Analysis

Based on the RCRA 3007 Survey, EPA determined that 103 facilities own CSO tanks which have the potential to generate CSO sludge wastewaters (i.e., wash waters) if the refinery used a water-generating cleanout method. Note that only 101 of the 103 facilities would be affected by a CSO sludge listing for non-wastewater. The additional two facilities have CSO tanks, but management of the CSO sludge itself would be exempt under a recycling exemption. Yet, these facilities may generate wash waters from their tank cleanout activities.

CSO tank wash water volumes were not reported in the RCRA 3007 Survey. Based on data obtained from public comments to the proposed listing and follow-up survey clarification telephone communication, approximately 2,750 to 20,000 gallons of wash water are generated per tank per year. An average value is 12,230 gallons per tank per year. Given that approximately 50 percent of the CSO tank cleanouts generate a wastewater, the petroleum refining industry generates between 588,300 and 5,438,300 gallons of wastewater per year, with an average total volume of 1,439,500 gallons per year.

Based on the RCRA 3007 Survey, EPA determined that 134 facilities have the potential to generate hydrotreating and/or hydrorefining reactor wastewaters.

Catalyst reactor wash water volumes were not reported in the RCRA 3007 Survey. Based on data obtained from public comments to the proposed listing and follow-up survey clarification telephone communication, approximately 3,500 to 500,000 gallons of wash water are generated per facility per year. The average values are 17,600 gallons per facility per year for management methods generating a "small" amount of wastewater and 264,400 gallons per facility per year for management methods generating a "large" amount of wastewater. Given that 43 to 99 percent of the 134 facilities with hydrotreating and hydrorefining reactors generate wastewater, the petroleum refining industry generates between 1,639,400 and

7,559,300 gallons of wastewater per year, with a typical total volume of 4,320,800 gallons per year.

Risk Reduction Alternative 1: Headwaters Exemption

CSO tank and catalyst reactor wash waters are exempted under the definition of solid waste if these wash waters are treated in an oil-recovery system prior to discharge to the wastewater treatment system. All refineries have API separator/DAF units readily available on site at the front end of their wastewater treatment system. Therefore, there is no incremental cost of compliance due to listing this waste if a headwaters exemption is granted under the definition of solid waste.

Risk Reduction Alternative 2: Cost Option 1 - Conditional Exemption, In-line Filtration System

Under Cost Option 1, CSO tank and catalyst reactor wash waters are discharged to the existing wastewater treatment system via the existing sewer system. However, a sand filter would be installed within the existing treatment system to collect sediments. The filtration system is sized the manage all plant wastewaters. Capital costs for this system include filtration beds, piping, pumps, instrumentation, foundations, treatment buildings (which also act as secondary containment), modifications of NPDES permits, and corrosion protection. Operation and maintenance costs include building maintenance, instrumentation maintenance, corrosion protection, pump replacement, electricity, and labor. Filtration system costs were developed for 11 different flowrates within the range of flowrates considered in this analysis. Costs were annualized on a before-tax basis assuming a 20-year borrowing period and a 7 percent real rate of return. Curve-fit equations, based on total wastewater treatment system flowrates, were developed from these 11 system costs.

Incremental compliance costs for Cost Option 1 are based on the estimated total wastewater treatment system flowrate for each facility. Total plant wastewater treatment system flowrates were estimated based on API's survey entitled "Management of Residual Materials: 1994 - Petroleum Refining Performance," from September 1996 which states that the quantity of water discharged daily from 72 refineries surveyed in 1994 ranged from 0 to 34 million gallons per day with a median value of 1.73 million gallons per day. EPA assumed that the minimum flowrate would be 50,000 gallons per day rather than no discharge for a conservative estimate. For the facilities potentially affected by listing of CSO tank and hydrotreating and hydrorefining reactor wash water, EPA applied the minimum, median, and maximum discharge flowrates to the minimum, median, and maximum crude daily rates, respectively, as reported by the facilities in the RCRA 3007 Survey. A curve-fit equation for total facility wastewater flowrate was developed as a function of facility crude daily rate. Costs for the filtration systems are based on the estimated total facility wastewater flowrates. Zero incremental costs were assumed for facilities generating no CSO tank, hydrotreating, or hydrorefining wash water.

Risk Reduction Alternative 2: Cost Option 2 - Conditional Exemption, Redundant API Separator/DAF/Filtration System

Under Cost Option 2, CSO tank and catalyst reactor wash waters are treated on site in a permitted RCRA Subtitle C wastewater treatment tank system prior to discharge to the existing wastewater treatment system. First, EPA assumes that the wastewater will need to be pumped into a tanker truck rather than to the sewer lines for the facility's wastewater treatment plant. A hazardous waste tanker truck service will need to be contracted when a tank cleanout is conducted. The truck will haul the wash waters from the tank to the a small-scale, batch-operated API separator unit. EPA assumes that an API separator/DAF units will be necessary to remove any separable oil layer. The recovered oil is assumed to be recycled back into a process unit. The oil handling cost and value received from the recovered oil likely cancel each other out. The remaining wastewaters are assumed to contain low concentrations of organics and are transferred to a DAF for further oil and volatile organic constituent stripping. Therefore, zero incremental compliance costs are assumed for sludge management. Finally, to satisfy the conditional exemption, the remaining wastewaters are filtered prior to discharge to the main wastewater treatment plant. The filtered sediments are hazardous due to the listing and are assumed to be managed with the listed wastewater treatment sludges from the main wastewater treatment plant. These sludges have traditionally been generated and managed within the context of the main wastewater treatment plant.

Capital costs for Cost Option 2 include a holding/equalization tank, an oil/water separator, a DAF with a compressor, a pressure sand filtration unit, transfer pumps, piping, instrumentation, foundation, corrosion protection, permitting, secondary containment, and start-up. Operation and maintenance costs include compressor maintenance, pressure sand filtration unit replacement, pump replacement, treatment chemicals, annual inspection and reporting, labor, electricity, and transportation of wash water to the system. Closure costs include decontamination, testing for success of pad and tank decontamination, and residual transport and disposal. Treatment system costs were developed for five different flowrates within the range of flowrates considered in this analysis. Costs were annualized on a before-tax basis assuming a 20-year borrowing period and a 7 percent real rate of return. Curve-fit equations, based on the maximum amount of wash water generated during a given CSO tank or reactor cleanout, were developed from these five system costs.

Incremental compliance costs for the management of CSO tank wash waters and hydrotreating and hydrorefining reactor wash waters were developed assuming that wash waters from all three sources would be managed in the same treatment system. Treatment system costs for each facility for Option 2 are based on the maximum amount of wash water generated during a given CSO tank or hydrotreating or hydrorefining reactor cleanout.

Risk Reduction Alternative 2: Cost Option 3 - Off-site RCRA Subtitle C Treatment

Under Cost Option 3, CSO sludge and catalyst reactor cleanout wastewaters are treated off site in a commercial RCRA Subtitle C wastewater treatment tank system. First, EPA assumes that the wastewater will need to be pumped into a tanker truck rather than to the sewer lines for the facility's wastewater treatment plant. A hazardous waste tanker truck service will need to be contracted when a tank cleanout is conducted. The truck will haul the wash waters off site to a commercial hazardous wastewater treatment facility.

Cost Option 3 includes transportation and treatment of hazardous wash water at an off-site hazardous wastewater treatment facility located within 200 miles of each refinery. Treatment costs for Cost Option 3 are based on the annual generation of wash waters from CSO tank and reactor cleanouts for each facility.

<u>Risk Reduction Alternative 2: Cost Option 4 - Conditional Exemption, Cost Effective Treatment Option</u>

The Least Cost Option includes the least expensive of the other three Alternative 2 options for each facility. Table 6 presents the incremental costs for the four options.

Cost Impacts

Incremental costs for the three options under Risk Reduction Alternative 2 above were calculated for each facility. For those facilities which <u>may</u> generate wastewater, a range of incremental costs was developed. For the expected incremental cost, the expected wash water volumes were assumed. This expected cost includes 100 percent of the incremental costs for facilities expected to generate wash water and 50 percent of the incremental costs for facilities which <u>may</u> generate wash water. For the minimum incremental cost, the minimum wash water volumes were assumed. This minimum cost includes 100 percent of the incremental costs for facilities expected to generate wash water and 25 percent of the incremental costs for facilities which <u>may</u> generate wash water. For the maximum incremental cost, the maximum wash water volumes were assumed. This maximum cost includes 100 percent of the incremental costs for facilities expected to generate wash water and 100 percent of the incremental costs for facilities which <u>may</u> generate wash water.

Incremental compliance cost estimates for the listing of CSO sludge, hydrotreating catalyst, and hydrorefining catalyst wastes that are non-wash waters are presented in Table 7. Annual incremental costs for wash water treatment in Table 6 can be added to costs in Table 7 to determine the total cost of compliance for a given option.

In summary, if no headworks exemption is granted, between $3.8 and $26.9 million (expected value of $11.4 million) in incremental compliance costs are incurred by the petroleum refining industry for off-site management of CSO tank and hydrotreating and hydrorefining wash waters. On-site management RCRA compliance costs relating to treatment impoundment closure, or impoundment permitting and redesign, in conjunction with biological treatment sludge management, will be substantially higher than off-site management of wash waters and were not estimated. Once again, if no headworks exemption is granted, but, EPA grants a conditional exemption, between $1 and $3.7 million (expected

PRLF-S0008D

DOCUMENT 4

COST IMPACT ANALYSIS OF THE DEFINITION OF SOLID WASTE
HEADWORKS EXEMPTION
FOR THE PROPOSED LISTINGS OF THREE
PETROLEUM REFINING INDUSTRY WASTES

April 9, 1997

MEMORANDUM

TO: Andy Wittner, EPA/OSW/EMRAD

FROM: Chris Lough, DPRA Incorporated

DATE: March 31, 1997

SUBJ: Impacts of SBREFA and Unfunded Mandates on the Proposed Petroleum Refining Hazardous Waste Listing

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This memorandum updates the Regulatory Flexibility Analysis included in the *Addendum to the Draft Final Report, Cost and Economic Impact Analysis of Listing Hazardous Wastes from the Petroleum Industry* (October 30, 1995), to reflect the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). It also presents an assessment of the potential for unfunded mandates resulting from this proposed rulemaking.

Background of SBREFA

Since its passage in 1980, the Regulatory Flexibility Act (RFA) has generally required every federal agency to prepare regulatory flexibility analyses for any notice-and-comment rule it issues, **unless** the agency certifies that the rule "will not, if promulgated, have a significant economic impact on a substantial number of small entities," which include small businesses, small governments, and small nonprofit organizations. The RFA was amended on March 29, 1996 by SBREFA in ways that strengthened the RFA's analytical and procedural requirements.

Prior to SBREFA's enactment, the Agency issued guidance regarding implementation of the RFA. The most recent guidance (dated April 1992) advised EPA program offices to prepare regulatory flexibility analyses for any rule that would have "any impact" on "any number" of small entities, which is more than the RFA requires. It still remains the Agency's policy that program offices should assess the impact of every rule on small entities and minimize any impact to the extent feasible, regardless of the size of the impact or number of small entities affected. Further, the outcome of that assessment and the steps taken to minimize any impact should be discussed or summarized in the preamble to the rule. In view of the changes made by SBREFA, however, the Agency has decided to implement the RFA as written; that is, regulatory flexibility analyses as specified by the RFA will **not** be required if the Agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.

Where the Agency does **not** certify that a rule will have no significant economic impact on a substantial number of small entities, regulatory flexibility analyses meeting the applicable statutory requirements must generally be prepared for the rule. Even where the Agency certifies that a rule will **not** have significant economic impact on a substantial number of small entities, the Agency's policy is that an assessment of the rule's impact on any small entities must still be made and efforts to minimize that impact undertaken. EPA has prepared guidance[1] regarding criteria and thresholds for determining whether a particular rule will not have a significant impact on a substantial number of small entities, as well as direction on how to prepare regulatory flexibility analyses, if required.

Existing Regulatory Flexibility Analysis

The regulatory flexibility analysis conducted for the Addendum examined whether the proposed petroleum waste listing will affect small entities. By way of background, EPA set forth guidance and criteria for identifying and evaluating whether a regulation will have an economic impact on small entities.[2] The guidelines address the following procedures:

- Identify the small entities affected by the rule;
- Determine if small entities are affected by the rule; and
- Determine whether the operating statute allows the Agency to consider regulatory alternatives to minimize the rule's impacts on small entities.

The RFA specifies that the term "small entity" shall be defined as including small businesses, small organizations, and small government jurisdictions. The Act defines small businesses as those firms that satisfy the criteria established under Section 3 of the Small Business Act. The Agency may use an alternative definition of "small business" after consultation with the Small Business Administration (SBA) and public comment. The SBA criteria apply to <u>firm size,</u> whereas the economic impact analysis for the proposed rule was conducted at the <u>facility level</u> (i.e., refinery level). For single-plant firms, the SBA criteria was applied directly. For firms (i.e., companies) owning more than one refinery, crude capacity was aggregated for all plants (i.e., refineries) to determine the overall size of the company.

Section 603 of the RFA requires a screening analysis be performed to determine whether "small business, organizations and governmental jurisdictions" will be affected by the regulation. If the regulation will have a "significant economic impact" on a "substantial number" of small entities, EPA is required to perform an Initial Regulatory Flexibility Analysis which evaluates the opportunities for and outcomes of introducing alternative regulatory options that minimize a rule's impact on small entities.

For SIC 2911, Petroleum Refining, the Small Business Administration defines small entities as those companies with refinery capacity less than or equal to 75,000 barrels of crude per calendar day. Based on this criterion, 32 of the 66 companies (48%), affected by the listing

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[1] EPA Interim Guidance for Implementing the Small Business Regulatory Fairness Act and Related Provisions of the Regulatory Flexibility Act, prepared by EPA SBREFA Task Force, February 5, 1997.

[2] "EPA Guidelines for Implementing the Regulatory Flexibility Act," Office of Regulatory Management and Evaluation, Office of Policy, Planning and Evaluation, Revised April 1992.

determination are considered to be small entities. Because a sizable percentage of small entities were affected, the Agency conducted an industry impact analysis to determine the impact on small entities. EPA determined, however, that even under the highest cost scenario (i.e., LDR upper bound), the estimated impacts of the listing determination were minimal, with almost no measurable impact on plant operations. Predicted price increases and reductions in domestic output were less than 1 percent for the ten petroleum products evaluated. For the lower bound and midpoint scenarios, impacts on the major variables of average price increase, annual production decrease, and job loss were all less than one-tenth of one percent.

Despite the high percentage of small entities in the population of refinery companies affected by the listing determination, anticipated impacts as a result of implementation of the listings were insignificant, with only up to two plant closures predicted under each of the scenarios evaluated. Because economic impacts were estimated to be minimal, no small entity exemptions or options were judged to be necessary in an effort to reduce economic impacts on small entities. Hence, EPA published in the preamble to the November 20, 1995 proposed rule, pursuant to Section 605(b) of the Regulatory Flexibility Act, "the Administrator certifies that this rule will not have a significant economic impact on a substantial number of small entities."

Impacts of SBREFA

The purpose of the Regulatory Flexibility Act (RFA), which remains the same under the SBREFA amendments, is to ensure that in developing rules, agencies identify and consider ways of tailoring regulations to the size of the regulated entities to minimize any significant economic impact a rule may impose on a substantial number of small entities. The RFA does not require that an agency necessarily minimize a rule's impact on small entities if there are legal, policy, factual or other reasons for not doing so. The RFA requires only that agencies determine, to the extent feasible, the rule's economic impact on a substantial number of such entities, and explain its ultimate choice of regulatory approach. The intent of SBREFA is to strengthen the RFA's analytical and procedural requirements.

The RFA references the definition of "small business" found in the Small Business Act, which itself authorizes the Small Business Administration (SBA) to further define "small business" by regulation. The SBA's small business definitions are codified at 13 CFR 121.201, and the SBA reviews and reissues those definitions every year. SBA's most recent revisions to its "size standards" can be found in the January 31, 1996 Federal Register (61 FR 3280). For SIC 2911, Petroleum Refining, the SBA defines a small business as a firm with no more than 1,500 employees nor more than 75,000 barrels per day capacity of petroleum-based inputs, including crude oil or bona fide feedstocks. These two criteria (i.e., employment and capacity) remain unchanged from the previous regulatory flexibility screening analysis conducted for the proposed listing. In that analysis, the Agency chose not to use SBA's criterion of company-level employment because few companies employ more than 1,500 employees, and data on the number of employees at the company level were much less readily available than were capacity data.

As stated previously, the RFA requires that an agency prepare an Initial Regulatory Flexibili Analysis for proposed and final rules, unless the head of the agency certifies that the rule(s) will not have a significant impact on a substantial number of small entities. The RFA does not define "significant economic impact on a substantial number" of small entities. Agencies therefore have substantial discretion in determining what is not a significant economic impact on, and a substantial number of, small entities. EPA's interim guidance suggests analytical methods, criteria and thresholds for making that determination. As noted above, if an agency certifies that a rule will not have a significant economic impact on a substantial number of small entities, it must support that certification with a factual explanation. Implementation of the SBREFA/RFA guidance will provide the factual predicate for certifying a rule. The RFA authorizes the head of an agency to certify a rule. EPA's Administrator has delegated that authority to the Agency official who has the authority to sign the rule for which a certification has been prepared, except that the authority to certify under the RFA cannot be redelegated below the Office Director level. Further, when an agency certifies a rule, it must publish that certification in the Federal Register at the same time it publishes the proposed or final rule to which the certification applies. The provisions of certification and publishing the certification in the Federal Register remain the same under SBREFA.

Under the RFA, as amended by SBREFA, if the rule will not have any adverse effect on **any** small entity subject to the rule's requirements, the program office may certify that the proposed and final rules will not have a significant economic impact on a substantial number of small entities on that basis. For a proposed or final rule that will have an adverse effect on one or more small entities, however, the program office must determine the extent of the impact and the number of small entities affected.

SBREFA's Economic Criteria

EPA's Interim Guidance provides suggested economic criteria for assessing the impact of a rule on small entities. These criteria are drawn from standard economic analyses and vary by type of small entity in view of the different economic characteristics of small businesses, governments, and nonprofit organizations. Further, for each type of small entity, several different criteria are listed. The criteria vary in terms of the type of data involved, and thus a program office may choose to apply one criterion over the others based on the type of information available. The guidance document nevertheless indicates a preferred criterion for each type of small entity. Where the program office has the necessary information, it should generally use the preferred criterion. The program office may nonetheless use one of the other criteria, or even a criterion not included in the guidance, where it has sound reasons for doing so and it explains those reasons in the rulemaking record. For small businesses, the preferred criterion is the *annualized compliance costs as a percentage of sales* (i.e., the sales test). The other quantitative criteria for evaluating the economic impact of a rule on small businesses are: debt-financed capital compliance costs relative to current cash flow ("cash flow test") and annualized compliance costs as a percentage of before-tax profits ("profit test").

The application of the preferred criterion, the "sales test," on the proposed petroleum waste listing, yields a quantitative estimate of the rule's impact on small entities. The Interim Guidance presents a matrix that categorize the rule based on the magnitude of its impact (as measured using the preferred criteria) and the number of entities expected to experience an impact of a particular magnitude.[3] Each category establishes either a process for determining, or a presumption regarding, whether the rule can be certified as having no significant impact on a substantial number of small entities.

The scope of each category is defined by various thresholds for three variables: the magnitude of the impact, the absolute number of small entities that will experience that impact, and the percentage of all the small entities subject to the rule that will experience that impact. It is important to keep in mind, however, that the thresholds are only guidelines for determining whether a rule will not have a significant impact on a substantial number of small entities. The RFA itself does not establish a formula for making this determination, and indeed, it would be impossible to develop a formula that would yield an appropriate answer in the context of every rule. For that reason, the thresholds are used to define categories that establish no more than a presumption; program offices and the Agency as a whole will have to exercise judgment in deciding whether to prepare a regulatory flexibility analysis for, or certify, a given rule.

EPA performed a screening analysis to evaluate the economic impact of the proposed waste listing on small entities using the preferred criterion (i.e., the sales test) whereby annualized compliance costs as a percentage of sales (i.e., revenues) for the ten petroleum products previously evaluated were calculated. For each waste stream (i.e., clarified slurry oil sludge, hydrotreating catalyst, and hydrorefining catalyst) and compliance option (i.e., listing scenario, LDR scenarios, and contingent management scenario) described in the *Addendum*, EPA determined the costs as a percentage of sales for each small entity at the close of 1992 (i.e., 32 companies operating 36 refineries). The following summarized results are reported:

Summary of Economic Impacts of Small Entities

	Listing Scenarios	LDR Scenario Lower Bound	LDR Scenario Upper Bound	Contingent Management Scenario
Range of Annualized Compliance Costs	$4,566 - $305,379	$4,556 - $7,561,781	$4,556 - $11,765,904	$4,556 - $2,321,305
Range of Annual Company Refinery Sales	$19,377,340 - $1,218,936,710			
Range of Annualized Compliance Costs as a Percentage of Company Refinery Sales	0.001% - 0.236%	0.001% - 0.620%	0.001% - 0.965%	0.001% - 0.236%

[3] As stated previously, the legal test for certifying a rule is whether the rule "will not, if promulgated, have a significant economic impact on a substantial number of small entities." The test thus has two steps—first, will the impact on any small entities subject to the rule be significant, and second, will the number of small entities significantly impacted be substantial? The Agency may certify a rule if its impact is significant but only with respect to a small number or percentage (i.e., not a "substantial number") of the small entities subject to the rule's requirements. The Agency may also certify a rule if its impact falls on a substantial number of small entities, but its impact is not significant. The Agency may not certify a rule if a substantial number of the small entities subject to the rule's requirements will be significantly impacted by the rule.

The above results represent a worst-case economic impact on small entities resulting from the listing of CSO tank sludge, hydrotreating catalyst, and hydrorefining catalyst. The range of annualized compliance costs for each regulatory option reported above is based on the highest possible cost estimated for each facility (i.e., cost estimates incorporating the greatest amount of uncertainty), rather than the expected compliance cost outcome. As is evident from the table, all small entities affected by the proposed listing have compliance costs as a percentage of sales of less than one percent, the threshold to determine potential economic impact. As a result, the proposed rule received a **Category 1** ranking and the rule is presumed **not** to have a significant economic impact on a substantial number of small entities.[4] Therefore, the Agency would support a certification that the rule will not have a significant economic impact on a substantial number of small entities.[5]

Unfunded Federal Mandates

In this section, EPA evaluates the potential implications of the Unfunded Mandates Reform Act of 1995 (UMRA) for the proposed petroleum listing determination. UMRA (P.L.104-4), which was signed into law on March 22, 1995, defines two categories of unfunded federal mandates, intergovernmental and private sector mandates, which must be considered. Unfunded federal mandates are defined as the following:

- Any provision in legislation, statute, or regulation that would impose an enforceable duty on state, local or tribal governments or the private sector, except as a condition of federal assistance or a duty arising from participation in a voluntary federal program; or

- Any provision that would reduce or eliminate federal financial assistance to state, local, or tribal governments for compliance with pre-existing regulations.

In addition to the criteria listed above, unfunded intergovernmental mandates are defined as any provision that relates to a pre-existing federal program under which $500 million or more is provided annually to state, local, and tribal governments under entitlement authority.

Title II (Section 202) of UMRA requires that a federal agency prepare a written statement for any proposal that is likely to result in a rule that includes an unfunded federal mandate resulting in expenditures of $100 million or more in any one year by smaller government bodies (i.e., state, local, and tribal governments) in the aggregate or by the private sector. This written statement can be prepared as part of any other analysis prepared by EPA for rulemakings and must include the following:

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[4] Although not required, the Assistant Administrator of the program office developing the rule may, at his or her discretion, decide to prepare a regulatory flexibility analysis for the rule.

[5] The certification statement must be included in the Regulatory Flexibility section of the rule's preamble and by at least a summary of the factual basis for the certification. If only a summary is provided, a full explanation must be provided elsewhere in the rulemaking record and the summary should reference that explanation.

- Identification of the provision of federal law under which the rule is promulgated;

- An assessment of the costs and benefits of the mandate, including the extent to which federal resources (e.g., financial assistance) will be available to carry out the mandate;

- An estimate of the future compliance costs;

- An estimate of the effect on the national economy (if feasible, relevant, and material); and

- A description of the Agency's prior consultation with affected governments, including summaries of the comments and concerns raised and the Agency's evaluation of those comments.

Under Section 205, agencies must also develop a process to permit elected state, local, and tribal government officials to provide "meaningful and timely input" into the development of regulatory proposals "containing significant intergovernmental mandates." In addition, agencies must consider a "reasonable number of regulatory alternatives" and select the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule, unless the provisions of the alternative are inconsistent with the law or an explanation is provided by the head of the affected agency.

EPA has determined that the proposed listing does not contain a federal mandate that will result in an expenditure of $100 million or more in any one year to state, local, or tribal governments in the aggregate or the private sector. According to the *Addendum*, the upper bound of the range of potential average annual costs is estimated to be $39.6 million, considerably below the $100 million annual threshold. Therefore, the proposed rule is not subject to the requirements of Sections 202 and 205 of the UMRA. No additional guidance, other than what is contained in OMB's "Economic Analysis of Federal Regulations Under Executive Order 12866" (January 11, 1996) for the analysis of unfunded federal mandates, could be located since EPA published the proposed rule on November 20, 1995 (60 FR 57747). In that OMB document, the only reference to the assessment of potential unfunded federal mandates was the requirement that all economic analyses of proposed regulations should satisfy the requirements of Title II of the UMRA.

cc: Gwen De Pietro, SAIC
Dave Gustafson, DPRA

DOCUMENT 3

IMPACTS OF SBREFA AND UNFUNDED MANDATES ON THE PROPOSED PETROLEUM REFINING HAZARDOUS WASTE LISTING

March 31, 1997

Waste Stream	Number of Gens	Streams	Generation (tons)
D008 D018 K052	1	1	6.000
K049 K050 K051 F037	1	1	5.769
K050 D007 D004 D005 D006	1	1	3.350
K050 D028	1	1	3.000
K050 D004 D005 D006 D007 D008	1	1	2.250
F037 D007 D008	1	1	2.237
D007 D008 K050	1	1	2.234
K050 D007	1	1	2.185
✓ D001 D018 F037	1	1	1.750
✓ F038 D001	1	1	1.608
K050 D007 D008	1	1	1.523
✓ D001 D003 D018 K051	1	1	1.300
K049 K050 K051	1	1	0.590
D008 K050	1	1	0.583
D001 D018 U220 U239 F037	1	1	0.550
✓ F037 F038 K048 K051	1	1	0.250
D009 D018 K050	1	1	0.238
K048 K050 K051 K052	1	1	0.140
K051 F037 D008 D018	1	1	0.125
D001 D018 K052	1	1	0.000
D007 D008 F037 K050	1	1	0.000
D008 K052	1	1	0.000
K051 K052	1	1	0.000
			9264953.375

✓ = 2,043,031 ≈ 2 million tons

Did not include any waste streams that are D004 - D011 (metals), K050 (heat exchanger bundles), or K052 (leaded tank bottoms).

Waste Stream	Number of Gens	Streams	Generation (tons)
D[illegible] D002 D003 D008 D018 K052 U019 U159 U220	1	1	56.000
F037 D019 D022	1	1	54.660
D007 D018 F037	1	1	54.140
F037 K049 K051 D018	1	1	47.837
D001 K050	2	3	45.730
F037 D018 D027	1	1	40.460
K051 K048 K049 K050 D018	1	1	37.110
K051 F037 F038 D018 D001	1	1	35.800
K050 D001 D003 D018	1	1	35.500
F037 F038 D003 D018	1	1	33.000
D003 D018 K049	1	1	28.880
K052 D018	3	3	24.380
K050 K051 F037	2	2	23.830
F[illegible] F038 K048 K049 K050 K051 K052	1	1	[illegible]2.570
D018 F037 K049 K050	1	1	18.000
D001 K051	2	2	17.500
K048 K049 D001 D018	1	1	16.423
D007 D008 D018 F037 F038 K048 K049 U019 U055 U056 U220 U239	1	2	15.710
D018 K050	1	1	14.903
K050 D018	2	2	13.729
F037 K050	1	1	13.500
F037 D003 D018 D001	1	1	12.236
K051 K050 D001 D018	1	1	12.150
K049 K051	1	1	10.253
K050 D007 D008 D009	1	1	10.100
F[illegible] D001 D018	2	2	8.705
K049 K051 D018	1	1	7.312
K048 K049 K051 F037	1	1	6.500

Waste Stream	Number of Gens	Streams	Generation (tons)
K[illegible]3 K050 K051 K052 D008 D018 F037 F038	1	1	205.800
K051 D018 D005	1	1	179.203
K048 F038 D018	1	1	178.000
K051 K049 D018 F037	1	1	159.150
F039 K048	1	1	148.253
K051 D007 D008 D009	1	1	148.210
D001 D018 K048 K049	1	2	146.710
K051 K050	1	1	145.540
D018 K048 K051	1	1	141.510
D018 F037 K048 K051	1	1	140.000
D018 F037 F038 K048 K051	1	1	133.000
K048 K051 F037	1	1	126.400
D001 D002 D008 D009 D018 K052 U019 U055 U220	1	1	122.350
F[illegible]7 D019 D022 D018 D001	1	1	112.685
D001 D018 K050	2	2	97.715
K049 K050	2	2	91.550
F037 D008	1	1	91.000
D007 D008 D018 F037	1	1	90.900
K051 K049 K048	1	1	88.774
D001 D002 D003 D008 D018 F005 F037 F038 K048 K049 K050 K051 K052	1	1	88.000
D001 D002 D003 D007 D008 D018 F037 F038 F039 K048 K049 K050 K051 K052	1	1	86.000
K051 K048 K050	1	1	78.290
K049 D003 D018	1	1	74.605
D001 D003 D007 F037	1	1	68.000
D007 D018 F037 K050	1	2	63.550
K051 K050 K049 K048	2	3	63.530
D018 F037 K048 K049 K050 K051	1	1	57.760
K050 D001 D018	3	3	56.281

Waste Stream	Number of Gens	Streams	Generation (tons)
D[illegible]3 D007 F037 F038 K048 K051	1	1	1175.260
K049 K050 K051 F038	1	1	1123.100
K052 D008	4	8	1052.650
K048 K051 F038	1	1	984.800
K048 K049 K050 K051 K052 F037	1	1	923.965
D001 D018 K048 K049 K050 K051 F037 F038	1	1	850.779
F038 K048	1	1	818.020
K049 F037 K050	1	1	702.500
K049 K051 F037 D018	1	1	672.122
F039 K048 K051	1	2	662.546
K051 F037 F038	1	2	654.100
D018 F037 F038 K048 K049	1	1	640.210
F037 F038 K050	1	1	571.435
D[illegible]1 D018 K049	1	1	564.800
F037 F038 K049 K050 K051	1	1	559.000
K051 F037	3	3	509.291
K051 K050 D001	1	1	475.777
F037 F038 K049	1	1	457.440
D003 D018 K051	1	1	448.120
F037 F038 K048 K049 K050 K051	1	1	372.260
K049 K051 D001 D018	1	1	360.337
D003 F037 K048 K049 K051	1	1	306.000
K052	19	21	297.608
D001 D018 D008 K050 F037	1	1	288.255
K051 K050 F037	1	1	274.130
D004 D005 D006 D007 D008 D009 D010 D011 D018 F[illegible] F038 K048 K049 K050 K051 K052 U019 U055 U2[illegible]0	1	1	273.270
D007 D008 D018 F037 F038	1	1	232.000
D001 D018 K051	2	2	219.200

Waste Stream	Number of Gens	Streams	Generation (tons)
D[illegible] F037	9	9	8619.630
D018 F037 F038	2	4	7620.000
K048 K049 K051 F037 F038	1	2	6383.279
D018 K048 K049	2	2	5977.100
F037 K048 K049 K050 K051	1	1	5419.000
F038	11	13	4271.963
D001 K049 K051	1	1	4171.500
K050 K051	5	5	4040.890
K048 K051 F037 F038	2	3	3560.704
K048 K051 K049 K050 F037	1	1	3270.800
F037 F038 D018	5	5	2690.396
K050	72	76	2638.367
✓ K049 D001 D018	1	3	2598.585
D[illegible] D007 D008 D018 K048 K049 K050 K051 K052	1	4	2450.000
D018 K048 K050 K051	1	1	2341.000
K051 D018	8	11	2279.364
D001 F037 F038	1	1	2204.590
K051 K048 K049 K050	1	3	2089.100
D018 F037 F038 K048 K049 K050 K051	2	2	1927.600
F037 F038 K048 K049 K051	2	2	1872.040
K048 K049 K050 K051 F037 D018	1	1	1836.900
D018 K048 K049 K050	1	1	1808.527
K049 K051 F037	3	4	1675.538
D018 D001 K048 K049 K050 K051	1	1	1535.552
D018 K051	3	3	1465.890
D018 F037 F038 K048 K049 K050 K051 K052 P110 U[illegible] U055 U056 U220	1	1	1320.370
K048 K049 K050 K051 K052	3	5	1261.000
K048 K049 K050 K051	3	5	1205.343

Waste streams, waste stream counts, generator counts, and generation in tons for 1993 BRS GM forms reporting SIC 2911 and a waste code in the F037, F 8, K048-52.

Waste Stream	Number of Gens	Streams	Generation (tons)
D007 D008 D018 F037 F038 K048 K049 K050 K051 K052	1	1	3460134.430
D018 K048 K049 K050 K051	2	2	3196790.991
D018 F038	1	1	548286.000
K048 D018	2	2	434882.500
K048 K049 K050 K051 F037	2	5	293979.313
K048	25	31	292506.753
F037	71	101	262942.354
D018 K049	4	5	108385.075
F037 F038	19	26	98170.107
K048 K052 F037	1	1	60399.200
K 8 K049 K051	4	5	57693.143
D001 D018 F037 F038 K048 K049 K050 K051	2	2	55048.640
D018 K048	3	3	46261.420
K049 K048	1	1	32013.300
K049 K050 K051 F038 D018	1	1	31900.000
K051	51	67	29027.375
F037 D018	9	9	20317.911
D018 D019 D040 K048 K049 K050 K051 U019 U220 U239	1	1	19851.750
K050 K049 K048 D018	1	2	17796.490
K049 D018	6	6	17552.555
K048 K049 K050 K051 F037 F038	1	1	16740.292
K050 K051 K048 K049 F037 D018	1	1	12100.000
K048 K049 K050 K051 D018	2	2	11545.729
K048 K051	10	11	11395.802
K048 K049	1	2	10352.200
K049	16	17	9940.676

EPA Waste Code	Total % Solids Content	Total % Water Content	Total % Oil Content
F037/F038	5	82	13
K048	5	82	13
K049	12	40	48
K051	20	65	15

Given the above waste stream characteristics for F037/F038, K048, K049, and K051, the solids content is very high for some of these waste streams. They are at levels that indicate that some of the samples may have been taken after filtering the wastes. At high solid concentrations, the wastes can not be pumped from the wastewater treatment tank via hard pipe to the coker.

DPRA assumes a range of 50 to 100 percent of the waste quantity may be fed back to the coker. Some wastes will not be recycled back to the coker in order to maintain coke product quality and/or efficient operation of the coker. Overall, DPRA assumes a percent oil fraction that ranges from 15 to 50 percent, with a typical value of 15 percent oil.

Waste Quantity

Attached is a printout from the 1993 Biennial Report System of all F037, F038, and K048 through K052 waste stream generation quantities for SIC 2911 (petroleum refining). In 1993, the petroleum refining industry generated 9.3 million tons (8.5 million metric tons) of these seven waste types. For this analysis, DPRA excluded all quantities associated with K050, K052, and/or wastes containing heavy metals (D004-D011) as not being appropriate to manage in a coker. The resulting quantity is 2.0 million tons (1.8 million metric tons).

Benefit Estimate

Assuming that 50 to 100 percent of the 1.8 million metric tons are recycled back to the coker, this waste contains approximately 135,000 to 270,000 metric tons (15 percent) of oil. Of these amounts, 70 percent of the oil is condensed into vapors for light hydrocarbon recovery and 30 percent is converted into petroleum coke ($1.36/barrel; $6.16/MT). Assuming that 90 percent of the oil is recovered from the condensed vapors and the recovered light hydrocarbons (pre-fuel quality) has 110 percent of the feedstock value of oil ($18.43/barrel; $136/MT) results in a benefit of approximately $13 to $26 million. This estimate does not include any costs for handling and transporting the waste to the coker or the coker operator's time to monitor and feed the wastes into the coker.

value of $2.1 million) in compliance costs will be incurred. However, if a headworks exemption is granted, no incremental compliance costs will be incurred and the above RCRA Subtitle C costs will be avoided

Table 6. Annual Incremental Costs for Wash Water Treatment

Risk Reduction Alternative and Cost Option	Annual Incremental Costs for Treatment of CSO Tank and Hydrotreating and Hydrorefining Reactor Wash Waters
Alternative 1: Headwaters exemption	$0
Alternative 2: Cost Option 1 - Conditional Exemption, In-line Filtration System (large system handling all plant wastewaters)	$9.4 Million ($6.6 Million - $14.8 Million)
Alternative 2: Cost Option 2 - Conditional Exemption, Redundant API/DAF/Filtration System (small system handling only wash waters)	$2.1 Million ($1.2 Million - $3.8 Million)
Alternative 2: Cost Option 3 - Off-site Subtitle C Treatment	$11.4 Million ($3.8 Million - $26.9 Million)
Alternative 2: Cost Option 4 - Conditional Exemption. Least Cost Option	$2.1 Million ($1.0 Million - $3.7 Million)

TABLE 7. Summary of the Incremental Compliance Costs by Waste Stream and Cost Impact Option ($ millions per year)[1]

Waste Stream	Listing Scenario Subtitle C Landfill of Sludges and Catalysts	LDR Scenario, Option 1 Off-Site Incineration of Sludges and Incineration and Vitrification of Catalysts	LDR Scenario, Option 2 On-/Off-Site Incineration of Sludges and Regeneration/Reclamation of Catalysts	Contingent Management Scenario (Conditional Listing) Subtitle D Landfill and Land Treatment (w/ controls) of Sludges and Regeneration/Reclamation of Catalysts
Clarified Slurry Oil Sludge	2.6 [1.3 - 4.5]	22.5 [11.2 - 37.6]	17.8 [9.9 - 28.0]	(0.5) [(0.3) - (0.8)]
Hydrotreating Catalyst	1.3 [0.8 - 2.9]	5.0 [3.5 - 7.6]	2.3 [1.2 - 4.5]	2.3 [1.2 - 4.5]
Hydrorefining Catalyst	1.5 [0.7 - 3.8]	11.6 [8.3 - 16.5]	3.9 [1.9 - 7.9]	3.9 [1.9 - 7.9]
RCRA Admin. Costs	0.4 [0.3 - 0.5]	0.4 [0.3 - 0.5]	0.7 [0.5 - 0.8]	0.4 [0.3 - 0.5]
TOTAL	5.9 [3.1 - 11.7]	39.6 [23.3 - 62.3]	24.7 [13.6 - 41.2]	6.1 [3.1 - 12.1]

[1] Costs are presented as the average cost followed by the range of costs from low to high in brackets. Parentheses indicate negative values, credits.

Source: U.S. EPA, "Addendum to Draft Final Report: Cost and Economic Impact Analysis of Listing Three Hazardous Wastes from the Petroleum Refining Industry," October 30, 1995.

PRLF-S0008.E

DOCUMENT 5

COST IMPACT ANALYSIS OF THE
COKING EXEMPTION
ON CRUDE OIL TANK SLUDGE AND CLARIFIED SLURRY OIL SLUDGE
COMPLIANCE COSTS FROM LISTING AS A RCRA HAZARDOUS WASTE

January 10, 1998

DPRA

E-1500 First National Bank Building St. Paul, Minnesota 55101-1314 Telephone 612-227-6500 FAX 612-227-5522

January 10, 1998

Mr. Andrew Wittner
U.S. Environmental Protection Agency, Crystal Station
Office of Solid Waste
Economics, Methods and Risk Assessment Division
2800 Crystal Drive
Arlington, Virginia 22202

RE: Cost Impact Analysis of the Coking Exemption on Crude Oil Tank Sludge and Clarified Slurry Oil Sludge Compliance Costs from Listing as a RCRA Hazardous Waste; DPRA WA No. 3821.316

Dear Andy:

Attached is the final draft report of the Cost Impact Analysis of the Coking Exemption on Crude Oil Tank Sludge and Clarified Slurry Oil Sludge Compliance Costs from Listing as a RCRA Hazardous Waste. The long term incremental compliance cost of listing with LDR impacts four petroleum refining wastes (crude oil tank sludge, clarified slurry oil sludge, hydrotreating catalyst, and hydrorefining catalyst), including the coking exemption for the sludges, ranges from approximately $35 to $75 million (1997$) annually, with an expected long term cost of around $50 million per year.

Please call me with any questions or comments at 612/227-6500.

Sincerely,

Dave Gustafson
Senior Associate

cc: Chris Long, SAIC
Chris Lough, DPRA

Mailing Address: P.O. Box 727 Manhattan, Kansas 66505 Telephone 913-539-3565 FAX 913-539-5353
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COST IMPACT ANALYSIS
OF THE COKING EXEMPTION ON
CRUDE OIL TANK SLUDGE AND CLARIFIED SLURRY OIL SLUDGE
COMPLIANCE COSTS FROM LISTING AS A RCRA HAZARDOUS WASTE

This report presents a cost impact analysis of the redefinition of petroleum cokers as process recycling units under the definition of solid waste (DSW). This rulemaking will exempt petroleum coking units from all regulatory requirements (i.e., design, operation, and permitting standards) under RCRA Subtitle C when recycling crude oil tank sludges (COTS) or clarified slurry oil (CSO) sludge for the production of petroleum coke, when the sludge is introduced into the non-quench cycle of the coker, or the quench cycle of the coker if data is provided to show that oil recovery occurs in amounts that show quenching is more like a normal refining operation. A complete exemption from RCRA Subtitle C storage, transportation, and management regulations is granted for all crude oil storage tank sludges and clarified slurry oil sludge that are recycled as feedstock into petroleum coking units (i.e., the front end of the coking unit rather than the quench cycle) for the purpose of producing petroleum coke.

ISSUE

Under the proposed listing, a coking exemption is being provided for COTS and CSO sludge that are recycled back into an on-site coking process unit, off-site coking process unit owned by the same company, or an off-site coking process unit owned by another company. Currently, COTS and CSO sludge are typically managed in Subtitle D landfill or land treatment units. Without the coking exemption, to comply with the listing itself, they will be required to be managed in Subtitle C landfill units. In addition, to comply with the Land Disposal Restrictions (LDR) requirements being specified simultaneously with the listing, they ultimately will be managed in Subtitle C thermal destruction (i.e., incineration) units. The scope of the analysis covers the impact the coking exemption has on compliance costs associated with COTS and CSO sludge.

GENERATION AND MANAGEMENT

COTS Generation and Current Management

Nearly all refineries store feedstock materials and products in tanks. Periodically crude oil storage tanks (COTS) require sludge removal due to maintenance, inspection, or sludge buildup. The average reported cleanout frequency in the 1992 RCRA 3007 Survey is once every 10.5 years. Also, on average, there are approximately eight crude oil tanks per refinery. Based on the average number of tanks per facility and the clean-out frequency, crude oil tank sludge is generated every 1.3 years at a facility. Crude oil tank sludge consists of heavy hydrocarbons, sediment and water, and entrapped oil that settles to the bottom of the tank. When removed, the oil is recovered while the solids are collected and discarded as a waste. The discarded waste may now be recycled in coking units under the newly proposed DSW rulemaking.

Petroleum refineries generate between 45,900 and 114,700 metric tons per year (Mtons/yr) with a typical value of approximately 80,300 Mtons/yr of COTS affected by this listing.[1] EPA estimates that 145 facilities generate this waste. Given the infrequent tank cleanout schedule and the structure of the 1992 RCRA 3002 Survey, 85 of 93 facilities reported generating this waste but did not report the total quantity associated with cleaning out all of their tanks. Fifteen facilities did not report cleanout quantities for any of their tanks. EPA also estimated that an additional 52 facilities have existing crude oil storage tanks but did not report generating this waste. All facilities with existing crude oil storage tanks are assumed to generate COTS unless it has been specifically stated in a cover letter or communication that the residual is not generated. Waste quantities for these non-reported quantities were estimated based on quantities reported by other refineries and their crude oil usage. These estimates account for approximately 86 percent of the typical annual quantity.

The 80,300 metric tons of COTS generated annually reflects the average annual quantity at the point of generation (i.e., prior to entering the waste management train). The annual quantity that is ultimately managed (i.e., reaches its final disposition) for COTS is much lower because refineries are filtering oily sludges and recycling the oil fraction back into process units. EPA assumes that all refineries who currently are not filtering oily sludges will install a filtration unit to recycle the oil back into process units as a cost-effective waste minimization practice. Some refineries reported both the quantity entering and exiting pressure filtration/centrifuge units, providing an estimate of the oil recovery rate. Based on this ratio, on average, 60 percent of the COTS volume filtered is recovered as oil and recycled back into process units. The "non-process recycled" annual quantities reaching the end of the waste management train (i.e., final management) is 14,600 Mtons/yr. If this filtration waste minimization practice is not implemented, the total would be 17,400 Mtons/yr. Of the 14,600 Mtons/yr, 2,700 Mtons/yr qualify for the wastewater treatment headworks exemption and 1,300 Mtons/yr currently are managed in RCRA Subtitle C disposal units.

For this cost analysis, it is assumed that refineries will de-oil the COTS first prior to placement in the coker. Therefore, the analysis continues to assume an oil-benefit for the recovered oil quantity, but excludes this same quantity from being available for a potential coke-benefit to avoid double counting of cost benefits. In addition, if the COTS is currently managed in the wastewater treatment headworks, it is assumed that the refinery will continue to manage the waste in that manner under the headworks exemption because of its likely low BTU content and low carbon content. Finally, those wastes currently being managed in RCRA Subtitle C disposal units now may be recycled in coking units and subject to potential cost benefits from the DSW coking

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[1] This quantity excludes amounts that currently are managed in RCRA-exempt process recycling units including on-site cokers (the focus of this cost impact analysis), on-site catalytic crackers, on-site distillation units, and other reported on-site/off-site recycling/reclamation/reuse practices that are not land applied.

recycling exemption. This analysis will focus on the economic tradeoffs between coker recycling and RCRA Subtitle C management options for the 11,900 Mtons of de-oiled COTS disposed annually (14,600 - 2,700).

The most common residual disposal methods for COTS are disposal in an off-site Subtitle D or C landfill. Pressure filtration/centrifuging is a common residual treatment method. Other treatment methods include thermal treatment, off-site incineration, washing with distillate or water, sludge thickening or de-watering, settling, filtration, chemical or thermal emulsion breaking, land treatment, discharge to an on-site wastewater treatment facility, drying on a pad, and stabilization. Other disposal methods include discharge to surface water under NPDES, disposal in an on-site Subtitle C landfill, and disposal in an on-site surface impoundment.

<u>CSO Sludge Generation and Current Management</u>

Petroleum refineries produce between 18,300 and 35,400 Mton/year with a typical value of approximately 26,800 Mton/year of clarified slurry oil sludge that is affected (i.e., subject to a compliance cost) by this listing. EPA estimates that 101 facilities generate this waste. Thirty-seven of the 54 facilities reporting generating this waste did not report quantities for cleaning out all of their tanks. Six of the 54 facilities did not provide a quantity. EPA also estimated that an additional 47 facilities did not report generating this waste. These estimates account for approximately 64 percent of the typical annual quantity.

Similarly to COTS quantity estimates, the 26,800 metric tons of CSO sludge generated annually reflects the average annual quantity at the point of generation (i.e., prior to entering the waste management train). The "non-process recycled" annual quantities reaching the end of the waste management train (i.e., final management) is 13,100 Mtons/yr. If the filtration waste minimization practice is not implemented, the total would be 18,000 Mtons/yr. Of the 13,100 Mtons/yr, 500 Mtons/yr qualify for the wastewater treatment headworks exemption and 2,000 Mtons/yr currently are managed in RCRA Subtitle C disposal units.

For this cost analysis, it is assumed that refineries will de-oil the CSO sludge first prior to placement in the coker. Therefore, the analysis continues to assume an oil-benefit for the recovered oil quantity, but excludes this same quantity from being available for a potential coke-benefit to avoid double counting of cost benefits. In addition, if the CSO sludge is currently managed in the wastewater treatment headworks, it is assumed that the refinery will continue to manage the waste in that manner under the headworks exemption because of its likely low BTU content and low carbon content. Finally, those wastes currently being managed in RCRA Subtitle C disposal units now may be recycled in coking units and subject to potential cost benefits from the DSW coking recycling exemption. This analysis will focus on the economic tradeoffs between coker recycling and RCRA Subtitle C management options for the 12,600 Mtons of de-oiled COTS disposed annually (13,100 - 500).

The most common residual disposal method for CSO sludge is disposal in an off-site Subtitle

D or C landfill. Pressure filtration/centrifuging is a common residual treatment method. Other treatment methods include on-site industrial flare, washing with distillate, sludge thickening or de-watering, settling, filtration, thermal emulsion breaking, land treatment, discharge to on-site wastewater treatment facility, drying on a pad, and stabilization. Other disposal methods include disposal in an on-site Subtitle D landfill.

Compliance Management Scenarios

Under the Listing Scenario (i.e., incremental compliance cost due to listing), the assumed compliance practice is disposal in an on-/off-site Subtitle C landfill. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Discharge of flushing waters to on-site wastewater treatment systems will be continued because of a "headwater exemption" provided for waste-derived sludges from wastewater treatment systems that are not already hazardous due to a previous listing. The practice of disposing this waste in land treatment and disposal surface impoundment units will be discontinued. In the evaluation of the coking exemption costs/benefits, when economically more advantageous, the cost for on-/off-site Subtitle C landfill and secondary containment retrofitting costs will be substituted with lower costs associated with recycling in a coking unit. Handling costs will be assumed to be equivalent. Only transportation and disposal/recycling costs are compared.

For the Land Disposal Restrictions (LDR) Scenario (i.e., incremental compliance cost due to listing and LDR regulations), the assumed compliance practice is disposal in either an on-site or off-site Subtitle C incinerator, depending on which practice is more economical. Storage and treatment units will be retrofitted with secondary containment systems to meet Subtitle C accumulation storage and treatment tank regulations. Discharge of flushing waters to on-site wastewater treatment systems will be continued because of a "headwater exemption" provided for waste-derived sludges from wastewater treatment systems that are not already hazardous due to a previous listing. The practice of disposing this waste in land treatment and disposal surface impoundment units will be discontinued. In the evaluation of the coking exemption costs/benefits, when economically more advantageous, the cost for on-/off-site Subtitle C incineration and secondary containment retrofitting costs will be substituted with lower costs associated with recycling in a coking unit. Handling costs will be assumed to be equivalent. Only transportation and disposal/recycling costs are compared.

LOCATION OF PETROLEUM COKERS

Petroleum refiners operate 47 petroleum coking units according to the 1992 RCRA 3007 Survey. Most of the units (51 percent) are located in Texas, Louisiana, and California. Table 1 presents the number of petroleum coking units by state.

Table 1. Petroleum Coking Units by State

State	Cokers
Texas	10
California	8
Louisiana	6
Kansas	4
Illinois	4
Oklahoma, Washington, Ohio	2 each
Mississippi, Alabama, Utah, Montana, Wyoming, Minnesota, Indiana, New Jersey, Virginia	1 each
Total	47

FEED MATERIAL QUALITY

The percentage of the COTS and CSO sludge having the appropriate "material qualities" to serve as feed material for petroleum cokers is a critical factor in determining the percentage of the total quantity of COTS and CSO sludge generated that can be recycled in coking units. An important quality is the carbon content. Available sampling data provide the percentage of oil and grease and the carbon content of the waste. These data are used to estimate the percentage of the total COTS and CSO sludge generation volume that may be appropriate for use as coker feed material.

The *Petroleum Refining Listing Determination Final Background Document,* from October 31, 1995, provides data for oil and grease and carbon content. For COTS, the 10th, mean, and 90th percentile values for oil and grease content (5%, 34.3%, and 80%, respectively) and carbon content (0%, 23%, and 65%, respectively) in percent volume. For CSO sludge, the 10th, mean, and 90th percentile values for oil and grease content (5%, 29.5%, and 80%, respectively) and carbon content (0%, 29%, and 70%, respectively) in percent volume. These data include <u>both</u> oily and de-oiled COTS and CSO sludge. A simple linear regression analysis of the COTS data results in the following predicted relationship between percent total organic carbon and percent oil and grease:

% Oil and Grease = 1.1458 x (% Total Organic Carbon) + 6.1566

no. of samples = 3
degrees of freedom = 1
R-squared = 0.99827
Standard Error of Coefficient = 0.04770
Standard Error of Y Estimate = 2.2233

The Final Background Document provides a range of oil and grease content values for de-oiled COTS of 4.87 percent to 41.1 percent. Oil and grease data for de-oiled CSO sludge is unavailable. Given the similar 10^{th} percentile, mean, and 90^{th} percentile oil and grease values for oily COTS and oily CSO sludge, the data available for de-oiled COTS is assumed for de-oiled CSO sludge. The question to be answered is what minimum percent total carbon does the COTS need to contain to have the appropriate material qualities to serve as feed material for a petroleum coker? Once the minimum total percent carbon is estimated, the methodology will be to calculate an equivalent percent oil and grease value using the regression equation provided above. Using the calculated minimum oil and grease value, linear interpolation will be used between the range of reported de-oiled COTS values to estimate a percentage of the total de-oiled COTS volume generated that can be used as feed material for petroleum coking units.

Conoco, in its advertisement for its delayed coking technology, provides a feed analysis of a light petroleum residual and a heavy petroleum residual. The percent carbon contents are 11.85 percent and 24.47 percent, respectively.[2] COTS and CSO sludge should have characteristics that are more similar to a heavy petroleum residual. So, they are assumed to have a typical value of approximately 25 percent carbon content when oily. Conoco advertises that it can process light petroleum residuals that contain only 11.85 percent carbon, therefore, a minimum value of 10% carbon is assumed for heavy petroleum residuals such as COTS and CSO sludge when de-oiled. Based on the regression equation, a de-oiled COTS waste that is 10 percent carbon contains approximately 17.6 percent oil and grease. Through linear interpolation, approximately 65 percent of the total de-oiled COTS quantity has sufficient carbon content for use as feed material in a petroleum coking unit [(41.1 - 17.6)/(41.1 - 4.87) = 0.649]. This amounts to 7,735 Mtons of the 11,900 Mtons of de-oiled COTS and 8,190 Mtons of the 12,600 Mtons of de-oiled CSO sludge disposed annually.

Another "material quality" issue that needs to be considered is how much petroleum coke is produced from every ton of COTS and CSO sludge used as feed material. Does it differ from other feed materials placed in the coking units? Does COTS and CSO sludge result in a lower-grade petroleum coke? For this analysis it is assumed that the quality of petroleum coke produced from COTS and CSO sludge will be similar to that produced from other petroleum residuals used as feedstocks. If this is not the case, the unit management cost will be higher to account for blending of the COTS and CSO sludge with other petroleum residuals over time in

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[2] http://www.conoco.com/coking/index.html, October 8, 1997.

proportions that will not compromise the quality of the coke. The cost should not be significantly higher because COTS and CSO sludge represents only a small fraction of the industry's feedstock at 7,735 Mtons/yr and 8,190 Mtons/yr, respectively. In the early 1990s, the industry produced 17 million tons of petroleum coke annually, with coke representing approximately 30 percent of the final product output from the coking unit.[3,4] Production increased to 23 million Mtons (25 million tons) in 1994.[5] The remainder of the feedstock is converted into petroleum liquid products such as naphtha, gas oil, and kerosene. Therefore, over 80 million tons of petroleum residuals are processed by petroleum coking units annually.

REPORTED COKING UNIT COSTS

The first step in determining unit costs for coking recycling is to assess the data provided in the 1992 RCRA 3007 Survey for those petroleum refineries currently recycling COTS in cokers. Reported unit costs for other wastes/residuals managed in cokers also are examined.

Reported On-Site Coker Practices

Four refineries reported recovering COTS in on-site coking units. Two refineries reported recovering CSO sludge in on-site coking units. No refinery provided unit cost information for COTS. Only one refinery reported a price for CSO sludge. Therefore, coking process costs were estimated from coking price information. This estimate is presented in the next section of this analysis.

Reported Transportation Methods

For transport from the tank to the coking unit, one refinery uses a vacuum truck and three refineries use piping for transporting COTS. Two refineries use a vacuum truck and tanker truck for transporting CSO sludge. Including other wastes/residuals reported being managed in cokers in the 1992 RCRA 3007 Survey, four refineries report recovery of COTS, two refineries recover CSO sludge, seven refineries recover unleaded gasoline tank sludge, two refineries recover hydrofluoric alkylation sludge, two refineries recover off-spec product and fines from thermal processes, and one refinery recovers sulfur complex sludge (other than Stretford).

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[3] DPRA Incorporated telephone communication with Ray Diamond, Pace Consultants (713/669-8800), June 8, 1995.

[4] http://www.conoco.com/coking/index.html, October 8, 1997.

[5] 1994 DOE Petroleum Supply Annual, Vol. 1, pp. 34, 51.

Reported Unit Costs

Four refineries provided unit management costs for CSO sludge, unleaded gasoline tank sludge, and sulfur complex sludge. Because of CBI issues, the associated waste types are not specified with the unit costs. Two of these refineries use a tanker truck to transport their waste to on-site coking units. It appears that because of the "bulk" nature of their operations (given their transportation practices) they have coking unit costs of between $14/Mton and $100/Mton. Two facilities use dumpsters or drums to transport their waste to on-site coking units and have significantly higher coking unit costs of $1,400/Mton and $45,000/Mton. Because of the nature of their transport operations, they likely manage very small quantities, resulting in high unit costs because of the high labor costs associated with handling operations. For example, if it takes one laborer, at $50/hour, eight hours to process 0.1 metric ton of sludge, the resulting unit cost is $4,000/Mton.

For COTS and CSO sludge currently being transported to on-site cokers via bulk methods such as tanker trucks and piping, it is more likely that the $14/Mton and $100/Mton reported above reflect the coker management costs associated with current COTS processing in cokers. However, COTS that are currently land farmed or landfilled are frequently transported via dumpster, which would indicate that the $1,400/Mton unit cost value also is plausible.

As discussed in more detail later in this document, three scenarios were developed to bound the incremental compliance cost estimates due to the listing and LDR impacts and a coker exemption for COTS and CSO sludge. The results of this analysis are presented in Table 2.

For the lower bound scenario (columns A and D of Table 2), Subtitle D landfill transportation unit costs are assumed for transportation to coker units because COTS and CSO sludge are exempt from Subtitle C regulation for this scenario when recycled as feedstock in a coker. Since coker transportation unit costs are very limited, average Subtitle D landfill transportation unit costs reported by 82 facilities in the 1992 RCRA 3007 Survey are used as a proxy. An average trucking distance of 100 miles to the nearest coker was assumed to derive a unit cost per Mton-mile. Petroleum coking units are not as common and widely dispersed as Subtitle D landfills. Therefore, transportation distances may be significant for refineries located in areas such as the Rocky Mountain and Southwest regions of the U.S. The following unit costs are used in this analysis:

- Truck with drums: $0.45/Mton-mile,
- Truck with dumpsters: $0.27/Mton-mile,
- Truck with bed: $0.17/Mton-mile, and
- Tanker truck: $0.55/Mton-mile.

For the expected scenario (columns B and E of Table 2), Subtitle C landfill transportation unit costs are assumed for transportation to coker units because COTS and CSO sludge are hazardous until they are inserted into the quench cycle of a coker, as assumed in this scenario. Also, only intracompany transfers are assumed in this scenario. Therefore, transportation distances are greater than those assumed for the lower bound scenario. An average distance of 200 miles to the nearest intracompany coker was assumed in deriving the unit cost estimates. The following unit costs are used in this analysis:

- Truck with drums: \$1.12/Mton-mile,
- Truck with dumpsters: \$0.36/Mton-mile,
- Truck with bed: \$0.24/Mton-mile, and
- Tanker truck: \$0.62/Mton-mile.

For the upper bound scenario (columns C and F of Table 2), only those refineries currently recycling COTS and CSO sludge in cokers are assumed to continue this waste management practice. Refineries not currently recycling COTS and CSO sludge in cokers (or managing these wastes by other exempt management practices) are assumed to dispose of these wastes in an off-site Subtitle C landfill for the listing scenario and an on- or off-site incinerator for the LDR scenario. Therefore, unit costs for transportation of waste from other refineries to cokers are not needed.

COKE PRICES AND COKING PROCESS UNIT COST ESTIMATE

In the early 1990s, the U.S. exported significantly more petroleum coke than that used domestically. Of the approximately 17 million tons of petroleum coke that were produced annually in the U.S., 16 million tons per year (94%) were exported and one million tons per year (6%) were used domestically.[6] World Production in 1991 was over 50 million Mtons, excluding China and the Commonwealth of Independent States.[7] Therefore, the U.S. produced less than one-third of total world production. World exports of green and calcined petroleum coke were around 17.9 million tpa between 1989 and 1991, with the U.S. accounting for 87% of the total exports in 1991.[8]

U.S. petroleum coke production capacity has increased since the early 1990s. In 1994, the U.S. produced 23 million Mtons of petroleum coke, of which 15 million Mtons were exported.[9] The U.S. domestic demand has increased while the quantity exported has remained approximately constant. U.S. petroleum coke prices have dropped to a point where they are competitive with

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[6] DPRA Incorporated telephone communication with Ray Diamond, Pace Consultants (713/669-8800), June 8, 1995.

[7] "Roskill Reports on Metals and Minerals - Petroleum Coke," http://www.roskill.co.uk/petcoke.html, October 8, 1997 (analysis uses early 1990s data, i.e., 1991 or 1992).

[8] Ibid.

[9] 1994 DOE Petroleum Supply Annual, Vol. 1, pp. 34, 51.

other fuels. The U.S. domestic demand has increased because of lower prices and new applications in industries such as cement kilns and electricity generation facilities. Therefore, the percentage of the total U.S. coke production that is exported has decreased.

The world outlook is one of rapidly increasing supply leading to lower prices with the expansion of coke production capacity at oil refineries to be prominent in the U.S. The reasons for this capacity growth in the U.S. are changing qualities of crude oil and environmental regulations requiring cleaner transportation fuels. Lower prices may mean increased use of petroleum coke as a fuel by electricity and cement producers. Some electricity plants now exist that consume petroleum coke as their sole fuel source. Petroleum coke also is an indispensable raw material for the aluminum industry whose demand is anticipated to increase. If primary aluminum smelter capacities are fully utilized, they would have consumed 6.4 million Mtons (approximately 13 percent) of petroleum coke worldwide in 1994.[10]

With projected increases in petroleum coke production capacity and increases in demand for petroleum coke from the aluminum, electricity, and cement industries, petroleum coke producers will be looking for additional feedstock materials. The 7,735 Mtons of COTS generated and 8,190 Mtons of CSO sludge generated annually (of feed material quality) represent a very small fraction of the feedstock materials used in petroleum coke production. Therefore, petroleum coking capacity and demand are not assumed to be market constraints to the petroleum refining industry. However, petroleum coking operators may charge higher prices to refiners wanting to recycle their COTS and CSO sludge knowing they are competing in a hazardous waste market that includes high-priced Subtitle C landfill and Subtitle C incineration management as alternative management methods.

Commercial coke prices from 1992 were obtained from *Coal Week International*. Commercial prices from the first quarter of 1996 also were obtained to check that the petroleum coke market has remained viable since 1992. All costs and prices used in the Economic Impact Analysis (EIA) are 1992 dollars.

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[10] "Roskill Reports on Metals and Minerals - Petroleum Coke," http://www.roskill.co.uk/petcoke.html, October 8, 1997 (analysis uses early 1990s data, i.e., 1991 or 1992).

Petroleum Coke Prices

	West Coast ($/Mton; % Sulfur)	Gulf Coast ($/Mton; % Sulfur)
1/14/92	40-44 (< 2%)	29-31 (> 2%)
4/7/92	47-53 (< 2%)	13-18 (> 2%)
7/7/92	25-28 (< 2%)	8-10 (> 2%)
10/20/92	26-28 (< 2%)	5-7 (> 2%)
1992 Avg.	$36	$15
1/2/96	41-44 (2%)	18-24 (4%)
1/2/96	32-36 (3.5%)	16-18 (6%)
1/2/96	---	11-15 (6%)
1996 Avg.	$38	$17

In using these prices, one must be concerned whether the coke product is marketable coke or catalyst coke (e.g., an intermediate product used for heating purposes in the production of gasoline). An initial step is to determine what the refinery price would be for selling the coke, excluding reseller markup and shipping costs. Paper trails of this type of information are very limited, if not nonexistent, because resellers are not going to volunteer this type of information in their price quotes. According to Pace Consultants, located on the Gulf Coast, refineries are receiving an export price of approximately $7/Mton (adjusted for transportation costs) for exported marketable coke (i.e., over seas) and $14/Mton (not adjusted for transportation costs) for use within their own company as an intermediate product for heating purposes in the production of gasoline.[11] The marketable domestic coke price would be approximately $14/Mton (not adjusted for transportation costs). The coking processing cost should be less than $7/Mton.

West Coast operations produce a lower sulfur coke and can charge a higher price because of the

[11] DPRA Incorporated telephone communication with Ray Diamond, Pace Consultants (713/669-8800), June 8, 1995.

Export Price ($15 per Mton):
$13.50 per short ton
- $5 or $6 for loading costs
- $1 for reseller markup

$6.50 - 7.50 per short ton refinery price (He indicated $5-7 per short ton as a refinery price.)

Within own company:
$13.50 short ton
- $1 for reseller markup

$12.50 per short ton

quality of the product. Refineries are receiving an export price of approximately $30/Mton (adjusted for transportation costs) for exports and $35/Mton (not adjusted for transportation costs) domestically.[12] The coking process cost should not be different than the Gulf Coast.

For this analysis, it is assumed that East Coast and Midwest refineries that operate petroleum coking units use similar petroleum oil feedstocks to the Gulf Coast refineries. Therefore, these refineries produce high sulfur petroleum and follow the Gulf Coast price structure. East Coast refineries are assumed to have similar export capabilities.

Accounting for profit, a coking process unit cost of $6/Mton is assumed for this analysis. Transportation costs are not included in the coking process unit cost estimate and are added separately.

COST IMPACT ANALYSIS

This analysis only assumes the costs associated with processing COTS and CSO sludge in a petroleum coking unit. The value gained from the coke produced is not assessed for those refineries that operate coking units. In addition, EPA did not consider the possibility that a facility may build a coker for COTS and CSO "sludge management."

Methodology

Frequently, several individual waste management methods make up the components of the waste management practice (i.e., waste management train) for storing, treating, recycling, and disposing a waste stream. Because of the significant number of waste management trains reported by the petroleum refining industry, current (baseline) and compliance management costs were developed for the individual components of each waste management train. The incremental difference in cost between the baseline and compliance management costs for each individual component of the waste management train were summed together to develop incremental compliance cost estimates for the complete waste management practice.

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12 Export Price ($36 per Mton):
$33 per short ton
- $5 or $6 for loading costs
- $1 for reseller markup

$27 - $28 per short ton refinery price
Within own company:
$33 short ton
- $1 for reseller markup

$32 per short ton

For example, Petroleum Refinery X generates 100 metric tons per year of crude oil tank sludge. The current (baseline) waste management train is to filter the oily sludge, recycling 60 metric tons (MT) of oil filtrate back to the distillation unit, and storing 40 MT of filter sludge in roll-on/roll-off bins within an accumulation container storage area prior to spreading the sludge in an on-site Subtitle D land treatment unit ($87/MT).

Under the listing and LDR scenarios <u>without</u> a coking exemption, the following compliance activities need to be conducted. To comply with Subtitle C accumulation treatment tank regulations, the filtration operation will require the construction and maintenance of a secondary containment system underneath the filtration unit ($2,500/yr). The cost for operating and maintaining the filtration unit will not change and a new filtration unit will not need to be purchased ($0/yr). The 60 MT of oil filtrate recycled back to the distillation unit is exempt from regulation under the "definition of solid waste". A recycled oil credit is applied to the oil filtrate if the facility has not been de-oiling its sludges as a baseline management practice ($110/MT credit). To comply with Subtitle C accumulation container storage area regulations, a new accumulation container storage area will need to be constructed and maintained ($4,800/yr). Under the listing scenario, to comply with Subtitle C disposal regulations, the refinery will abandon the on-site land treatment unit ($87/MT), choose not to construct an on-site Subtitle C land treatment unit in anticipation of future LDR regulations that will mandate the closure of such a unit, and transport and dispose the waste in an off-site Subtitle C landfill ($73/MT for transport and $233/MT for Subtitle C landfill). Under the LDR scenario, off-site Subtitle C incineration ($92/MT for transport and $1,867/MT for Subtitle C incineration) will be the required disposal method. The baseline costs are subtracted from the compliance cost estimates developed for each scenario to calculate an estimated incremental compliance cost.

Under the listing and LDR scenarios <u>with</u> a coking exemption, the compliance cost is the cheaper of the above estimated costs compared with the cost of transporting and using the waste as feedstock material in a coking unit. As noted previously, only 65 percent of the COTS and CSO sludge quantity is assumed to be of sufficient quality to be used as feedstock for coking units. The remaining 35 percent of the quantity is assumed to be managed in either a Subtitle C landfill or Subtitle C incinerator.

Because of the uncertainty regarding plant-specific coker capacity availability, access limitations, cost limitations, feedstock quality limitations, and state regulatory restrictions, three scenarios were evaluated to bound the possible results of the listing and LDR scenarios with a coking exemption. As an upper bound cost scenario, it is assumed that only those facilities currently recycling COTS and CSO sludge will continue to do so. However, refiners will seek new cost optimization solutions since coking is now economical when compared to Subtitle C management instead of Subtitle D management. Therefore, a second scenario is considered assuming that, when economical, facilities will transport COTS and CSO sludge to the nearest refinery within the same company (i.e., intracompany) that currently operates a coker. For this scenario, it is assumed that intercompany transfers of COTS and CSO sludge will not occur because of liability issues for management of hazardous waste. As a lower bound cost scenario, it is assumed that technology allowing insertion of de-oiled COTS and CSO sludges into coker feedstocks will be developed and intercompany transfers will occur, with no market pricing. However, it is not likely that there will be no market pricing given potential profits (compared to Subtitle C management costs) and potential benefits received by both the generator and recycler.

Results

Table 2 presents the COTS and CSO sludge management costs for the listing and LDR scenarios with the coker exemption. Columns A and D represent lower bound scenarios, assuming that technology allowing insertion of de-oiled COTS and CSO sludges into coker feedstocks will be developed and intercompany transfers will occur, with no market pricing. Subtitle D storage, treatment, and transportation costs are assumed. Columns B and E represent cost-optimization scenarios, assuming that refineries with cokers will manage COTS and CSO sludges in the quench cycle of cokers, when economical, and other refineries will transfer sludges to other refineries within the same company with cokers. Subtitle C storage, treatment, and transportation costs are assumed. Columns C and F represent upper bound scenarios, assuming that only those refineries currently recycling COTS and CSO sludge in cokers will continue to do so. EPA is promulgating LDRs with the listing of four petroleum refining wastes at this time. Therefore, costs in columns D, E, and F apply. Costs are anticipated to range between $22 and $113 million annually, with an expected value of $46 million per year. Shortly following the promulgation of the listing including LDR impacts, costs are anticipated to range between approximately $46 and $68 million annually due to sludge quality possibly being inappropriate for use as coker feedstock material and as refineries obtain approval for inserting sludge into the quench cycle of the coker. In the long term, improvements in technology for sludge use as coker feedstock material and intercompany transfers with market pricing are possibilities. Given the potential for market pricing for intercompany transfers of wastes for management in coking units, the minimum cost estimate is more of a lower bound estimate (i.e., column D). The long term costs are estimated to range between approximately $35 and $75 million annually with expected costs around $50 million per year.

Seven facilities that generate COTS are located in Alaska, Hawaii, Puerto Rico, and Virgin Islands. Two facilities that generate CSO sludge are located in Hawaii and Puerto Rico. For these facilities, the transportation cost to the nearest coker is significant. Therefore, EPA assumes that these facilities will not manage COTS or CSO sludge in a coker for the listing or LDR scenario. It should be noted that for the lower bound listing scenario with a coking exemption (column A), the non-continental facilities will incur approximately 40 percent of the incremental cost of compliance associated with COTS. In addition, for the lower bound LDR scenario with a coking exemption (column D), the non-continental facilities will incur over 22 percent of the incremental cost of compliance associated with COTS. One of these facilities that generates COTS incurs a high amount of the cost under both scenarios.

Table 2. Annualized Incremental Compliance Costs for Management of Four Petroleum Refining Wastes (1997$ millions)[1]

Waste Stream	Unconditional Listing			Unconditional Listing Including LDR Impact		
	A	B	C	D	E	F
	1) De-oil Sludges 2) "Not Same Person" Coking (100 % Used in Feedstock) 3) Off-Site Subtitle C Landfill Remaining Sludges 4) Off-Site Subtitle C Landfill of Catalysts	1) De-oil Sludges 2) "Same Person" Coking (100% Used in Quench) 3) Off-Site Subtitle C Landfill Remaining Sludges 4) Off-Site Subtitle C Landfill of Catalysts	1) De-oil Sludges 2) Continue Current On-Site Coking (100% Used in Quench) 3) Off-Site Subtitle C Landfill Remaining Sludges 4) Off-Site Subtitle C Landfill of Catalysts	1) De-oil Sludges 2) "Not Same Person" Coking (100 % Used in Feedstock) 3) Off-Site Subtitle C Incineration Remaining Sludges 4) Off-Site Subtitle C Incineration & Ash Vitrification of Catalysts	1) De-oil Sludges 2) "Same Person" Coking (100% Used in Quench) 3) Off-Site Subtitle C Incineration Remaining Sludges 4) Off-Site Subtitle C Incineration & Ash Vitrification of Catalysts	1) De-oil Sludges 2) Continue Current On-Site Coking (100% Used in Quench) 3) Off-Site Subtitle C Incineration Remaining Sludges 4) Off-Site Subtitle C Incineration & Ash Vitrification of Catalysts
Crude Oil Tank Sludge	1.1 [0.4 - 2.1]	1.8 [0.8 - 3.3]	2.5 [1.1 - 4.4]	8.7 [4.1 - 14.9]	**13.2** **[6.1 - 22.9]**	24.1 [10.4 - 43.3]
Clarified Slurry Oil Sludge	0.3 [0.0 - 0.9]	1.1 [0.5 - 2.0]	2.9 [1.4 - 5.0]	8.1 [3.9 - 13.8]	**13.8** **[7.0 - 23.0]**	25.1 [12.5 - 42.0]
Hydrotreating Catalyst	1.5 [0.9 - 3.2]	1.5 [0.9 - 3.2]	1.5 [0.9 - 3.2]	5.6 [3.9 - 8.5]	**5.6** **[3.9 - 8.5]**	5.6 [3.9 - 8.5]
Hydrorefining Catalyst	1.7 [0.8 - 4.2]	1.7 [0.8 - 4.2]	1.7 [0.8 - 4.2]	13.0 [9.3 - 18.4]	**13.0** **[9.3 - 18.4]**	13.0 [9.3 - 18.4]
RCRA Administrative Costs	0.6 [0.4 - 0.7]	0.6 [0.4 - 0.7]	0.6 [0.4 - 0.7]	0.6 [0.4 - 0.8]	**0.6** **[0.4 - 0.8]**	0.6 [0.4 - 0.8]
TOTAL	5.2 [2.5 - 11.1]	6.7 [3.4 - 13.4]	9.2 [4.6 - 17.5]	36.0 [21.6 - 56.4]	**46.2** **[26.7 - 73.6]**	68.4 [36.5 - 113.0]

[1] Costs are presented as the average cost followed by the range of costs from low to high in brackets. In the economic impact analysis, 1992 costs were estimated. Costs were inflated to 1997 dollars using an inflation factor of 1.11657. The inflation factor is based on Engineering News-Record construction (25% weighted) and common labor (75% weighted) cost indexes. The inflation factor is weighted towards labor factors because compliance costs are more operational in function. Costs are annualized assuming a discounted rate of seven percent over a 20 year period.

Notes:

1) All crude oil tank and clarified slurry oil sludges are assumed to be de-oiled in the cost estimate. The recovered oil is recycled back into process units. For those refineries that reported oil recovery fractions that data were used. For refineries that did not provide data, using an industry average for CSO sludge and COTS, 60 percent of the quantity entering the filtration unit is assumed to be recovered as oil and the remaining 40 percent goes on for further management.

2) Of the remaining de-oiled sludge quantity (i.e., 40 percent fraction), 65 percent is assumed to have coker feedstock/quench quality. The remaining 35 percent is subject to Subtitle C management (see Note 3).

If sludges are recycled back into coking units through the quench cycle, they are not granted the oil-bearing exclusion (columns B, C, E, and F). Therefore, all storage, treatment, and transportation of these wastes are subject to RCRA Subtitle C regulation. Columns B and E reflect management of sludges in cokers owned by the same company (i.e., "same person"). Refineries owned by the same company will be willing to share any liability associated with handling sludges subject to Subtitle C regulation.

If sludges are recycled back into coking units with the feedstock material, they are granted the oil-bearing exclusion (columns A and D). Therefore, all storage, treatment, and transportation of these wastes are not subject to RCRA Subtitle C regulation. Columns A and D assume no technical limitations for using the sludges as feedstock material for the coking unit. Currently, technical limitations appear to exist for using these sludges as feedstock materials in coking units which will deter intercompany transfers (i.e., "not same person"). If so, the oil-bearing exclusion will not be available and Subtitle C regulations are attached to the transferred waste and the costs in columns B and E should be used. However, a market may develop where refineries will charge more to handle intercompany sludge transfers as a hazardous waste. If so, the costs will be between columns A and B and D and E, respectively.

3) LDRs are being promulgated for CSO sludge and COTS under this rulemaking. Therefore, the costs in columns D, E, and F apply. Where it is not economically feasible to insert the sludge into a coking unit, Subtitle C incineration is the assumed compliance practice in the cost estimate.

4) LDRs are being promulgated for hydrotreating and hydrorefining catalysts under this rulemaking. Therefore, the costs in columns D, E, and F apply. Subtitle C incineration and ash vitrification are the assumed compliance practice in the cost estimate.

Bold Numbers: The numbers in bold reflect the best approximation of the costs associated with this rulemaking. Costs are anticipated to range between $22 and $113 million annually, with an expected value of $46 million per year. Shortly following the promulgation of the listing including LDR impacts, costs are anticipated to range between approximately $46 and $68 million annually due to sludge quality being inappropriate for use as coker feedstock material. In the long term, improvements in technology for sludge use as coker feedstock material and intercompany transfers with market pricing are anticipated. Given the potential for market pricing for intercompany transfers of wastes inserted into the quench cycle of the coking units, the minimum cost estimate is unlikely. The long term costs are estimated to range between approximately $35 and $75 million annually with an expected cost around $50 million per year.