



Regulatory Impact Analysis of the Petroleum Refinery NSPS

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SECTION 1

EXECUTIVE SUMMARY

EPA has characterized the facilities and companies potentially affected by the NSPS by examining existing refineries and the companies that own them. EPA projects that new refineries and processes will be similar to existing ones, and that the companies owning new sources will also be similar to the companies owning existing refineries. EPA has collected data on 150 existing refineries, owned by 58 companies. Of the affected parent companies, twenty-five are identified as small entities based on the Small Business Administration size standard criteria for NAICS 324110, for they employ 1,500 or fewer employees.

EPA estimates that complying with the final NSPS will have an annualized cost of approximately \$31 million per year (2006 dollars) in the fifth year after proposal. Using these costs, EPA estimates that the NSPS will have limited impacts on the market for motor gasoline. Based on sales data obtained for the affected small entities, EPA estimates that, due to the expected annualized cost savings, that the NSPS will not result in a SISNOSE (a significant economic impacts for a substantial number of small entities).

The final petroleum refineries NSPS is considered subject to the requirements of Circular A-4 because EPA expects that the sum of benefits and costs are potentially \$1 billion or higher. EPA's estimate of the benefits of the NSPS, based on information from the PM_{2.5} expert elicitation study released in October, 2006, is a range from \$220 million to \$1.9 billion (2006 dollars) in the fifth year after proposal. EPA believes that the benefits are likely to exceed the costs by a substantial margin under this rulemaking even when taking into account uncertainties in the cost and benefit estimates.

SECTION 2

INTRODUCTION

The U.S. Environmental Protection Agency's (EPA's) Office of Air Quality Planning and Standards (OAQPS) is currently revising the existing Subpart J New Source Performance Standards (NSPS) for petroleum refineries. In addition, the Agency is adding a Subpart Ja that provides new requirements, including new emissions limits for new fluid catalytic cracking units (FCCUs), new fluid coking units, and new flares. This final regulation includes emissions limits for new and modified/reconstructed sources, and these limits are set for sulfur dioxide (SO₂), nitrogen oxides (NO_x), coarse particulate matter (PM₁₀), volatile organic compounds (VOC), and other pollutants. This regulatory impact analysis (RIA), prepared in response to requirements under Executive Order 12866, presents the results of analyses undertaken in support of this final rule including compliance costs, benefits, economic impacts, and impacts to small businesses.

2.1 Introduction

The petroleum refining industry comprises establishments primarily engaged in refining crude petroleum into refined petroleum. Examples of refined petroleum products include gasoline, kerosene, asphalt, lubricants, solvents, and a variety of other products. Petroleum refining falls under the North American Industrial Classification System (NAICS) 324110.

This RIA is organized as follows:

- Section 1: Executive Summary,
- Section 2: Introduction,
- Section 3 and an Appendix A: Profile of the Petroleum Refinery Industry,
- Section 4: NSPS Regulatory Alternatives, and Costs and Emission Reductions From Complying with the NSPS, and an Appendix B: Summary of Significant Comments and Responses, And Rationales for NSPS Emission Limits
- Section 5: Economic Impacts of the NSPS,
- Section 6: Potential Impacts on Small Businesses,
- Section 7: Benefits of the NSPS, and
- Appendix C: Overview of Economic Model Equations

2.2 Reason for Today's Action: Market Failure or Other Social Purpose

The petroleum refinery NSPS is of sufficient impact to be considered as falling under the requirements of Circular A-4, an addendum to the existing requirements for Executive Order

12866 (OMB, 2003). This final regulation is being issued in response to a court-ordered settlement between U.S. EPA and various parties requiring review of the existing NSPS.

As discussed in Circular A-4, among the reasons a regulation such as this one may also be issued is to address market failure. The major types of market failure include: externality, market power, and inadequate or asymmetric information. Correcting market failures is a reason for regulation, but it is not the only reason. Other possible justifications include improving the functioning of government, removing distributional unfairness, or promoting privacy and personal freedom.

2.2.1 Externality, Common Property Resource, and Public Good

An externality occurs when one party's actions impose uncompensated benefits or costs on another party. Environmental problems are a classic case of externality. For example, the smoke from a factory may adversely affect the health of local residents while soiling the property in nearby neighborhoods. If bargaining were costless and all property rights were well defined, people would eliminate externalities through bargaining without the need for government regulation. From this perspective, externalities arise from high transactions costs and/or poorly defined property rights that prevent people from reaching efficient outcomes through market transactions.

Resources that may become congested or overused, such as fisheries or the broadcast spectrum, represent common property resources. "Public goods," such as defense or basic scientific research, are goods where provision of the good to some individuals cannot occur without providing the same level of benefits free of charge to other individuals.

2.2.2 Market Power

Firms exercise market power when they reduce output below what would be offered in a competitive industry in order to obtain higher prices. They may exercise market power collectively or unilaterally. Government action can be a source of market power, such as when regulatory actions exclude low-cost imports. Generally, regulations that increase market power for selected entities should be avoided. However, there are some circumstances in which government may choose to validate a monopoly. If a market can be served at lowest cost only when production is limited to a single producer B local gas and electricity distribution services, for example B a natural monopoly is said to exist. In such cases, the government may choose to approve the monopoly and to regulate its prices and/or production decisions. Nevertheless, you should keep in mind that technological advances often affect economies of scale. This can, in

turn, transform what was once considered a natural monopoly into a market where competition can flourish.

2.2.3 *Inadequate or Asymmetric Information*

Market failures may also result from inadequate or asymmetric information. Because information, like other goods, is costly to produce and disseminate, your evaluation will need to do more than demonstrate the possible existence of incomplete or asymmetric information. Even though the market may supply less than the full amount of information, the amount it does supply may be reasonably adequate and therefore not require government regulation. Sellers have an incentive to provide information through advertising that can increase sales by highlighting distinctive characteristics of their products. Buyers may also obtain reasonably adequate information about product characteristics through other channels, such as a seller offering a warranty or a third party providing information.

Even when adequate information is available, people can make mistakes by processing it poorly. Poor information-processing often occurs in cases of low probability, high-consequence events, but it is not limited to such situations. For instance, people sometimes rely on mental rules-of-thumb that produce errors. If they have a clear mental image of an incident which makes it cognitively “available,” they might overstate the probability that it will occur. Individuals sometimes process information in a biased manner, by being too optimistic or pessimistic, without taking sufficient account of the fact that the outcome is exceedingly unlikely to occur. When mistakes in information processing occur, markets may overreact. When it is time-consuming or costly for consumers to evaluate complex information about products or services (e.g., medical therapies), they may expect government to ensure that minimum quality standards are met. However, the mere possibility of poor information processing is not enough to justify regulation. If you think there is a problem of information processing that needs to be addressed, it should be carefully documented.

2.2.4 *Other Social Purposes*

There are justifications for regulations in addition to correcting market failures. A regulation may be appropriate when you have a clearly identified measure that can make government operate more efficiently. In addition, Congress establishes some regulatory programs to redistribute resources to select groups. Such regulations should be examined to ensure that they are both effective and cost-effective. Congress also authorizes some regulations to prohibit discrimination that conflicts with generally accepted norms within our society.

Rulemaking may also be appropriate to protect privacy, permit more personal freedom or promote other democratic aspirations.

2.3 References

U.S. Office of Management and Budget. Circular A-4, September 17, 2003. Found on the Internet at <<http://www.whitehouse.gov/omb/circulars/a004/a-4.pdf>>.

SECTION 3 INDUSTRY PROFILE

3.1 Introduction

The U.S. Environmental Protection Agency's (EPA's) Office of Air Quality Planning and Standards (OAQPS) is currently revising the existing Subpart J New Source Performance Standards (NSPS) for petroleum refineries. In addition, the Agency is adding a Subpart Ja that provides new requirements, including new emissions limits for new and modified and reconstructed fluid catalytic cracking units (FCCUs), new fluid coking units, new process heaters, and new flares. These standards include emissions limits for reductions of sulfur dioxide (SO₂), nitrogen oxides (NO_x), coarse particulate matter (PM₁₀), volatile organic compounds, (VOC) and other pollutants. This industry profile of the petroleum refining industry provides information that will support subsequent regulatory impact analyses (RIAs) and economic impact analyses (EIAs) that will assess the impacts of these standards.

At its core, the petroleum refining industry comprises establishments primarily engaged in refining crude petroleum into finished petroleum products. Examples of these petroleum products include gasoline, kerosene, asphalt, lubricants, and solvents, among others.

Firms engaged in petroleum refining are categorized under the North American Industry Classification System (NAICS) code 324110. In 2006, 149 establishments owned by 58 parent companies were refining petroleum. That same year, the petroleum refining industry shipped products valued at over \$489 billion (U.S. Department of Commerce, Bureau of the Census, 2007).

This industry profile report is organized as follows. Section 3.2 provides a detailed description of the inputs, outputs, and processes involved in petroleum refining. Section 3.3 describes the applications and users of finished petroleum products. Section 3.4 discusses the organization of the industry and provides facility- and company-level data. In addition, small businesses are reported separately for use in evaluating the impact on small business to meet the requirements of the Small Business Regulatory Enforcement and Fairness Act (SBREFA). Section 3.5 contains market-level data on prices and quantities and discusses trends and projections for the industry.

3.2 The Supply Side

Estimating the economic impacts of any regulation on the petroleum refining industry requires a good understanding of how finished petroleum products are produced (the “supply side” of finished petroleum product markets). This section describes the production process used to manufacture these products as well as the inputs, outputs, and by-products involved. The section concludes with a description of costs involved with the production process.

3.2.1 *Production Process, Inputs, and Outputs*

Petroleum pumped directly out of the ground, known as crude oil, is a complex mixture of hydrocarbons (chemical compounds that consist solely of hydrogen and carbon) and various impurities such as salt. To manufacture the variety of petroleum products recognized in every day life, this tar-like mixture must be refined and processed over several stages. This section describes the typical stages involved in this process as well as the inputs and outputs.

3.2.1.1 *The Production Process*

The process of refining crude oil into useful petroleum products can be separated into two phases and a number of supporting operations. These phases are described in detail in the following section. In the first phase, crude oil is desalted and then separated into its various hydrocarbon components (known as “fractions”). These fractions include gasoline, kerosene, naphtha, and other products (EPA, 1995).

In the second phase, the distilled fractions are converted into petroleum products (such as gasoline and kerosene) using three different types of downstream processes: combining, breaking, and reshaping (EPA, 1995). An outline of the refining process is presented in Figure 3-1.

Desalting. Before separation into fractions, crude oil is treated to remove salts, suspended solids, and other impurities that could clog or corrode the downstream equipment. This process, known as “desalting,” is typically done by first heating the crude oil, mixing it with process water, and depositing it into a gravity settler tank. Gradually, the salts present in the oil will be dissolved into the process water (EPA, 1995). After this takes place, the process water is separated from the oil by adding demulsifier chemicals (a process known as chemical separation) and/or by applying an electric field to concentrate the suspended water globules at the bottom of the settler tank (a process known as electrostatic separation). The effluent water is then removed from the tank and sent to the refinery wastewater treatment facilities (EPA, 1995). This process is illustrated in Figure 3-2.

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

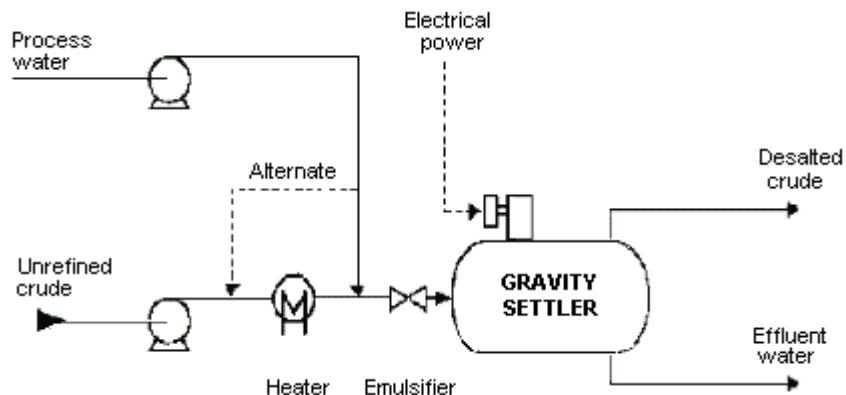


Figure 3-2. Desalting Process

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

As the hot vapor rises, its temperature is gradually reduced. Lighter fractions condense onto trays located at successively higher portions of the tower. For example, motor gasoline will condense at higher portion of the tower than kerosene because it condenses at lower temperatures. This process is illustrated in Figure 3-3. As these fractions condense, they will be drawn off their respective trays and potentially sent downstream for further processing (OSHA, 2003; EPA, 1995).

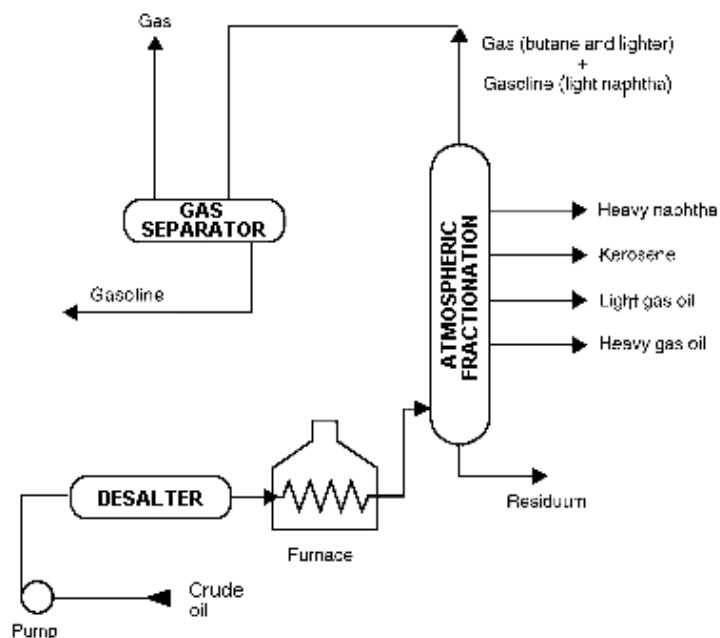


Figure 3-3. Atmospheric Distillation Process

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

Vacuum Distillation. The atmospheric distillation tower cannot distil the heaviest fractions (those at the bottom of the tower) without cracking under requisite heat and pressure. So these fractions are separated using a process called vacuum distillation. This process takes place in one or more vacuum distillation towers and is similar to the atmospheric distillation process, except very low pressures are used to increase volatilization and separation. A typical first-phase vacuum tower may produce gas oils or lubricating-oil base stocks (EPA, 1995). This process is illustrated in Figure 3-4.

Downstream Processing. To produce the petroleum products desired by the market place, most fractions must be further refined after distillation or “downstream.” These downstream processes change the molecular structure of the hydrocarbon molecules by breaking them into smaller molecules, joining them to form larger molecules, or shaping them into higher quality molecules (EPA, 1995).

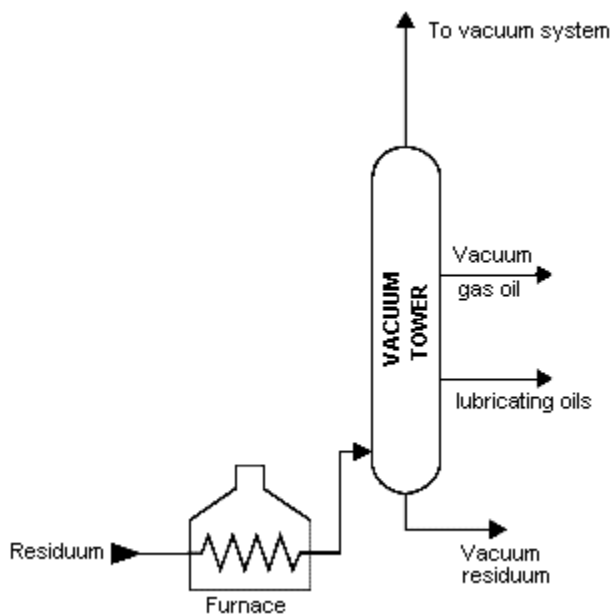


Figure 3-4. Vacuum Distillation Process

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

Downstream processes include thermal cracking, coking, catalytic cracking, catalytic hydrocracking, hydrotreating, alkylation, isomerization, polymerization, catalytic reforming, solvent extraction, merox, dewaxing, propane deasphalting and other operations (EPA, 1995).

3.2.1.2 Supporting Operations

In addition to the processes described above, there are other refinery operations that do not directly involve the production of hydrocarbon fuels, but serve in a supporting role. Some of the major supporting operations are described in this section.

Wastewater Treatment. Petroleum refining operations produce a variety of wastewaters including process water (water used in process operations like desalting), cooling water (water used for cooling that does not come into direct contact with the oil), and surface water runoff (resulting from spills to the surface or leaks in the equipment that have collected in drains).

Wastewater typically contains a variety of contaminants (such as hydrocarbons, suspended solids, phenols, ammonia, sulfides, and other compounds) and must be treated before it is recycled back into refining operations or discharged. Petroleum refineries typically utilize two stages of wastewater treatment. In primary wastewater treatments, oil and solids present in the wastewater are removed. After this is completed, wastewater can be discharged to a publicly owned treatment facility or undergo secondary treatment before being discharged directly to surface water. In secondary treatment, microorganisms are used to dissolve oil and other organic pollutants that are present in the wastewater (EPA, 1995; OSHA, 2003).

Gas Treatment and Sulfur Recovery. Petroleum refinery operations such as coking and catalytic cracking emit gases with a high concentration of hydrogen sulfide mixed with light refinery fuel gases (such as methane and ethane). Sulfur must be removed from these gases in order to comply with Clean Air Act's SO_x emission limits and to recover saleable elemental sulfur.

Sulfur is recovered by first separating the fuel gases from the hydrogen sulfide gas. Once this is done, elemental sulfur is removed from the hydrogen sulfide gas using a recovery system known as the Claus Process. In this process, hydrogen sulfide is burned under controlled conditions producing sulfur dioxide. A bauxite catalyst is then used to react with the sulfur dioxide and the unburned hydrogen sulfide to produce elemental sulfur. However, the Claus process only removed 90% of the hydrogen sulfide present in the gas stream, so other processes must be used to recover the remaining sulfur (EPA, 1995).

Additive Production. A variety of chemicals are added to petroleum products to improve their quality or add special characteristics. For example, ethers have been added to gasoline to increase octane levels and reduce CO emissions since the 1970s.

The most common ether additives being used today are methyl tertiary butyl ether (MTBE), and tertiary amyl methyl ether (TAME). Larger refineries tend to manufacture these additives themselves by reacting isobutylene (a by-product of several refinery processes) with methanol (OSHA, 2003).

Heat Exchangers, Coolers, and Process Heaters. Petroleum refineries require very high temperatures to perform many of their refining processes. To achieve these temperatures, refineries use fired heaters fueled by refinery or natural gas, distillate, and residual oils. This heat is managed through heat exchanges, where are composed of bundles of pipes, tubes, plate coils, and other equipment that surround heating or cooling water, steam, or oil. Heat exchanges facilitate the indirect transfer of heat as needed (OSHA, 2003).

Pressure Release and Flare Systems. As liquids and gases expand and contract through the refining process, pressure must be actively managed to avoid accident. Pressure-relief systems enable the safe handling of liquids and gases that that are released by pressure-relieving devices and blow-downs. According to the OSHA Technical Manual, “pressure relief is an automatic, planned release when operating pressure reaches a predetermined level. A blow-down normally refers to the intentional release of material, such as blow-downs from process unit startups, furnace blow-downs, shutdowns, and emergencies” (OSHA, 2003).

Blending. Blending is the final operation in petroleum refining. It is the physical mixture of a number of different liquid hydrocarbons to produce final petroleum products that have desired characteristics. For example, additives such as ethers can be blended with motor gasoline to boost performance and reduce emissions. Products can be blended in-line through a manifold system, or batch blended in tanks and vessels (OSHA, 2003).

3.2.1.3 Inputs

The inputs in the production process of petroleum products include general inputs such as labor, capital, and water. The inputs specific to this industry are crude oil and the variety of chemicals used in producing petroleum products. These two specific inputs are discussed below.

Crude Oil. Contrary to popular conception, crude oils are complex, heterogeneous mixtures. Crude oils contain many different hydrocarbon compounds that vary in appearance and composition from one oil field to another. An “average” crude oil contains about 84% carbon; 14% hydrogen; and less than 2% sulfur, nitrogen, oxygen, metals, and salts (OSHA, 2003).

In 2004, the petroleum refining industry used 5.6 billion barrels of crude oil in the production of finished petroleum products (EIA, 2005).¹

Common Refinery Chemicals. In addition to crude oil, a variety of chemicals are used in the production of petroleum products. The specific chemicals used will depend on specific characteristics of the product in question. Table 3-1 lists the most common chemicals used by petroleum refineries, their characteristics, and their applications.

In 2004, the petroleum refining industry used 581 million barrels of natural gas liquids and other liquids in the production of finished petroleum products (EIA, 2005).

3.2.1.4 Types of Product Outputs

The petroleum refining industry produces a number of products that tend to fall into one of three categories: fuels, finished nonfuel products, and feedstock for the petrochemical industry. Table 3-2 briefly describes these product categories. A more detailed discussion of petroleum fuel products can be found in Section 3.3.

Table 3-1. Types and Characteristics of Raw Materials used in Petroleum Refineries

Type	Description
Crude Oil	Heterogeneous mixture of different hydrocarbon compounds.
Oxygenates	Substances which, when added to gasoline, increase the amount of oxygen in that gasoline blend. Ethanol, methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), and methanol are common oxygenates.
Caustics	Caustics are added to desalting water to neutralize acids and reduce corrosion. They are also added to desalted crude in order to reduce the amount of corrosive chlorides in the tower overheads. They are used in some refinery treating processes to remove contaminants from hydrocarbon streams.
Leaded Gasoline Additives	Tetraethyl lead (TEL) and tetramethyl lead (TML) are additives formerly used to improve gasoline octane ratings but are no longer in common use except in aviation gasoline
Sulfuric Acid and Hydrofluoric Acid	Sulfuric acid and hydrofluoric acid are used primarily as catalysts in alkylation processes. Sulfuric acid is also used in some treatment processes.

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

¹ A barrel is a unit of volume that is equal to 42 U.S. gallons.

Table 3-2. Major Refinery Product Categories

Product Category	Description
Fuels	Finished Petroleum products that are capable of releasing energy. These products power equipment such as automobiles, jets, and ships. Typical petroleum fuel products include gasoline, jet fuel, and residual fuel oil.
Finished nonfuel products	Petroleum products that are not used for powering machines or equipment. These products typically include asphalt, lubricants (such as motor oil and industrial greases), and solvents (such as benzene, toluene, and xylene).
Feedstock	Many products derived from crude oil refining, such as ethylene, propylene, butylene, and isobutylene, are primarily intended for use as petrochemical feedstock in the production of plastics, synthetic fibers, synthetic rubbers, and other products.

Source: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

3.2.2 Emissions and Controls in Petroleum Refining

Petroleum refining leads to emissions of metals; spent acids; numerous toxic organic compounds; and gaseous pollutants, including carbon monoxide (CO), sulfur oxides, (SO_x), nitrogen oxides (NO_x), particulates, ammonia (NH₃), hydrogen sulfide (H₂S), and volatile organic compounds (VOCs).

3.2.2.1 Gaseous and VOC Emissions

As previously mentioned, CO, SO_x, NO_x, NH₃, and H₂S emissions are produced along with petroleum products. Sources of these emissions from refineries include fugitive emissions of the volatile constituents in crude oil and its fractions, emissions from the burning of fuels in process heaters, and emissions from the various refinery processes themselves.

Fugitive emissions occur as a result of leaks throughout the refinery. Although individual leaks may be small, the sum of all leaks can result in a lot of hazardous emissions. These emissions can be reduced by purchasing leak-resistant equipment and maintaining an ongoing leak detection and repair program (EPA, 1995).

The numerous process heaters used in refineries to heat process streams or to generate steam (boilers) for heating or other uses can be potential sources of SO_x, NO_x, CO, and hydrocarbons emissions. Emissions are low when process heaters are operating properly and using clean fuels such as refinery fuel gas, fuel oil, or natural gas. However, if combustion is not complete, or the heaters are fueled using fuel pitch or residuals, emissions can be significant (EPA, 1995).

The majority of gas streams exiting each refinery process contain varying amounts of refinery fuel gas, H₂S, and NH₃. These streams are directed to the gas treatment and sulfur recovery units described in the previous section. Here, refinery fuel gas and sulfur are recovered using a variety of processes. These processes create emissions of their own, which normally contain H₂S, SO_x, and NO_x gases (EPA, 1995).

Emissions can also be created by the periodic regeneration of catalysts that are used in downstream processes. These processes generate streams that may contain relatively high levels of CO, particulates, and VOCs. However, these emissions are treated before being discharged to the atmosphere. First, the emissions are processed through a CO boiler to burn CO and any VOCs, and then through an electrostatic precipitator or cyclone separator to remove particulates (EPA, 1995).

3.2.2.2 Wastewater and Other Wastes

Petroleum refining operations produce a variety of wastewaters including process water (water used in process operations like desalting), cooling water (water used for cooling that does not come into direct contact with the oil), and surface water runoff (resulting from spills to the surface or leaks in the equipment that have collected in drains). This wastewater typically contains a variety of contaminants (such as hydrocarbons, suspended solids, phenols, NH₃, sulfides, and other compounds) and is treated in on-site facilities before being recycled back into the production process or discharged.

Other wastes include forms of sludges, spent process catalysts, filter clay, and incinerator ash. These wastes are controlled through a variety of methods including incineration, land filling, and neutralization, among other treatment methods (EPA, 1995).

3.2.3 Costs of Production

Between 1995 and 2006, expenditures on input materials accounted for the largest cost to petroleum refineries—amounting to 94% of total expenses (Figure 3-5). These material costs included the cost of all raw materials, containers, scrap, and supplies used in production or repair during the year, as well as the cost of all electricity and fuel consumed.

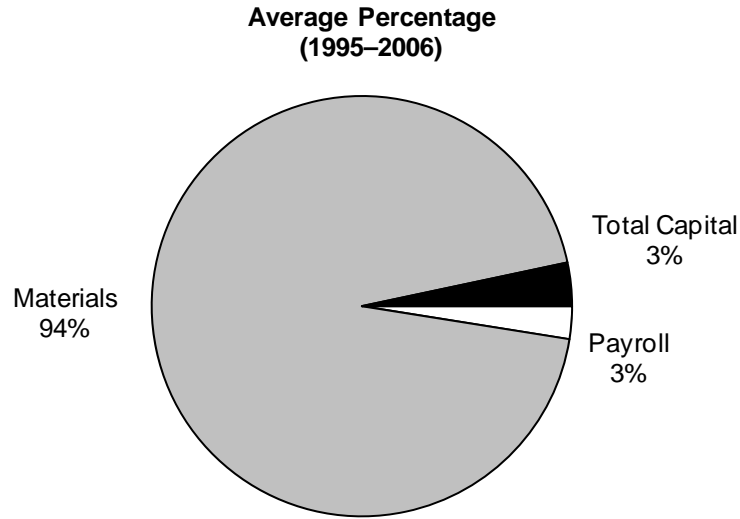


Figure 3-5. Petroleum Refinery Expenditures

Labor and capital accounted for the remaining expenses faced by petroleum refiners. Capital expenditures include permanent additions and alterations to facilities and machinery and equipment used for expanding plant capacity or replacing existing machinery. A detailed breakdown of how much petroleum refiners spent on each of these factors of production over this 11-year period is provided in Table 3-3. A more exhaustive assessment of the costs of materials used in petroleum refining is provided in Table 3-4.

3.3 The Demand Side

Estimating the economic impact the regulation will have on the petroleum refining industry also requires characterizing various aspects of the demand for finished petroleum products. This section describes the characteristics of finished petroleum products, their uses and consumers, and possible substitutes.

Table 3-3. Labor, Material, and Capital Expenditures for Petroleum Refineries (NAICS 324110)

Year	Payroll (\$millions)		Materials (\$millions)		Total Capital (\$millions)	
	Reported	2005	Reported	2005	Reported	2005
1995	3,791	4,603	112,532	136,633	5,937	7,209
1996	3,738	4,435	132,880	157,658	5,265	6,247
1997	3,885	4,595	127,555	150,865	4,244	5,020
1998	3,695	4,415	92,212	110,187	4,169	4,982
1999	3,983	4,682	114,131	134,146	3,943	4,635
2000	3,992	4,509	180,568	203,967	4,685	5,292
2001	4,233	4,743	158,733	177,838	6,817	7,638
2002	4,386	4,947	166,368	187,646	5,152	5,811
2003	4,752	5,227	185,369	203,893	6,828	7,510
2004	5,340	5,635	251,467	265,369	6,601	6,966
2005	5,796	5,796	345,207	345,207	10,525	10,525
2006	5,984	5,751	396,980	381,546	11,175	10,741

Note: Adjusted for inflation using the producer price index industry for total manufacturing industries (Table 5-6).

Sources: U.S. Department of Commerce, Bureau of the Census. 2007. 2006 Annual Survey of Manufactures.

Obtained through American Fact Finder Database < http://factfinder.census.gov/home/saff/main.html?_lang=en>.

U.S. Department of Commerce, Bureau of the Census. 2006. *2005 Annual Survey of Manufactures*. M05(AS)-1.

Washington, DC: Government Printing Office. Available at

<<http://www.census.gov/prod/2006pubs/am0531gs1.pdf>>. As obtained on October 23, 2007.

U.S. Department of Commerce, Bureau of the Census. 2003a. *2001 Annual Survey of Manufactures*. M01(AS)-1.

Washington, DC: Government Printing Office. Available at <<http://www.census.gov/prod/2003pubs/m01as-1.pdf>>. As obtained on October 23, 2006.

U.S. Department of Commerce, Bureau of the Census. 2001. *1999 Annual Survey of Manufactures*. M99(AS)-1 (RV). Washington, DC: Government Printing Office. Available at <<http://www.census.gov/prod/2001pubs/m99-as1.pdf>>. As obtained on October 23, 2006.

U.S. Department of Commerce, Bureau of the Census. 1998. *1996 Annual Survey of Manufactures*. M96(AS)-1 (RV). Washington, DC: Government Printing Office. Available at <<http://www.census.gov/prod/3/98pubs/m96-as1.pdf>>. As obtained on October 23, 2006.

U.S. Department of Commerce, Bureau of the Census. 1997. *1995 Annual Survey of Manufactures*. M95(AS)-1. Washington, DC: Government Printing Office. Available at <<http://www.census.gov/prod/2/manmin/asm/m95as1.pdf>>. As obtained on October 23, 2006.

3.3.1 Product Characteristics

Petroleum refining firms produce a variety of different products. The characteristics these products possess largely depend on their intended use. For example, the gasoline fueling our automobiles has different characteristics than the oil lubricating the car's engine. However, as discussed in Section 3.1.4, finished petroleum products can be categorized into three broad groups based on their intended uses (EIA, 1999a):

- **fuels**—petroleum products that are capable of releasing energy such as motor gasoline

Table 3-4. Costs of Materials Used in Petroleum Refining Industry

Material	2002		1997	
	Delivered Cost (\$10 ⁶)	Percentage of Material Costs	Delivered Cost (\$10 ⁶)	Percentage of Material Costs
Petroleum Refineries NAICS 324110				
Total materials	157,415,200	100.0%	118,682,535	100.0%
Domestic crude petroleum, including lease condensate	63,157,497	40.1%	47,220,759	39.8%
Foreign crude petroleum, including lease condensate	69,102,574	43.9%	48,172,988	40.6%
Foreign unfinished oils (received from foreign countries for further processing)	2,297,967	1.5%	2,373,376	2.0%
Ethane (C2) (80% purity or more)	D		D	
Propane (C3) (80% purity or more)	118,257	0.1%	269,928	0.2%
Butane (C4) (80% purity or more)	1,925,738	1.2%	1,567,875	1.3%
Gas mixtures (C2, C3, C4)	1,843,708	1.2%	952,009	0.8%
Isopentane and natural gasoline	810,530	0.5%	1,381,100	1.2%
Other natural gas liquids, including plant condensate	455,442	0.3%	1,427,123	1.2%
Toluene and xylene (100% basis)	159,563	0.1%	N	
Additives (including antioxidants, antiknock compounds, and inhibitors)	40,842	0.0%	262,228	0.2%
Other additives (including soaps and detergents)	709	0.0%	200,005	0.2%
Animal and vegetable oils	D		D	
Chemical catalytic preparations	D		647,040	0.5%
Sodium hydroxide (caustic soda) (100% NaOH)	129,324	0.1%	41,741	0.0%
Sulfuric acid, excluding spent (100% H ₂ SO ₄)	189,912	0.1%	56,514	0.0%
Metal containers	9,450	0.0%	60,531	0.1%
Plastics containers	D		N	
Paper and paperboard containers	D		18,404	0.0%
Cost of materials received from petroleum refineries and lube manufacturers	8,980,758	5.7%	4,981,370	4.2%
All other materials and components, parts, containers, and supplies	5,722,580	3.6%	4,233,383	3.6%
Materials, ingredients, containers, and supplies, nsk	576,175	0.4%	4,779,890	4.0%

Source: U.S. Department of Commerce, Bureau of the Census. 2004. *2002 Economic Census, Industry Series—Shipbuilding and Repair*. Washington, DC: Government Printing Office. Available at <<http://www.census.gov/prod/ec02/ec0231i324110.pdf>>. As obtained on October 23, 2006.

- **nonfuel products**—petroleum products that are not used for powering machines or equipment such as solvents and lubricating oils
- **petrochemical feedstocks**—petroleum products that are used as a raw material in the production of plastics, synthetic rubber, and other goods

A list of selected products from each of these groups is presented in Table 3-5 along with a description of each product's characteristics and primary uses.

Table 3-5. Major Refinery Products

Product	Description
Fuels	
Gasoline	A blend of refined hydrocarbons, motor gasoline ranks first in usage among petroleum products. It is primarily used to fuel automobiles and lightweight trucks as well as boats, recreational vehicles, lawn mowers, and other equipment. Other forms of gasoline include Aviation gasoline, which is used to power small planes.
Kerosene	Kerosene is a refined middle-distillate petroleum product that finds considerable use as a jet fuel. Kerosene is also used in water heaters, as a cooking fuel, and in lamps.
Liquefied petroleum gas (LPG)	LPG consists principally of propane (C ₃ H ₈) and butane (C ₄ H ₁₀). It is primarily used as a fuel in domestic heating, cooking, and farming operations.
Distillate fuel oil	Distillate fuel oil includes diesel oil, heating oils, and industrial oils. It is used to power diesel engines in buses, trucks, trains, automobiles, as well as other machinery.
Residual fuels	Residual fuels are the fuels distilled from the heavier oils that remain after atmospheric distillation, they find their primary use generating electricity in electric utilities. However, residual fuels can also be used as fuel for ships, industrial boiler fuel, and commercial heating fuel.
Petroleum coke	Coke is a high carbon residue that is the final product of thermal decomposition in the condensation process in cracking. Coke can be used as a low-ash solid fuel for power plants.
Finished Nonfuel Products	
Coke	In addition to use as a fuel, petroleum coke can be used a raw material for many carbon and graphite products such as furnace electrodes and liners.
Asphalt	Asphalt, used for roads and roofing materials, must be inert to most chemicals and weather conditions.
Lubricants	Lubricants are the result of a special refining process that produce lubricating oil base stocks, which are mixed with various additives. Petroleum lubricating products include spindle oil, cylinder oil, motor oil, and industrial greases.
Solvents	A solvent is a fluid that dissolves a solid, liquid, or gas into a solution. Petroleum based solvents, such as Benzene, are used to manufacture detergent and synthetic fibers. Other solvents include toluene and xylene.
Feedstock	
Ethylene	Ethylene is the simplest alkene and has the chemical formula C ₂ H ₄ . It is the most produced organic compound in the world and it is used in the production of many products. For example, one of ethylene's derivatives is ethylene oxide, which is a primary raw material in the production of detergents.
Propylene	Propylene is an organic compound with the chemical formula C ₃ H ₆ . It is primarily used in the production of polypropylene, which is used in the production of food packaging, ropes, and textiles.

Sources: U.S. Department of Labor, Occupational Safety and Health Administration (OSHA). 2003. OSHA Technical Manual, Section IV: Chapter 2, Petroleum Refining Processes. TED 01-00-015. Washington, DC: U.S. DOL. Available at <http://www.osha.gov/dts/osta/otm/otm_iv/otm_iv_2.html>. As obtained on October 23, 2006.

U.S. Department of Energy, Energy Information Administration (EIA). 1999.

3.3.2 *Uses and Consumers*

Finished petroleum products are rarely consumed as final goods in themselves. Instead, they are used as primary inputs in the creation of a vast number of other goods and services. For example, goods created from petroleum products include fertilizers, pesticides, paints, thinners, cleaning fluids, refrigerants, and synthetic fibers (EPA, 1995). Similarly, fuels made from petroleum are used to run vehicles and industrial machinery and generate heat and electrical power. As a result, the demand for many finished petroleum products is derived from the demand for the goods and services they are used to create.

The principal end users of petroleum products can be separated into five sectors:

- Residential sector—private homes and residences
- Industrial sector—manufacturing, construction, mining, agricultural, and forestry establishments
- Transportation sector—private and public vehicles that move people and commodities such as automobiles, ships, and aircraft
- Commercial sector—nonmanufacturing or nontransportation business establishments such as hotels, restaurants, retail stores, religious and nonprofit organizations, as well federal, state, and local government institutions
- Electric utility sector—privately and publicly owned establishments that generate, transmit, distribute, or sell electricity (primarily) to the public; nonutility power producers are not included in this sector

Of these end users, the transportation sector consumes the largest share of petroleum products, accounting for 67% of total consumption in 2005 (EIA, 2006a). In fact, petroleum products like motor gasoline, distillate fuel, and jet fuel provide virtually all of the energy consumed in the transportation sector (EIA, 1999a).

Of the three petroleum product categories, end-users primarily consume fuel. Fuel products account for 9 out of 10 barrels of petroleum used in the United States (EIA, 1999a). In 2005, motor gasoline alone accounted for 49% of demand for finished petroleum products (EIA, 2006a).

3.3.3 *Substitution Possibilities in Consumption*

A major influence on the demand for finished petroleum products is the availability of substitutes. In some sectors, like the transportation sector, it is currently difficult to switch quickly from one fuel to another without costly and irreversible equipment changes, but other sectors can switch relatively quickly and easily (EIA, 1999a).

For example, equipment at large manufacturing plants often can use either residual fuel oil or natural gas. Often coal and natural gas can be easily substituted for residual fuel oil at electricity utilities. As a result, we would expect demand in these industries to be more sensitive to price (in the short run) than in others (EIA, 1999a).

However, over time, demand for petroleum products could become more elastic. For example, automobile users could purchase more fuel-efficient vehicles or relocate to areas that would allow them to make fewer trips. Technological advances could also create new products that compete with petroleum products that currently have no substitutes. An example of such a technological advance would be the invention of ethanol (an alcohol produced from biomass), which can substitute for gasoline in spark-ignition motor vehicles (EIA, 1999a).

3.4 Industry Organization

This section examines the organization of the U.S. petroleum refining industry, including market structure, firm characteristics, plant location, and capacity utilization. Understanding the industry's organization helps determine how it will be affected by new emissions standards.

3.4.1 Market Structure

Market structure characterizes the level and type of competition among petroleum refining companies and determines their power to influence market prices for their products. For example, if an industry is perfectly competitive, then individual producers cannot raise their prices above the marginal cost of production without losing market share to their competitors. Understanding pricing behavior in the petroleum refining industry is crucial for performing subsequent EIAs.

According to basic microeconomic theory, perfectly competitive industries are characterized by unrestricted entry and exit of firms, large numbers of firms, and undifferentiated (homogenous) products being sold. Conversely, imperfectly competitive industries or markets are characterized by barriers to entry and exit, a smaller number of firms, and differentiated products (resulting from either differences in product attributes or brand name recognition of products). This section considers whether the petroleum refining industry is competitive based on these three factors.

3.4.1.1 Barriers to Entry

Firms wanting to enter the petroleum refining industry may face at least two major barriers to entry. First, according to a 2004 Federal Trade Commission staff study, there are significant economies of scale in petroleum refinery operations. This means that costs per unit

fall as a refinery produces more finished petroleum products. As a result, new firms that must produce at relatively low levels will face higher average costs than firms that are established and produce at higher levels, which will make it more difficult for these new firms to compete (Nicholson, 2005). This is known as a technical barrier to entry.

Second, legal barriers could also make it difficult for new firms to enter the petroleum refining industry. The most common example of a legal barrier to entry is patents—intellectual property rights, granted by the government, that give exclusive monopoly to an inventor over his invention for a limited time period. In the petroleum refining industry, firms rely heavily on process patents to appropriate returns from their innovations. As a result, firms seeking to enter the petroleum refining industry must develop processes that respect the novelty requirements of these patents, which could potentially make entry more difficult for new firms (Langinier, 2004). A second example of a legal barrier would be environmental regulations that apply only to new entrants or new pollution sources. Such regulations would raise the operating costs of new firms without affecting the operating costs of existing ones. As a result, new firms may be less competitive.

Although neither of these barriers are impossible for new entrants to overcome, they can make it more difficult for new firms to enter the market for manufactured petroleum products. As a result, existing petroleum refiners could potentially raise their prices above competitive levels with less worry about new firms entering the market to compete away their customers with lower prices. It was not possible during this analysis to quantify how significant these barriers would be for new entrants or what effect they would have on market prices. However, existing firms would still face competition from each other. In an unconcentrated industry, competition among existing firms would work to keep prices at competitive levels.

3.4.1.2 Measures of Industry Concentration

Economists often use a variety of measures to assess the concentration of a given industry. Common measures include four-firm concentration ratios (CR4), eight-firm concentration ratios (CR8), and Herfindahl-Hirschmann indexes (HHI). The CR4s and CR8s measure the percentage of sales accounted for by the top four and eight firms in the industry. The HHIs are the sums of the squared market shares of firms in the industry. These measures of industry concentration are reported for the petroleum refining industry (NAICS 324110) in Table 3-6 for selected years between 1985 and 2003.

Table 3-6. Market Concentration Measures of the Petroleum Refining Industry: 1985 to 2003

Measure	1985	1990	1996	2000	2001	2002	2003
Herfindahl-Hirschmann Index (HHI)	493	437	412	611	686	743	728
Four-firm concentration ratio (CR4)	34.4	31.4	27.3	40.2	42.5	45.4	44.4
Eight-firm concentration ratio (CR8)	54.6	52.2	48.4	61.6	67.2	70.0	69.4

Source: Federal Trade Commission (FTC). 2004. "The Petroleum Industry: Mergers, Structural Change, and Antitrust Enforcement." Available at <<http://www.ftc.gov/opa/2004/08/oilmergersrpt.shtm>>. As obtained on February 6, 2007.

Between 1990 and 2000, the HHI rose from 437 to 611, which indicates an increase in market concentration over time. This increase is partially due to merger activity during this time period. Between 1990 and 2000, over 2,600 mergers occurred across the petroleum industry; 13% of these mergers occurred in the industry's refining and marketing segments (GAO, 2007).

Unfortunately, there is no objective criterion for determining market structure based on the values of these concentration ratios. However, accepted criteria have been established for determining market structure based on the HHIs for use in horizontal merger analyses (U.S. Department of Justice and the Federal Trade Commission, 1992). According to these criteria, industries with HHIs below 1,000 are considered unconcentrated (i.e., more competitive); industries with HHIs between 1,000 and 1,800 are considered moderately concentrated (i.e., moderately competitive); and industries with higher HHIs are considered heavily concentrated. Based on this criterion, the petroleum refining industry continues to be unconcentrated even after an increase in merger activity.

A more rigorous examination of market concentration was conducted in a 2004 Federal Trade Commission (FTC) staff study. This study explicitly accounted for the fact that a refinery in one geographic region may not exert competitive pressure on a refinery in another region if transportation costs are high. This was done by comparing HHIs across Petroleum Administration for Defense Districts (PADDs). PADDs separate the United States into five geographic regions or districts. They were initially created during World War II to help manage the allocation of fuels during wartime. However, they have remained in use as a convenient way of organizing petroleum market information (FTC, 2004).

This study concluded that these geographic markets were not highly concentrated. PADDs I, II, and III (East Coast, Midwest, and Gulf Coast) were sufficiently connected that they exerted a competitive influence on each other. The HHI for these combined regions was 789 in 2003, indicating a low concentration level. Concentration in PADD IV (Rocky Mountains) was

also low in 2003, with an HHI of 944. PADD V gradually grew more concentrated in the 1990s after a series of significant refinery mergers. By 2003, the region's HHI was 1,246, indicating growth to a moderate level of concentration (FTC, 2004).

3.4.1.3 Product Differentiation

Another way firms can influence market prices for their product is through product differentiation. By differentiating one's product and using marketing to establish brand loyalty, manufacturers can raise their prices above marginal cost without losing market share to their competitors.

While we saw in Section 3.3 that there are a wide variety of petroleum products with many different uses, individual petroleum products are by nature quite homogenous. For example, there is little difference between premium motor gasoline produced at different refineries (Mathtech, 1997). As a result, the role of product differentiation is probably quite small for many finished petroleum products. However, there are examples of relatively small refining businesses producing specialty products for small niche markets. As a result, there may be some instances where product differentiation is important for price determination.

3.4.1.4 Competition among Firms in the Petroleum Refining Industry

Overall, the petroleum industry is characterized as producing largely generic products for sale in relatively unconcentrated markets. Although it is not possible to quantify how much barriers to entry and other factors will affect competition among firms, it seems unlikely that individual petroleum refiners would be able to significantly influence market prices given the current structure of the market.

3.4.2 Characteristics of U.S. Petroleum Refineries and Petroleum Refining Companies

A petroleum refinery is a facility where labor and capital are used to convert material inputs (such as crude oil and other materials) into finished petroleum products. Companies that own these facilities are legal business entities that conduct transactions and make decisions that affect the facility. The terms "facility," "establishment," and "refinery" are synonymous in this study and refer to the physical location where products are manufactured. Likewise, the terms "company" and "firm" are used interchangeably to refer to the legal business entity that owns one or more facilities. This section presents information on refineries, such as their location and capacity utilization, as well as financial data for the companies that own these refineries.

3.4.2.1 Geographic Distribution of U.S. Petroleum Refineries

There are approximately 149 petroleum refineries operating in the United States, spread across 33 states. The number of petroleum refineries located in each of these states is listed in Table 3-7. This table illustrates that a significant portion of petroleum refineries are located along the Gulf of Mexico region. The leading petroleum refining states are Texas, California, and Louisiana.

Table 3-7. Number of Petroleum Refineries, by State

State	Number of Petroleum Refineries
Alabama	4
Alaska	6
Arkansas	2
California	21
Colorado	2
Delaware	1
Georgia	1
Hawaii	2
Illinois	4
Indiana	2
Kansas	3
Kentucky	2
Louisiana	18
Michigan	1
Minnesota	2
Mississippi	4
Montana	4
Nevada	1
New Jersey	6
New Mexico	3
North Dakota	1
Ohio	4
Oklahoma	5
Oregon	1
Pennsylvania	5
Tennessee	1
Texas	25
Utah	5
Virginia	1
Washington	5
West Virginia	1
Wisconsin	1
Wyoming	5
Total	149

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2006b. "Refinery Capacity Report 2006." Available at <http://www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html>. As obtained on October 23, 2006.

3.4.2.2 Capacity Utilization

Capacity utilization indicates how well current refineries meet demand. One measure of capacity utilization is capacity utilization rates. A capacity utilization rate is the ratio of actual production volumes to full-capacity production volumes. For example, if an industry is producing as much output as possible without adding new floor space for equipment, the capacity utilization rate would be 100 percent. On the other hand, if under the same constraints the industry were only producing 75 percent of its maximum possible output, the capacity utilization rate would be 75 percent. On an industry-basis, capacity utilization is highly variable from year to year depending on economic conditions. It is also variable on a company-by-company basis depending not only on economic conditions, but also on company's strategic position in its particular industry. While some plants may have idle production lines or empty floor space, others need additional space or capacity.

Table 3-8 lists the capacity utilization rates for petroleum refineries from 2000 to 2006. It is interesting to note the significant drop in capacity utilization in 2005. This would seem counter intuitive since there does not appear to be evidence that demand for petroleum products is not dropping. To understand why this might be the case, one must first realize that the capacity utilization ratio in petroleum industry represents the utilization of the atmospheric crude oil distillation units.

Table 3-8. Full Production Capacity Utilization Rates for Petroleum Refineries

Year	Petroleum Refineries Capacity Utilization Rates (NAICS 324110)	Gross Input to Atmospheric Crude Oil Distillation Units (1,000s of barrels per day)	Operational Capacity (1,000s of barrels per day)
2000	92.6	15,299	16,525
2001	92.6	15,352	16,582
2002	90.7	15,180	16,744
2003	92.6	15,508	16,748
2004	93.0	15,783	16,974
2005	90.6	15,578	17,196
2006	89.7	15,602	17,385

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2007a. "Refinery Utilization and Capacity." Available at <http://tonto.eia.doe.gov/dnav/pet/pet_pnp_unc_dcu_nus_m.htm>. As obtained on January, 2007.

This is calculated for the petroleum industry by dividing the gross input to atmospheric crude oil distillation units (all inputs involved in atmospheric crude oil distillation, such as crude oil) by the industry's operational capacity.

In 2004, operational capacity increased from 16,974,000 barrels per calendar day to 17,196,000 barrels per calendar day. However, gross inputs fell from 15,783,000 barrels per calendar day in 2004 to 15,578,000 in 2005. This indicates that capacity utilization sagged due to a drop in production inputs. In 2006, gross inputs grew 0.15% to 15,602,000 barrels per day. However, since operational capacity grew much faster (from 17,196,000 to 17,385,000 or 1.00%), capacity utilization rates for the industry continued to fall.

3.4.2.3 Characteristics of Small Businesses Owning U.S. Petroleum Refineries

According to the Small Business Administration (SBA), a small business in the petroleum refining industry is defined for government procurement purposes as having 1,500 or fewer employees and an Operable Atmospheric Crude Oil Distillation capacity of no more than 125,000 barrels per calendar day total (SBA, 2008). We applied this definition in defining a small business refiner in our proposal RIA. However, as part of a response to a comment made on the proposal, we define a small business as only as having 1,500 or fewer employees.

As of January 2006, there were 149 petroleum refineries operating in the continental United States with a cumulative capacity of processing over 17 million barrels of crude per calendar day (EIA, 2006c). RTI identified 58 parent companies owning refineries in the United States and was able to collect employment and sales data for 47 (84%) of them.

The distribution of employment across companies is illustrated in Figure 3-6. As this figure shows, 25 companies (53%) of these 47 employ fewer than 1,500 workers and would be considered small businesses. These firms earned an average of \$1.04 billion of revenue per year, while firms employing more than 1,500 employees earned an average of \$84.2 billion of revenue per year (Figure 3-7). A distribution of the number of firms earning different levels of revenue is presented in Figure 3-8.

Employment, crude capacity, and location information are provided in Table 3-9 for each of companies employing 1,500 employees or less. Similar information can be found for all 56 companies owning petroleum refineries in Appendix A.

In Section 3.4.2.1, we discussed how petroleum refining operations are characterized by economies of scale—that the cost per unit falls as a refinery produces more finished petroleum products. This means that smaller petroleum refiners face higher per unit costs than larger refining operations because they produce fewer petroleum products. As a result, some smaller firms have sought to overcome their competitive disadvantage by locating close to product-consuming areas to lower transportation costs and serving niche product markets (FTC, 2004).

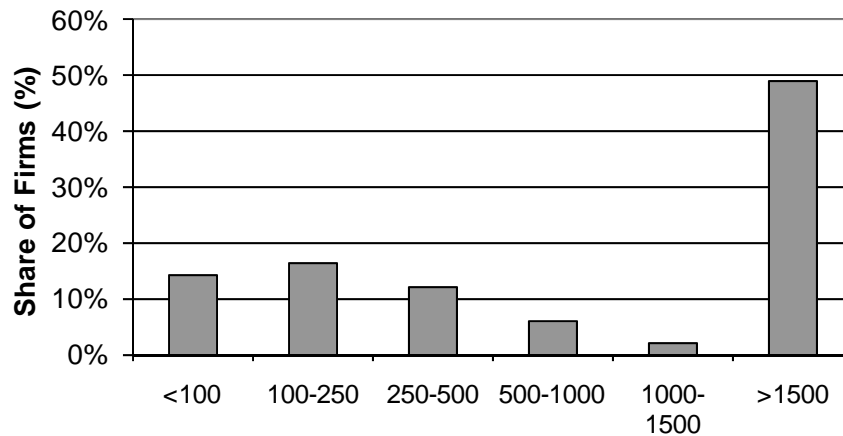


Figure 3-6. Employment Distribution of Companies Owning Petroleum Refineries (N=47)

Sources: Dun & Bradstreet. 2007a. 2007 D&B Million Dollar Directory. Pennsylvania: Dun & Bradstreet Inc.

Dun & Bradstreet Small Business Solutions. Small Business Database. Available at <http://smallbusiness.dnb.com/default.asp?bhcd2=1107465546>.

Gale Research Inc. 2007. Ward's Business Directory of U.S. Private and Public Companies. Detroit: Gale Research.

Hoovers. 2007. Free Content, Company Information. Available at <http://www.hoovers.com/free/>.

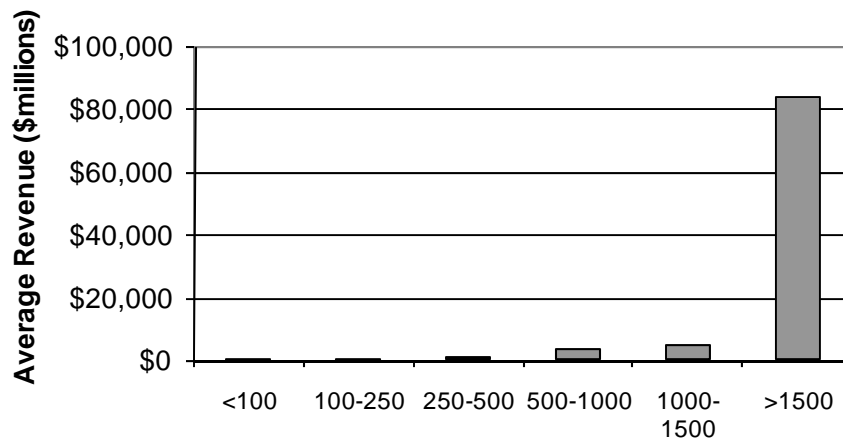


Figure 3-7. Average Revenue of Companies Owning Petroleum Refineries by Employment (N=47)

Sources: Dun & Bradstreet. 2007. 2007 D&B Million Dollar Directory. Pennsylvania: Dun & Bradstreet Inc.

Dun & Bradstreet Small Business Solutions. Small Business Database. Available at <http://smallbusiness.dnb.com/default.asp?bhcd2=1107465546>.

Gale Research Inc. 2007. Ward's Business Directory of U S Private and Public Companies. Detroit: Gale Research.

Hoovers. 2007. Free Content, Company Information. Available at <http://www.hoovers.com/free/>.

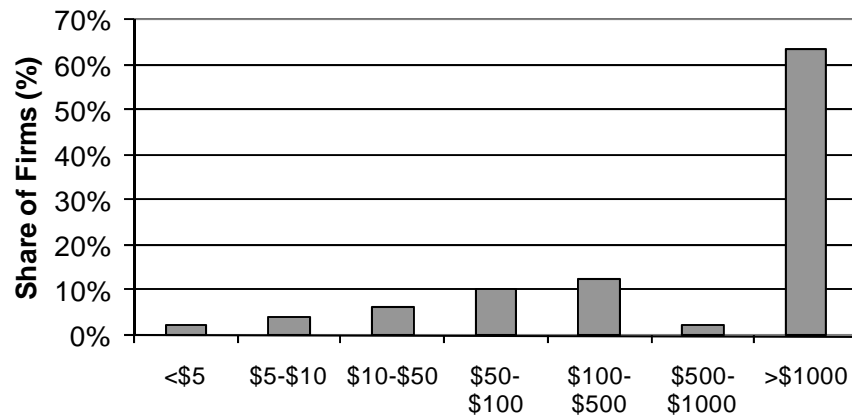


Figure 3-8. Revenue Distribution of Companies Owning Petroleum Refineries (N=47)

Sources: Dun & Bradstreet. 2007. 2007 D&B Million Dollar Directory. Pennsylvania: Dun & Bradstreet Inc.

Dun & Bradstreet Small Business Solutions. Small Business Database. Available at <http://smallbusiness.dnb.com/default.asp?bhcd2=1107465546>.

Gale Research Inc. 2007. Ward's Business Directory of U S Private and Public Companies. Detroit: Gale Research.

Hoovers. 2007. Free Content, Company Information. Available at <http://www.hoovers.com/free/>.

A good example of a firm locating close to prospective customers is Countrymark Cooperative, Inc., which was started in the 1930s for the express purpose of providing farmers in Indiana with a consistent supply of fuels, lubricants, and other products. A good example of a firm producing niche products is Calumet Lubricants, which focuses on developing and manufacturing naphthenic specialty oils.

However, recent developments are making these factors less important for success in the industry. For example, the entry of new product pipelines is eroding the locational advantage of smaller refineries (FTC, 2004). This trend can possibly be illustrated by the fact that most refineries owned by small businesses tend to be located in relatively rural areas (see Table 3-9). The median population density of counties occupied by small refineries is 94 people per square mile. This could suggest that refineries do not rely on the population surrounding them to support their refining operations.

To obtain a better sense of where the customers of these small refiners are located, RTI spoke with representatives from four different companies. Three of these representatives indicated that they primarily serve customers outside their local areas. In particular, two of these businesses were primarily fuel producers that used pipelines to deliver their product to customers up to 300 miles away.

Table 3-9. Characteristics of Small Businesses in the Petroleum Refining Industry

Parent Company	Parent Company Type	Cummulative Crude Capacity (bbl/cd)	Parent Company Sales (\$Millions)	Parent Company Employment (#)	Facility Name	Facility City	Facility State	Facility County	County ID	Facility County Population Density (2000)
AGE Refining & Manufacturing	Private	12,200	287	52	AGE Refining & Manufacturing	San Antonio	TX	Bexar County	TXBexar County	1,117
American Refining Group	Private	10,000	350	310	American Refining Group	Bradford	PA	McKean County	PAMcKean County	47
Arabian American Development Co	Public	0	80	118	South Hampton Resources Inc.	Silsbee	TX	Hardin County	TXHardin County	54
Calcasieu Refining Co.	Private	30,000	638	51	Calcasieu Refining Co.	Lake Charles	LA	Calcasieu Parish	LACalcasieu Parish	171
Calumet Specialty Products	Public	63,320	1,641	350	Calumet Specialty Products	Shreveport	LA	Caddo Parish	LACaddo Parish	286
					Calumet Specialty Products	Cotton Valley	LA	Caddo Parish	LACaddo Parish	286
					Calumet Specialty Products	Princeton	LA	Caddo Parish	LACaddo Parish	286
Countrymark Cooperative, Inc.	Private	23,000	87	300	Countrymark Cooperative, Inc.	Mt. Vernon	IN	Posey County	INPosey County	66
Cross Oil & Refining Co. Inc.	Private	7,200	49	110	Cross Oil & Refining Co. Inc.	Smackover	AR	Union County	ARUnion County	44
CVR Energy Inc.	Public	112,000	3,038	577	Coffeyville Resources LLC	Coffeyville	KS	Montgomery County	KSMontgomery County	56
Foreland Refining Co.	Private	2,000	56	100	Foreland Refining Co.	Tonopah/Eagle Springs	NV	Nye County	NVNye County	2
Frontier Oil Corp	Private	153,000	4,000	727	Frontier Oil & Refining Co.	Cheyenne	WY	Laramie County	WYLaramie County	30
					Frontier Oil Corp	El Dorado	KS	Butler County	KSButler County	42
Gary-Williams Co	Private	54,000	97	200	Wynnewood Refining Co.	Wynnewood	OK	Garvin County	OKGarvin County	34

(Continued)

Table 3-9. Characteristics of Small Businesses in the Petroleum Refining Industry (continued)

Parent Company	Parent Company Type	Cumulative Crude Capacity (bbl/cd)	Parent Company Sales (\$Millions)	Parent Company Employment (#)	Facility Name	Facility City	Facility State	Facility County	Facility County Population Density (2000)
Goodway Refining LLC	Private	4,100	3	18	Goodway Refining LLC	Atmore	AL	Escambia County	41
Greka Integrated Inc	Private	9,500	22	145	Greka Integrated Inc	Santa Maria	CA	Santa Barbara County	146
Gulf Atlantic Operations LLC	Private	16,700	9	32	Gulf Atlantic Operations LLC	Mobile Bay	AL	Mobile County	324
Holly Corp.	Public	99,700	4,023	859	Holly Corp.	Woods Cross	UT	Davis County	785
					Navajo Refining Co.	Artesia	NM	Eddy County	12
Hunt Refining Co.	Private	45,500	4,871	1,100	Hunt Refining Co.	Tuscaloosa	AL	Tuscaloosa County	125
					Hunt Southland Refining	Lumberton	MS	Lamar County	79
					Hunt Southland Refining	Sandersville	MS	Lamar County	79
Lion Oil Co.	Private	70,000	247	425	Lion Oil Co.	El Dorado	AR	Union County	44
Pelican Refining Co. LLC	Private	0	29	62	Pelican Refining Co. LLC	Lake Charles	LA	Calcasieu Parish	171
Placid Refining Inc.	Private	56,000	1,400	200	Placid Refining Inc.	Port Allen	LA	West Baton Rouge Parish	113
San Joaquin Refining Co., Inc.	Private	15,000	288	20	San Joaquin Refining Co., Inc.	Bakersfield	CA	Kern County	81
Somerset Oil Inc	Private	5,500	55	150	Somerset Refinery Inc.	Somerset	KY	Pulaski County	85
Trigeant Ltd.	Private	0	5	50	Trigeant Ltd.	Corpus Christi	TX	Nueces County	375

(Continued)

Table 3-9. Characteristics of Small Businesses in the Petroleum Refining Industry (continued)

Parent Company	Parent Company Type	Cumulative Crude Capacity (bbl/cd)	Parent Company Sales (\$Millions)	Parent Company Employment (#)	Facility Name	Facility City	Facility State	Facility County	Facility County Population Density (2000)
Western Refining, Inc.	Public	212,200	4,200	416	Western Refining, Inc.	El Paso	TX	El Paso County	671
					Giant Refining Co.	Yorktown	VA	York County	533
					Giant Refining Co.	Bloomfield	NM	San Juan County	21
					Giant Refining Co.	Gallup	NM	McKinley County	14
World Oil Corp	Private	8,500	277	475	Lunday-Thagard Co.	South Gate	CA	Los Angeles County	2,344
Wyoming Refining Co.	Private	12,500	340	107	Wyoming Refining Co.	Newcastle	WY	Weston County	3
Total		2,128,860	59,738	12,688					

Sources: Dun & Bradstreet. 2007. *2007 D&B Million Dollar Directory*. Pennsylvania: Dun & Bradstreet Inc.

Dun & Bradstreet Small Business Solutions. Small Business Database. Available at <<http://smallbusiness.dnb.com/default.asp?bhcd2=1107465546>>.

Gale Research Inc. 2007. *Ward's Business Directory of U S Private and Public Companies*. Detroit: Gale Research.

Hoovers. 2007. Free Content, Company Information. Available at <<http://www.hoovers.com/free/>>. As obtained on April 11, 2007.

U.S. Department of Commerce, Bureau of the Census. 2000. "Population Density by County: Census 2000 Summary File 1 (SF 1) 100-Percent Data". Available through American Fact Finder <http://factfinder.census.gov/home/saff/main.html?_lang=en>. As obtained on February 21, 2008.

Capacity information for the 29 refineries owned by small businesses also suggests that fewer small businesses are focusing on developing specialty products or serving local customers as major parts of their business plan. For example, in 2006 these 29 refineries had a collective crude refining capacity of 778,920 barrels per calendar day or 857,155 barrels per stream day (EIA, 2006c). Approximately 21% of this total capacity was devoted to producing specialty products or more locally focused products such as aromatics, asphalt, lubricants, and petroleum coke. The remaining 79% was used to produce gasoline, kerosene, diesel fuel, and liquefied petroleum gases. As discussed in Section 3.4.1.3, fuel products tend to be quite homogenous (gasoline from one refinery is not very different from gasoline from another refinery), and they are also normally transported by pipeline.

3.5 Markets

This section provides data on the volume of petroleum products produced and consumed in the United States, the quantity of products imported and exported, and the average prices of major petroleum products. The section concludes with a discussion of future trends for the petroleum refining industry.

3.5.1 U.S. Petroleum Consumption

Figure 3-9 illustrates the amount of petroleum products supplied between 2000 and 2006 (measured in millions of barrels of oil). These data represent the approximate consumption of petroleum products because it measures the disappearance of these products from primary sources (i.e., refineries, natural gas processing plants, blending plants, pipelines, and bulk terminals).

Between 2000 and 2004, U.S. consumption of petroleum products increased by 5%. Consumption grew steadily from 2001 and 2004 before leveling off and slightly declining in 2006 (Figure 3-9). This reduced growth was primarily the result of less jet fuel and residual fuel being consumed in recent years (Table 3-10).

3.5.2 U.S. Petroleum Production

Table 3-11 reports the number of barrels of major petroleum products produced in the United States between 2000 and 2006. U.S. production of petroleum products at refineries and blenders grew steadily between 1995 and 2003. However, production declined by 0.35% in 2005. This drop was possibly the result of damage inflicted by two hurricanes (Hurricane Katrina and Hurricane Rita) on the U.S. Gulf Coast—the location of many U.S. petroleum refineries (Section 3.4.2). According to the American Petroleum Institute, approximately 30% of the U.S. refining industry was shut down as a result of the damage (API, 2006). In 2006, production of

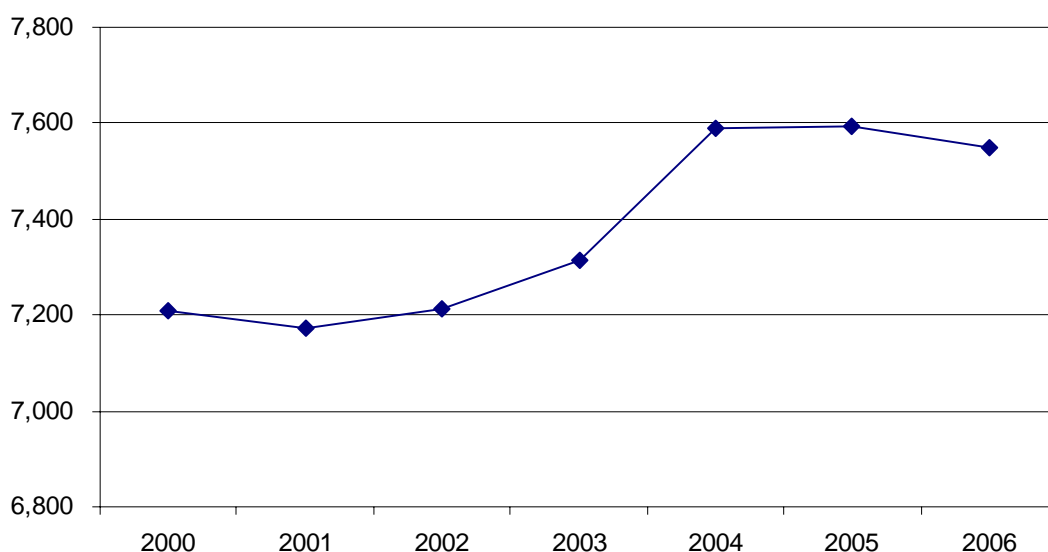


Figure 3-9. Total Petroleum Products Supplied (millions of barrels per year)

Table 3-10. Total Petroleum Products Supplied (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
2000	3,101	631	1,362	333	816	967	7,211
2001	3,143	604	1,404	296	746	978	7,172
2002	3,229	591	1,378	255	789	969	7,213
2003	3,261	576	1,433	282	757	1,003	7,312
2004	3,333	597	1,485	316	780	1,076	7,588
2005	3,343	613	1,503	336	741	1,057	7,593
2006	3,377	596	1,522	251	749	1,055	7,551

Source: U.S. Department of Energy, Energy Information Administration (EIA). "Petroleum Supply Annuals 1996–2007, Volume 1." Available at <http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html>. As obtained on October 31, 2007.

petroleum products rebounded, increasing 1% over 2004 levels. Additional production data are presented in Table 3-12, which reports the value of shipments of products produced by the petroleum refining industry between 1997 and 2006.

3.5.3 International Trade

International trade is a growing component of the U.S. Petroleum refining industry. This trend is demonstrated in Tables 3-13 and 3-14. Between 1995 and 2006, imports and exports of petroleum products increased by more than 50%. While imports of most major petroleum

Table 3-11. U.S. Refinery and Blender Net Production (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
2000	2,910	588	1,310	255	258	990	6,311
2001	2,928	558	1,349	263	243	968	6,309
2002	2,987	553	1,311	219	245	990	6,305
2003	2,991	543	1,353	241	240	1,014	6,383
2004	3,025	566	1,396	240	236	1,057	6,520
2005	3,036	564	1,443	229	209	1,015	6,497
2006	3,053	541	1,475	232	229	1,032	6,561

Source: U.S. Department of Energy, Energy Information Administration (EIA). "Petroleum Supply Annuals 1996–2007, Volume 1." Available at <http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html>. As obtained on October 31, 2007.

Table 3-12. Value of Product Shipments of the Petroleum Refining Industry

Year	Millions of \$Reported	Millions of \$2005
1997	152,756	180,671
1998	114,439	136,746
1999	140,084	164,651
2000	210,187	237,425
2001	195,898	219,476
2002	186,761	210,647
2003	216,764	238,425
2004	290,280	306,328
2005	419,063	419,063
2006	489,051	470,037

Note: Numbers were adjusted for inflation using producer price index industry data for Total Manufacturing Industries (Table 5-6).

Sources: U.S. Department of Commerce, Bureau of the Census. 2007. 2006 Annual Survey of Manufactures. Obtained through American Fact Finder Database < http://factfinder.census.gov/home/saff/main.html?_lang=en>.

U.S. Department of Commerce, Bureau of the Census. 2003b. 2001 Annual Survey of Manufactures. M01(AS)-2. Washington, DC: Government Printing Office. Available at < <http://www.census.gov/prod/2003pubs/m01as-2.pdf>>. As obtained on March 4, 2008.

products grew at approximately the same rate, the growth of petroleum product exports was driven largely by residual fuel oil and other petroleum products.

However, the United States remains a net importer of petroleum products. In 2006, the United States imported nearly three times more petroleum products than it exported. These imported petroleum products accounted for 17% of total petroleum products consumed that year (1,310 millions of barrels per year/7,551 millions of barrels per year).

Table 3-13. Imports of Major Petroleum Products (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
1995	97	35	71	68	53	262	586
1996	123	40	84	91	61	322	721
1997	113	33	83	71	62	345	707
1998	114	45	77	101	71	324	731
1999	139	47	91	86	66	344	774
2000	156	59	108	129	79	343	874
2001	166	54	126	108	75	400	928
2002	182	39	98	91	67	396	872
2003	189	40	122	119	82	397	949
2004	182	47	119	156	96	520	1,119
2005	220	69	120	193	120	587	1,310
2006	173	68	133	128	121	687	1,310

Source: U.S. Department of Energy, Energy Information Administration (EIA). "Petroleum Supply Annuals 1996–2007, Volume 1." Available at <http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html>. As obtained on October 31, 2007.

Table 3-14. Exports of Major Petroleum Products (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
1995	38	8	67	49	21	128	312
1996	38	17	70	37	19	138	319
1997	50	13	56	44	18	147	327
1998	46	9	45	50	15	139	305
1999	40	11	59	47	18	124	300
2000	53	12	63	51	27	157	362
2001	48	10	44	70	16	159	347
2002	45	3	41	65	24	177	356
2003	46	7	39	72	20	186	370
2004	45	15	40	75	16	183	374
2005	49	19	51	92	19	183	414
2006	52	15	79	103	21	203	472

Source: U.S. Department of Energy, Energy Information Administration (EIA). "Petroleum Supply Annuals 1996–2007, Volume 1." Available at <http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_annual/psa_volume1/psa_volume1.html>. As obtained on October 31, 2007.

3.5.4 Market Prices

The average nominal prices of major petroleum products sold to end users are provided for selected years in Table 3-15.¹ As these data illustrate, nominal prices rose substantially between 2004 and 2006. In particular, the price of motor gasoline rose 48% over this 2-year period.

¹ Sales to end users are those made directly to the consumer of the product. This includes bulk consumers, such as agriculture, industry, and utilities, as well as residential and commercial consumers.

Table 3-15. Average Price of Major Petroleum Products Sold to End Users (cents per gallon)

Product	1995	2000	2002	2004	2005	2006
Motor gasoline	76.5	110.6	94.7	143.5	182.9	212.8
No. 1 distillate fuel	62	98.8	82.8	126.2	183.2	213.7
No. 2 distillate fuel	56	93.4	75.9	123.5	177.7	209.1
Jet fuel	54	89.9	72.1	120.7	173.5	199.8
Residual fuel oil	39.2	60.2	56.9	73.9	104.8	121.8

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2007b. "Refiner Petroleum Product Prices by Sales Type." Available at <http://tonto.eia.doe.gov/dnav/pet/pet_pri_refoth_dcu_nus_m.htm>. As obtained on January 11, 2008.

Note: Prices do not include taxes.

The nominal prices domestic petroleum refiners receive for their products have also been rising much faster than prices received by other U.S. manufacturers. This trend is demonstrated in Table 3-16 by comparing the producer price index (PPI) for the petroleum refining industry against the index for all manufacturing industries. Between 1995 and 2006, prices received by petroleum refineries for their products rose by 223%, while prices received by all manufacturing firms rose by 26%. The vast majority of this growth in prices has been experienced in the years after 2002.

Table 3-16. Producer Price Index Industry Data: 1995 to 2006

Year	Petroleum Refining (NAICS 32411)		Total Manufacturing Industries	
	PPI	Annual Percentage Change in PPI	PPI	Annual Percentage Change in PPI
1995	74.5	3%	124.2	3%
1996	85.3	14%	127.1	2%
1997	83.1	-3%	127.5	0%
1998	62.3	-25%	126.2	-1%
1999	73.6	18%	128.3	2%
2000	111.6	52%	133.5	4%
2001	103.1	-8%	134.6	1%
2002	96.3	-7%	133.7	-1%
2003	121.2	26%	137.1	3%
2004	151.5	25%	142.9	4%
2005	205.3	36%	150.8	6%
2006	241.0	17%	156.9	4%

Source: U.S. Bureau of Labor Statistics (BLS). 2007. "Producer Price Index Industry Data: Customizable Industry Data Tables." Available at <<http://www.bls.gov/ppi/>>. As obtained on October 11, 2007.

3.5.5 Profitability of Petroleum Refineries

Estimates of the mean profit (before taxes) to net sales ratios for petroleum refiners are reported in Table 3-17 for the 2006–2007 fiscal year. These ratios were calculated by Risk

Table 3-17. Mean Ratios of Profit before Taxes as a Percentage of Net Sales for Petroleum Refiners, Sorted by Value of Assets

Fiscal Year	Total Number of Statements	0 to 500,000	500,000 to 2 Million	2 Million to 10 Million	10 Million to 50 Million	50 Million to 100 Million	100 Million to 250 Million	All Firms
4/1/2006– 3/31/2007	44	—	—	4.6	6.5	—	—	6.7

Source: Risk Management Association (RMA). 2008. *Annual Statement Studies 2007-2008*. Pennsylvania: RMA, Inc.

Management Associates by dividing net income into revenues for 44 firms in the petroleum refining industry. They are broken down based on the value of assets owned by the reporting firms.

As these ratios demonstrate, firms that reported a greater value of assets also received a greater return on sales. For example, firms with assets valued between \$10 and \$50 million received a 6.5% average return on net sales, while firms with assets valued between \$2 and \$10 million only received a 4.6% average return. The average return on sales for the entire industry was 6.7%.

Obtaining profitability information specifically for small petroleum refining companies can be difficult as most of these firms are privately owned. However, five of the small, domestic petroleum refining firms identified in Section 3.4.2.3 are publicly owned companies—the Arabian American Development Co., CVR Energy Inc., Calumet Specialty Products Partners, L.P., Holly Corporation, Western Refining, Inc. Profit ratios were calculated for these companies using data obtained from their publicly available 2006 income statements. These ratios are presented for in Table 3-18.

3.5.6 Industry Trends

The Energy Information Administration's (EIA's) 2007 Annual Energy Outlook provides forecasts of average petroleum prices, petroleum product consumption, and petroleum refining capacity utilization to the year 2030. Trends in these variables are affected by many factors that are difficult to predict, such as energy prices, U.S. economic growth, advances in technologies, changes in weather patterns, and future public policy decisions. As a result, the EIA evaluated a wide variety of cases based on different assumptions of how these factors will behave in the future. This section focuses on the EIA's "reference case" forecasts, which assume that current policies affecting the energy sector will remain unchanged throughout the projection period (EIA, 2007c).

According to the 2007 Annual Energy Outlook's reference forecast, world oil prices (defined as the average price of low-sulfur, light crude oil) are expected to fall significantly over

Table 3-18. Net Profit Margins for Publicly Owned, Small Petroleum Refiners: 2006

Company	Net Income (\$millions)	Total Revenue (\$millions)	Net Profit Margin (%)
Arabian American Development Co.	7.9	98.5	8.0%
Calumet Specialty Products Partners	93.9	1,641.0	5.7%
CVR Energy Inc.	191.6	3,037.6	6.3%
Holly Corporation	266.6	4,023.2	6.6%
Western Refining, Inc.	204.8	4,199.5	4.9%

Sources: Arabian American Development Co. April 6, 2007. 10K for year ended December 31, 2006. EDGAR Database. Available at <<http://www.sec.gov/Archives/edgar/data/7039/000095013407007709/0000950134-07-007709-index.htm>>.

Calumet Specialty Products Partners. February 23, 2007. 10K for year ended December 31, 2006. EDGAR Database. Available at <<http://www.sec.gov/Archives/edgar/data/1340122/000095013407003992/h43776e10vk.htm>>.

CVR Energy Inc. 2006. Google Finance. Available at <<http://finance.google.com/finance?q=NYSE:CVI>> As obtained on February 28, 2008.

Holly Corporation. March 1, 2007. 10K for year ended December 31, 2006. EDGAR Database. Available at <<http://www.sec.gov/Archives/edgar/data/48039/000095013407004555/d44106e10vk.htm>>.

Western Refining, Inc. March 8, 2007. 10K for year ended December 31, 2006. EDGAR Database. Available at <<http://www.sec.gov/Archives/edgar/data/1339048/000095013407005096/h44360e10vk.htm>>.

the next 10 years as the amount of oil supplied by non-OPEC and OPEC countries increases. Since crude oil is the primary input in petroleum refining, a decline in its price would likewise represent a decline in production costs of petroleum refiners. As a result, the prices of petroleum products sold to end users are expected to decline over the same period (Table 3-19). These lower prices will, in turn, encourage more petroleum products to be consumed (Table 3-20). Between 2007 and 2015, the prices of major petroleum products are expected to fall approximately 20% to 25%, while consumption of those products is expected to rise by 9%.

Operational capacity of U.S. petroleum refineries is also expected to grow for the foreseeable future. The expansion of dozens of petroleum refineries has already been announced (Reuters, 2007). The *Oil & Gas Journal's* 2007 Worldwide Construction Update survey alone catalogued nearly 40 refining construction projects being pursued in the United States. Table 3-21 lists selected refinery construction projects that would be subject to the rule. The projects listed include two refinery expansion projects and five new processes (distillation units and delayed cokers).

Table 3-19. Forecasted Average Price of Major Petroleum Products Sold to End Users in 2005 Currency (cents per gallon)

Product	2007	2008	2009	2010	2011	2012	2013	2014	2015
Motor gasoline	257.4	241.3	227.3	217.3	209.2	204.7	201.1	195.2	194.9
Jet fuel	175.4	158.3	152.0	147.2	140.0	135.8	135.5	132.9	133.5
Distillate fuel	253.8	236.6	224.1	215.9	205.0	197.2	194.7	190.3	191.0
Residual fuel oil	123.5	125.8	120.6	113.9	107.7	102.8	96.6	95.9	98.0
LPGs	257.4	241.3	227.3	217.3	209.2	204.7	201.1	195.2	194.9

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2007c. "Annual Energy Outlook." Available at <[http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383\(2007\).pdf](http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383(2007).pdf)>. As obtained on January 21, 2007.

Table 3-20. Total Petroleum Products Supplied (millions of barrels per year)

Year	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases	Other Products	Total
2007	3,388	622	1,600	275	819	940	7,643
2008	3,407	646	1,613	278	824	953	7,721
2009	3,446	675	1,631	281	815	955	7,804
2010	3,479	713	1,654	287	809	937	7,879
2011	3,520	728	1,682	289	811	961	7,990
2012	3,563	739	1,710	294	812	958	8,076
2013	3,610	749	1,735	303	812	967	8,177
2014	3,663	758	1,755	306	814	953	8,249
2015	3,716	766	1,774	300	815	970	8,341

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2007c. "Annual Energy Outlook." Available at <[http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383\(2007\).pdf](http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383(2007).pdf)>. As obtained on January 21, 2007.

Table 3-21. Selected Refinery Construction Projects: 2008–2011

Company and Location	Project	Projected Added Capacity (barrels per day)	Expected Completion
Cenex Harvest States, Laurel, MT	New delayed coker unit	N/A	2008
Frontier Oil Corp, El Dorado, KS	New crude distillation unit	N/A	2008
	New vacuum distillation unit	N/A	2008
Marathon Petroleum Co. LLC, Garyville, LA	New crude distillation unit	180,000	2009
	New delayed coker unit	N/A	2009
Motiva Enterprises LLC, Port Arthur, TX	Refinery expansion	325,000	2010
Sinclair Oil Corp, Tulsa, OK	Refinery expansion	45,000	2011

Source: *Oil and Gas Journal*. November 19, 2007. Worldwide Construction Update.

In particular, several U.S. refineries are planning projects to expand their ability to handle cheaper and lower-quality varieties of crude oil (known as “heavy crudes”). For example, ConocoPhillips will be expanding its capacity to handle heavy crude oils at its refinery in Billings, Montana, to 46,000 barrels per day (Reuters, 2007).

In addition to these expansions, two entirely new refineries could potentially be constructed within the next 5 years. The first is the Arizona Clean Fuels Refinery in Phoenix. This facility will cost \$3 billion to construct and will be capable of producing 6 million gallons of gasoline, diesel, and jet fuel per day (Arizona Clean Fuels, 2007). Second, a proposal to construct the MHA Nation Clean Fuels Refinery in North Dakota is being reviewed. If constructed, this facility will be capable of producing 15,000 barrels of fuel per day (EPA, 2006).

Overall, the EIA forecasts that U.S. operational capacity will increase by a total of 2% between 2007 and 2015 (Table 3-22). However, since consumption of petroleum products is projected to grow much more quickly, the rate of capacity utilization is projected to average 90% during this period.

Table 3-22. Full Production Capacity Utilization Rates for Petroleum Refineries

Year	Petroleum Refineries Capacity Utilization Rates (NAICS 324110)	Gross Input to Atmospheric Crude Oil Distillation Units (1,000s of barrels per day)	Operational Capacity (1,000s of barrels per day)
2007	88.8%	15,630	17,597
2008	88.1%	15,587	17,684
2009	88.6%	15,712	17,737
2010	89.1%	15,879	17,822
2011	89.9%	16,055	17,852
2012	90.9%	16,267	17,897
2013	91.4%	16,378	17,914
2014	91.6%	16,433	17,940
2015	92.2%	16,628	18,031

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2007c. “Annual Energy Outlook.” Available at <[http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383\(2007\).pdf](http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383(2007).pdf)>. As obtained on January 21, 2007.

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Appendix A. Parent Company Information for Petroleum Refineries^a

Facility Name	City	State	Capacity (bbl/cd)	Foreign or Domestic	Sales (\$million)	Employment	Company Type (Private or Public or Subsidiary)	Owning Company	Owning Company Type	Sales (\$million)	Employment (#)	Source	Year of Data
AGE Refining & Manufacturing	San Antonio	TX	12,200	D	287	52	Private					D&B	Unknown
Alon USA Energy Inc.	Big Spring	TX	67,000	F			Subsidiary	Alon Israel Oil Company LTD	Private	NA	NA		
American Refining Group	Bradford	PA	10,000	D	350	310	Private					D&B	Unknown
Big West of CA	Bakersfield	CA	66,000	D			Subsidiary	Flying J Inc	Private	11,350	16,300	Hoovers	2007
Big West Oil Co.	Salt Lake City	UT	29,400	D			Subsidiary	Flying J Inc	Private	11,350	16,300	Hoovers	2007
BP	Whiting	IN	410,000	F			Subsidiary	BP PLC	Public	274,316	97,000	Hoovers	2007
BP	Texas City	TX	437,000	F			Subsidiary	BP PLC	Public	274,316	97,000	Hoovers	2007
BP	Prudhoe Bay	AK	12,500	F			Subsidiary	BP PLC	Public	274,316	97,000	Hoovers	2007
BP	Carson	CA	260,000	F			Subsidiary	BP PLC	Public	274,316	97,000	Hoovers	2007
BP	Ferndale	WA	225,000	F			Subsidiary	BP PLC	Public	274,316	97,000	Hoovers	2007
BP	Toledo	OH	131,000	F			Subsidiary	BP PLC	Public	274,316	97,000	Hoovers	2007
Calcasieu Refining Co.	Lake Charles	LA	30,000	D	638	51	Private					D&B	Unknown
Calumet Specialty Products	Shreveport	LA	42,000	D	1,641	350	Public					Hoovers	2006
Calumet Specialty Products	Cotton Valley	LA	13,020	D	1,641	350	Public					Hoovers	2006
Calumet Specialty Products	Princeton	LA	8,300	D	1,641	350	Public					Hoovers	2006
Cenex Harvest States	Laurel	MT	55,000	D	11,900	6,370	Public						
Chevron USA Inc.	Perth Amboy	NJ	80,000	D			Subsidiary	Chevron Corporation	Public	210,118	62,500	Hoovers	2006
Chevron USA Inc.	Salt Lake City	UT	45,000	D			Subsidiary	Chevron Corporation	Public	210,118	62,500	Hoovers	2006
Chevron USA Inc.	Portland	OR		D			Subsidiary	Chevron Corporation	Public	210,118	62,500	Hoovers	2006
Chevron USA Inc.	Pascagoula	MS	330,000	D			Subsidiary	Chevron Corporation	Public	210,118	62,500	Hoovers	2006

(continued)

Appendix A. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Foreign or Domestic	Sales (\$million)	Employment	Company Type (Private or Public or Subsidiary)	Owning Company	Owning Company Type	Sales (\$million)	Employment (#)	Source	Year of Data
Chevron USA Inc.	El Segundo	CA	260,000	D			Subsidiary	Chevron Corporation	Public	210,118	62,500	Hoovers	2006
Chevron USA Inc.	Richmond	CA	242,901	D			Subsidiary	Chevron Corporation	Public	210,118	62,500	Hoovers	2006
Chevron USA Inc.	Honolulu (Barber's Point)	HI	54,000	D			Subsidiary	Chevron Corporation	Public	210,118	62,500	Hoovers	2006
Citgo	Corpus Christi	TX	156,000	F			Subsidiary	Petróleos de Venezuela S.A. (PDVSA)	Government Owned	NA	49,180	Hoovers	2004
Citgo Asphalt Refining Co.	Paulsboro	NJ	32,000	F			Subsidiary	Petróleos de Venezuela S.A. (PDVSA)	Government Owned	NA	49,180	Hoovers	2004
Citgo Petroleum	Savannah	GA	28,000	F			Subsidiary	Petróleos de Venezuela S.A. (PDVSA)	Government Owned	NA	49,180	Hoovers	2004
Citgo Petroleum Corp.	Lake Charles	LA	429,500	F			Subsidiary	Petróleos de Venezuela S.A. (PDVSA)	Government Owned	NA	49,180	Hoovers	2004
Coffeyville Resources LLC	Coffeyville	KS	112,000	D	3,038	577	Public	CVR Energy Inc.				Hoovers	2006
ConocoPhillips	Westlake	LA	239,400	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Ponca City	OK	194,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Billings	MT	58,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Borger	TX	146,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Sweeny	TX	247,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Ferndale	WA	96,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Linden	NJ	238,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Wood River	IL	306,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	LA - Carson/Wilmington	CA	139,000	D	188,523	38,400	Public					Hoovers	2006

(continued)

Appendix A. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Foreign or Domestic	Sales (\$million)	Employment	Company Type (Private or Public or Subsidiary)	Owning Company	Owning Company Type	Sales (\$million)	Employment (#)	Source	Year of Data
ConocoPhillips	SF - Rodeo	CA	76,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Arroyo Grande (Santa Maria)	CA	44,200	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Belle Chasse	LA	247,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Trainer (Marcus Hook)	PA	185,000	D	188,523	38,400	Public					Hoovers	2006
ConocoPhillips	Kuparuk	AK	14,000	D	188,523	38,400	Public					Hoovers	2006
Countrymark Cooperative, Inc.	Mt. Vernon	IN	23,000	D	87	300	Private						
Cross Oil & Refining Co. Inc.	Smackover	AR	7,200	D	49	110	Private						
Delek Refining Ltd	Tyler	TX	58,000	F			Subsidiary	Delek Group LTD	Public	6,237	2,803	Hoovers	2006
Edgington Oil Co.	Long Beach	CA	26,000	F			Subsidiary	Alon Israel Oil Company LTD	Private	NA	NA		
Ergon Refining Inc.	Vicksburg	MS	23,000	D			Subsidiary	Ergon, Inc.	Private	1,300	2,300		
Ergon-West Virginia Inc.	Newell (Congo)	WV	20,000	D			Subsidiary	Ergon, Inc.	Private	1,300	2,300		
ExxonMobil Corp.	Baton Rouge	LA	501,000	D	377,635	82,100	Public					Hoovers	2006
ExxonMobil Corp.	Billings	MT	60,000	D	377,635	82,100	Public					Hoovers	2006
ExxonMobil Corp.	Joliet	IL	238,500	D	377,635	82,100	Public					Hoovers	2006
ExxonMobil Corp.	Beaumont	TX	348,500	D	377,635	82,100	Public					Hoovers	2006
ExxonMobil Corp.	Torrance	CA	149,500	D	377,635	82,100	Public					Hoovers	2006
ExxonMobil Corp.	Chalmette	LA	188,160	D	377,635	82,100	Public					Hoovers	2006
ExxonMobil Oil Corp	Baytown	TX	562,500	D			Subsidiary	ExxonMobil Corp.	Public	377,635	82,100	Hoovers	2006
Flint Hills Resources	Corpus Christi	TX	288,126	D			Subsidiary	Koch Industries Inc	Private	51,500	85,000		
Flint Hills Resources	North Pole	AK	210,000	D			Subsidiary	Koch Industries Inc	Private	51,500	85,000		

(continued)

Appendix A. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Foreign or Domestic	Sales (\$million)	Employment	Company Type (Private or Public or Subsidiary)	Owning Company	Owning Company Type	Sales (\$million)	Employment (#)	Source	Year of Data
Flint Hills Resources	Rosemount	MN	279,300	D			Subsidiary	Koch Industries Inc	Private	51,500	85,000		
Foreland Refining Co.	Tonopah/Eagle Springs	NV	2,000	D	56	100	Private					D&B	Unknown
Frontier Oil & Refining Co.	Cheyenne	WY	47,000	D			Subsidiary	Frontier Oil Corp	Private	4,000	727		
Frontier Oil Corp	El Dorado	KS	106,000	D	4,000	727	Private						
Giant Refining Co.	Yorktown	VA	58,600	D			Subsidiary	Western Refining, Inc.	Private	4,200	416	Hoovers	2006
Giant Refining Co.	Bloomfield	NM	16,800	D			Subsidiary	Western Refining, Inc.	Private	4,200	416	Hoovers	2006
Giant Refining Co.	Gallup	NM	20,800	D			Subsidiary	Western Refining, Inc.	Private	4,200	416	Hoovers	2006
Goodway Refining LLC	Atmore	AL	4,100	D	3	18	Private					D&B	Unknown
Greka Integrated Inc	Santa Maria	CA	9,500	D	22	145	Private						
Gulf Atlantic Operations LLC	Mobile Bay	AL	16,700	D	9	32	Private					D&B	Unknown
Hess Corporation	Port Reading	NJ		D	23,200	11,610	Public						
Holly Corp.	Woods Cross	UT	24,700	D	4,023	859	Public					Hoovers	2006
Hunt Refining Co.	Tuscaloosa	AL	34,500	D	4,871	1,100	Private					Ward's	2007
Hunt Southland Refining	Lumberton	MS		D			Subsidiary	Hunt Refining Co.	Private	4,871	1,100	Ward's	2007
Hunt Southland Refining	Sandersville	MS	11,000	D			Subsidiary	Hunt Refining Co.	Private	4,871	1,100	Ward's	2007
Kern Oil & Refining Co.	Bakersfield	CA	26,000	D	NA	NA	Private						
Lion Oil Co.	El Dorado	AR	70,000	D	247	425	Private						
Little America Refining Co.	Evansville (Casper)	WY	24,500	D			Subsidiary	Sinclair Companies	Private	5,500	7,000		
Lunday-Thagard Co.	South Gate	CA	8,500	D			Subsidiary	World Oil Corp	Private	277	475	Hoovers	2007

(continued)

Appendix A. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Foreign or Domestic	Sales (\$million)	Employment	Company Type (Private or Public or Subsidiary)	Owning Company	Owning Company Type	Sales (\$million)	Employment (#)	Source	Year of Data
Lyondell-Citgo Refining Co.	Houston	TX	270,200	D			Subsidiary	Lyondell Chemical Co	Public	18,600	10,880		
Marathon Petroleum Co. LLC	Robinson	IL	192,000	D			Subsidiary	Marathon Oil Corp	Public	65,449	28,195	Hoovers	2006
Marathon Petroleum Co. LLC	Catlettsburg	KY	222,000	D			Subsidiary	Marathon Oil Corp	Public	65,449	28,195	Hoovers	2006
Marathon Petroleum Co. LLC	Detroit	MI	100,000	D			Subsidiary	Marathon Oil Corp	Public	65,449	28,195	Hoovers	2006
Marathon Petroleum Co. LLC	Canton	OH	73,000	D			Subsidiary	Marathon Oil Corp	Public	65,449	28,195	Hoovers	2006
Marathon Petroleum Co. LLC	St. Paul Park	MN	70,000	D			Subsidiary	Marathon Oil Corp	Public	65,449	28,195	Hoovers	2006
Marathon Petroleum Co. LLC	Texas City	TX	72,000	D			Subsidiary	Marathon Oil Corp	Public	65,449	28,195	Hoovers	2006
Marathon Petroleum Co. LLC	Garyville	LA	245,000	D			Subsidiary	Marathon Oil Corp	Public	65,449	28,195	Hoovers	2006
Montana Refining Co.	Great Falls	MT	8,200	F			Subsidiary	Connacher Oil and Gas Limited	Public	NA	NA		
Motiva Enterprises	Norco	LA	226,500	D	32,100	2,700	Private						
Motiva Enterprises	Port Arthur	TX	285,000	D	32,100	2,700	Private						
Motiva Enterprises	Convent	LA	235,000	D	32,100	2,700	Private						
Murphy Oil USA Inc.	Superior	WI	34,300	D			Subsidiary	Murphy Oil Corp	Public	14,307	7,296	Hoovers	2006
Murphy Oil USA Inc.	Meraux	LA	120,000	D			Subsidiary	Murphy Oil Corp	Public	14,307	7,296	Hoovers	2006
National Cooperative Refinery Association	McPherson	KS	81,200	D			Subsidiary	Cenex Harvest States	Public	11,900	6,370		
Navajo Refining Co.	Artesia	NM	75,000	D			Subsidiary	Holly Corp.	Public	4,023	859	Hoovers	2006
Paramount Petroleum Corp.	Paramount	CA	50,000	F			Subsidiary	Alon Israel Oil Company LTD	Private	NA	NA		
Pasadena Refining Systems Inc.	Pasadena	TX	100,000	F			Subsidiary	Petroleo Brasileiro, S.A.	Government Owned	72,347	62,266	Hoovers	2006

(continued)

Appendix A. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Foreign or Domestic	Sales (\$million)	Employment	Company Type (Private or Public or Subsidiary)	Owning Company	Owning Company Type	Sales (\$million)	Employment (#)	Source	Year of Data
PDV Midwest Refining	Lemont	IL	167,000	F			Subsidiary	Petróleos de Venezuela S.A. (PDVSA)	Government Owned	NA	NA		
Pelican Refining Co. LLC	Lake Charles	LA		D	29	62	Private						
Petro Star Inc.	North Pole	AK	17,000	D			Subsidiary	Arctic Slope Regional Corp	Private	1,500	5,743		
Petro Star Inc.	Valdez	AK	48,000	D			Subsidiary	Arctic Slope Regional Corp	Private	1,500	5,743		
Placid Refining Inc.	Port Allen	LA	56,000	D	1,400	200	Private						
San Joaquin Refining Co., Inc.	Bakersfield	CA	15,000	D	288	20	Private						
Shell Chemical LP	St. Rose	LA	55,000	F			Subsidiary	Royal Dutch Shell, PLC	Public	312,323	108,000	Hoovers	2006
Shell Chemical LP	Saraland	AL	80,000	F			Subsidiary	Royal Dutch Shell, PLC	Public	312,323	108,000	Hoovers	2006
Shell Oil Products US	Anacortes	WA	145,000	F			Subsidiary	Royal Dutch Shell, PLC	Public	312,323	108,000	Hoovers	2006
Shell Oil Products US	Martinez	CA	155,600	F			Subsidiary	Royal Dutch Shell, PLC	Public	312,323	108,000	Hoovers	2006
Shell Oil Products US	Wilmington	CA	98,500	F			Subsidiary	Royal Dutch Shell, PLC	Public	312,323	108,000	Hoovers	2006
Shell Oil Products US - Deer Park Refining Limited Partnership	Deer Park	TX	333,700	F			Subsidiary	Royal Dutch Shell, PLC	Public	312,323	108,000	Hoovers	2006
Silver Eagle Refining Inc.	Evanston	WY	3,000	D	NA	NA	Private						
Silver Eagle Refining Inc.	Woods Cross	UT	10,250	D	NA	NA	Private						
Sinclair Oil Corp.	Tulsa	OK	70,300	D			Subsidiary	Sinclair Companies	Private	5,500	7,000		

(continued)

Appendix A. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Foreign or Domestic	Sales (\$million)	Employment	Company Type (Private or Public or Subsidiary)	Owning Company	Owning Company Type	Sales (\$million)	Employment (#)	Source	Year of Data
Sinclair Oil Corp.	Sinclair	WY	66,000	D			Subsidiary	Sinclair Companies	Private	5,500	7,000		
Somerset Refinery Inc.	Somerset	KY	5,500	D			Subsidiary	Somerset Oil Inc	Private	55	150		
South Hampton Resources Inc.	Silsbee	TX		D			Subsidiary	Arabian American Development Co	Public	80	118		
Suncor Energy	Commerce City	CO	62,000	F			Subsidiary	Suncor Energy Inc	Public	13,583	5,152	Hoovers	2006
Suncor Energy	Denver	CO	32,000	F			Subsidiary	Suncor Energy Inc	Public	13,583	5,152	Hoovers	2006
Sunoco, Inc.	Westville	NJ	145,000	D	38,715	14,000	Public					Hoovers	2006
Sunoco, Inc.	Marcus Hook	PA	175,000	D	38,715	14,000	Public					Hoovers	2006
Sunoco, Inc.	Toledo	OH	160,000	D	38,715	14,000	Public					Hoovers	2006
Sunoco, Inc.	Tulsa	OK	85,000	D	38,715	14,000	Public					Hoovers	2006
Sunoco, Inc.	Phil. (Girard Pt & Pt Breeze)	PA	335,000	D	38,715	14,000	Public					Hoovers	2006
Ten By Inc.	Oxnard	CA	2,800		NA	NA							
Tesoro	Mandan	ND	58,000	D			Subsidiary	Tesoro Corp	Public	18,104	3,950	Hoovers	2006
Tesoro	Salt Lake City	UT	58,000	D			Subsidiary	Tesoro Corp	Public	18,104	3,950	Hoovers	2006
Tesoro	Anacortes	WA	120,000	D			Subsidiary	Tesoro Corp	Public	18,104	3,950	Hoovers	2006
Tesoro	Golden Eagle	CA	166,000	D			Subsidiary	Tesoro Corp	Public	18,104	3,950	Hoovers	2006
Tesoro	Kapolei	HI	93,500	D			Subsidiary	Tesoro Corp	Public	18,104	3,950	Hoovers	2006
Tesoro	Kenai	AK	72,000	D			Subsidiary	Tesoro Corp	Public	18,104	3,950	Hoovers	2006
Total SA	Port Arthur	TX	232,000	F	175,189	95,070	Public					Hoovers	2005
Trigeant Ltd.	Corpus Christi	TX		D	5	50	Private					D&B	Unknown
United Refining Co.	Warren	PA	65,000	D			Subsidiary	Red Apple Group Inc	Private	4,200	7,000		
US Oil & Refining Co.	Tacoma	WA	37,850		NA	NA							
Valero Energy	Corpus Christi	TX	142,000	D	91,833	21,836	Public					Hoovers	2006

(continued)

Appendix A. Parent Company Information for Petroleum Refineries (continued)

Facility Name	City	State	Capacity (bbl/cd)	Foreign or Domestic	Sales (\$million)	Employment	Company Type (Private or Public or Subsidiary)	Owning Company	Owning Company Type	Sales (\$million)	Employment (#)	Source	Year of Data
Valero Energy	Houston	TX	83,000	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Texas City	TX	213,750	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Krotz Springs	LA	80,000	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Benicia	CA	144,000	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Wilmington	CA	6,200	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Norco	LA	185,003	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Delaware City	DE	181,500	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Lima	OH	146,900	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Memphis	TN	180,000	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Three Rivers	TX	90,000	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Sunray	TX	158,327	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Ardmore	OK	83,640	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Wilmington	CA	80,887	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Paulsboro	NJ	160,000	D	91,833	21,836	Public					Hoovers	2006
Valero Energy	Port Arthur	TX	260,000	D	91,833	21,836	Public					Hoovers	2006
Western Refining, Inc.	El Paso	TX	116,000	D	4,200	416	Public					Hoovers	2006
Wynnewood Refining Co.	Wynnewood	OK	54,000	D	97	200	Subsidiary	Gary-Williams Co	Private				

Note: All data were collected from the 2007 D&B Million Dollar Direction unless noted other wise. Data collected from the 2006 D&B Small Business Database are indicated using “D&B” in the source column. Data collected from Ward’s Business Directory are identified using “Ward’s” in the source column.

^a These data are shown with the permission of D&B.

Sources: Dun & Bradstreet. 2007. *2007 D&B Million Dollar Directory*. Pennsylvania: Dun & Bradstreet Inc.

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SECTION 4

NSPS REGULATORY OPTIONS, COSTS AND EMISSION REDUCTIONS FROM COMPLYING WITH THE NSPS

This section of the RIA provides descriptions of the regulatory options considered in the developing of this final NSPS, and also the costs and emission reductions estimated for each option. An appendix to this section (Appendix B) provides details on the rationale behind the choice of each option that is included in this NSPS.

4.1 Background Information on the Setting of NSPS

New source performance standards (NSPS) implement CAA section 111(b) and are issued for categories of sources which cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The primary purpose of the NSPS is to attain and maintain ambient air quality by ensuring that the best demonstrated emission control technologies are installed as the industrial infrastructure is modernized. Since 1970, the NSPS have been successful in achieving long-term emissions reductions in numerous industries by assuring cost-effective controls are installed on new, reconstructed, or modified sources.

Section 111 of the CAA requires that NSPS reflect the application of the best system of emission reductions which (taking into consideration the cost of achieving such emission reductions, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. This level of control is commonly referred to as best demonstrated technology (BDT).

Section 111(b)(1)(B) of the CAA requires EPA to periodically review and revise the standards of performance, as necessary, to reflect improvements in methods for reducing emissions. As a result of our periodic review of the NSPS for petroleum refineries (40 CFR part 60, subpart J), we proposed amendments to the current standards of performance and separate standards of performance for new process units (72 FR 27278, May 14, 2007). In response to several requests, we extended the 60-day comment period from July 13, 2007, to August 27, 2007 (72 FR 35375, June 28, 2007). We also issued a notice of data availability (72 FR 69175, December 7, 2007) (NODA) to notify the public that additional information had been added to the docket; the NODA also extended the public comment period on the proposed rule to January 7, 2008. We received a total of 38 comments from refineries, industry trade associations, and consultants; State and local environmental and public health agencies; environmental groups; and members of the public during the extended comment period and 8 additional comments on

the NODA. These final rules reflect our full consideration of all of the comments we received. Detailed responses to the comments are contained in the Response to Comments document which is included in the docket for this rulemaking.

4.2 Summary of the Final NSPS and Changes Since Proposal

We are promulgating several amendments to provisions in the existing NSPS in 40 CFR part 60, subpart J. Many of these amendments are technical clarifications and corrections that are also included in the final standards in 40 CFR part 60, subpart Ja. For example, we are revising the definition of “fuel gas” to indicate that vapors collected and combusted to comply with certain wastewater and marine vessel loading provisions are not considered fuel gas. Consequently, these vapors are exempt from the sulfur dioxide (SO₂) treatment standard in 40 CFR 60.104(a)(1) and are not required to be monitored. In a related amendment, we are clarifying that monitoring is not required for fuel gases that are identified as inherently low sulfur or demonstrated to contain a low sulfur content. We are also revising the coke burn-off equation to account for oxygen (O₂)-enriched air streams. Other amendments include clarification of definitions and correction of grammatical and typographical errors.

The final standards in 40 CFR part 60, subpart Ja include emission limits for fluid catalytic cracking units (FCCU), fluid coking units (FCU), sulfur recovery plants (SRP), and fuel gas combustion devices. Subpart Ja also includes work practice standards for minimizing emissions of volatile organic compounds (VOC) from flares and SO₂ emissions from fuel gas combustion devices and for reducing emissions of VOC from delayed coking units. Only those affected facilities that begin construction, modification, or reconstruction after May 14, 2007 will be affected by the standards in 40 CFR part 60, subpart Ja. Units for which construction, modification, or reconstruction began on or before May 14, 2007 must continue to comply with the applicable standards under the current NSPS in 40 CFR part 60, subpart J, as amended.

4.2.1 Final Amendments to the NSPS

As proposed, we are amending the definition of “fuel gas” to specifically exclude vapors that are collected and combusted in an air pollution control device installed to comply with a specified wastewater or marine vessel loading emissions standard. The thermal combustion control devices themselves are still considered to be affected fuel gas combustion devices if they combust other gases that meet the definition of fuel gas, and all auxiliary fuel gas fired to these devices are subject to the fuel gas limit; however, continuous monitoring is not required for the vapors collected from wastewater or marine vessel loading operations that are being incinerated

because these gases are not considered to be fuel gases under the definition of “fuel gas” in subpart J.

We are also exempting certain fuel gas streams from all continuous monitoring requirements. Monitoring is currently not required for combustion in a flare of process upset gases or flaring of gases from relief valve leakage or emergency malfunctions. Additionally, monitoring is not required for inherently low sulfur fuel gas streams. These streams include pilot gas flames, gas streams that meet commercial-grade product specifications with a sulfur content of 30 parts per million by volume (ppmv) or less, fuel gases produced by process units that are intolerant to sulfur contamination, and fuel gas streams that an owner or operator can demonstrate are inherently low-sulfur. Owners and operators are required to document the exemption for which each fuel gas stream applies and ensure that the stream remains qualified for that exemption.

We proposed to amend the definition of “Claus sulfur recovery plant” in 40 CFR 60.101(i) to clarify that the SRP may consist of multiple units and that primary sulfur pits are considered part of the Claus SRP based on a recent applicability determination. However, due to concerns regarding retroactive non-compliance, we are not amending this definition in the final amendments for subpart J. Similarly, we proposed revisions to the subpart J definitions of “oxidation control system” and “reduction control system” in 40 CFR 60.101(j) and 40 CFR 60.101(k), respectively, to clarify that these systems were intended to recycle the sulfur back to the Claus SRP. The proposed amendments needlessly limit the types of tail gas treatment systems that can be used; therefore, we are not amending these definitions in the final amendments for subpart J.

4.2.2 Final requirements for New FCCU and New FCU

The final standards for new fluid catalytic cracking units include emission limits for particulate matter (PM), SO₂, nitrogen oxides (NO_x), and carbon monoxide (CO). The final standards include no universal opacity limit because the opacity limit in subpart J is intended to ensure compliance with the PM limit. Subpart Ja requires that sources use direct PM monitoring, bag leak detection systems, or parameter monitoring (along with annual emission tests) to ensure compliance with the PM limit. A provision for a site-specific opacity operating limit is provided for units that meet the PM emission limits using a cyclone.

For PM emissions from new FCCU and new FCU, we proposed a PM limit of 0.5 pounds (lb)/1,000 lb coke burnoff in the regenerator or (if a PM continuous emission monitoring system (CEMS) is used), 0.020 grains per dry standard cubic feet (gr/dscf) corrected to 0% excess air.

We have revised the final PM standards to establish separate limits for modified or reconstructed FCCU (1 lb/1,000 lb coke burn or 0.040 gr/dscf corrected to 0% excess air) and newly constructed FCCU (0.5 lb/1,000 lb coke burn or 0.020 gr/dscf corrected to 0% excess air). The final PM limit for new, modified, or reconstructed FCU is 1 lb/1,000 lb coke burn or 0.040 gr/dscf corrected to 0% excess air).

Initial compliance with the PM emission limits for FCCU and FCU is determined using EPA Method 5, 5B or 5F (40 CFR part 60, appendix A) instead of being restricted to only EPA Method 5 as previously proposed. Procedures for computing the PM emission rate using the total PM concentration, effluent gas flow rate, and coke burn-off rate are the same as in 40 CFR part 60, subpart J, as amended. To demonstrate ongoing compliance, an owner or operator must monitor PM emission control device operating parameters and conduct annual PM performance tests, use a PM CEMS, or operate bag leak detection systems and conduct annual PM performance tests. A new alternative allows refineries with wet scrubbers as PM control devices to use the approved alternative in 40 CFR 63.1573(a) for determining exhaust gas flow rate instead of a continuous parameter monitoring system (CPMS). An alternative to the requirements for monitoring the pressure drop from wet scrubbers that are equipped with jet ejectors or atomizing spray nozzles is to conduct a daily check of the air or water pressure to the nozzles and record the results of each inspection. The final rule also includes procedures for establishing an alternative opacity operating limit for refiners that use continuous opacity monitoring systems (COMS); this alternative is allowed only for units that choose to comply with the PM limit using cyclones. If operating parameters are used to demonstrate ongoing compliance, the owner or operator must monitor the same parameters during the initial performance test, and develop operating parameter limits for the applicable parameters. The operating limits must be based on the three-run average of the values for the applicable parameters measured over the three test runs. If ongoing compliance is demonstrated using a PM CEMS, the CEMS must meet the conditions in Performance Specification 11 (40 CFR part 60, appendix B) and the quality assurance (QA) procedures in Procedure 2, 40 CFR part 60, appendix F. The relative response audits must be conducted annually (in lieu of annual performance tests for units not employing a PM CEMS) and response correlation audits must be conducted once every 5 years.

For NO_x emissions from affected FCCU and FCU, we proposed a limit of 80 ppmv based on a 7-day rolling average (dry basis corrected to 0% excess air) and co-proposed having no limit for FCU. We are adopting the 80 ppmv NO_x emission limits for FCCU and FCU as proposed. Initial compliance with the 80 ppmv emission limit is demonstrated by conducting a performance evaluation of the CEMS in accordance with Performance Specification 2 in 40 CFR part 60,

appendix B, with Method 7 (40 CFR part 60, appendix A) as the reference method. Ongoing compliance with these emission limits is determined using the CEMS to measure NO_x emissions as discharged to the atmosphere, averaged over 7-day periods.

No changes have been made to the proposed SO₂ emission limits for affected FCCU and FCU. The final SO₂ emission limits are to maintain SO₂ emissions to the atmosphere less than or equal to 50 ppmv on a 7-day rolling average basis, and less than or equal to 25 ppmv on a 365-day rolling average basis (both limits corrected to 0% moisture and 0% excess air). Initial compliance with the final SO₂ emission limits is demonstrated by conducting a performance evaluation of the SO₂ CEMS in accordance with Performance Specification 2 in 40 CFR part 60, appendix B with Method 6, 6A, or 6C of 40 CFR part 60, appendix A as the reference method. Ongoing compliance with both SO₂ emission limits is determined using the CEMS to measure SO₂ emissions as discharged to the atmosphere, averaged over the 7-day and 365-day averaging periods.

No changes have been made since proposal to the CO limits. The final CO emission limit for affected fluid catalytic cracking units and FCU is 500 ppmv (1-hour average, dry at 0% excess air). Initial compliance with this emission limit is demonstrated by conducting a performance evaluation for the CEMS in accordance with Performance Specification 4 in 40 CFR part 60, appendix B, with Method 10 or 10A in 40 CFR part 60, appendix A as the reference method. For Method 10, the integrated sampling technique is to be used. Ongoing compliance with this emission limit is determined on an hourly basis using the CEMS to measure CO emissions as discharged to the atmosphere. An exemption from monitoring may be requested for an FCCU or FCU if the owner or operator can demonstrate that “average CO emissions” are less than 50 ppmv (dry basis). This limit and the compliance procedures are the same as in the existing NSPS for FCCU. As proposed, units that are exempted from the CO monitoring requirements must comply with control device operating parameter limits.

4.2.3 Final Requirements for New Sulfur Recovery Plants (SRP)

For new, modified, and reconstructed SRP with a capacity greater than 20 long tons per day (LTD), we proposed a limit of 250 ppmv total sulfur (combined SO₂ and reduced sulfur compounds) as SO₂ (dry basis at 0% excess air determined on a 12-hour rolling average basis). The refinery could comply with the limit for each process train or release point or with a flow rate weighted average of 250 ppmv for all release points. For affected SRP with a capacity less than 20 LTD, we proposed a mass emissions limit for total sulfur equal to 1 weight percent or less of sulfur recovered (determined hourly on a 12-hour rolling average basis).

In this final rule, we are adopting the current limits in subpart J (which include separate emission limits for oxidative and reductive systems) for affected SRP with a capacity greater than 20 LTD. For these affected SRP, the final limits for SRP having an oxidation control system or a reduction control system followed by incineration is 250 ppmv (dry basis) of SO₂ at 0% excess air. For an affected SRP with a reduction control system not followed by incineration, the final limit is 300 ppmv of reduced sulfur compounds and 10 ppmv of hydrogen sulfide (H₂S), each calculated as ppm SO₂ by volume (dry basis) at 0% excess air. If the SRP consists of multiple process trains or release points, the limits apply to each process train or release points. A new alternative allows refineries to use a correlation to calculate their effective emission limit for Claus SRP that use oxygen enrichment in the Claus burner. For an affected SRP with a capacity of 20 LTD or less, the sulfur recovery efficiency standard is based on a sulfur recovery efficiency of 99%. However, due to the difficulties associated with on-going monitoring of SRP recovery efficiency, in this final rule, we are promulgating concentration limits that correlate with a sulfur recovery efficiency of 99%. For a Claus unit with an oxidative control system or any small SRP followed by an incinerator the emission limit is 2,500 ppmv (dry basis) of SO₂ at 0% excess air. For all other small SRP, the emission limit is 3,000 ppmv reduced sulfur compound and 100 ppmv H₂S, each calculated as ppm SO₂ by volume (dry basis) at 0% excess air. A similar correlation is provided for small Claus SRP that use oxygen enrichment, similar to that provided for large SRP. The standards for small SRP apply to all release points from the SRP combined (note that secondary sulfur storage units are not considered part of the SRP). We are not promulgating the H₂S limit of 10 ppmv (dry basis, at 0% excess air determined on a 12-hour rolling average basis) or related operating limits that were included in §60.102a(e) and (f) of the proposed rule.

Initial compliance with the emission limit for large SRP (capacity greater than 20 LTD) is demonstrated by conducting a performance evaluation for the SO₂ CEMS in accordance with either Performance Specification 2 (40 CFR part 60, appendix B) for SRP with oxidation control systems or reduction control systems followed by incineration or Performance Specification 5 (40 CFR part 60, appendix B) for SRP with reduction control systems not followed by incineration.

Ongoing compliance with the SO₂ limits for large SRP is determined using an SO₂ CEMS (for oxidative or reductive systems followed by incineration) or a CEMS that uses an air or O₂ dilution and oxidation system to convert the reduced sulfur to SO₂ and then measures the total resultant SO₂ concentration (for reductive systems not followed by incineration). An O₂

monitor is also required for converting the measured combined SO₂ concentration to the concentration at 0% O₂.

Initial and ongoing compliance requirements for small SRPs are the same as for large SRPs.

4.2.4 Final Requirements for New Fuel Gas Combustion Devices

In the subpart Ja proposal, we divided fuel gas combustion units into two separate affected sources: “process heaters” and “other fuel gas combustion devices.” In response to comments, we have eliminated the proposed definition of “other fuel gas combustion devices” and revised the standards to either refer to fuel gas combustion devices, which include process heaters, or to refer specifically to process heaters. This revision makes the definition of “fuel gas combustion devices” consistent with subpart J. We have also added a definition of “flare.”

We proposed a primary sulfur oxides emission limit for fuel gas combustion devices of 20 ppmv or less SO₂ (dry at 0% excess air) on a 3-hour rolling average basis and 8 ppmv or less on a 365-day rolling average basis. We also proposed an alternative limit of 160 ppmv H₂S or, in the case of coker-derived fuel gas, for total reduced sulfur (TRS) on a 3-hour rolling average basis and 60 ppmv or less on a 365-day rolling average basis. We are promulgating the 20 ppmv and 8 ppmv limits for SO₂ as proposed. We are also promulgating the alternative limit, except that the limits are expressed and measured as H₂S in all cases. The alternative H₂S limit is 162 ppmv or less in the fuel gas on a 3-hour rolling average basis and 60 ppmv or less in the fuel gas on a 365-day rolling average basis. The final rule does not include an alternative TRS limit for SO₂.

Initial compliance with the 20 ppmv SO₂ limit or the 162 ppmv H₂S concentration limits is demonstrated by conducting a performance evaluation for the CEMS. The performance evaluation for an SO₂ CEMS is conducted in accordance with Performance Specification 2 in 40 CFR part 60, appendix B. The performance evaluation for an H₂S CEMS is conducted in accordance with Performance Specification 7 in 40 CFR part 60, appendix B. Ongoing compliance with the sulfur oxides emission limits is determined using the applicable CEMS to measure either SO₂ in the exhaust gas to the atmosphere or H₂S in the fuel gas, averaged over the 3-hour and 365-day averaging periods.

Similar to clarifications for 40 CFR part 60, subpart J, the definition of “fuel gas” includes exemptions for vapors collected and combusted in an air pollution control device installed to comply with specified wastewater or marine vessel loading provisions. We are also

streamlining the process for an owner or operator to demonstrate that a fuel gas stream not explicitly exempted from continuous monitoring is inherently low sulfur.

For new, modified, or reconstructed process heaters with a rated capacity greater than 20 million British thermal units per hour (MMBtu/hr), we proposed a NO_x limit of 80 ppmv (dry basis, corrected to 0% excess air) on a 24-hour rolling average basis. The final NO_x emission limit for affected process heaters is 40 ppmv on a 24-hour rolling average basis (dry at 0% excess air) for process heaters greater than 40 MMBtu/hr. For process heaters greater than 100 MMBtu/hr capacity, initial compliance with the 40 ppmv emission limit is demonstrated by conducting a performance evaluation of the CEMS in accordance with Performance Specification 2 in 40 CFR part 60, appendix B. For process heaters between 40 MMBtu/hr and 100 MMBtu/hr capacity, initial compliance is demonstrated using EPA Method 7. For process heaters greater than 100 MMBtu/hr capacity, ongoing compliance with this emission limit is determined using the CEMS to measure NO_x emissions as discharged to the atmosphere, averaged over 24-hour periods. For process heaters between 40 MMBtu/hr and 100 MMBtu/hr capacity, ongoing compliance with this emission limit is determined using biennial performance tests.

4.2.5 *Final Work Practice Standards*

We proposed three work practice standards to reduce SO₂, VOC, and NO_x emissions from flares and from startup, shutdown, and malfunction events and to reduce VOC and SO₂ emissions from delayed coking units. We also co-proposed to require only one of these work practice standards: the requirement to depressure delayed coking units. This proposed standard required new delayed coking units to depressure to 5 pounds per square inch gauge (psig) during reactor vessel depressuring and vent the exhaust gases to the fuel gas system.

We are promulgating a work practice standard for delayed coking units and modified requirements to reduce emissions from flares. The final work practice standard for delayed cokers requires affected delayed coking units to depressure to 5 pounds per square inch gauge (psig) during reactor vessel depressuring. We are requiring the exhaust gases to be vented to the fuel gas system as proposed or to a flare.

To reduce SO₂ emissions from the combustion of sour fuel gases, the final rule requires refineries to conduct a root cause analysis of any emissions limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge into the atmosphere, either directly or indirectly, from any fuel gas combustion unit subject to the provisions of subpart Ja that exceeds

500 pounds per day (lb/day) of SO₂. Recordkeeping and reporting requirements apply in the event of such a discharge.

We are not promulgating the proposed definition of “fuel gas producing unit” and the proposed requirement for “no routine flaring.” Instead, we are promulgating the following requirements: (1) flare fuel gas flow rate monitoring; (2) a flare fuel gas flow rate limit; and (3) a flare management plan. Affected flares cannot exceed 250,000 standard cubic feet per day (scfd) on a 30-day rolling average basis. In cases where the flow exceeds this value, this would require installation of a flare gas recovery system or other methods to reduce flaring from the affected flare. A provision is provided for an exclusion from the flow limitation for times when the refinery can demonstrate that the refinery produces more fuel gas than it needs to fuel the refinery combustion devices (i.e., it is fuel gas rich) or that the flow is due to an upset or malfunction, provided the refinery follows procedures outlined in the flare management plan. The flare management plan should address potential causes of fuel gas imbalances (i.e., excess fuel gas) and records to be maintained to document these periods. To demonstrate compliance with the flow limitations, flow rate monitors must be installed and operated. As described in 40 CFR 60.103a(a), the flare management plan must include a diagram illustrating all connections to each affected flare, identification of the flow rate monitoring device and a detailed description of the manufacturer’s specifications regarding quality assurance procedures, procedures to maintain to minimize flaring during planned start-up and shut down events, and procedures for implementing root cause analysis when daily flow to the flare exceeds 500,000 scfd. The root cause analysis procedures should address the evaluation of potential causes of upsets or malfunctions and records to be maintained to document the cause of the upset or malfunction. Excess emission events for the flow rate limit of 250,000 scfd and the result of root cause analysis must be reported in the semi-annual compliance reports.

Because affected flares are also affected fuel gas combustion devices, the root cause analysis for SO₂ emissions exceeding 500 lbs/day also applies to flares. However, compliance with the 500 lb/day root cause analysis will also require continuous monitoring of total reduced sulfur of all gases flared. Although all fuel gas combustion devices are required to comply with continuous H₂S monitoring of fuel gas, flares routinely accept gases from upsets, malfunctions and startup and shutdown events, and H₂S or sulfur monitoring is not specifically required for these gases. In subpart Ja, we explicitly require TRS monitoring to ensure that the 500 lb/day SO₂ trigger is accurately measured. We also note that for affected flares, the RCA trigger is 500 lbs/day, not 500 lbs/day in excess of an emissions limit.

4.2.6 Modification and Reconstruction Provisions

Existing affected facilities that commence modification or reconstruction after May 14, 2007, are subject to the final standards in 40 CFR part 60, subpart Ja. A modification is any physical or operational change to an existing affected facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies (see 40 CFR 60.14). Changes to an existing affected facility that do not result in an increase in the emission rate, as well as certain changes that have been exempted under the General Provisions (see 40 CFR 60.14(e)), are not considered modifications.

In response to comments regarding the work practice standards for flares and fuel gas producing units, we re-evaluated the work practice standards and have decided to define a flare as the affected source rather than a fuel gas producing unit. The intermittent operation of a flare makes it difficult to use the criteria of 40 CFR 60.14 to determine when a flare is modified; therefore, we have specified in the final rule the criteria that define a modification to a flare. A flare is considered to be modified if: (1) any piping from a refinery process unit or fuel gas system is newly connected to the flare or (2) the flare is physically modified to increase flow capacity .

Special provisions are included for NO_x emissions from certain existing process heaters that were modified or reconstructed between proposal and promulgation of this final rule in order to avoid the retroactive application of the more stringent NO_x emissions limit in the final rule. Existing process heaters with a rated capacity of greater than 40 MMBtu/hr for which modification or reconstruction commenced after May 14, 2007, and on or before the date of publication of this final rule in the *Federal Register* are subject to the same NO_x emission limit as proposed (80 ppmv, dry basis corrected to 0% excess air on a 24-hour rolling average basis).

Petroleum refinery process units are subject to the final standards in 40 CFR part 60, subpart Ja if they meet the criteria under the reconstruction provisions, regardless of changes in emission rate. Reconstruction means the replacement of components of an existing facility such that (1) the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility; and (2) it is technologically and economically feasible to meet the applicable standards (40 CFR 60.15).

4.3 Model Facility, Source Projections, and Cost Assumptions

EPA developed control options for this final to limit emissions of particulate matter, sulfur dioxide, nitrous oxides and volatile organic compounds from new and modified processes at petroleum refineries, including FCCUs, SRUs, cokers, and process heaters. EPA has estimated

the costs of complying with the final NSPS under each of the options, using a model facility approach. During the 5-year period of analysis (or the analysis of impacts in the fifth year after proposal), EPA assumes the industry will invest in enough new processes to be equivalent to an average of three new refineries per year, or a total of 15 new refineries. Further, the new sources are assumed to be 40% new processes or facilities and 60% modified or reconstructed facilities or processes.

Table 4-1 illustrates the assumptions used to characterize the model facilities and processes upon which the costs of complying with the rule are based. More details follow on these assumptions.

To project the number of new, reconstructed, and modified process units over the next 5 years, we used many of the same assumptions as in the analysis for subpart GGG, including the average number of process units at a refinery (Parrish, Randall, and Coburn, 2006). That analysis assumes that there are 0.8 FCCUs and 0.4 coking units per refinery and that 15 refineries' worth of process units become subject (i.e., are either new, reconstructed, or modified) over the 5 years following proposal. We also assumed that 40% of the FCCUs are new and 60% are reconstructed or modified.

4.3.1 FCCUs

We identified four scenarios to characterize FCCUs, one for new process units and three for reconstructed and modified process units. In this analysis, currently refers to the situation prior to new NSPS requirements and baseline refers to the requirements if no new standards are implemented (in most cases, baseline is compliance with subpart J).

1. New (baseline = comply with subpart J)
2. Currently subject to subpart J (baseline = continue to comply with subpart J)
3. Currently subject to consent decree (baseline = continue to comply with consent decree requirements, assuming these are equal to or more stringent than subpart J)
4. Currently subject to MACT (baseline = comply with subpart J)

We assumed that the currently existing process units that are reconstructed or modified are broken down into Scenarios 2, 3, and 4 as follows:

- 10% are subject to MACT and not subpart J (Scenario #4).

Table 4-1. Model Facility Descriptions

Model Facility Description	Items Included in the Costs	Number Facilities
New facility/major new expansion	<ul style="list-style-type: none"> ▪ FCCU PM, SO₂, and NO_x controls ▪ 11 new process heaters with NO_x controls ▪ New fuel gas combustion device ▪ Implement work practice standards^a 	2
New FCCU	<ul style="list-style-type: none"> ▪ FCCU PM, SO₂, and NO_x controls ▪ 2 new process heaters with NO_x controls ▪ Modified/reconstructed fuel gas combustion device ▪ Implement work practice standards^b 	1
New processes	<ul style="list-style-type: none"> ▪ 2 process heaters with NO_x controls ▪ Modified/reconstructed fuel gas combustion device ▪ Implement work practice standards^b 	6
Small business with new processes	<ul style="list-style-type: none"> ▪ SRU tail gas treatment ▪ 3 process heaters with retrofit NO_x controls ▪ Modified/reconstructed fuel gas combustion device ▪ Implement work practice standards^b 	1
Multi-process and FCCU revamp	<ul style="list-style-type: none"> ▪ FCCU PM, SO₂, and NO_x retrofit controls ▪ 9 new process heaters with NO_x controls ▪ Modified/reconstructed fuel gas combustion device ▪ Implement work practice standards^a 	3
Multi-process and FCCU revamp (no delayed coker unit [DCU])	<ul style="list-style-type: none"> ▪ FCCU PM, SO₂, and NO_x controls ▪ 9 new process heaters with NO_x controls ▪ Modified/reconstructed fuel gas combustion device ▪ Implement work practice standards^b 	2
FCCU revamp	<ul style="list-style-type: none"> ▪ FCCU PM, SO₂, and NO_x controls ▪ 2 process heaters with retrofit NO_x controls ▪ Modified/reconstructed fuel gas combustion device ▪ Implement work practice standards^b 	4
Fluid coking unit revamp	<ul style="list-style-type: none"> ▪ FCCU PM, SO₂, and NO_x controls ▪ 7 new process heaters with NO_x controls ▪ Modified/reconstructed fuel gas combustion device ▪ Implement work practice standards^b 	1
Modified processes	<ul style="list-style-type: none"> ▪ 3 process heaters with retrofit NO_x controls ▪ Modified/reconstructed fuel gas combustion device ▪ Implement work practice standards^b 	8
Small business with modified processes	<ul style="list-style-type: none"> ▪ SRU tail gas treatment ▪ 3 process heaters with retrofit NO_x controls ▪ Modified/reconstructed fuel gas combustion device ▪ Implement work practice standards^b 	1

^a Work practice standards include: fuel gas recovery for fuel gas producing units; flare minimization plan for planned start-up and shutdown; sulfur shedding plan; root-cause analysis; and delayed coking depressurization gas recovery.

^b All of the work practices above except delayed coking depressurization gas recovery.

- 76.5% are units subject to a consent decree (Scenario #3). For purposes of this analysis, average consent decree requirements are assumed to be 1.0 kg PM/Mg coke burn (using Method 5B or 5F), 50 ppmv SO₂ over a 7-day average, and 25 ppmv SO₂ over a 365-day average.
- The remaining 13.5% are subject to subpart J (Scenario #2).

The assumptions outlined above translate into the following values:

- 12 total new, reconstructed, or modified FCCUs (multiply estimate of 0.8 FCCU per refinery by 15 refineries' worth of process units)
- 4.8 FCCUs are new
- 7.2 FCCUs are reconstructed or modified
 - 1 is currently subject to subpart J
 - 5.5 are currently subject to consent decree
 - 0.7 are currently subject to MACT only

4.3.2 Fluid Coking Units (FCU)

We assumed that there will be six new, reconstructed, or modified coking units over the next 5 years. Based on industry trends, we anticipate that five of these will be delayed coking units and only one will be a fluid coking unit.¹ We assumed that the single fluid coking unit will become subject through modification or reconstruction rather than new construction. At baseline, this fluid coking unit would comply with subpart J, which includes no requirements for coking units.

We assumed that 30 refineries will construct, reconstruct, or modify a fuel gas combustion device over the next 5 years. This estimate is based in part on the assumed average numbers of process units at a refinery from the analysis for subpart GGG (Parrish, Randall, and Coburn, 2006). Industry representatives have indicated that most fuel gas systems are centralized. Therefore, the entire system that includes the new, reconstructed, or modified combustion device will essentially have to meet subpart Ja standards in order for the new or reconstructed fuel gas combustion device to comply with subpart Ja.

4.4 Emissions Estimation by Unit Type

For both FCCUs and fluid coking units, PM and SO₂ controls were evaluated together because a wet scrubber installed to reduce PM will also achieve SO₂ reductions. The other control device considered for FCCUs was an electrostatic precipitator (ESP) for PM reduction and catalyst additives for SO₂ emission reduction. This option is not technically feasible for a

¹ 10–26 meeting minutes.

fluid coking unit; therefore, the analysis for the one affected fluid coking unit assumed a wet scrubber as the control device.

4.4.1 FCCUs

We assumed a model FCCU size of 50,000 barrels (bbl) per day. This model FCCU also has a volumetric flow rate of 140,000 dry standard cubic feet per minute (dscfm) and a coke burn-off rate of 800,000 pounds (lb) per day. It operates at 95% of capacity.

In order to determine emission reductions beyond subpart J for each option, we first estimated emissions attributed to meeting subpart J. Based on industry trends and control device capabilities, we assumed that 35% of the FCCUs would meet subpart J with a wet scrubber and 65% would meet subpart J using an ESP and catalyst additives. We assumed the basic model wet scrubber could meet the subpart J PM limit with an 80% control efficiency and would average about 25 ppmv SO₂. The model ESP also had a control efficiency of 80% for PM. For SO₂, we calculated that the 9.8 kg/Mg coke burn is equivalent to about 265 ppmv.

We estimated emissions of PM as the total of filterable PM that is less than 10 micrometers (µm) in diameter (PM₁₀), filterable PM that is less than 2.5 (µm) in diameter (PM_{2.5}), and condensable PM. At baseline, an FCCU meeting subpart J with a wet scrubber would emit 236 tons PM per year and an ESP would emit 305 tons PM per year. (A wet scrubber has a lower operating temperature than an ESP, which provides improved removal of condensable PM and results in lower PM emissions.) Based on the assumptions described above, we estimated baseline PM emissions for the 12 FCCUs at 3,370 tons per year (1,350 tons per year from new FCCUs and 2,020 tons per year from reconstructed and modified FCCUs). For this model FCCU, we estimated emissions of SO₂ as 1,540 tons per year for catalyst additives meeting 265 ppmv and 145 tons per year for wet scrubbers and catalyst additives meeting 25 ppmv. Based on the assumptions described above, we estimated baseline SO₂ emissions for the 12 FCCUs at 9,600 tons per year (5,050 tons per year from new FCCUs and 4,560 tons per year from reconstructed and modified FCCUs).

To determine the emissions for each option, we assumed that the ratio of ESPs to wet scrubbers chosen for new FCCUs would change depending on the particular emission limits being considered. For example, as the SO₂ limit tightens, a wet scrubber becomes more cost-effective compared to the catalyst additives. On the other hand, we have no data to support an assumption that wet scrubbers could achieve the Option 5 PM limit of 0.15 kg/Mg coke burn, so we assumed that for Option 5, all FCCUs would be controlled with an ESP and catalyst additives. In addition to these considerations, we considered for reconstructed and modified

FCCUs with an existing control device whether cost-effectiveness or technical limitations for each option would drive an operator to change the control device. For example, for Option 5, all wet scrubbers would be removed in favor of ESPs that can meet the lower PM limit.

For each of the five options, we again estimated PM emissions as a total of filterable PM₁₀ and PM_{2.5} and condensable PM. The total values vary for each option and for the specific control device chosen. In addition to the SO₂ emissions described for baseline, we estimated emissions of 290 tons per year for catalyst additives meeting 50 ppmv. We also assumed that wet scrubbers designed to meet 0.5 kg PM/Mg coke burn would achieve 12.5 ppmv SO₂, which we calculated to be equivalent to 73 tons per year.

4.4.2 FCUs

We assumed a model fluid coking unit size of 40,000 bbl/day. This model coking unit also has a volumetric flow rate of 200,000 dscfm. At baseline, there are no requirements for fluid coking units, so there are no emission reductions for either PM or SO₂. For Option 1, we assumed that a basic wet scrubber would be chosen. We estimated emission reductions of 1,710 tons PM per year (based on 84% efficiency) and 20,600 tons SO₂ per year (based on estimates of 94% efficiency and uncontrolled SO₂ emissions of 3.0 lb/bbl).² For Option 2, we assumed that an enhanced wet scrubber would be chosen to meet the emission limits. We estimated emission reductions of 1,970 tons PM per year (based on 97% efficiency) and 21,200 tons SO₂ per year (also based on an estimate of 97% efficiency).

We assumed that an average amine treatment system for fuel gas combustion devices would have an average gas flow rate of 10,000 standard cubic feet per minute (scfm). We developed this model system based on information from various sources (Polasek, Bullin, and Donnelly, 1982; Fedich, Woerner, and Chitnis, 2004; Voltz, Corley, and Fedich, 2004). Based on this flow rate and an emission limit of 20 ppmv, one system would emit 0.27 pounds (lbs) of SO₂ per minute (min), or 70 tons per year (tons/yr). Nationwide (i.e., for 30 systems), the total emissions are 2,100 tons per year. The emissions from one system, nationwide emissions, and the reduction from the baseline for each of the three options are shown in Table 4-2.

² Valero submittal (test report specifically).

Table 4-2. Emissions for Fuel Gas Combustion Devices

Option	Emissions from One System		Nationwide Emissions (tons SO ₂ /yr)	Reduction from Baseline (tons SO ₂ /yr)
	(lb SO ₂ /min)	(tons SO ₂ /yr)		
1	0.13	35	1,050	1,050
2	0.10	26	786	1,310
3	0.07	17	524	1,570

4.5 Control Technologies in Analysis

The following NO_x control techniques were included in the cost analysis for the control options:

- **Flue Gas Recirculation.** Flue gas recirculation (FGR) uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the heater or stack and returned to the burner via a duct and blower. The addition of flue gas with the combustion air reduces the oxygen content of the inlet air stream to the burner. The lower oxygen level in the combustion zone reduces flame temperatures, which in turn reduces NO_x emissions. The normal NO_x control efficiency range for FGR is 30% to 50%. When coupled with low-NO_x burners (LNB) the control efficiency increases to 50%–72%.
- **Low-NO_x Burners.** Low-NO_x burner (LNB) technology utilizes advanced burner design to reduce NO_x formation through the restriction of oxygen, flame temperature, and/or residence time. The two general types of low NO_x burners are staged fuel and staged air burners. Staged fuel LNBs are particularly well-suited for boilers and process heaters burning process and natural gas, which generate higher thermal NO_x. The estimated NO_x control efficiency for LNBs where applied to petroleum refining fuel burning equipment is generally around 40%.
- **Ultra-low NO_x Burners.** Ultra-low NO_x burners (ULNBs) may incorporate a variety of techniques including induced flue gas recirculation (IFGR), steam injection, or a combination of techniques. These burners combine the benefits of flue gas recirculation and low-NO_x burner control technologies. Rather than a system of fans and blowers (like FGR), the burner is designed to recirculate hot, oxygen-depleted flue gas from the flame or firebox back into the combustion zone. This leads to a reduction in the average oxygen concentration in the flame without reducing the flame temperature below temperatures necessary for optimal combustion efficiency. The estimated NO_x control efficiency for ULNBs in high temperature applications is 50%. Newer designs have yielded efficiencies of between 75% and 85%. When coupled with selective catalytic reduction, efficiencies in the range of 85% to 97% can be obtained.
- **Controlling Excess Oxygen in Complete Combustion FCCU Catalyst Regenerators.** Most of the previous control options are specific to process heaters and carbon monoxide (CO) boilers. However, controlling the oxygen concentration in

the FCCU regenerator exhaust at approximately 0.5% has been seen to reduce NO_x concentrations by 20% to 40% as compared to NO_x concentrations when the regenerator exhaust oxygen concentration is between 1% and 2%. As such, complete combustion FCCU regenerators with active excess oxygen controls are expected to have similar performance as partial combustion FCCUs followed by CO boilers that use low-NO_x burners or flue gas recirculation.

- **Selective Non-Catalytic Reduction.** In the selective non-catalytic reduction (SNCR) process, urea or ammonia-based chemicals are injected into the flue gas stream to convert nitric oxide (NO) to nitrogen gas (N₂) and water. Without the participation of a catalyst, the reaction requires a high temperature range to obtain activation energy. The optimum operating temperature for SNCR is 1,600°F to 2,100°F. At temperatures above 2,000°F, NO_x control efficiency decreases rapidly. The normal NO_x control efficiency range for SNCR is 50% to 70%. SNCR systems are usually lower in capital cost than SCR systems for the same application. One advantage of this technology is the fact that no liquid or solid waste is generated. SNCR technology has been applied to CO boilers, process heaters and boilers in the petroleum refining sector where control efficiencies are consistent with the range mentioned above.
- **LoTOx™ Technology.** The LoTOx™ process (i.e., low-temperature oxidation) is a patented technology that uses ozone to oxidize NO_x to nitric pentoxide and other higher order nitrogen oxides, all of which are water soluble and easily removed from exhaust gas in a wet scrubber. The system operates optimally at temperatures below 300°F. Thus, ozone is injected after scrubber inlet quench nozzles and before the first level of scrubbing nozzles. Outlet NO_x emission levels have been reduced to less than 20 parts per million by volume (ppmv), and often as low as 10 ppmv, when inlet NO_x concentrations ranged from 50 to 200 ppmv (an 80% to 90% reduction efficiency).
- **Selective Catalytic Reduction.** Selective catalytic reduction (SCR) is a post-combustion NO_x control technology in which ammonia (NH₃) is injected into the post-combustion gas stream in the presence of a catalyst. A catalyst bed containing metals in the platinum family is used to lower the activation energy required for NO_x decomposition. The reaction of NH₃ and NO_x is favored by the presence of excess oxygen. The NH₃ oxidation to NO_x increases with increasing temperature. The normal NO_x control efficiency range for SCR is 70% to 90%. There are at least three SCRs currently in-use at refineries to control FCCU NO_x emissions.
- **Combination System.** Combination systems have used combustion controls followed by SCR or SNCR technology in order to reduce costs of NO_x removal from a flue gas. For example, LNB has been combined with SNCR technology to minimize the capital and operating cost for NO_x removal as well as improve the control efficiency.
- **Catalyst Additives.** An additional NO_x emission control option specific for the FCCU is the use of catalyst additive, such as X-NO_x and DENOX (from Grace-Davison; Bruhin et al., 2003). Non-platinum combustion promoter additives appear to achieve a 30% to 50% emission reduction. Additional catalyst additives have had limited success at further reducing the NO_x emissions from the FCCU, and the results of these other additives have been quite varied.

Not all of these control technologies are applicable to all units. For example, use of catalyst additives is applicable only to FCCUs, while the use of low-NO_x burners are not applicable to complete combustion FCCU catalyst regenerators. For each source type, costs for four control scenarios were developed in 2005 dollars; the control scenarios ranged between 35% and 95% NO_x emission reduction efficiencies. As the baseline emissions of different FCCUs can span a fairly significant range of outlet NO_x concentrations, representative baseline concentrations were assigned a weighting factor to simulate the distribution of baseline NO_x emissions. For each representative baseline NO_x concentration, the control scenario needed to achieve a given emission limit was assigned to the fraction of FCCUs represented by that concentration. The overall costs for a given scenario were then calculated based on the weighting attributed to that uncontrolled NO_x concentration range. Although this basic approach was used for each NO_x emission source type, the specific costing methodologies for each of the three types of sources are presented in separate sections to clearly identify the differences in the costs developed for the different sources.

For SO₂ and VOC, and PM control technologies, please refer to the technical memoranda in the public docket for this rulemaking.

4.6 Cost Analysis for Control Options

EPA examined control options for individual refinery processes as well as work practice options affecting the refinery as a whole. This section describes these control options and the estimated costs of implementing them.

The costs presented in this section are calculated based on the control cost methodology presented in the EPA (2002) Air Pollution Control Cost Manual prepared by the U.S. Environmental Protection Agency.³ This methodology sets out a procedure by which capital and annualized costs are defined and estimated, and this procedure is often used to estimate the costs of rulemakings such as this one. The capital costs presented in this section are annualized using a 7% interest rate, a rate that is consistent with the guidance provided in the Office of Management and Budget's (OMB's) (2003) Circular A-4.⁴ Equipment lives for the control technologies employed in this analysis can vary greatly (usually from 10 to 25 years).

³ Available on the Internet at <http://epa.gov/ttn/catc/products.html#cccinfo>.

⁴ Available on the Internet at <http://www.whitehouse.gov/omb/circulars/a004/a-4.pdf>.

Four sources of information were considered in reviewing the appropriateness of the current NSPS requirements for new sources: (1) source test data from recently installed control systems; (2) applicable State and local regulations; (3) control vendor emission control guarantees; and (4) consent decrees. (A significant number of refineries, representing over 80% of the national refining capacity, are subject to consent decrees that limit the emissions from subpart J process units.) In addition, we received a total of 46 comments during the public comment periods associated with the proposed rule and NODA. These comments were received from refineries, industry trade associations, and consultants; state and local environmental and public health agencies; environmental groups; and members of the public. In response to these public comments, most of the cost and emission reduction impact estimates were recalculated, resulting in several changes to the final amendments and new standards. A summary of the remainder of the comments received during the comment period and responses thereto can be found in the docket for the final amendments and new standards (Docket ID No. EPA–OAR–HQ–2007–0011). The docket also contains further details on all the analyses summarized in the responses below.

Once we identified potential emission limits for various process units, we evaluated each limit in conjunction with control technology, costs, and emission reductions to determine the Best Demonstrated Technology (BDT) for each process unit. In responding to the public comments, we re-evaluated the costs and cost-effectiveness of the control options and re-evaluated our BDT determinations. In our BDT determinations, we took all relevant factors into account, including cost considerations, which are generally consistent with other Agency decisions. It is important to note that, due to the different health effects associated with different pollutants, the acceptable cost-effectiveness of a control option is pollutant dependent. These pollutant-specific factors were considered in our BDT determinations.

The cost methodology incorporates the calculation of annualized costs and emission reductions associated with each of the options presented. Cost-effectiveness is the annualized cost of control divided by the annual emission reductions achieved. Incremental cost-effectiveness refers to the difference in annualized cost from one option to the next divided by the difference in emission reductions from one option to the next. For NSPS regulations, as mentioned earlier in this chapter, the standard metric for expressing costs and emission reductions is the impact on all affected facilities in the fifth year after proposal. Details of the calculations can be found in the public docket.

4.7 Summary of Cost, Environmental, Energy, and Economic Impacts

We are presenting estimates of the impacts for the final requirements of subpart Ja that change the performance standards: the emission limits for fluid catalytic cracking units, sulfur recovery plants, fluid coking units, fuel gas combustion devices, and process heaters, as well as the work practice standards for flares and delayed coking units. The cost, environmental, and economic impacts presented in this section are expressed as incremental differences between the impacts of petroleum refining process units complying with the final subpart Ja and the current NSPS requirements of subpart J (i.e., baseline). The impacts are presented for petroleum refining process units that commence construction, reconstruction, or modification over the next 5 years.

In order to determine the incremental costs and emission reductions of this final rule, we first estimated baseline impacts. For new sources, baseline costs and emission reductions were estimated for complying with subpart J; incremental impacts for subpart Ja were estimated as the costs to comply with subpart J subtracted from the costs to comply with final subpart Ja. Sources that are modified or reconstructed over the next 5 years must comply with subpart J in the absence of final subpart Ja. We assumed that prior to reconstruction or modification, these sources will either be subject to a consent decree (equivalent to more than 80% of the industry by capacity), complying with subpart J or equivalent limits, and/or complying with 40 CFR part 63, subpart UUU (MACT II). Baseline costs and emission reductions were estimated as the effort needed to comply with subpart J from one of those three starting points. The costs and emission reductions to comply with final subpart Ja were estimated from those starting points as well. When considering and selecting emission limits for the final rule, we evaluated the cost-effectiveness of each option for new sources separately from reconstructed and modified sources. In most cases, our selections for each process unit and pollutant were consistent for modified and reconstructed units and new units. In this section, we are presenting our costs and emission reductions for the overall rule. We estimate that the final amendments for new and modified and reconstructed sources together will reduce emissions of PM by 1,300 tons/yr, SO₂ by 17,000 tons/yr, NO_x by 11,000 tons/yr, and VOC by 1,400 tons/yr from the baseline. The estimated increase in annual cost, including annualized capital costs, is \$31,000,000 (2006 dollars). The estimated nationwide 5-year incremental emissions reductions and cost impacts for the final standards are summarized in Table 4-3. A summary of the impacts by all options considered in the course of preparing the final NSPS, for new and for modified and reconstructed sources, is available in Appendix B.

4.7.1 Secondary Impacts

Indirect or secondary air quality impacts of this final rule will result from the increased electricity usage associated with the operation of control devices. Assuming that plants will purchase electricity from a power plant, we estimate that the final standards will increase secondary emissions of criteria pollutants, including PM, SO₂, NO_x, and CO from power plants. For new, modified or reconstructed sources, this final rule will increase secondary PM emissions by 56 Megagrams per year (Mg/yr) (62 tons/yr); secondary SO₂ emissions by about 1,400 Mg/yr

Table 4-3. National Incremental Emission Reductions and Cost Impacts for Petroleum Refinery Units Subject to Final Standards Under 40 CFR Part 60, Subpart Ja (Fifth Year After Proposal)^a

Process Unit	Total Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Annual Emission Reductions (tons PM/yr)	Annual Emission Reductions (tons SO ₂ /yr)	Annual Emission Reductions (tons NO _x /yr)	Annual Emission Reductions (tons VOC/yr)	Cost-Effectiveness (\$/ton)
FCCU	8,500	6,400	240	4,300	2,600		890
FCU	14,000	4,000	1,000	5,900	660		530
SRP	1,700	730		420			1,700
Fuel gas combustion devices	34,000	12,000		5,200			2,300
Process heaters	23,000	12,000			7,500		1,600
Flaring	40,000	-6,600		80	5	206	-23,000
Delayed coking units	17,000	1,600		440		25	3,400
Sulfur pits	8,300	1,000		300			3,400
Total	150,000	30,700	1,300	17,000	11,000	1,400	1,070

^a All costs are in 2006 dollars.

(1,500 tons/yr); secondary NO_x emissions by about 530 Mg/yr (580 tons/yr).

As explained earlier, we expect that affected facilities will control emissions from fluid catalytic cracking units by installing and operating ESP or wet gas scrubbers. We also expect that the emissions from the affected FCU will be controlled with a wet scrubber. For these process units, we estimated solid waste impacts for both types of control devices and water impacts for wet gas scrubbers. In addition, the controls needed by small sulfur recovery plants will generate condensate. We project that this final rule will generate 1.6 billion gallons of water per year for the 5 years following proposal. We also estimate that this final rule will generate 2,200 Mg/yr (2,400 tons/yr) of solid waste over those 5 years.

Energy impacts as defined in this preamble section consist of the electricity and steam needed to operate control devices and other equipment that would be required under the final rule. Our estimate of the increased energy demand includes the electricity needed to produce the required amounts of steam as well as direct electricity demand. We project that this final rule will increase overall energy demand by about 410 gigawatt-hours per year (1,400 billion British thermal units per year). An analysis of energy impacts that accounts for reactions in affected markets to the costs of this final rule can be found in the section on Executive Order 13211 found later in this RIA.

4.8 Limitations and Uncertainties Associated with the Cost Analyses

Limitations and uncertainties associated with the cost analyses presented above are presented here.

1. Assumptions behind the cost savings estimated for this NSPS. These annualized cost savings are driven by the recovery of natural gas associated with the minimization of flaring. The calculation presumes that all refiners owning new and modified or reconstructed that must comply with the NSPS will be able to accomplish this, particularly since they are estimated to receive a return on their investment. However, opportunity costs may exist to make such an investment more financially difficult than we may expect. Smaller refiners may have less capital available to them than larger refiners, and may find the investment in necessary capital and development of a flare gas minimization plan more challenging than larger refiners. In addition, there may be varying abilities among refiners to develop such minimization plans with their current labor force due to tightness in labor markets, though such difficulties could be remedied beyond the short run. Finally, many refiners have a minimum rate of return that must be met before an investment to expand capacity, or for other reasons, is carried out. For example, the Ad Hoc Coalition of Small Business Refineries asserted in a comment on the proposed petroleum refineries NSPS that an acceptable rate of return of well above 10% served as a minimum for investment purposes at their refineries.⁵ It also should be noted, however, that the natural gas price that underlies the estimate of cost savings is \$7/Mcf (1,000 cubic feet), which is the average natural gas price in 2006, the base year for the cost analysis. Current spot prices for natural gas exceed \$10/Mcf, and there is potential for further increases in such natural gas prices to as high as \$20/Mcf in the future by some estimates.⁶ An increase in natural gas price may lead to additional incentive for refiners to engage in flare gas minimization.
2. Effect of consent decrees on overall impact estimates. As mentioned in the preamble for this final NSPS, the estimates of impacts in this RIA are based on a baseline that

⁵ Comments by Ad Hoc Coalition of Small Business Refiners to U.S. EPA, August 27, 2007. Comments on Proposed subpart Ja Rule: Standards for New, Modified, and Reconstructed Process Units at Petroleum Refineries. 72 FR 27178. p. 6.

⁶ Wall Street Journal, April 18, 2008. "Surge in Natural Gas Price Stoked by New Global Trade."

includes consent decrees reached by the U.S. Department of Justice (DOJ) as part of the Refinery Enforcement Initiative with refiners representing 77% of U.S. refinery capacity. Consent decrees continue to take place, however. For example, Holly Oil and Refining Co. in Woods Cross, UT, just entered into a consent decree this month with the U.S. DOJ to reduce emissions of SO₂, NO_x, and VOC from their refinery. With this act, refiners representing 87% of U.S. refinery capacity are now under a consent decree.⁷ As more refiners are covered by consent decrees, the impacts associated with this NSPS will be less.

3. New source bias. An NSPS is an example of what is known as a “vintage differentiated regulation (VDR),” which is a term often used to describe regulations that are fixed with respect to the date of entry of regulated units, with later vintages facing more stringent standards. Often, units produced before a given date are exempted or “grandfathered” from regulation. Reasons that are given for their being commonly applied in regulatory policy is that it is more efficient and cost-effective to control a given amount of pollution at a new plant as compared to retrofitting an existing plant. Also, there may be greater equity in not changing environmental regulations for facilities that have already been built, and instead focus on only new facilities. However, there may be incentive for existing firms to desire implementation of VDRs, for these can be used to erect entry barriers to restrict competition and protect rents created by existing command-and-control standards. Thus, there are efficiency and equity considerations inherent in the setting of an NSPS like this one for the petroleum refineries industry, as well as potential concerns about it being a possible barrier to entry, though this depends on the degree of stringency in the NSPS. This NSPS may create economic inefficiency by discouraging technological innovation and investment/modernization among regulated sources. Insofar as refiners that manage to avoid triggering NSPS will be rewarded, while those that do invest/modernize in capacity expansions may trigger it, the rule will impose efficiency losses on the economy that are not captured well by the economic impact model used in the RIA. All of these considerations could affect the actual estimates of impacts associated with this NSPS; it may become more difficult to build new and modified and reconstructed process units (cost savings notwithstanding), while existing units and refiners may receive an advantage in terms of some protection against entry of new firms and process units. Overall efficiency from a social welfare standpoint may also be affected.
4. Projections of new and modified and reconstructed sources. We project that during the 5-year period of analysis, EPA assumes the industry will invest in enough new processes to be equivalent to an average of three new refineries per year, or a total of 15 new refineries. Further, the new sources are assumed to be 40% new processes or facilities and 60% modified or reconstructed facilities or processes. Our baseline estimates of emissions and process units, and thus our incremental analysis options that are applied to these baseline estimates, depend strongly on these estimates. Many of these estimates are taken from industry trade journals (e.g., *Oil and Gas Journal*).

⁷ Quoted from the U.S. EPA Web site for the Refinery Enforcement Initiative at <http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html>.

The certainty of these estimates is only as high as that of the experts' capabilities that prepare these estimates.

4.9 References

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APPENDIX B:
SUMMARY OF SIGNIFICANT COMMENTS AND RESPONSES, AND RATIONALES
FOR NSPS EMISSION LIMITS

Below is a summary of the public comments and our responses to them organized by source type and pollutant controlled. Within this appendix is the rationale for the emission limits included in the final NSPS for each source type and pollutant.

B.1 PM Limits for Fluid Catalytic Cracking Units

Comment: Several commenters opposed the proposed tightening of the FCCU PM standards relative to subpart J and the concurrent change in PM monitoring methods. Some commenters supported the co-proposal to keep the 1 lb/1,000 lb coke burn PM emission limit based on Method 5B and/or 5F; other commenters either did not oppose or supported the 0.5 lb/1,000 lb coke burn emission limit for new “grassroots” units, provided EPA demonstrates it is cost-effective and that the limit is based on EPA Method 5B or 5F (40 CFR part 60, Appendix A-3).

Commenters stated that EPA should only impose the more stringent emission limits on new construction because it is much more difficult and costly to meet the proposed emission limits for modified or reconstructed equipment. Commenters suggested that if EPA does include more stringent limits on modifications, it should exclude certain actions (like projects implemented to meet consent decree requirements) from the definition of a modification.

Several commenters suggested that the costs in Table 11 of the proposal preamble are significantly underestimated. Commenters contended that the single “model plant” approach used in EPA’s cost analysis does not realistically consider important factors such as the inherent sulfur content of the feed, partial-burn versus full-burn regeneration, FCCU/regenerator size, and sources that are already well-controlled due to other regulations. Commenters asserted that the purchased equipment costs escalated from estimates that are 20 to 30 years old are underestimated. Several commenters provided estimates of costs and emission reductions for several actual projects, which they stated indicate that EPA’s costs are significantly underestimated and that the proposed standards are much less cost-effective than presented by EPA.

A number of commenters asserted that the PM standards should be based on EPA Methods 5B or 5F (40 CFR part 60, Appendix A-3), and not on EPA Method 5 of Appendix A-3

to part 60. According to these commenters, the achievability of the proposed 0.5 lb/1,000 lb coke burn PM limit based on EPA Method 5 is questionable because there are inadequate data on FCCU using EPA Method 5, and controlling combined condensable and filterable PM to the 0.5 lb/1,000 lb coke burn level has not been demonstrated to be cost-effective.

On the other hand, several commenters stated that any PM limit must include condensable and filterable PM as condensable PM account for a large portion of refinery PM emissions and all condensable PM is PM that is less than 2.5 micrometers in diameter (PM_{2.5}), which has more adverse health impacts than larger particles; the commenters therefore agreed with the use of EPA Method 5 to determine filterable PM and requested that EPA consider Method 202 (40 CFR part 51, Appendix M) for condensable PM. Commenters also stated that the limits for PM and SO₂ in subpart Ja should apply to all new, reconstructed, and modified FCCU. One commenter recommended that a total PM limit (filterable and condensable) be set at 1 lb/1,000 coke burn; another stated that the total PM limit, including both filterable and condensable PM, should be 0.5 lb/1,000 lb coke burn, and EPA has not demonstrated that current BDT cannot achieve this limit. Finally, one commenter suggested that EPA should evaluate the cost of removing each pollutant (PM and SO₂) separately.

Response: In response to these comments, we have revised our analysis to consider each unique existing FCCU in the United States. By doing so, we fully account for plant size, partial-burn versus full-burn regeneration, existing control configuration, and specific consent decree requirements. (Details on the specific revisions to the analysis can be found in the docket.) With a revised analysis, we were able to more directly assess the impacts of process modifications or reconstruction of existing equipment. We also assessed the effects of PM and SO₂ standards separately in this analysis.

In our revised analysis, we considered three options for PM: (1) maintain the existing subpart J standard of 1.0 lb/1,000 lb of coke burn-off (filterable PM as measured by Method 5B or 5F); (2) 0.5 lb/1,000 lb of coke burn-off (filterable PM as measured by Method 5B or 5F of Appendix A-3 to part 60); and (3) 0.5 lb/1,000 lb of coke burn-off (filterable PM as measured by Method 5 of Appendix A-3 to part 60). Similar to the analysis for the proposed standards, costs and emission reductions for each option were estimated as the increment between complying with subpart J and subpart Ja. We note that none of the available data suggest that a 0.5 lb/1,000 lb coke burn emission limit that includes both filterable and condensable PM as measured using

EPA Method 202 is achievable in practice for the full range of facilities using BDT controls, so we disagree with the comments suggesting this level is appropriate to consider as an option for a total PM limit in this rulemaking.

Option 1 includes the same emissions and requirements for PM as the current 40 CFR part 60, subpart J, so it will achieve no additional emissions reductions. The PM limit in Option 2 is the same numerical limit that was proposed in subpart Ja, but the PM emissions are determined using Methods 5B and 5F (40 CFR part 60, Appendix A-3). These test methods are commonly used for PM tests of FCCU and are the methods that were used to generate a majority of the test data we reviewed. Option 3 is a limit of 0.5 lb/1,000 lb coke burn using Method 5 and is the performance level that was proposed for subpart Ja.

The impacts of these three options for new FCCU are presented in Table B-1; the impacts for modified and reconstructed FCCU are presented in Table B-2.

Table B-1. National Fifth Year Impacts of Options for PM Limits Considered for New Fluid Catalytic Cracking Units Subject to 40 CFR Part 60, Subpart Ja^a

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons PM/yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	0	0	0	N/A	N/A
2	3,600	1,100	240	5,600	5,600
3	7,100	1,700	300	6,700	11,000

^a PM cost-effectiveness calculated for PM-fine, assuming 83.3% of the PM is PM-fine.

Table B-2. National Fifth Year Impacts of Options for PM Limits Considered for Reconstructed and Modified Fluid Catalytic Cracking Units Subject to 40 CFR Part 60, Subpart Ja^a

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons PM/yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	0	0	0	N/A	N/A
2	75,000	12,000	690	21,000	21,000
3	100,000	15,000	810	23,000	37,000

^a PM cost-effectiveness calculated for PM-fine, assuming 83.3% of the PM is PM-fine.

The available data and impacts for the options considered suggest that BDT for new FCCU is different than BDT for modified and reconstructed FCCU. For new FCCU, the costs for Option 2 are reasonable compared to the emission reduction achieved. The incremental cost between Option 2 and Option 3 of \$11,000 per ton PM-fine would generally be considered

reasonable, but there are uncertainties in the achievability of Option 3. The estimated PM emission reduction achieved by Option 3 compared to Option 2 equals the amount of sulfates and other condensable PM between 250°F and 320°F that would be measured by Method 5 but not Method 5B or 5F (40 CFR part 60, Appendix A-3). Additionally, available test data indicate that electrostatic precipitators (ESP) and wet scrubbers can reduce total filterable PM to 0.5 lb/1,000 lb of coke burn or less, as measured by Method 5-equivalent test methods. Although there were few test data points using Method 5-equivalent test methods, we concluded at proposal that both electrostatic precipitators and wet scrubbers can achieve this level of PM emissions. However, the data supporting Option 3 are not extensive, and it is unclear at this time whether a limit of 0.5 kg/Mg of coke burn as measured by Method 5 (40 CFR part 60, Appendix A-3) could be met by all configurations of FCCU. In addition, while the Agency supports reducing condensable PM emissions, the amount of condensable PM captured by Method 5 is small relative to methods that specifically target condensable PM, such as Method 202 (40 CFR part 51, Appendix M). We prefer to develop a single performance standard that considers all condensable PM rather than implementing phased standards targeting different fractions of condensable PM. Such an approach would be costly and inefficient. Therefore, we conclude that Option 2, control of PM emissions (as measured by Methods 5B and 5F of Appendix A-3 to part 60) to 0.5 lb/1,000 lb of coke burn or less, is BDT for newly constructed FCCU. This option achieves PM emission reductions of 240 tons per year (tons/yr) from a baseline of 910 tons/yr at a cost of \$5,600 per ton of PM.

For modified and reconstructed FCCU, Option 1 is the baseline level of control established by the existing requirements of subpart J. It will achieve no additional cost or emission reduction. The overall costs and the incremental costs for Options 2 and 3 are reasonable compared to the PM emission reduction; however, as with new FCCU, the performance of Option 3 has not been demonstrated, so it is rejected. Most of the existing FCCU that could become subject to subpart Ja through modification or reconstruction are either already subject to subpart J or are covered by the consent decrees. The consent decrees are generally based on the existing subpart J. Industry has made significant investments in complying with these subpart J requirements which may be abandoned if they become subject to subpart Ja. In addition, the additional costs could create a disincentive to modernize FCCU to make them more energy efficient or to produce more refined products. For these reasons, we reject Option 2 for

modified or reconstructed FCCU and conclude that control of PM emissions (as measured by Methods 5B and 5F of Appendix A-3 to part 60) is 1.0 lb/1,000 lb of coke burn or less is BDT for reconstructed and modified FCCU.

B.2 SO₂ Limits for Fluid Catalytic Cracking Units

Comment: Several commenters supported the co-proposal for modified and reconstructed FCCU to meet subpart J and not the 25 ppmv 365-day rolling average limit for SO₂. Commenters provided data to suggest that the retrofits of existing sources are not cost effective, particularly if catalyst additives cannot be used. The current subpart J includes three compliance options: (1) if using an add-on control device, reduce SO₂ emissions by at least 90 percent or to less than 50 ppmv; (2) if not using an add-on control device, limit sulfur oxides emissions (calculated as SO₂) to no more than 9.8 kg/Mg of coke burn-off; or (3) process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight. Several commenters objected to the elimination of the additional compliance options in the existing subpart J for subpart Ja because: (1) there are no data to show that the SO₂ limits proposed in subpart Ja are BDT for all FCCU regenerator configurations; (2) the three options are already established as BDT and, therefore, the CAA requires that EPA make them available; and (3) the substantial cost and other burdens for a reconstructed or modified FCCU already complying with one of the alternative options in subpart J to change to daily monitoring by Method 8 (40 CFR part 60, Appendix A-4) or to install CEMS were not addressed in the proposal.

One commenter supported the proposed SO₂ limit under Ja for new “grassroots” FCCU if the standard is demonstrated to be cost-effective.

Response: As acknowledged in the previous response on PM standards for FCCU, we completely revised our impacts analysis to evaluate SO₂ standards for every existing FCCU that may become subject to subpart Ja through modification or reconstruction. We did not have access to the inherent sulfur content of the feed for each FCCU so SO₂ emissions are still estimated using average emission factors relevant to the type of control device used for FCCU not subject to consent decree requirements. Nonetheless, we significantly revised the impact analysis to fully account for FCCU-specific throughput, existing controls, and consent decree requirements. (Details on the specific revisions to the analysis can be found in Docket ID No. EPA-HQ-OAR-2007-0011.) We evaluated two options: (1) current subpart J, including all three

compliance options; and (2) 50 ppmv SO₂ on a 7-day average and 25 ppmv on a 365-day average. Data are not available on which to base a more stringent control level.

Option 1 includes the same emissions and requirements as the current 40 CFR part 60, subpart J, so it will achieve no additional emissions reductions. Based on information provided by vendors and data submitted by petroleum refiners, Option 2 can be met with catalyst additives or a wet scrubber. Of 38 FCCU currently subject to a 50/25 ppmv SO₂ limit through consent decrees, 26 used wet scrubbers and 12 used catalyst additives or other (unspecified) techniques. Given the number of FCCU currently meeting the 50/25 ppmv SO₂ emission limit, we conclude that this limit is technically feasible.

The data in the record suggest that all systems with wet scrubbers can meet the 50/25 ppmv SO₂ emission limit with no additional cost. Further, based on information from the consent decrees, we believe that the owner or operator of an existing FCCU that does not already have a wet scrubber and is modified or reconstructed such that it becomes subject to subpart Ja can use catalyst additives to meet the 50/25 ppmv SO₂ emission limit. Therefore, the cost of Option 2 is calculated using catalyst additives as the method facilities choose for meeting the standard. We reject the idea that the 90 percent control efficiency, the 9.8 kg/Mg coke burn-off limit, or the 0.3 weight percent sulfur content alternatives are equivalent to the 50/25 ppmv SO₂ emission limit. Based on the original background document for the subpart J standards, these alternatives are expected to have outlet SO₂ concentrations of 200 to 400 ppmv. In reality the currently used wet scrubbers and catalyst additives achieve much higher SO₂ removal efficiencies and much lower outlet SO₂ concentrations. The impacts of these options are presented in Table B-3.

Table B-3. National Fifth Year Impacts of Options for SO₂ Limits Considered for New, Reconstructed, and Modified Fluid Catalytic Cracking Units Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons SO ₂ /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	0	0	0	N/A	N/A
2	0	3,000	4,400	700	700

Based on the data we reviewed to select the options and the estimated impacts of those options, we conclude that Option 2, control of SO₂ emissions to 25 ppmv or less averaged over 365 days and 50 ppmv or less averaged over 7 days, is technically feasible and cost-effective for

new, reconstructed, and modified fluid catalytic cracking units. This option has no capital cost and achieves SO₂ emission reductions of 4,400 tons/yr from a baseline of 5,900 tons/yr at a cost of \$700 per ton of SO₂. Therefore, we conclude that control of SO₂ emissions to 25 ppmv or less averaged over 365 days and 50 ppmv or less averaged over 7 days is BDT for new, reconstructed, or modified fluid catalytic cracking units.

B.3 NO_x Limit for Fluid Catalytic Cracking Units

Comment: Several commenters stated that they would support a NO_x limit of 80 ppmv for new sources only, provided a corrected impact analysis considers the different characteristics of FCCU and demonstrates that the NO_x limit for new sources is truly cost-effective.

Commenters supported the co-proposal for modified and reconstructed FCCU to meet subpart J and not be subject to a NO_x emission limit. A few commenters provided cost data showing the cost of NO_x controls is high for modified and reconstructed units due to the high cost and space needed for add-on controls. The commenters also stated that a large number of existing FCCU in the U.S. are covered by consent decrees, so significant NO_x reductions have already been (or will soon be) achieved, and an additional incremental reduction to 20 or 40 ppmv over a 365-day average are not widely demonstrated and would not be cost-effective.

One commenter stated that selective noncatalytic reduction (SNCR), selective catalytic reduction (SCR), and catalyst additives have not been demonstrated over significant periods of operational life. Commenters also cited environmental side-effects, such as the generation of ammonia compounds that contribute to condensable PM emissions, as a reason not to require these types of controls. Commenters also asserted that technologies like flue gas recirculation or advanced burner design are typically only cost-effective for new units and may be technically infeasible for existing FCCU.

One commenter suggested that if a limit is necessary for modified or reconstructed FCCU, recent catalyst additive trials support an emission limit of approximately 150 ppmv on a 7-day rolling average; this limit would only be achievable if a 24-hour CO averaging time was provided since lowering NO_x tends to increase CO emissions in FCCU. The commenter noted that this limit is equivalent to the 0.15 pounds per million British thermal units (lb/MMBtu) standard for reconstructed and modified heaters and boilers in NSPS subpart Db.

Other commenters supported the inclusion of a NO_x limit for FCCU and opposed the co-proposal of no NO_x standard for modified and reconstructed FCCU. These commenters also

recommended more stringent NO_x limits for FCCU and stated that 80 ppmv does not represent an adequate level of control given the evolution of emerging technologies. In addition, a BDT of 80 ppmv on 7-day rolling average does not look “toward what may be fairly projected for the regulated future” as required by *Portland Cement I* (486 F. 2d 375 at 384 (D.C. Cir. 1973)) and other court decisions. The commenters disagreed with the feasibility and cost analyses for modified and reconstructed FCCU and stated that FCCU under a consent decree are achieving lower levels than the 80 ppmv proposed by EPA. Given the significant hazards to human health and the environment posed by NO_x emissions, the commenters recommended limits of 20 ppmv over a 365-day rolling average and 40 ppmv over a 7-day rolling average for all FCCU. The commenters noted that these limits have been successfully achieved under consent decrees and they are technically feasible on new units at reasonable costs without additional controls.

Response: As shown by the disparate comments received, many commenters suggest lower NO_x emission limits are achievable, while other commenters do not believe the proposed NO_x emission limits are cost-effective. While we do acknowledge that lower NO_x emission limits are technically achievable, the incremental cost of achieving these lower limits was high when we evaluated options for the proposed standards. Therefore, we concluded at proposal that 20 or 40 ppmv NO_x limits were not BDT. In our BDT assessment, we evaluated the various methods to meet alternative NO_x limits as BDT rather than identifying one technology. One of the reasons for this is that each technology has its own advantages and limitations. While non-platinum oxidation promoters and advanced oxidation controls do not achieve the same reduction in NO_x emissions as add-on control devices such as SCR, they do so without any significant secondary impacts. The added NO_x reduction of SCR and SNCR must be balanced with these secondary impacts. Part of the basis for selecting control methods to achieve an 80 ppmv NO_x emission limit as BDT included both cost and secondary impacts. This approach is necessary when conducting our BDT analysis, thus ensuring the best overall environmental benefit from the subpart Ja standards.

To ensure that we addressed the commenters’ concerns, we re-evaluated the impacts for FCCU NO_x controls. We also collected additional data from continuous NO_x monitoring systems for a variety of FCCU NO_x control systems. These data suggest that as refiners gain more experience with the NO_x control systems (including catalyst additive improvements), NO_x control performance has improved over the past year or two. These data suggest that the

achievable level for combustion controls and catalyst additives is 80 ppmv and the achievable level for add-on control systems is 20 ppmv. Therefore, we evaluated three outlet NO_x emission level options as part of the BDT determination: (1) 150 ppmv; (2) 80 ppmv; and (3) 20 ppmv. Each NO_x concentration is averaged over 7 days. To estimate impacts for Option 1, we estimated that some units have current NO_x emissions below 150 ppmv, and all other units can meet this level with combustion controls such as limiting excess O₂ or using non-platinum catalyst combustion promoters and other NO_x-reducing catalyst additives in a complete combustion catalyst regenerator or a combination of NO_x-reducing combustion promoters and catalyst additives with low-NO_x burners (LNB) in a CO boiler after a partial combustion catalyst regenerator. Data collected from FCCU complying with consent decrees show that Option 2 can also be met using combustion controls; therefore, we estimated impacts for Option 2 using a similar method as Option 1. The main difference is that a larger number of FCCU must use combustion controls to meet the emission limit (*i.e.*, the FCCU with current NO_x emissions between 150 and 80 ppmv would not need controls under Option 1 but would need controls under Option 2). Option 3 is the level at which we expect all units to install more costly control technology such as LoTOxTM or SCR.

The estimated fifth-year emission reductions and costs for each option for new FCCU are summarized in Table B-4; the impacts for modified and reconstructed FCCU are summarized in Table B-5.

Table B-4. National Fifth Year Impacts of Options for NO_x Limits Considered for New Fluid Catalytic Cracking Units Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons NO _x /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	860	320	370	880	880
2	1,200	640	860	750	650
3	12,000	3,600	1,400	2,600	5,800

Table B-5. National Fifth Year Impacts of Options for NO_x Limits Considered for Modified and Reconstructed Fluid Catalytic Cracking Units Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons NO _x /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	2,800	1,000	860	1,200	1,200
2	3,700	1,600	1,800	920	660
3	45,000	11,000	3,200	3,600	6,800

Options 1 and 2 provide cost-effective NO_x control with limited or no secondary impacts. The costs of Option 1 and Option 2 are commensurate with the emission reductions for new FCCU as well as modified and reconstructed FCCU. Option 3 would impose compliance costs that are not warranted for the emissions reductions that would be achieved, as shown by the incremental cost-effectiveness values of about \$6,000 per ton of NO_x emission reduction between Option 2 and Option 3.

In evaluating these options, we also considered the secondary impacts. In addition to the direct PM impacts of SNCR and SCR, SCR and LoToxTM units require additional electrical consumption. The increased energy consumption for Option 3 is 40,000 MW-hr/yr for new, modified, and reconstructed units. We also evaluated the secondary PM, SO₂, and NO_x emission impacts of the additional electrical consumption for Option 3. Based on the energy impacts, Option 3 will generate secondary emissions of PM, SO₂, and NO_x of 6, 150, and 57 tons/yr, respectively.

Based on the impacts shown in Table B-4 and Table B-5, and taking secondary impacts into account, we conclude that BDT is Option 2, a NO_x emission limit of 80 ppmv, for all affected FCCU. For new FCCU, this option achieves NO_x emission reductions of 860 tons/yr from a baseline of 1,500 tons/yr at a cost of \$750 per ton of NO_x. For modified and reconstructed FCCU, this option achieves NO_x emission reductions of 1,800 tons/yr from a baseline of 3,600 tons/yr at a cost of \$920 per ton of NO_x.

B.4 PM and SO₂ Limits for Fluid Coking Units

Comment: Several commenters stated that EPA's proposed standards for FCU under subpart Ja are inappropriate and not cost-effective. Commenters asserted that based on the significant differences between FCU and FCCU operations, a separate BDT determination is needed for FCCU and FCU. Commenters stated that an FCU has higher particulate loading; a

heavier feedstock that typically contains a higher concentration of sulfur, increasing the SO₂ and sulfur trioxide (SO₃) emissions; and a wider range of feedstocks with considerable variability in the nitrogen content.

The commenters noted that the impacts analysis performed for the FCU has shortcomings similar to those in the impacts analysis for FCCU (e.g., the analysis did not properly consider the additional costs and technical difficulties of meeting the proposed emission limits for modified or reconstructed sources, existing units are already controlled and thus the emission reductions have already been achieved). One commenter provided site-specific engineering cost estimates to indicate that the PM controls are much less cost-effective than EPA estimates. The commenter requested that EPA consider instances when wastewater limitations require regenerative wet scrubbers and amend the impact estimates accordingly. One commenter stated that a newly installed regenerative wet scrubber system on an existing FCU could not meet the proposed Ja PM standards.

Response: As described in the preamble to the proposed standards, the original analysis assumed that one of the larger existing FCU will become a modified or reconstructed source in the next 5 years. However, the two larger FCU in the U.S. are both subject to consent decrees: one has installed controls and the other is in the process of installing controls. The remaining two FCU are significantly smaller than the original model FCU; therefore, a new analysis was conducted using a smaller model FCU indicative of the size of the two remaining FCU that are not subject to consent decree requirements. In our new analysis, this FCU has approximately one-half the sulfur content as the larger FCU for which we have data, based on information received regarding the variability in sulfur content across different FCU in the public comments.

In addition to revising our impact analysis, we also collected additional source test data from the one FCU operating a newly installed wet scrubber system to better characterize the control system's performance. At proposal, we had one FCU source test from this source, which suggested that the FCU wet scrubber could meet a PM limit of 0.5 lb/1,000 coke burn. However, following proposal, we received an additional performance test for this same FCU wet scrubber with an emission rate between 0.5 and 1.0 lb/1,000 lb coke burn. There was no indication of unusual performance during either of these two tests, so we conclude that these tests demonstrate the variability of the emission source and control system. Based on the available data, therefore, we conclude that an appropriate PM performance level to consider for a BDT analysis is 1.0

lb/1,000 lb coke burn using EPA Method 5B (40 CFR part 60, Appendix A-3) for a FCU with a wet scrubber. We also conclude that the PM emission limit initially proposed for FCU had not been adequately demonstrated as an emission limit with which one must comply at all times.

Using our revised model FCU and based on the additional source test data, we re-evaluated BDT for PM and SO₂ emissions from FCU based on two options: (1) no new standards, or current subpart J; and (2) a PM limit of 1.0 lb/1,000 lb coke burn (as measured using Methods 5B and 5F of 40 CFR part 60, Appendix A-3), a short-term SO₂ limit of 50 ppmv averaged over 7 days, and a long-term SO₂ limit of 25 ppmv averaged over 365 days. Unlike the FCCU, catalyst additives cannot be used in a FCU to reduce SO₂, so a wet scrubber is the most likely technology (and the one demonstrated technology) that would be used to meet the PM and SO₂ limits of Option 2. Therefore, we estimated costs for an enhanced wet scrubber to meet both the PM and SO₂ limits. The resulting emission reductions and costs for both of the options are shown in Table B-6.

Table B-6. National Fifth Year Impacts of Options for PM and SO₂ Limits Considered for Fluid Coking Units Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons PM/yr)	Emission Reduction (tons SO ₂ /yr)	Cost-Effectiveness (\$/ton PM and SO ₂)
1	0	0	0	0	N/A
2	10,000	3,200	1,000	5,900	460
2a	100,000	18,600	1,000	5,900	2,700

One commenter indicated that we should consider the costs of a regenerative wet scrubber. This type of system is not needed in most applications, however, in the event such a system were needed, we estimated the cost of a regenerative wet scrubber to meet Option 2. The results of this analysis are also provided in Table B-6 as Option 2a. As seen in Table B-6, even under the most conservative assumptions the costs associated with the PM and SO₂ emission reductions are reasonable.

Based on the available technology and the costs presented in Table B-6, we conclude that BDT is Option 2, which requires technology that reduces PM emissions to 1.0 kg/Mg of coke burn and reduces SO₂ emissions to 50 ppmv averaged over 7 days and 25 ppmv averaged over 365 days. This option achieves PM emission reductions of 1,000 tons/yr from a baseline of 1,100 tons/yr and SO₂ emission reductions of 5,900 tons/yr from a baseline of 6,100 tons/yr at a cost of \$460 per ton of PM and SO₂ combined.

B.5 NO_x Limit for Fluid Coking Units

Comment: A number of commenters opposed the co-proposal of no NO_x standard for FCU, and some disagreed with EPA's 80 ppmv NO_x limit for FCU. These commenters recommended limits of 20 ppmv as a 365-day rolling average and 40 ppmv as a 7-day rolling average for FCU, as has been successfully achieved under consent decrees. The commenters noted that these limits are achievable on new units without additional controls.

One commenter supported the co-proposal that no new NO_x standard be established for FCU.

Response: Similar to the revised analysis for PM and SO₂ impacts, we re-evaluated BDT for the FCU NO_x controls for a smaller modified or reconstructed FCU. We evaluated three options: (1) no new standards, which is the current subpart J; (2) outlet NO_x concentration of 80 ppmv; and (3) outlet NO_x concentration of 20 ppmv. Similar to the analysis for FCCU NO_x and depending on the baseline emissions for the FCU, we anticipate that Option 2 can be met using combustion controls and Option 3 will require add-on control technology. The results of this analysis are shown in Table B-7.

Table B-7. National Fifth Year Impacts of Options for NO_x Limits Considered for Fluid Coking Units Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons NO _x /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	0	0	0	N/A	N/A
2	3,700	850	660	1,300	1,300
3	6,000	1,300	750	1,700	5,000

The costs for Option 1 and Option 2 are commensurate with the emission reductions, but the incremental impacts for Option 3 are not reasonable, as shown in Table B-7. Option 3 achieves an additional 90 tons per year NO_x reduction, but the incremental costs between options 2 and 3 of achieving this reduction is \$5,000 per ton of NO_x removed. The cost of achieving this 12 percent additional emission reduction nearly triples the total annualized cost of operating the controls. As with FCCU, the add-on NO_x controls for FCU have increased energy requirements and secondary air pollution impacts. Based on these projected impacts, we support our original determination that BDT is Option 2, or technology needed to meet an outlet NO_x concentration of 80 ppmv or less. This option achieves NO_x emission reductions of 660 tons/yr from a baseline of 800 tons/yr at a cost of \$1,300 per ton of NO_x.

B.6 SO₂ Limit for Small Sulfur Recovery Plants (SRP)

Comment: One commenter stated that no new requirements should be added for SRP less than 20 LTD (small SRP) because the controls are not cost-effective. The commenter provided data on tail gas treatment projects but noted that these costs are for large SRP, and controls for small SRP will be less cost-effective. Several commenters noted that if EPA does establish standards for small SRP, the monitoring and compliance evaluation methods for the 99 percent control standard are not clearly specified in the rule and could create difficulties in documenting compliance for small Claus plants. Therefore, the small SRP should be allowed to comply with the 250 ppmv SO₂ emission limit provided to large SRP. One commenter suggested that non-Claus units should be subject to a 95 percent recovery efficiency standard.

Response: To ensure that we addressed the commenters' concerns regarding cost-effectiveness, we re-evaluated the impacts for small SRP. We adjusted our cost estimates upward based on capital costs provided by industry representatives. We evaluated three SO₂ control options as part of the BDT determination for small SRP: (1) no new standards, or current subpart J; (2) 99 percent sulfur recovery; and (3) 99.9 percent sulfur recovery. As noted in the preamble to the proposed standards (section V.D), the 99 percent and 99.9 percent recovery levels are achievable for SRP of all sizes by various types of SRP or tail gas treatments.

The estimated fifth-year emission reductions and costs for new SRP are summarized in Table B-8; the impacts for modified and reconstructed SRP are summarized in Table B-9. These values reflect the impacts only for SRP smaller than 20 LTD; there are no additional cost impacts for larger Claus units because they would already have to comply with the existing standards in subpart J.

Table B-8. National Fifth Year Impacts of Options for SO₂ Limits Considered for New Small Sulfur Recovery Plants Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons SO ₂ /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	0	0	0	N/A	N/A
2	130	63	42	1,500	1,500
3	590	230	52	4,500	18,000

Table B-9. National Fifth Year Impacts of Options for SO₂ Limits Considered for Modified and Reconstructed Small Sulfur Recovery Plants Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons SO ₂ /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	0	0	0	N/A	N/A
2	1,600	670	380	1,800	1,800
3	7,800	2,600	470	5,700	23,000

The costs for Option 2 are reasonable considering the emission reductions achieved, but the incremental impacts shown in Table 9 and Table 10 for Option 3 are beyond the costs that the Agency believes are reasonable for these small units to achieve an additional 100 tons per year of SO₂ emission reductions. The additional equipment needed to achieve these reductions quadruples the capital costs. These smaller units would also generally be found at small refineries. Based on these projected impacts and available performance data, we support our original determination that BDT is Option 2, or 99 percent sulfur recovery. For new SRP, this option achieves SO₂ emission reductions of 42 tons/yr from a baseline of 150 tons/yr at a cost of \$1,500 per ton of SO₂. For modified and reconstructed SRP, this option achieves SO₂ emission reductions of 380 tons/yr from a baseline of 1,400 tons/yr at a cost of \$1,800 per ton of SO₂.

We note that we are also revising the format of the standard in response to public comments in terms of sulfur outlet concentrations. Based on the Option 2 BDT selection of a recovery efficiency of 99 percent, the emission limit for small SRP is either 2,500 ppmv SO₂ or 3,000 ppmv reduced sulfur compounds and 100 ppmv of H₂S, both of which are determined on a dry basis, corrected to 0 percent O₂.

B.7 NO_x Limit for Process Heaters

Comment: Several commenters stated that the 80 ppmv NO_x limit for process heaters is not stringent enough. Commenters stated that considering recent settlement negotiations and regulation development, NO_x emissions reductions well below 80 ppmv can be achieved cost effectively. The commenters stated that NO_x emissions of less than 40 ppmv at 0 percent O₂ are achievable with combustion modifications such as LNB, ultra low-NO_x burners (ULNB), and flue gas recirculation technologies; post-combustion controls such as SCR, SNCR, and LoTOxTM achieve NO_x reductions an order of magnitude below those from combustion modifications. The

commenters noted that Bay Area Air Quality Management District (BAAQMD) Regulation 9, Rule 10, requires process heaters to meet a 0.033 lb/MMBtu NO_x limit (roughly 32 ppmv NO_x at 0 percent oxygen). One commenter stated that 30 ppmv has been demonstrated under consent decrees to be an achievable level and ample technology exists. The commenters also noted that 7 to 10 ppmv NO_x limits (at 3 percent oxygen) have been achieved in practice. One commenter stated that NSPS subparts J and Ja should impose NO_x emission limits on all fuel gas combustion devices that are at least as stringent as the most stringent consent decree. Some consent decrees require next generation ULNB designed to achieve NO_x emissions rates of 0.012 to 0.020 lb/MMBtu (12 to 20 ppmv NO_x at 0 percent oxygen). Commenters recommending more stringent requirements suggested limits ranging from 7 ppmv NO_x (at 3 percent oxygen) to 30 ppmv for new process heaters fueled by refinery fuel gas.

Other commenters stated that alternative monitoring options should be provided to small fuel gas combustion devices due to the high costs of CEMS relative to the emissions from the small devices. One commenter suggested an exemption from the fuel gas monitoring requirements for process heaters less than 50 MMBtu/hr. Another commenter recommended an exemption from the fuel gas monitoring requirements for process heaters less than 40 MMBtu/hr as used by South Coast Air Quality Management District (SCAQMD).

Response: We revisited the BDT determination based on the public comments and revised the methodology used to calculate the cost and emission reduction impacts for the proposed standards. We evaluated three options as part of the BDT determination. Each option consists of a potential NO_x emission limit and applicability based on process heater size. These differ slightly from the proposal options based on commenter suggestions. Option 1 would limit NO_x emissions to 80 ppmv or less for all process heaters with a capacity greater than 20 MMBtu/hr (the proposed standards). Option 2 would limit NO_x emissions to 40 ppmv or less for all process heaters with a capacity greater than 40 MMBtu/hr. This option is similar to many consent decrees that set an emission limit of 0.040 lb/MMBtu (roughly 40 ppmv NO_x at 0 percent oxygen) for process heaters greater than 40 MMBtu/hr. Option 3 would limit NO_x emissions to 20 ppmv or less for all process heaters with a capacity greater than 40 MMBtu/hr. In each option, the NO_x concentration is based on a 24-hour rolling average.

The estimated fifth-year emission reductions and costs for each option for new process heaters are summarized in Table B-10; impacts for modified and reconstructed process heaters are summarized in Table B-11. Similar to the proposal analysis, we considered LNB, ULNB, flue gas recirculation, SCR, SNCR, and LoTOxTM as feasible technologies. We believe that nearly all process heaters at refineries that will become subject to subpart Ja can meet Option 1 or Option 2 using combustion controls (LNB or ULNB). Most process heaters would need to use more efficient control technologies, such as LoTOxTM or SCR, to meet the NO_x concentration limit in Option 3. Per commenters' request to focus on the larger units, Options 2 and 3 do not include process heaters between 20 MMBtu/hr and 40 MMBtu/hr. We evaluated the cost-effectiveness of NO_x control options for these units to achieve the proposed standard of 80 ppmv. For these process heaters with smaller capacities we found the cost-effectiveness ranged from \$3,500/ton to \$4,200/ton of NO_x reduced, which was determined not to be reasonable for these small heaters, which would primarily be located at small refineries.

Table B-10. National Fifth Year Impacts of Options for NO_x Limits Considered for New Process Heaters Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons NO _x /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	9,000	7,300	4,800	1,500	1,500
2	9,000	7,500	5,200	1,400	500
3	110,000	30,000	5,900	5,100	37,000

Table B-11. National Fifth Year Impacts of Options for NO_x Limits Considered for Modified and Reconstructed Process Heaters Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons NO _x /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	12,000	4,000	2,100	1,900	1,900
2	14,000	4,300	2,200	1,900	2,100
3	64,000	15,000	2,500	5,900	39,000

Based on the impacts in Tables B-10 and B-11, the costs of Options 1 and 2 are reasonable compared to the emission reductions. The incremental cost between Options 2 and 3

of almost \$40,000/ton of NO_x is not commensurate with the additional 1,000 tons of emission reduction achieved for new and modified or reconstructed process heaters. Moreover, the capital costs of Option 3 are about \$150 million greater than the capital costs for Option 2, which are only \$23 million. Therefore, we conclude that BDT for process heaters greater than 40 MMBtu/hr is technology that achieves an outlet NO_x concentration of 40 ppmv or less, or Option 2. For new process heaters, this option achieves NO_x emission reductions of 5,200 tons/yr from a baseline of 7,500 tons/yr at a cost of \$1,400 per ton of NO_x. For modified and reconstructed process heaters, this option achieves NO_x emission reductions of 2,200 tons/yr from a baseline of 3,200 tons/yr at a cost of \$1,900 per ton of NO_x. Although we agree that lower NO_x concentrations are achievable, we determined that the incremental cost to achieve these lower NO_x concentrations was not reasonable.

B.8 Fuel Gas Combustion Devices

Comment: Several commenters contended that the proposed standards for fuel gas combustion devices were not stringent enough; EPA should ensure that the best demonstrated emission control technologies are installed as the industry is modernized. Given the significant hazards to human health and the environment posed by SO₂ emissions, the commenters suggested that the 365-day average limits should be 40 ppmv TRS and 5 ppmv SO₂. The commenters also recommended that EPA tighten the 3-hour concentration limit to 100 ppmv TRS. On the other hand, another commenter contended that although amine treatment applications for product gases can achieve H₂S concentrations of 1 to 5 ppmv, a tighter standard is not BDT for refinery fuel gas.

Several commenters objected to the addition of the 60 ppmv H₂S and 8 ppmv SO₂ limits (365-day rolling average) in the proposed subpart Ja standards for fuel gas combustion devices because they are infeasible and/or not cost-effective. According to commenters, EPA erroneously assumed that the additional reductions could be achieved with existing equipment. Although this may be true in some cases, commenters asserted that some refineries would need to add additional amine adsorber/regenerator capacity and some may also need to add additional sulfur recovery capacity (e.g., an additional Claus train and tail gas treatment unit). One commenter requested an exemption be provided for refineries that cannot meet the tighter long-term standard by simply increasing their amine circulation rates. One commenter stated that there will be little incremental environmental benefit from the long-term limit, and it unnecessarily penalizes refineries that designed their amine systems to treat to levels near the

proposed annual standard. The commenters provided cost data for examples of projects requiring new amine adsorption units to show that the proposed standards are not cost-effective.

A number of commenters particularly opposed the proposed revision to include TRS limits for fuel gas produced from coking units or any fuel gas mixed with fuel gas produced from coking units. One commenter noted that some State and local agencies have specific TRS standards, but these requirements were not based on a BDT assessment. According to commenters, EPA has included no technical basis for the achievability of the TRS fuel gas standard or explanation of why control of TRS is limited to fuel gas generated by coking units. The commenters recommended that EPA postpone adoption of a TRS limit until it has gathered and evaluated adequate data to conclude that the limit is technically feasible and cost effective.

Commenters stated that EPA did not address the cost-effectiveness and non-air quality impacts of the TRS standards and did not define BDT for the removal of TRS. One commenter stated that without an established de minimis level, an entire fuel gas system could be subject to the TRS limits if any amount of coker gas enters the fuel gas system. Amine scrubbing systems are selective to H₂S and are not suitable to other TRS compounds such as mercaptans, according to the commenters. Commenters stated that the non-H₂S TRS compounds are not amenable to amine treating and there is no technology readily in-place at refineries for reducing non-H₂S TRS compounds. Therefore, according to the commenters, removing these other TRS compounds would require significant capital outlay for new equipment, costs that were not considered in the impacts analysis.

One commenter provided an example of a treatment system installed to meet a facility-wide fuel gas total sulfur standard of 40 ppmv; the commenter estimated the capital cost of the entire system to be \$150 million. The commenter also indicated that low-BTU gas from flexicoking units would need to be specially treated at a capital cost of \$61 million to achieve a total sulfur content of less than 150 ppmv, and the treatment would increase energy consumption, resulting in increases in NO_x and CO emissions. Another commenter provided an order-of-magnitude engineering estimate of \$50 million to treat TRS down to 45 ppmv (long-term average). Based on one commenter's experience with a new fuel gas treating facility, non-acidic TRS cannot be treated down to the proposed levels utilizing Merox-amine treatment. A cost-effective solution could be natural gas blending at the affected combustion device; however, this

option has the negative effect of reducing the production of refinery fuel gas and therefore reducing the refinery's capacity for making gasoline.

Several commenters stated that the original BDT determination was based on amine scrubbing of H₂S and not on SO₂; the SO₂ standard was simply a compliance option that was calculated to be equivalent to the H₂S concentration limit at 0 percent excess air. They also asserted that EPA cannot use the SO₂ option as a basis for the TRS standard because the SO₂ option is not BDT. On the other hand, one commenter requested that EPA clarify the fuel gas standards in subpart J to expressly indicate that the 20 ppmv SO₂ limit is a valid compliance option (instead of including it only in the monitoring section). According to the commenter, focus has been on H₂S due to the structure of the requirements of subpart J and permits rarely require that combustion sources demonstrate compliance with the 20 ppmv SO₂ limit. The commenter stated that refiners clearly should be allowed to comply with the broader, more comprehensive SO₂ limit.

A few commenters noted that, as H₂S is part of TRS, the TRS standard is even more stringent than the H₂S standard. One commenter recommended that no change in the fuel gas standards be made or that the standards focus on H₂S only with an alternative emission limit for SO₂. One commenter stated that EPA developed the 160 ppmv H₂S standard to be more stringent than the 20 ppmv SO₂ standard specifically because H₂S did not represent all of the sulfur in the fuel gas. Commenters stated that using an F-factor approach (Method 19, 40 CFR part 60, Appendix A-7), the TRS limit that is equivalent to the 20 ppmv SO₂ emission limit is 260 ppmv and the TRS limit that is equivalent to the 8 ppmv SO₂ emission limit is 104 ppmv.

Response: We initially concluded that fuel gas generated by the coking unit was mixed with other fuel gases that were mostly H₂S and that increasing the amine circulation rate would result in additional H₂S removal that could be used to meet the proposed standard. However, based on a review of the available data, non-H₂S sulfur content in coker fuel gas may be 300 to 500 ppmv. At these levels, specific treatment to reduce these other sulfur compounds would be needed. As indicated by one commenter, a plant-wide total sulfur limit of 40 ppmv has been achieved in practice in at least one refinery using a treatment train consisting of a Merox system, sponge oil absorbers, MEA absorbers, and caustic wash towers. Therefore, total sulfur fuel gas treatment methods are demonstrated. We evaluated the cost of this treatment based on information provided in the public comments.

Based on the public comments and additional data, we revisited the BDT determination and assessed three options for increasing SO₂ control of fuel gas combustion devices: (1) 20 ppmv SO₂ or 162 ppmv H₂S averaged over 3 hours; (2) Option 1 plus 8 ppmv SO₂ or 60 ppmv H₂S averaged over 365 days; and (3) a compliance option of 162 ppmv TRS averaged over 3 hours and 60 ppmv TRS averaged over 365 days for fuel gas combustion devices combusting fuel gas generated by a coking unit and Option 2 for combustion devices combusting fuel gas not generated by a coking unit. Option 1 includes the same limits that are in subpart J, so there are no additional costs or emission reductions beyond those expected from the application of subpart J. To address the commenters' concerns that not all facilities have available amine capacity to ensure compliance with the new long-term limits, we revised our proposal analysis to include additional costs for the estimated 10 percent of the affected facilities that would increase their amine capacity to achieve Option 2. We estimated costs for a separate treatment train that can treat TRS for Option 3 because, based on the public comments received, we have concluded that amine treatment systems are not effective for non-H₂S components of TRS.

The estimated fifth-year impacts of each of these options for new fuel gas combustion devices are presented in Table B-12; the impacts for modified and reconstructed fuel gas combustion devices are presented in Table B-13.

Table B-12. National Fifth Year Impacts of Options for SO₂ Limits Considered for New Fuel Gas Combustion Devices Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons SO ₂ /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	0	0	0	N/A	N/A
2	1,200	770	520	1,500	1,500
3	100,000	13,000	930	14,000	31,000

Table B-13. National Fifth Year Impacts of Options for SO₂ Limits Considered for Modified and Reconstructed Fuel Gas Combustion Devices Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons SO ₂ /yr)	Cost-Effectiveness (\$/ton)	
				Overall	Incremental
1	0	0	0	N/A	N/A
2	33,000	11,000	4,700	2,400	2,400
3	1,700,000	200,000	9,100	22,000	42,000

Overall costs for Options 1 and 2 are reasonable compared to the emission reduction achieved for new, modified and reconstructed fuel gas combustion devices. We further evaluated the incremental costs and reductions between the three options and found that they were reasonable for Options 1 and 2, while the incremental cost for Option 3 is not. While Option 3 provides significant additional SO₂ emission reductions, the additional capital cost of \$1.7 billion is high and could pose a significant barrier to future refinery upgrades and expansions. Based on these impacts and consideration of current operating practices, we conclude that BDT is use of technology that reduces the emissions from affected fuel gas combustion devices to 20 ppmv SO₂ or 162 ppmv H₂S averaged over 3 hours and 8 ppmv SO₂ or 60 ppmv H₂S averaged over 365 days, or Option 2. For new fuel gas combustion devices, this option achieves SO₂ emission reductions of 510 tons/yr from a baseline of 1,000 tons/yr at a cost of \$1,400 per ton of SO₂. For modified and reconstructed fuel gas combustion devices, this option achieves SO₂ emission reductions of 4,700 tons/yr from a baseline of 10,000 tons/yr at a cost of \$2,400 per ton of SO₂.

We note that although we have determined that Option 3 is not BDT and we will not limit the amount of SO₂ emissions from combustion of sulfur compounds other than H₂S in subpart Ja, we plan to continue to work with the industry to understand the magnitude of these SO₂ emissions and to identify technologies that can be cost effectively applied to reduce the emissions. We have learned through this process that the SO₂ emissions from combustion of TRS in coker gas are generally not reflected in emission inventories and we plan to explore this issue in greater detail in the future to determine where SO₂ emissions are underestimated and the best way to correct the inventories.

Comment: Several commenters stated that it is impossible for a refinery owner or operator to specify, acquire, install, and calibrate a continuous monitoring system within 15 days of a change that increases the H₂S concentration such that an exempt stream is no longer exempt. One commenter suggested quarterly stain tube sampling for 1 year prior to revoking an exemption from monitoring to confirm the change is permanent. The commenter suggested that after 1 year of confirmation, an additional 12 months be provided to specify, acquire, install, and calibrate the continuous monitoring system. One commenter suggested 1 year be provided for installing a CEMS, while another commenter suggested 180 days be provided (with an allowance for an additional extension) for installing a CEMS, rather than the 15 days proposed.

Response: We believe that in most cases, the process change would be a deliberate, planned act and that the potential consequences of this deliberate change would be evaluated. That is, before the equipment is modified, the refinery owner or operator is expected to assess the impacts of this change on the exempted fuel gas stream. If the change is expected to increase the sulfur content of the fuel gas, then the owner or operator can plan to install the required CEMS when modifying the process. We recognize that some process changes may have unexpected consequences, and a modification that was not expected to increase the sulfur content of the fuel gas can result in an increase in sulfur content. In this case, it may be impossible to install the required CEMS within 15 days. However, quarterly sampling does not provide any basis by which the refinery owner or operator can demonstrate compliance with the H₂S concentration standard. Instead, we have added provisions that require an owner or operator to install a CEMS as soon as practicable and no later than 180 days after a change that makes the stream no longer exempt. Between the process change and the time a CEMS is installed, the owner or operator must conduct daily stain tube sampling to demonstrate compliance with the H₂S concentration standard. During this time, a single daily sample exceeding 162 ppmv must be reported as an exceedance of the 3-hour H₂S concentration limit and a rolling 365-day average concentration must be determined. A daily average H₂S concentration of 5 ppmv is to be used for the days prior to the process change for the previously exempt stream in calculating the rolling 365-day average concentration.

B.9 Flaring of Refinery Fuel Gas

Comment: Several commenters supported the proposed work practice standards to eliminate routine flaring and develop startup, shutdown, and malfunction (SSM) plans; the commenters opposed the co-proposal of no standards. One commenter supported the determination that elimination of routine flaring is BDT, citing reductions in hydrocarbon, NO_x, SO₂, and carbon dioxide (CO₂) emissions. One commenter stated that both subparts J and Ja should explicitly require that flaring be used only as a last resort in unusual circumstances, such as emergencies, and not on a routine basis. Commenters asserted that monitoring on an ongoing basis is needed to verify that no flaring of nonexempt gases occurs. Commenters stated that subpart Ja should also require refiners to install a flare gas recovery system, although such

requirements should not preclude monitoring requirements. One commenter stated that the NSPS should require a SSM plan to eliminate venting or flaring during such planned start-up, shutdown, and maintenance activities and explicitly prohibit venting or flaring during these planned activities; proper operation and maintenance practices should completely eliminate the need to use flares during these activities. One commenter noted that those refineries that have evaluated their startup and shutdown procedures to reduce or eliminate direct venting or flaring during planned startup and shutdown events have demonstrated the best technology; therefore, their actions represent BDT and should be adopted in the NSPS. The commenters also supported conducting a root cause analysis (RCA) in the event of flaring and other venting releases of 500 lb/day SO₂.

A number of commenters generally supported the intent to reduce flaring and the idea of SSM plans to address flaring during planned startups and shutdowns (one commenter also included combustion of high sulfur-containing fuel gases during a malfunction), flare management plans, and RCA for flare events in excess of 500 lb/day. However, they opposed the work practice standard for elimination of routine flaring and the proposed creation of fuel gas producing units for subpart Ja. The commenters stated that the definition of “fuel gas producing unit” is overly broad, making it difficult to determine what constitutes a modification or reconstruction, and the proposed work practice standard for these units is infeasible, unnecessary, and not cost-effective. Facility operators and regulators would have difficulty discerning if a flaring event was caused by an affected fuel gas producing unit or a unit not subject to the standard. One commenter indicated that there is no de minimis level by which units that produce insignificant quantities of fuel gas can be excluded from the extensive work practice standards.

Commenters recommended that the affected source be the flare which is already subject to the standard as a fuel gas combustion device. The commenters suggested that for each affected flare, the facility would develop a written Flare Management Plan designed to minimize flaring of fuel gas during all periods of operation. This plan, along with the RCA, would ensure that all flaring events with potential excess emissions will be minimized. One commenter noted that EPA could require a flare management plan for any flare tied to a fuel gas system that has an affected fuel gas combustion device as a better alternative to “fuel gas producing units.” One commenter noted that an exemption from the notification requirements for modified or

reconstructed units could be provided as an incentive for early adoption of the flare management plan; another commenter suggested that regulatory incentives such as exemptions from monitoring and developing flare management plans should be provided for facilities that have installed flare gas recovery systems. One commenter supported this type of requirement for flares currently subject to subpart J, assuming a minimum of 9 months is provided for plan development and implementation. On the other hand, one commenter noted that the definitions of the affected facility under subparts J and Ja are different and recommended that the distinction be made stronger so that it is clear that existing process unit facilities are “grandfathered” and exempt from the flaring minimization standards.

One commenter suggested that the work practices language should be clarified to indicate that routing offgas to the flare system would be acceptable if the system was equipped with a flare gas recovery system. The prohibition should be specific to the flare itself as some flare systems are equipped with recovery compressors, the use of which should be encouraged rather than discouraged.

Commenters stressed the need for flares as safety devices; any flare minimization program must not interfere with the ability of the refinery owner or operator to use flares for safety reasons. The commenters stated that “routine” flaring cannot be adequately defined in practice; therefore, restrictions on “routine” flaring will lead to unsafe operations in attempts to avoid enforcement actions. The commenters requested that EPA include language in the regulation, consistent with the preamble discussion, that: “Nothing in this rule should be construed to compromise refinery operations and practices with regard to safety.”

One commenter indicated that the proposed work practice standards for “no routine flaring” interfere with flare minimization plans implemented in response to consent decrees. The proposed work practice standard could be interpreted as prohibiting flaring during start-up and shutdown, and EPA has not determined this to be BDT. The commenter stated that the BAAQMD analysis applies to eliminating flaring during normal operation [similar to proposed §60.103a(b)], not during start-up and shutdown as in proposed §60.103a(a). The commenter provided cost estimates for one refinery to install a recovery system to eliminate flaring during start-up and shutdowns; the costs ranged from \$200,000 to \$800,000 per ton of VOC reduced and higher for other criteria pollutants. Therefore, they contend §60.103a(a) should clearly exclude start-up and shutdown gases.

A few commenters provided overall project costs for flare gas recovery projects indicating the annual costs are higher than those in the analysis supporting the proposed work practice. One commenter stated that EPA underestimated the cost of flare gas recovery systems and, given the uncertainty in emission reductions, contended that flare gas recovery systems for the no-flaring option are not cost-effective within the NSPS context. The commenter also stated that the regulation should include maintenance provisions for flare gas recovery systems (that allow flaring) during times of routine and non-routine maintenance, as no redundant capacity within the flare system exists.

A number of commenters provided an alternative to EPA's proposed work practice standards. The suggestions included a 500 lb/day SO₂ standard tied with a flare management plan as an alternative compliance option (to the H₂S concentration limit) for flares. The commenters recommended that this alternative compliance option be provided in both subparts J and Ja and noted that it could be used as an incentive for the flare management plan to cover all flares. One commenter also noted that these requirements should be applicable to flares that receive process gas, fuel gas, or process upset gas; they should not be applicable to flares used solely as an air pollution control device, such as a flare used exclusively to control emissions from a gasoline loading rack. Another commenter clarified that if the refinery elects to comply with this alternative for any flare, all flares at the refinery would need a flare management plan. The commenter noted that EPA could choose to set the 500 lb/day SO₂ limit as a total for all flares for which the alternative compliance option is chosen (*i.e.*, if the alternative compliance option is selected for two flares at a refinery, the total emissions from both flares would be limited to 500 lb/day).

Response: Although commenters suggested that certain provisions be made applicable to facilities subject to subpart J, the following provisions are only applicable to facilities subject to subpart Ja as CAA section 111 provides that new requirements apply only to new sources. We considered these comments and agree that the standards are more straightforward when the affected facility is defined as the flare. Therefore, we have eliminated "fuel gas producing units" as an affected facility in this final rule, and we specifically define a flare as a subset of fuel gas combustion device, which is an affected facility in this final rule. A "flare" means "an open-flame fuel gas combustion device used for burning off unwanted gas or flammable gas and liquids. The flare includes the foundation, flare tip, structural support, burner, igniter, flare

controls including air injection or steam injection systems, flame arrestors, knockout pots, piping and header systems.”

There are three general work practice standards that were proposed for “fuel gas producing units,” which may be summarized as follows: (1) the “no routine flaring” requirement; (2) flare minimization plan for start-up, shutdown, and malfunction events; and (3) a root-cause analysis for SO₂ releases exceeding 500 lb/day (which was proposed for all affected fuel gas producing units). The “no routine flaring” work practice was not intended to prohibit flaring during SSM events; the provisions were intended to apply only during normal operating conditions. We agree with the commenter that suggested that nothing in this rule should be construed to compromise refinery operations and practices with regard to safety. Additionally, as discussed in the preamble to the proposed rule, we specifically rejected a prohibition on flaring for planned start-up and shutdown events. We agree with the commenters that noted that numerous refineries have demonstrated that flare minimization during planned start-up and shutdown activities can greatly reduce flaring during these events. We do believe, however, that a complete elimination of flaring during these events is very site-specific and although it is reported to have been achieved at a limited number of refineries, we do not have information to suggest that it has been adequately demonstrated for universal application. As “no routine flaring” is difficult to define in practice, we have re-evaluated BDT using more specific options.

Option 1 is no additional standards for flares. In Option 2, any routine emissions event or any process start-up, shutdown, upset or malfunction that causes a discharge into the atmosphere more than 500 pounds per day of SO₂ (in excess of the allowable emission limit) from an affected fuel gas combustion device or sulfur recovery plant would require a root cause analysis to be performed. This approach is similar to what is included in most consent decrees. We are also including a requirement for continuous monitoring of TRS for all gases flared (including those from upsets, startups, shutdowns, and malfunction events), in order to accurately measure SO₂ emissions from affected flares.

Option 3 includes: (1) the SO₂ root cause analysis in Option 2; (2) a limit on the fuel gas flow rate to the flare of 250,000 scfd; and (3) a flare management plan for SSM events. The flow limit of 250,000 scfd is based on our cost analysis that indicates that for typical gas streams in quantities above this limit, the value of recovered fuel completely offsets the costs of installing and operating recovery systems. Many refineries have implemented flare gas recovery to reduce

energy needs and save money. The flare management plan must: (1) include a diagram illustrating all connections to each affected flare; (2) identify the flow rate monitoring device and a detailed description of manufacturer's specifications regarding quality assurance procedures; (3) include standard operating procedures for planned start-ups and shutdowns of refinery process units that vent to the flare (such as staging of process shutdowns) to minimize flaring during these events; (4) include procedures for a root cause analysis of any process upset or equipment malfunction that causes a discharge to the flare in excess of 500,000 scfd; and (5) include an evaluation of potential causes of fuel gas imbalances (i.e., excess fuel gas), upsets or malfunctions and procedures to minimize their occurrence and records to be maintained to document periods of excess fuel gas. Excess emission events for the flow rate limit of 250,000 scfd and the result of root cause analysis must be reported in the semi-annual compliance reports.

Option 4 is identical to Option 3 except that flaring is limited to 50,000 scfd. This level is estimated to be a baseline level that accounts for the flow requirement needed to maintain safe operations of the flare (i.e., flow of sweep gas and compressor cycle gas). For both Option 3 and Option 4, the limit on the flow rate does not apply during malfunctions and unplanned startups and shutdowns. The flow rate limits in Options 3 and 4 were developed to reduce VOC, SO₂, and NO_x emissions; the limits are based on 30-day rolling average flow rate values.

It is anticipated that a flare gas recovery system will be used to comply with Options 3 and 4 when a flare is currently used on a continuous basis, and the recovered flare gas offsets natural gas purchases. The cost-effectiveness of the flare gas recovery system is primarily dependent on the quantity of gas that the system can recover. Many refineries have already implemented similar work practices through consent decrees and local rules (BAAQMD and SCAQMD), and these requirements have had a demonstrated reduction in flaring events. Flare gas recovery will reduce SO₂, NO_x, and VOC emissions. However, if a refinery produces more fuel gas than the refinery needs to power its equipment, there is no place the refinery can use the recovered fuel gas and there is no additional natural gas purchases to offset. In these cases, flare gas recovery is not considered technically feasible because the excess fuel gas will have to be flared. Therefore, we have included specific provision within the flare management plan to address instances of excess fuel gas. For periods when the refinery owner or operator can demonstrate, through records of natural gas purchases or other means as described in their flare

management plan, that the refinery is fuel gas rich, compliance with the flow limit is demonstrated by implementing the procedures described in the flare management plan.

Impacts for each of the four options are based on estimates of current flaring quantities and include the root cause analysis, flare management plan, and flare gas recovery systems when needed. The impacts for each option for new flares are presented in Table B-14; impacts for modified and reconstructed flares are presented in Table B-15.

Table B-14. National Fifth Year Impacts of Options for Work Practices Considered for New Flaring Devices Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons SO ₂ /yr)	Emission Reduction (tons NO _x /yr)	Emission Reduction (tons VOC/yr)	Cost-Effectiveness (\$/ton)	
						Overall	Incremental
1	0	0	0	0	0	N/A	N/A
2	0	23	15	0	0	1,600	1,600
3	8,800	(1,300)	16	1	41	(23,000)	(31,000)
4	15,000	(840)	16	1	52	(12,000)	43,000

Table B-15. National Fifth Year Impacts of Options for Work Practices Considered for Modified and Reconstructed Flaring Devices Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons SO ₂ /yr)	Emission Reduction (tons NO _x /yr)	Emission Reduction (tons VOC/yr)	Cost-Effectiveness (\$/ton)	
						Overall	Incremental
1	0	0	0	0	0	N/A	N/A
2	0	92	59	0	0	1,600	1,600
3	35,000	(5,300)	64	4	165	(23,000)	(31,000)
4	59,000	(3,300)	66	6	207	(12,000)	43,000

Based on these impacts and consideration of technically feasible operating practices, we conclude that BDT is Option 3. Option 3 includes a set of work practice standards that requires root cause analysis for a discharge into the atmosphere in excess of 500 pounds per day of SO₂ (over the allowable emission limit) from a fuel gas combustion device or sulfur recovery plant or in excess of 500,000 scfd flow to a flare. It also includes a flare management plan. Finally, fuel gas flow to the flare is limited to 250,000 scfd. To support implementation of these requirements, monitoring and reporting of the flow rate and sulfur content is required. For new flaring devices, this option achieves SO₂ emission reductions of 16 tons/yr from a baseline of 32

tons/yr, NO_x emission reductions of 1 tons/yr from a baseline of 2 tons/yr, and VOC emission reductions of 41 tons/yr from a baseline of 67 tons/yr with a net fuel savings of \$23,000 per ton of combined SO₂, NO_x, and VOC. For modified and reconstructed flaring devices, this option achieves SO₂ emission reductions of 64 tons/yr from a baseline of 129 tons/yr, NO_x emission reductions of 4 tons/yr from a baseline of 7 tons/yr, and VOC emission reductions of 165 tons/yr from a baseline of 266 tons/yr with a net fuel savings of \$23,000 per ton of combined SO₂, NO_x, and VOC.

Comment: Several commenters requested clarification of how one would assess a flare “modification.” Questions included: (1) how the emission basis of a flare should be calculated; (2) if the modification determination would be based on flare capacity or increase in discharge capability of units connected to the flare; (3) whether the modification determination would include all possible flaring events or just non-emergency flaring; (4) whether adding a new line to a flare is considered to increase the capacity of the flare and cause a modification; (5) whether flare tip replacements are considered routine maintenance instead of a modification of the flare, even if the new flare tip has a different geometry (e.g., a larger diameter to reduce noise); and (6) how SSM streams are considered when calculating baseline emissions for a modification determination. The commenters also suggested that EPA should clarify whether and how the exemption in §60.14(e)(2) applies to a flare, including how the production rate for a flare would be defined.

Response: Section 60.14(a) defines modification as follows: “Except as provided in paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification.” Section 60.14(e) provides exclusions for maintenance activities, increased production rates, increased hours of operation, etc. However, except for the maintenance exclusion, the other exemptions are either not applicable or ambiguous when applied to a flare. More importantly, §60.14(f) states that “Applicable provisions set forth under an applicable subpart of this part shall supersede any conflicting provisions of this section.” Therefore, to eliminate ambiguity, we specifically define what constitutes a flare modification in subpart Ja.

A flare is considered to be modified in one of two ways. First, a flare is considered to be modified when any piping from a refinery process unit or fuel gas system is newly connected to

the flare. This new piping could allow additional gas to be sent to the flare, consequently increasing emissions from the flare. Second, a flare is considered to be modified if that flare is physically altered to increase flow capacity.

B.10 Delayed Coking Units

Comment: Several commenters supported the proposal that requires delayed coking units to depressure the coke drums to the fuel gas system down to 5 psig. One commenter supported venting the delayed coker gas to a flare or to the atmosphere at pressures less than 5 psig; at pressures greater than 5 psig, the commenter suggested that the rule should only prohibit gases from being sent to a flare and allow any other disposition. That is, the commenter stated that EPA should not restrict the disposition of the coker depressurization gas to only the fuel gas system.

One commenter supported inclusion of a coke drum pressure limit above which the coke drum exhaust gases must be sent to a recovery system, disagreed that it is technically infeasible to divert emissions for recovery at pressures below 5 psig, and urged EPA to require venting until the pressure drops below 2 psig. The commenter recently issued a permit including the 2 psig level, and although the modification has not been completed, the commenter believes the requirement is technically feasible.

A number of commenters objected to the finding that BDT is to depressure delayed coking units to the fuel gas system down to 5 psig. Commenters provided examples of coking units whose current mode of operations (e.g., set points or timed cycles) may divert to a flare or to the atmosphere at pressures of approximately 10 to 20 psig and that it would not be cost-effective to modify these units to comply with the proposed work practice standard. One commenter supported the premise that it is cost-effective for delayed coking discharge to be routed to fuel gas blowdown, but depressurization down to 5 psig may not be feasible with existing equipment; the commenter recommended that the work practice simply require a closed blow down system following procedures described in the facility's SSM plan. At a minimum, an alternative is needed for existing units that would require capital expenditure to meet the 5 psig proposal. One commenter stated that compressors cannot recover blowdown system gases at pressures below the fuel gas recovery compressor suction pressure. The minimum pressure at which a suction compressor can operate depends on the design of the coking unit and the blowdown management system. Because there is uncertainty surrounding the available emission

information, the costs are not minimal in most cases, and the emissions are difficult to measure, the commenter stated that EPA cannot determine that controls on coker vents is BDT.

Response: Based on the public comments, we re-evaluated BDT for delayed coking units. We considered three options: (1) depressurization down to 15 psig; (2) depressurization down to 5 psig; and (3) depressurization down to 2 psig. We estimated that the baseline is, on average, depressurization down to 15 psig and then venting to the atmosphere. Therefore, there are no impacts for Option 1. Impacts for Options 2 and 3 were estimated based on the baseline conditions, the size of typical coke drums, and cost information provided in public comments. We also collected emissions test data to support and verify the projected emissions and emission reductions.

The impacts for each option for new delayed coking units are presented in Table B-16; impacts for modified and reconstructed delayed coking units are presented in Table B-17.

Table B-16. National Fifth Year Impacts of Options for Work Practices Considered for New Delayed Coking Units Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons SO ₂ /yr)	Emission Reduction (tons VOC/yr)	Cost-Effectiveness (\$/ton)	
					Overall	Incremental
1	0	0	0	0	N/A	N/A
2	2,400	230	170	10	1,200	1,200
3	24,000	2,300	230	13	9,500	37,000

Table B-17. National Fifth Year Impacts of Options for Work Practices Considered for Modified and Reconstructed Delayed Coking Units Subject to 40 CFR Part 60, Subpart Ja

Option	Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Emission Reduction (tons SO ₂ /yr)	Emission Reduction (tons VOC/yr)	Cost-Effectiveness (\$/ton)	
					Overall	Incremental
1	0	0	0	0	N/A	N/A
2	14,000	1,400	260	15	4,900	4,900
3	54,000	5,100	340	19	14,000	45,000

Based on these impacts and consideration of technically feasible operating practices, we confirmed our conclusion at proposal that BDT is depressurization down to 5 psig, or Option 2. For new delayed coking units, this option achieves SO₂ emission reductions of 170 tons/yr from

a baseline of 520 tons/yr and VOC emission reductions of 2 tons/yr from a baseline of 7 tons/yr at a cost of \$1,300 per ton of combined SO₂ and VOC. For modified and reconstructed delayed coking units, this option achieves SO₂ emission reductions of 260 tons/yr from a baseline of 780 tons/yr and VOC emission reductions of 4 tons/yr from a baseline of 11 tons/yr at a cost of \$5,100 per ton of combined SO₂ and VOC. Although Option 3 has been established in one refiner's permit, this level of depressurization has not been demonstrated in practice.

Additionally, the difference in the quantity of gas released when the set point is 2 psig rather than 5 psig is relatively small, 80 tons of SO₂ and 4 tons of VOC, and the resulting incremental cost-effectiveness from Option 2 to Option 3 is about \$40,000/ton, which is much greater. Therefore, Option 3, or depressurization down to 2 psig, is not BDT.

B.11 Summary of Results for New Sources and Modified and Reconstructed Sources

Below in Table B-18 is a summary of results for the analyses done above for options applied to new sources. Table B-19 contains a similar summary for the modified and reconstructed sources.

Table B-18. National Incremental Emission Reductions and Cost Impacts for Options Applied to New Petroleum Refinery Units Subject to Final Standards Under 40 CFR Part 60, Subpart Ja (Fifth Year After Proposal)

Process Unit	Pollutant Controlled	Option	Total Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Annual Emission Reductions (tons PM/yr)	Annual Emission Reductions (tons SO ₂ /yr)	Annual Emission Reductions (tons NO _x /yr)	Annual Emission Reductions (tons VOC/yr)	Annual Cost-Effectiveness (\$/ton)	Incremental Annual Cost-Effectiveness (\$/ton)
FCCU	PM	1 (baseline)								
		2 ^a	3,600	1,100	235				5,600	5,600
		3	7,100	1,700	300				6,700	10,900
	SO ₂	1 (baseline)								
		2 ^a	0	1,400		1,993			700	700
		1	900	300			368		900	900
	NO _x	2 ^a	1,200	600			859		700	600
		3	12,200	3,600			1,382		2,600	5,800
Small SRP	SO ₂	1 (baseline)								
		2 ^a	100	100		42			1,500	1,500
		3	600	200		52			4,500	17,700
Fuel gas combustion devices	SO ₂	1 (baseline)								
		2 ^a	1,200	800		524			1,500	1,500
		3	100,200	13,200		926			14,300	31,000
Process heaters	NO _x	1	9,000	7,300			4,841		1,500	1,500
		2 ^a	9,000	7,500			5,237		1,400	1,400
		3	110,700	30,100			5,853		5,100	36,700

(continued)

Table B-18. National Incremental Emission Reductions and Cost Impacts for Options Applied to New Petroleum Refinery Units Subject to Final Standards Under 40 CFR Part 60, Subpart Ja (Fifth Year After Proposal) (continued)

Process Unit	Pollutant Controlled	Option	Total Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Annual Emission Reductions (tons PM/yr)	Annual Emission Reductions (tons SO ₂ /yr)	Annual Emission Reductions (tons NO _x /yr)	Annual Emission Reductions (tons VOC/yr)	Annual Cost-Effectiveness (\$/ton)	Incremental Annual Cost-Effectiveness (\$/ton)
Flare gas minimization	SO ₂ , VOC	1 (baseline)								
		2	0	23		15	0	0	1,600	1,600
		3 ^a	8,800	-1,300		16	1	41	-23,000	-31,000
		4	15,000	-840		16	1	52	-12,000	43,000
Delayed coking units	SO ₂ , VOC	1								
		2 ^a	2,400	200		174		10	1,200	1,200
		3	24,000	2,300		227		13	9,500	36,900
Sulfur pits	SO ₂	1								
		2 ^a	700	100		30			2900	2,900
		3	1,300	200		31			5,600	114,000

^a Denotes selected option. All costs are in 2006 dollars. 83.3% of the PM emissions are PM_{2.5}.

Table B-19. National Incremental Emission Reductions and Cost Impacts for Options Applied to Modified and Reconstructed Petroleum Refinery Units Subject to Final Standards Under 40 CFR part 60, subpart Ja (Fifth Year After Proposal)

Process Unit	Pollutant Controlled	Option	Total Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Annual Emission Reductions (tons PM/yr)	Annual Emission Reductions (tons SO ₂ /yr)	Annual Emission Reductions (tons NO _x /yr)	Annual Emission Reductions (tons VOC/yr)	Annual Cost-Effectiveness (\$/ton)	Incremental Annual Cost-Effectiveness (\$/ton)
FCCU	PM	1 (baseline) ^a								
		2	75,200	11,900	690				20,700	20,700
		3	101,100	15,500	808				23,000	36,500
	SO ₂	1 (baseline)								
		2 ^a	0	1,600		2,400			700	700
	NO _x	1	2,800	1,000			856		1,200	900
		2 ^a	3,700	1,600			1,784		900	700
		3	44,800	11,500			3,234		3,600	6,800
FCU	PM, SO ₂	1 (baseline)								
		2 ^a	10,400	3,200	1,000	5,900			500	500
	NO _x	1 (baseline)								
		2	800	200			410		400	400
		3 ^a	3,700	900			657		1,300	2,700
		4	6,000	1,300			745		1,700	5,000
Small SRP	SO ₂	1 (baseline)								
		2 ^a	1,600	700		381			1,800	1,800
		3	7,800	2,600		466			5,700	23,000

(continued)

Table B-19. National Incremental Emission Reductions and Cost Impacts for Options Applied to Modified and Reconstructed Petroleum Refinery Units Subject to Final Standards Under 40 CFR part 60, subpart Ja (Fifth Year After Proposal) (continued)

Process Unit	Pollutant Controlled	Option	Total Capital Cost (\$1,000)	Total Annual Cost (\$1,000/yr)	Annual Emission Reductions (tons PM/yr)	Annual Emission Reductions (tons SO ₂ /yr)	Annual Emission Reductions (tons NO _x /yr)	Annual Emission Reductions (tons VOC/yr)	Annual Cost-Effectiveness (\$/ton)	Incremental Annual Cost-Effectiveness (\$/ton)
Fuel gas combustion devices	SO ₂	1 (baseline)								
		2 ^a	32,900	11,300		4,700			2,400	2,400
		3	1,674,000	198,100		9,100			21,700	42,300
Process heaters	NO _x	1	11,700	4,000			2,075		1,900	1,900
		2 ^a	14,000	4,300			2,244		1,900	2,100
		3	64,100	14,800			2,509		5,900	39,400
Flare gas minimization	SO ₂ , VOC	1 (baseline)								
		2	0	100		59	0	0	1,600	1,600
		3 ^a	35,000	-5,300		64	4	165	-23,000	-31,000
		4	59,000	-3,300		66	6	207	-12,000	43,000
Delayed coking units	SO ₂ , VOC	1								
		2 ^a	14,400	1,400		261		15	4,900	4,900
		3	54,000	5,100		340		19	14,200	45,100
Sulfur pits	SO ₂	1								
		2 ^a	7,700	900		269			3,500	3,500
		3	15,300	1,900		275			6,800	138,800

^a Denotes selected option. All costs are in 2006 dollars. 83.3% of the PM emissions are PM_{2.5}.

SECTION 5

ECONOMIC IMPACT ANALYSIS: METHODS AND RESULTS

The EIA is designed to inform decision makers about the potential economic consequences of a regulatory action. The analysis consists of estimating the social costs of a regulatory program and the distribution of these costs across stakeholders (consumers and producers). As defined in EPA's (2000) *Guidelines for Preparing Economic Analyses*,¹ social costs are the value of the goods and services lost by society resulting from using resources to comply with and implement a regulation and reductions in output.

5.1 Market Model

EPA constructed partial equilibrium models of the national markets for five major petroleum products (motor gasoline, jet fuel, distillate fuel oil, residual fuel oil, and liquefied petroleum gases).² These models were used to measure the economic consequences of the regulatory program in the intermediate run (when some factors of production are fixed and others are variable).³ Partial equilibrium models track the effects of regulatory action in a single market, while ignoring interactions with other markets.

Each of the 5 intermediate-run market models uses a common analytic expression to estimate how an increase in the per-unit (per-gallon) costs of producing a product will impact that product's price (Berck and Hoffmann, 2002; Fullerton and Metcalfe, 2002). This expression is presented in Equation 5.1. A full description for how it is derived and used is provided in Appendix C.

$$\Delta \text{price} = \frac{\text{Supply Elasticity}}{\text{Supply Elasticity} - \text{Demand Elasticity}} \times \text{Per-Gallon Cost} \quad (5.1)$$

This approach follows EPA guidelines for analyzing the economic impacts of a regulatory program (EPA, 1999; EPA, 2000).

5.2 Model Baseline

Standard EIA practice compares and contrasts the state of a market with and without a regulatory policy. EPA selected 2012, the fifth year after proposal, as the baseline year for the analysis. Forecasts for the price and consumption of each petroleum product in 2012 were

¹ These guidelines are under review by the Agency.

² National market models were selected in order to be consistent with the national-level cost estimates provided by the engineering cost analysis.

³ For a complete discussion of how the intermediate run is defined, please see the *OAQPS Economic Analysis Resource Document* (EPA, 1999).

collected from the Energy Information Administration's Annual Energy Outlook and reported in Chapter 3 (Tables 3-19 and 3-20). However, these data had to be standardized for use in EPA's models.

First, the 2007 Annual Energy Outlook reports the price of petroleum products in terms of 2005 dollars. However, compliance costs were estimated in terms of 2006 dollars. Therefore, to ensure that common units were being used, petroleum product prices were converted to 2006 dollars by dividing the 2012 forecasted price in 2012 by the ratio of the Consumer Price Indices (CPI) in 2006 and 2005.

Second, the 2007 Annual Energy Outlook reports the quantity of petroleum products consumed in terms of barrels, while the price of petroleum products is reported in terms of dollars per gallon. Therefore, to ensure that common units were being used, the number of barrels produced each year was divided by 42 (the number of gallons in a barrel). A summary of the baseline data used in each of the five market models after these adjustments were made is reported in Table 5-1.

Table 5-1. Baseline Market Data: 2012

Market	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases
Price (\$2006/per gallon)	\$2.11	\$1.40	\$2.04	\$1.06	\$1.55
Quantity (billion gallons/per year)	149.67	31.04	71.83	12.36	34.10

Sources: 2012 Petroleum product price and consumption forecasts: U.S. Department of Energy, Energy Information Administration (EIA). 2007. "Annual Energy Outlook." Available at <[http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383\(2007\).pdf](http://www.eia.doe.gov/oiaf/archive/aeo07/pdf/0383(2007).pdf)>. As obtained on January 21, 2007.

2005 and 2006 Consumer Price Indices: U.S. Department of Energy, Energy Information Administration (EIA). 2008. "Short-Term Energy Outlook: Real Petroleum Prices." Available at <http://www.eia.doe.gov/emeu/steo/pub/fsheets/real_prices.html>. As obtained on April 21, 2008.

5.3 Model Parameters

An essential component of partial equilibrium models are supply and demand price elasticities. These elasticities measure the responsiveness of producers and consumers to prices changes and determine how the social costs of a regulatory program are distributed between the two groups of stakeholders. Economic theory suggests consumers will bear a higher share of the economic welfare losses if the supply of a petroleum product is more responsive to price changes than is the demand for that product. A summary of the estimates of demand and supply elasticities used in this analysis is provided in Table 5-2.

Table 5-2. Estimates of Price Elasticity of Demand and Supply

Market	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases
Demand elasticity	-0.69	-0.15	-0.75	-0.68	-0.8
Supply elasticity	1.24	1.24	1.24	1.24	1.24

Sources: U.S. Environmental Protection Agency. 1995. *Economic Impact Analysis for Petroleum Refineries NESHAP*. EPA-452/R-95-003, Final Report. Washington DC: Government Printing Office.

5.4 Results

Chapter 4 reports that the estimated change in total annualized costs resulting from the regulatory program is a cost of approximately \$31 million (measured in 2006 dollars). According to the 2007 Annual Energy Outlook, the forecasted consumption of all petroleum products in 2012 is 8.08 billion barrels or 339.25 billion gallons. Assuming that the production process of all petroleum products are equally affected this regulatory program is expected to result in a \$0.000091 per-gallon cost to consumers (\$31 million / 339.25 billion gallons).⁴

Based on EPA's partial equilibrium analysis, the costs induced by this regulatory program do not have a significant impact on market-level prices or quantities. The results of this analysis are summarized in Table 5-3. As this table shows, prices for all products rise by less than 1 penny (0.003%–0.006%). In addition, the quantity of each petroleum product produced declines. Motor gasoline and distillate fuel face the largest absolute quantity reductions (2.8 and 1.4 million gallons, respectively, or 0.002%), while residual fuel oil sees the largest proportional decline in production (0.004%).

As a result of higher prices, consumers of petroleum products see a decline in surplus. For example, consumers of motor gasoline lose \$8.78 million of surplus. In addition, producers also receive a smaller surplus as a result of higher production costs. In the case of motor gasoline, producers lose \$4.89 million. Total surplus losses for consumers and producers of motor gasoline are estimated to be \$13.67 million. Thus, the total annualized loss in surplus in the markets analyzed, which is an estimate of the social cost of this NSPS, is \$27.30 million or slightly less than the total annualized compliance cost in these markets. In addition to the loss in surplus for these petroleum products, an additional \$3.7 million in costs will affect markets for other petroleum products.

⁴ In addition to motor gasoline, jet fuel, distillate fuel oil, residual fuel oil, and liquefied petroleum gases, other petroleum products will experience cost savings as a result of the regulatory program. These products include asphalt, lubricants, road oil, petroleum coke and others. However, these impacts were not explicitly modeled for this analysis.

Table 5-3. Summary of Intermediate Run Economic Impacts by Petroleum Product: 2012

	Motor Gasoline	Jet Fuel	Distillate Fuel Oil	Residual Fuel Oil	Liquefied Petroleum Gases
Change in price	0.003%	0.006%	0.003%	0.006%	0.004%
	Less than a penny per gallon	Less than a penny per gallon	Less than a penny per gallon	Less than a penny per gallon	Less than a penny per gallon
Change in quantity	−0.002%	−0.001%	−0.002%	−0.004%	−0.003%
	(−2.8 million gallons per year)	(−0.2 million gallons per year)	(−1.4 million gallons per year)	(−0.4 million gallons per year)	(−0.9 million gallons per year)
	Welfare Impacts (\$million)	Welfare Impacts (\$million)	Welfare Impacts (\$million)	Welfare Impacts (\$million)	Welfare Impacts (\$million)
Change in consumer surplus	−\$8.78	−\$2.53	−\$4.10	−\$0.73	−\$1.89
Change in producer surplus	−\$4.89	−\$0.31	−\$2.46	−\$0.40	−\$1.22
Change in total surplus	−\$13.67	−\$2.83	−\$6.56	−\$1.13	−\$3.11

5.5 Executive Order 13211 (Energy Effects)

This rule is not a “significant energy action” as defined in Executive Order 13211, “Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use” (66 FR 28355 [May 22, 2001]) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. We prepared an analysis of the impacts on energy markets as part of our economic impact analysis for today’s action. Our analysis shows that there is a reduction in output of the five petroleum products included in this analysis of between 0.2 and 2.8 million gallons, or a decrease in output of less than 0.01%, in the fifth year after proposal of this action. In addition, our analysis shows that prices increase less than 0.001% in the fifth year after proposal of this action for all petroleum products analyzed. Given such a small increase in domestic prices, no significant increase in our dependence on foreign energy supplies should take place. Finally, today’s action will have no adverse effect on crude oil supply, coal production, electricity production, and energy distribution. Based on the findings from the analysis of impacts on energy markets, we conclude that today’s action is not a “significant energy action” as defined in Executive Order 13211. For more information on this analysis, please refer to the economic impact analysis shown earlier in this chapter.

5.6 Limitations

The results of economic should be viewed with the following limitations in mind. First, the national competitive market assumption may influence the findings, because the markets for petroleum products such as motor gasoline are regional. Regional price and quantity impacts could be different from the average impacts reported in this analysis if local market structures, production costs, or demand conditions are substantially different from those used in this analysis. Second, the model uses a market supply function and analyzes supply behavior at or near a single market baseline equilibrium using a supply elasticity parameter. Therefore, it does not address facility-level impacts such as closures or changes in employment. Although developing a facility-level model could potentially provide these outputs, this type of model requires substantial amounts of detailed data for individual facilities and a level of effort beyond the scope of this analysis. As a result, EPA conducted a cost-to-sales ratio analysis to assess impacts on firms, specifically small firms (see Section 6).

5.7 References

- Berck, P., and S. Hoffmann. 2002. “Assessing the Employment Impacts.” *Environmental and Resource Economics* 22:133–156.
- Fullerton, D., and G. Metcalf. 2002. “Tax Incidence.” In A. Auerbach and M. Feldstein, eds., *Handbook of Public Economics*, Vol. 4. Amsterdam: Elsevier.

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SECTION 6

SMALL BUSINESS ANALYSIS

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.¹ This section begins by describing the data and methods used for performing this small business analysis and end by reporting the results of the analysis.

6.1 Data and Methods for Flexibility Analysis

The impact of the rule on small businesses is assessed using the ratio of compliance costs to the annual revenue of the ultimate parent company. This is known as the cost-to-sales ratio or CSR and it can be computed using the following equation:

$$CSR = \frac{\sum_i^n TACC}{TR_j} \quad (6.1)$$

where

- TACC = total annual compliance costs,
- i = indexes the number of affected plants owned by company j,
- n = number of affected plants, and
- TR_j = total annual revenue of a representative ultimate parent company j in each industry

If the CSR is less than 1%, then the regulatory program is considered to not have a significant impact on the parent company in question. This approach assumes affected firms absorb the control costs, rather than pass them onto consumers in the form of higher prices.

In Chapter 3, 25 small companies owning petroleum refineries classified as small according. As previously discussed, small businesses in the petroleum refining industry (NAICS code 324100) are defined for the purposes of this rule as having 1,500 or fewer employees.²

¹ Small entities include small businesses, small organizations, and small governmental jurisdictions.

² Refer to http://www.sba.gov/idc/groups/public/documents/sba_homepage/serv_sstd_tablepdf.pdf for more information on SBA small business size standards.

Table 6-1 duplicates sales employment data for these 25 small companies originally reported in Chapter 3.

Table 6-1. Characteristics of Small Businesses in the Petroleum Refining Industry

Facility Name	Refineries (#)	Parent Company Sales (\$Millions)	Parent Company Employment (#)
AGE Refining & Manufacturing	1	287	52
American Refining Group	1	350	310
Arabian American Development Co	1	80	118
Calcasieu Refining Co.	1	638	51
Calumet Specialty Products	3	1,641	350
Countrymark Cooperative, Inc.	1	87	300
Cross Oil & Refining Co. Inc.	1	49	110
CVR Energy Inc.	1	3,038	577
Foreland Refining Co.	1	56	100
Frontier Oil Corp	2	4,000	727
Gary-Williams Co	1	97	200
Goodway Refining LLC	1	3	18
Greka Integrated Inc	1	22	145
Gulf Atlantic Operations LLC	1	9	32
Holly Corp.	2	4,023	859
Hunt Refining Co.	3	4,871	1,100
Lion Oil Co.	1	247	425
Pelican Refining Co. LLC	1	29	62
Placid Refining Inc.	1	1,400	200
San Joaquin Refining Co., Inc.	1	288	20
Somerset Oil Inc	1	55	150
Trigeant Ltd.	1	5	50
Western Refining, Inc.	4	4,200	416
World Oil Corp	1	277.3	475
Wyoming Refining Co.	1	340	107

We note here, that we inadvertently used a different small business size standard for small refiners in the proposed NSPS. The small business analysis for the final rulemaking incorporates the correct SBA small business size standard of 1,500 employees per ultimate parent refiner. The effect of this correction on the affected small refiner universe is an increase of one small firm. There is no effect on our determination of no significant economic impact on a substantial number of small entities (to be shown later) as a result of this correction.

6.2 Results of Small Business Analysis

As described in Chapter 4, the EPA estimates that small businesses will invest in two new or modified process units during the five-year period of analysis. Investing in these process units would require the small businesses to incur an average \$1.5 million per facility in annualized compliance cost and earn an average \$0.6 million per facility in cost savings as a result of the final NSPS—a net total annualized compliance cost of \$910 thousand per facility.

Literature on the petroleum refining industry was examined to identify and characterize small firms likely to be affected by the rule. The *Oil & Gas Journal's* 2008 Worldwide Construction Update survey catalogued over 40 refining construction projects that have been announced in the United States. Among the companies announcing construction projects³, three were identified by EPA as small businesses—Frontier Oil Corp, Holly Corp, and Placid Refining Inc. EPA therefore estimates that three small businesses will invest in new or modified process units during the five-year period of analysis.

As indicated in Table 6-1, each of these companies earned over \$1 billion in revenue in the base year for this analysis (2006). Assuming that these three small businesses (out of 25 total small businesses identified by EPA) are representative of the small businesses that will invest in new or modified process units over the five year period of analysis, their cost to sales ratios would be less than 1%. As a result, the final NSPS is not expected to have a significant impact on small companies.

After considering the economic impact of today's action on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. Of the affected entities, none are estimated to incur annualized compliance cost over 1% of sales.

Although this action would not have a significant economic impact on any small entities, EPA nonetheless has tried to reduce the impact of this action on small entities by incorporating specific standards for small sulfur recovery plants and streamlining procedures for exempting inherently low-sulfur fuel gases from continuous monitoring. In addition, EPA has updated this small business analysis to incorporate capacity data for small refiners provided in a comment by the Ad Hoc Coalition of Small Business Refiners.

³ Construction projects included in the *Oil & Gas Journal's* analysis include new, expanded, and upgraded processes.

SECTION 7

HUMAN HEALTH BENEFITS OF EMISSIONS REDUCTIONS

7.1 Calculation of Human Health Benefits

In order to estimate the human health benefits of reducing emissions from refineries through this final rulemaking, EPA used the benefits transfer approach and methodology described in EPA's benefits analysis the Technical Support Document (TSD)¹ accompanying the recent National Ambient Air Quality Standards (NAAQS) for Ozone.² In that RIA, EPA applied a benefits transfer approach to estimate the PM_{2.5} co-benefits resulting from reductions in emissions of NO_x; EPA is adapting that method to estimate the health benefits for the projected emission reductions of PM_{2.5} precursor pollutants associated with this final rulemaking.

EPA did not perform an air quality modeling assessment of the emission reductions resulting from installing controls on these refineries because of the time and resource constraints and the limited value of such an analysis for the purposes of developing the regulatory approach for this final rule. This lack of air quality modeling limited EPA's ability to perform a comprehensive benefits analysis for this final rulemaking since our benefits model requires either air quality modeling or monitoring data.

To estimate the human health benefits of emission reductions from refineries for this analysis in the absence of modeling data, we used the studies from the PM NAAQS Regulatory Impact Analysis (RIA)³ to generate benefit-per-ton values. These PM_{2.5} precursor pollutant benefit per-ton estimates provide the total monetized human health benefits (the sum of premature mortality and premature morbidity) of reducing one ton of PM_{2.5} and PM_{2.5} precursor emissions from a specified source. These benefits estimates have been updated in the final NSPS to utilize the mortality valuation estimates obtained in the expert elicitation study, as mentioned in the proposal. In addition, we also include VOC benefit-per-ton estimates.⁴ EPA has used a similar technique in previous RIAs, beginning with the PM NAAQS RIA (U.S. EPA, 2006). EPA has requested the SAB to review the presentation of benefits estimates based on the mortality

¹ U.S. EPA, 2008a. *Technical Support Document: Calculating Benefit Per-Ton estimates*, Ozone NAAQS Docket #EPA-HQ-OAR-2007-0225-0284.

² U.S. EPA, 2008b. *Regulatory Impact Analysis, 2008 National Ambient Air Quality Standards for Ground-level Ozone*, Chapter 6. Available on the Internet at <http://www.epa.gov/ttn/ecas/regdata/RIAs/6-ozoneriachapter6.pdf>.

³ U.S. EPA, 2006. *Regulatory Impact Analysis, 2006 National Ambient Air Quality Standards for Particulate Matter*, Chapter 5. Available on the Internet at <http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205--Benefits.pdf>.

⁴ In this analysis, the monetized benefits of reducing VOCs only reflect their effects as a PM_{2.5} precursor pollutant. In this analysis, we are not quantifying any ozone-related health benefits.

valuation estimates obtained in the expert elicitation study in the context of an RIA. The 14 estimates presented below derive from the application of three alternative methods:

- One estimate is based on the concentration-response (C-R) function developed from the study of the American Cancer Society (ACS) cohort reported in Pope et al. (2002), which has previously been reported as the primary estimate in recent RIAs
- One estimate is based on Laden et al.'s (2006) reporting of the extended Six Cities cohort study; this study is a more recent PM epidemiological study that was used as an alternative in the PM NAAQS RIA.
- The other 12 estimates are based on the results of EPA's expert elicitation study on the PM-mortality relationship, as first reported by Industrial Economics (2006) and interpreted for benefits analysis in EPA's final RIA for the PM NAAQS, published in September 2006 (EPA, 2006). For that study, 12 experts (labeled A through L) provided independent estimates of the PM-mortality C-R function. EPA practice has been to develop independent estimates of PM-mortality estimates corresponding to the concentration-response function provided by each of the 12 experts.

EPA believes that these updated estimates will better characterize the uncertainty associated with using the benefit-per-ton approach to derive an estimate of total benefits. Readers interested in the complete methodology for creating the benefit-per-ton estimates used in this analysis may consult the Technical Support Document accompanying the final Ozone NAAQS RIA (EPA, 2008).

To develop the estimate of the benefits of reducing emissions from this rulemaking, we calculated the monetized benefits-per-ton of emissions reduction estimates for direct PM_{2.5} and each PM_{2.5} precursor pollutant.⁵ In the TSD, we describe in detail how we generated the benefit-per-ton estimates. In summary, we used a model to convert emissions of direct PM_{2.5} and PM_{2.5} precursors (i.e., SO₂, NO_x, and VOCs) into changes in PM_{2.5} air quality. Next, we used the benefits model to estimate the changes in human health based on the change in PM_{2.5} air quality. Finally, the monetized health benefits were divided by the emission reductions to create the benefit per ton estimates. Even though all fine particles are assumed to have equivalent health effects, the benefit-per-ton estimates vary because each ton of precursor reduced has a different propensity to become PM_{2.5}. For example, NO_x has a lower benefit-per-ton estimate than direct PM_{2.5} because it does not form as much PM_{2.5}, thus the exposure would be lower, and the monetized health benefits would be lower.

⁵ Emission reductions shown in the tables below are in terms of total PM, but it is estimated that 83.3% of the PM emissions are in the PM_{2.5} fraction. For the purposes of this benefits analysis, all of the PM benefits shown in the following tables are the PM_{2.5} fraction. Therefore, we do not provide any benefits estimates for the reductions of PM other than PM_{2.5} (e.g., PM₁₀) that will take place as a result of this final NSPS.

After generating the benefit-per-ton estimate, we then multiply this estimate by the number of tons of each pollutant reduced to derive an overall monetary value of benefits. We show a range of benefits estimates per pollutant (and option) rather than a single point estimate in order to reflect the range of estimates obtained in the expert elicitation study.⁶ Table 7-1 provides a general summary of the results by pollutant for the selected options, including the emissions reductions and monetized benefits-per-ton range. Figure 7-1 provides a visual representation of the full range of benefits estimates by pollutant at a discount rate of 3%. Tables 7-2 and 7-3 summarize the range of benefits of the selected options at discount rates of 3% and 7%, respectively. Tables 7-4 and 7-5 provide the range of benefits for all options discounted at 3% and 7% for new and modified/reconstructed units, respectively. All benefits estimates are for the fifth year after proposal (2012). More details on the options, emissions, and emission reductions can be found in Chapter 4 of this RIA.

Table 7-1. General Summary of Range of Benefits Estimates for Selected Options in the Final NSPS^a

Pollutant	Emissions Reductions (tons)	Benefit per Ton (low, 3%)	Benefit per Ton (high, 3%)	Benefit per Ton (low, 7%)	Benefit per Ton (high, 7%)	Total Monetized Benefits (millions 2006\$ at 3%)			Total Monetized Benefits (millions 2006\$ at 7%)		
Direct PM _{2.5}	1,054	\$68,000	\$570,000	\$63,000	\$520,000	\$72	to	\$600	\$66	to	\$540
PM _{2.5} Precursor											
SO ₂	16,714	\$8,000	\$68,000	\$7,400	\$62,000	\$130	to	\$1,100	\$120	to	\$1,000
NO _x	10,786	\$1,300	\$11,000	\$1,200	\$9,600	\$14	to	\$110	\$13	to	\$100
VOC	230	\$210	\$1,700	\$190	\$1,500	\$0.05	to	\$0.38	\$0.04	to	\$0.35
Total						\$220	to	\$1,900	\$200	to	\$1,700

^a All estimates are for the analysis year (fifth year after proposal, 2012), and are rounded to two significant figures so numbers may not sum across columns. Emission reductions reflect the combination of selected options for both new and reconstructed/modified sources. All benefits estimates are shown at both 3% and 7% discount rate. The PM_{2.5} fraction of total PM emissions is estimated at 83.3%, and only the reduction in the PM_{2.5} fraction is monetized in this analysis. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary because each ton of precursor reduced has a different propensity to become PM_{2.5}. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

⁶ In the Expert Elicitation, Expert K represented the lowest estimate, and Expert E represented the highest estimate. Therefore, the total range of benefits is presented as the range from Expert K to Expert E.

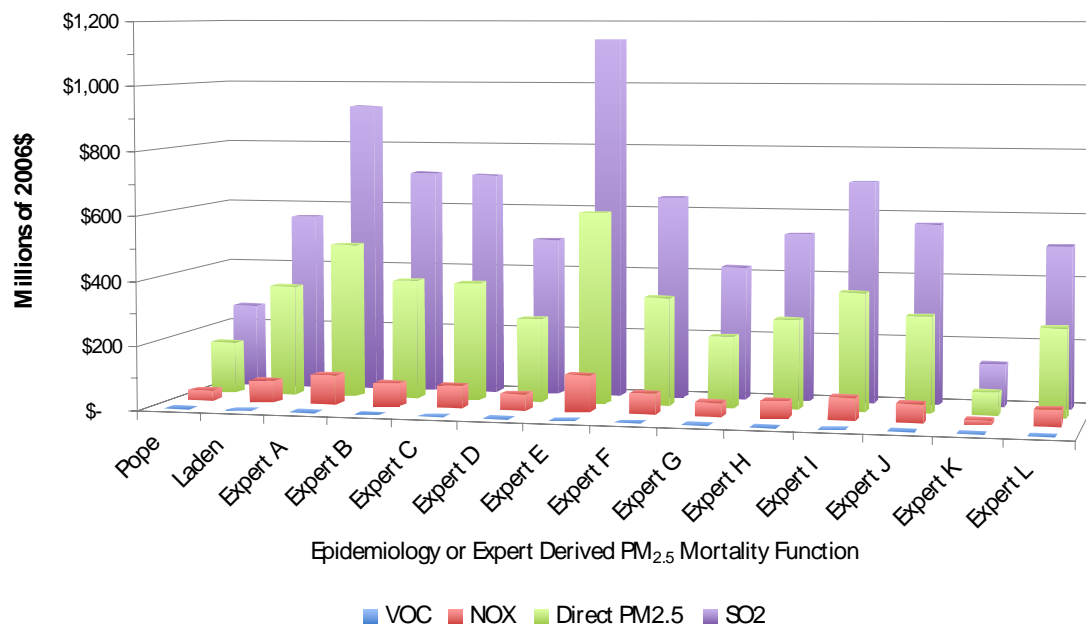


Figure 7-1. Monetized Benefits for Selected Options for Final Petroleum Refineries NSPS at 3% Discount Rate by PM_{2.5} Precursor Emitted in 2012^a

^a This graph shows 14 PM benefits estimates, which are treated as independent and equally probable, for each precursor pollutant. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary because each ton of precursor reduced has a different propensity to become PM_{2.5}. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

It is important to note that the monetized benefit-per-ton estimates used here reflect specific geographic patterns of emissions reductions and specific air quality and benefits modeling assumptions. Use of these \$/ton values to estimate benefits associated with different emission control programs (e.g., for reducing emissions from large stationary sources like EGUs) may lead to higher or lower benefit estimates than if benefits were calculated based on direct air quality modeling. Great care should be taken in applying these estimates to emission reductions occurring in any specific location, as these are all based on national or broad regional emission reduction programs and therefore represent average benefits-per-ton over the entire United States. The benefits-per-ton for emission reductions in specific locations may be very different than the national average.

Table 7-2. Summary of Monetized Benefits for Selected Options at 3% Discount Rate in 2012 (millions of 2006\$)

Process Unit (new)	Selected Option ^a	Pollutant ^b	Emissions Reduction (tons)	Total Benefit (millions) ^c		
FCCU	2	PM	235	\$13	–	\$110
	2	SO ₂	1,993	\$16	–	\$140
	2	NO _x	859	\$1.1	–	\$9.1
Small SRP	2	SO ₂	42	\$3.4	–	\$2.9
Fuel gas combustion	2	SO ₂	524	\$4.2	–	\$36
Flaring gas minimization	3	SO ₂	24	\$2.0	–	\$1.7
	3	NO _x	9	\$0.1	–	\$0.9
	3	VOC	277	\$0.6	–	\$4.6
Delayed cokers	2	SO ₂	174	\$1.4	–	\$12
	2	VOC	10	\$0.0	–	\$0.2
Process heater	2	NO _x	5,237	\$6.9	–	\$56
Sulfur pits	2	SO ₂	30	\$2.4	–	\$2.0
Total				\$43	–	\$370
Process Unit (modified/reconstructed)						
FCCU	1	PM	0	\$0.0	–	\$0.0
	2	SO ₂	2,350	\$19	–	\$160
	2	NO _x	1,784	\$2.3	–	\$19
Fluid coker	2	PM	1,030	\$47	–	\$400
	2	SO ₂	5,893	\$59	–	\$490
Fluid coker	3	NO _x	657	\$8.6	–	\$7.0
SRP	2	SO ₂	381	\$3.1	–	\$26
Fuel gas combustion	2	SO ₂	4,717	\$38	–	\$320
Process heaters	2	NO _x	2,244	\$3.0	–	\$24
Flaring gas minimization	3	SO ₂	97	\$7.8	–	\$6.6
	3	NO _x	35	\$0.5	–	\$3.7
	3	VOC	1,108	\$2.3	–	\$1.8
Delayed cokers	2	SO ₂	261	\$2.1	–	\$18
	2	VOC	15	\$0.0	–	\$0.2
Sulfur pits	2	SO ₂	269	\$2.2	–	\$18
Total				\$180	–	\$1,500

^a Refer to Chapter 4 of this RIA for more details on options.

^b The PM_{2.5} fraction is estimated at 83.3% of the total PM emissions, and only reductions in the PM_{2.5} fraction is monetized in this analysis. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary because each ton of precursor reduced has a different propensity to become PM_{2.5}. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

^c All estimates rounded to two significant figures and may not sum across columns.

Table 7-3. Summary of Monetized Benefits for Selected Options at 7% Discount Rate in 2012 (millions of 2006\$)

Process Unit (new)	Selected Option ^a	Pollutant ^b	Emissions Reduction (tons)	Total Benefit (millions) ^c		
FCCU	2	PM	235	\$12	–	\$100
	2	SO ₂	1,993	\$15	–	\$120
	2	NO _x	859	\$1.0	–	\$8.2
Small SRP	2	SO ₂	42	\$3.1	–	\$2.6
Fuel gas combustion	2	SO ₂	524	\$3.9	–	\$32
Flaring gas minimization	3	SO ₂	16	\$1.2	–	\$1.0
	3	NO _x	1	\$0.00	–	\$0.01
	3	VOC	41	\$0.01	–	\$0.06
Delayed cokers	2	SO ₂	174	\$1.3	–	\$11
	2	VOC	10	\$0.00	–	\$0.02
Process heater	2	NO _x	5,237	\$6.3	–	\$50
Sulfur pits	2	SO ₂	30	\$2.2	–	\$1.8
Total				\$40	–	\$320
Process Unit (modified/reconstructed)						
FCCU	1	PM	0	\$0.00	–	\$0.00
	2	SO ₂	2,350	\$17	–	\$140
	2	NO _x	1,784	\$2.2	–	\$17
Fluid coker	2	PM	1,030	\$43	–	\$360
	2	SO ₂	5,893	\$54	–	\$440
Fluid coker	3	NO _x	657	\$7.9	–	\$6.3
SRP	2	SO ₂	381	\$2.8	–	\$23
Fuel gas combustion	2	SO ₂	4,717	\$35	–	\$290
Process heaters	2	NO _x	2,244	\$2.7	–	\$21
Flaring gas minimization	3	SO ₂	64	\$4.7	–	\$3.9
	3	NO _x	4	\$0.01	–	\$0.04
	3	VOC	165	\$0.03	–	\$3
Delayed cokers	2	SO ₂	261	\$1.9	–	\$16
	2	VOC	15	\$0.00	–	\$0.02
Sulfur pits	2	SO ₂	269	\$2.0	–	\$17
Total				\$160	–	\$1,300

^a Refer to Chapter 4 of this RIA for more details on options.

^b The PM_{2.5} fraction is estimated at 83.3% of the total PM emissions, and only reductions in the PM_{2.5} fraction is monetized in this analysis. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary because each ton of precursor reduced has a different propensity to become PM_{2.5}. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

^c All estimates rounded to two significant figures and may not sum across columns.

Table 7-4. Estimated Range of Monetized Benefits in 2012 for All Options of New Process Units (thousands of 2006\$)^a

Process Unit	Pollutant ^B	Option	Total Benefits Low 3% (\$1,000/yr)	Total Benefits High 3% (\$1,000/yr)	Total Benefits Low 7% (\$1,000/yr)	Total Benefits High 7% (\$1,000/yr)
FCCU	PM	1 Baseline (1.0 lb/klb coke burn (M5B or 5F))	\$—	\$—	\$—	\$—
		2 0.5 lb/klb coke burn (M5B or 5F) ^C	\$13,000	\$110,000	\$12,000	\$100,000
		3 0.5 lb/klb coke burn (M5)	\$17,000	\$140,000	\$16,000	\$130,000
FCCU	SO ₂	1 Baseline	\$—	\$—	\$—	\$—
		2 25 ppmv ^C	\$16,000	\$140,000	\$15,000	\$120,000
FCCU	NO _x	1 150 ppmv	\$480	\$3,900	\$450	\$3,500
		2 80 ppmv ^C	\$1,100	\$9,100	\$1,000	\$8,200
		3 20 ppmv	\$1,800	\$15,000	\$1,700	\$13,000
Small SRP	SO ₂	1 Baseline	\$—	\$—	\$—	\$—
		2 Less than 20 ltpd @ 99% ^C	\$340	\$2,900	\$310	\$2,600
		3 All at 250 ppmv	\$420	\$3,500	\$380	\$3,200
Fuel gas combustion	SO ₂	1 Baseline	\$—	\$—	\$—	\$—
		2 long term limit of 60 ppmv H ₂ S ^C	\$4,200	\$36,000	\$3,900	\$32,000
		3 TRS limits of 160/60 ppm	\$7,400	\$63,000	\$6,800	\$57,000
Process heaters	NO _x	1 80 ppmv >20 MMBtu/hr	\$6,400	\$51,000	\$5,900	\$46,000
		2 40 ppmv >40 MMBt/hr ^C	\$6,900	\$56,000	\$6,300	\$50,000
		3 20 ppmv, 40 MMBtu/hr	\$7,700	\$62,000	\$7,100	\$56,000
Flare gas minimization	SO ₂ /VOC	1 Baseline (no standard)	\$—	\$—	\$—	\$—
		2 RCA >500 lb/day SO ₂	\$120	\$1,000	\$110	\$910
		3 Option 2 + Flare minimization plan ^C	\$140	\$1,200	\$130	\$1,100
		4 Option 2 + No routine flaring	\$140	\$1,200	\$130	\$1,100
Delayed cokers	SO ₂ /VOC	1 Depressure to control to 15 psig	\$—	\$—	\$—	\$—
		2 Depressure to control to 5 psig ^C	\$1,400	\$12,000	\$1,300	\$11,000
		3 Depressure to control to 2 psig	\$1,800	\$15,000	\$1,700	\$14,000

(continued)

Table 7-4. Estimated Range of Monetized Benefits in 2012 for All Options of New Process Units (thousands of 2006\$)^a
(continued)

Process Unit	Pollutant^B	Option	Total Benefits Low 3% (\$1,000/yr)	Total Benefits High 3% (\$1,000/yr)	Total Benefits Low 7% (\$1,000/yr)	Total Benefits High 7% (\$1,000/yr)
Sulfur pits	SO ₂	1 Do not include sulfur pits	\$—	\$—	\$—	\$—
		2 Include primary sulfur pits ^c	\$240	\$2,000	\$220	\$1,800
		3 Include primary pits and secondary tanks	\$250	\$2,100	\$230	\$1,900

^a All estimates rounded to two significant figures.

^b The PM_{2.5} fraction is estimated at 83.3% of the total PM emissions, and only the reduction in the PM_{2.5} fraction is monetized in this analysis. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary because each ton of precursor reduced has a different propensity to become PM_{2.5}. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

^c This is the selected option.

Table 7-5. Estimated Range of Monetized Benefits in 2012 for All Options of Modified/Reconstructed Process Units (thousands of 2006\$)^a

Process Unit	Pollutant ^b	Option	Total Benefits Low 3% (\$1,000/yr)	Total Benefits High 3% (\$1,000/yr)	Total Benefits Low 7% (\$1,000/yr)	Total Benefits High 7% (\$1,000/yr)
FCCU	PM	1 Baseline (1.0 lb/klb coke burn (M5B or 5F)) ^c	\$—	\$—	\$—	\$—
		2 0.5 lb/klb coke burn (M5B or 5F)	\$39,000	\$330,000	\$36,000	\$300,000
		3 0.5 lb/klb coke burn (M5)	\$46,000	\$380,000	\$42,000	\$350,000
FCCU	SO ₂	1 Baseline	\$—	\$—	\$—	\$—
		2 25 ppmv ^c	\$19,000	\$160,000	\$17,000	\$140,000
FCCU	NO _x	1 150 ppmv	\$1,100	\$9,100	\$1,000	\$8,200
		2 80 ppmv ^c	\$2,300	\$19,000	\$2,200	\$17,000
		3 20 ppmv	\$4,300	\$34,000	\$3,900	\$31,000
Fluid coker	PM/SO ₂	1 Baseline	\$—	\$—	\$—	\$—
		2 1.0 lb/klb coke burn (M5B or 5F)/25 ppmv ^c	\$110,000	\$890,000	\$97,000	\$810,000
Fluid coker	NO _x	1 Baseline	\$—	\$—	\$—	\$—
		2 80 ppmv ^c	\$540	\$4,300	\$500	\$3,900
		3 20 ppmv	\$980	\$7,900	\$900	\$7,100
Small SRP	SO ₂	1 Baseline	\$—	\$—	\$—	\$—
		2 Less than 20 ltpd @ 99% ^c	\$3,100	\$26,000	\$2,800	\$23,000
		3 All at 250 ppmv	\$3,700	\$32,000	\$3,400	\$29,000
Fuel gas combustion	SO ₂	1 Baseline	\$—	\$—	\$—	\$—
		2 long term limit of 60 ppmv H ₂ S ^c	\$38,000	\$320,000	\$35,000	\$290,000
		3 TRS limits of 160/60 ppm	\$73,000	\$620,000	\$67,000	\$560,000
Process heaters	NO _x	1 80 ppmv >20 MMBtu/hr	\$2,700	\$22,000	\$2,500	\$20,000
		2 40 ppmv >40 MMBt/hr ^c	\$3,000	\$24,000	\$2,700	\$21,000
		3 20 ppmv, 40 MMBtu/hr	\$3,300	\$27,000	\$3,000	\$24,000
Flare gas minimization	SO ₂ /VOC	1 Baseline (no standard)	\$—	\$—	\$—	\$—
		2 RCA >500 lb/day SO ₂	\$470	\$4,000	\$430	\$3,600
		3 Option 2 + Flare minimization ^c	\$550	\$4,700	\$510	\$4,200
		4 Option 2 + No routine flaring	\$580	\$4,900	\$530	\$4,400

(continued)

Table 7-5. Estimated Range of Monetized Benefits in 2012 for All Options of Modified/Reconstructed Process Units (thousands of 2006\$)^a (continued)

Process Unit	Pollutant^b	Option	Total Benefits Low 3% (\$1,000/yr)	Total Benefits High 3% (\$1,000/yr)	Total Benefits Low 7% (\$1,000/yr)	Total Benefits High 7% (\$1,000/yr)
Delayed cokers	SO ₂ /VOC	1 Depressure to control to 15 psig	\$—	\$—	\$—	\$—
		2 Depressure to control to 5 psig ^c	\$2,100	\$18,000	\$1,900	\$16,000
		3 Depressure to control to 2 psig	\$2,700	\$23,000	\$2,500	\$21,000
Sulfur pits	SO ₂	1 Do not include sulfur pits	\$—	\$—	\$—	\$—
		2 Include primary sulfur pits ^c	\$2,200	\$18,000	\$2,000	\$17,000
		3 Include primary pits and secondary tanks	\$2,200	\$19,000	\$2,000	\$17,000

^a All estimates rounded to two significant figures.

^b The PM_{2.5} fraction is estimated at 83.3% of the total PM emissions, and only the reduction in the PM_{2.5} fraction is monetized in this analysis. All fine particles are assumed to have equivalent health effects, but the benefit per ton estimates vary because each ton of precursor reduced has a different propensity to become PM_{2.5}. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

^c This is the selected option.

7.2 Characterization of Uncertainty in the Benefits Estimates

In any complex analysis, there are likely to be many sources of uncertainty. Many inputs are used to derive the final estimate of economic benefits, including emission inventories, air quality models (with their associated parameters and inputs), epidemiological estimates of concentration-response (C-R) functions, estimates of values, population estimates, income estimates, and estimates of the future state of the world (i.e., regulations, technology, and human behavior). For some parameters or inputs it may be possible to provide a statistical representation of the underlying uncertainty distribution. For other parameters or inputs, the necessary information is not available.

The annual benefit estimates presented in this analysis are also inherently variable due to the processes that govern pollutant emissions and ambient air quality in a given year. Factors such as hours of equipment use and weather are constantly variable, regardless of our ability to measure them accurately. As discussed in the PM_{2.5} NAAQS RIA (Table 5.5), there are a variety of uncertainties associated with these PM benefits. Therefore, the estimates of annual benefits should be viewed as representative of the magnitude of benefits expected, rather than the actual benefits that would occur every year.

Above we present the estimates of the total benefits, based on our interpretation of the best available scientific literature and methods and supported by the SAB-HES and the NAS (NRC, 2002). The benefits estimates are subject to a number of assumptions and uncertainties. For example, for key assumptions underlying the estimates for premature mortality, which typically account for at least 90% of the total benefits, we were able to quantify include the following:

1. Inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Although biological mechanisms for this effect have not been established definitively yet, the weight of the available epidemiological evidence supports an assumption of causality.
2. All fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because PM produced via transported precursors emitted from EGUs may differ significantly from direct PM released from diesel engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.
3. The impact function for fine particles is approximately linear within the range of ambient concentrations under consideration. Thus, the estimates include health benefits from reducing fine particles in areas with varied concentrations of PM,

including both regions that are in attainment with fine particle standard and those that do not meet the standard.

4. The forecasts for future emissions and associated air quality modeling are valid. Although recognizing the difficulties, assumptions, and inherent uncertainties in the overall enterprise, these analyses are based on peer-reviewed scientific literature and up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.
5. Benefits estimated here reflect the application of a national dollar benefit-per-ton estimate of the benefits of reducing directly emitted fine particulates from point sources. Because they are based on national-level analysis, the benefit-per-ton estimates used here do not reflect local variability in meteorology, exposure, baseline health incidence rates, or other local factors that might lead to an over-estimate or under-estimate of the actual benefits of controlling directly emitted fine particulates.

This RIA does not include the type of detailed uncertainty assessment found in the PM NAAQS RIA because we lack the necessary air quality input and monitoring data to run the benefits model. Moreover, it was not possible to develop benefit-per-ton metrics and associated estimates of uncertainty using the benefits estimates from the PM RIA because of the significant differences between the sources affected in that rule and those regulated here. However, the results of the Monte Carlo analyses of the health and welfare benefits presented in Chapter 5 of the PM RIA can provide some evidence of the uncertainty surrounding the benefits results presented in this analysis.

7.3 Updating the Benefits Data Underlying the Benefit-per-Ton Estimates

As described above, the estimates provided in Tables 7-1 through 7-5 are derived through a benefits transfer technique that adapts monetized benefits from reductions in PM_{2.5} precursor pollutants that were estimated for the Ozone RIA utilizing nationally distributed emissions reductions. EPA is currently in the process of generating localized benefit-per-ton estimates to better account for the spatial heterogeneity of benefits. EPA believes that these localized estimates may better represent the actual benefits than estimates that use national averages.

7.4 Comparison of Benefits and Costs

EPA estimates the range of annualized benefits of this rulemaking to be a combined \$220 million to \$1.9 billion (\$2006) for new and reconstructed/modified sources at a 3% discount rate and annualized costs calculated at a 7% interest rate as mentioned in Chapter 4 of this RIA for these sources to be \$31 million (\$2006) in the fifth year after proposal (2012). Thus, net benefits are \$190 million to \$1.8 billion in the fifth year after proposal at a 3% discount rate for the benefits. Figure 7-2 shows the full range of net benefits estimates (i.e., annual benefits in 2012

minus annualized costs) utilizing the 14 different PM_{2.5} mortality functions at the 3% discount rate. EPA believes that the benefits are likely to exceed the costs by a substantial margin under this rulemaking even when taking into account uncertainties in the cost and benefit estimates.

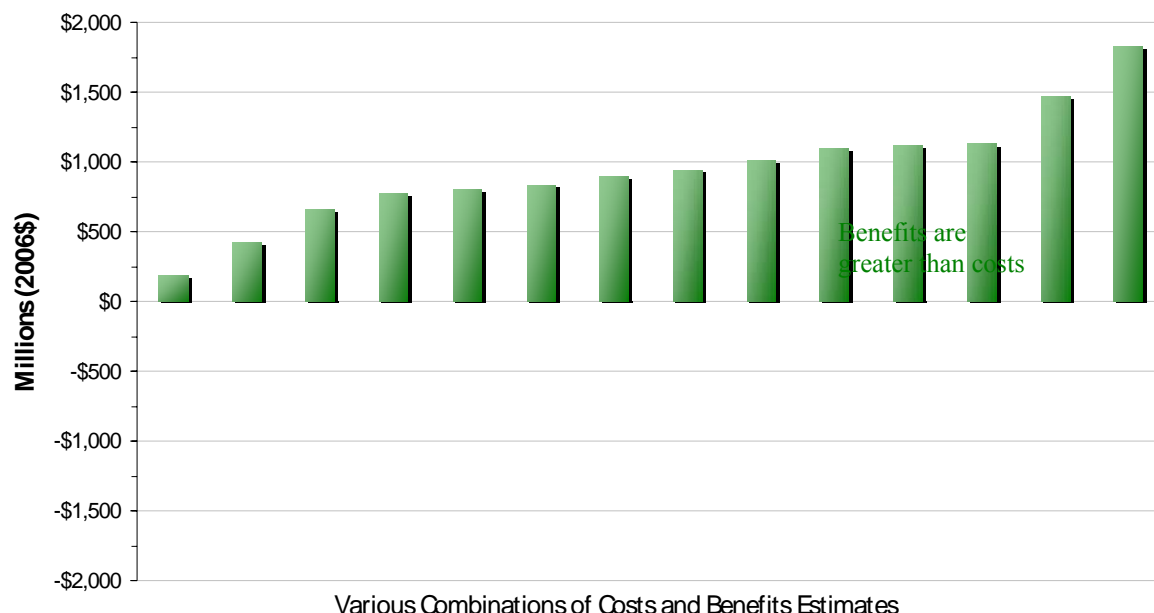


Figure 7-2. Range of Estimated Net Benefits for Selected Options for Final Petroleum Refineries NSPS^a

^a Net Benefits are quantified in terms of PM_{2.5} benefits at a 3% discount rate for the fifth year after proposal. This graph shows 14 benefits estimates combined with the cost estimate. All combinations are treated as independent and equally probable. All fine particles are assumed to have equivalent health effects, but the benefit-per-ton estimates vary because each ton of precursor reduced has a different propensity to become PM_{2.5}. The monetized benefits incorporate the conversion from precursor emissions to ambient fine particles.

7.5 References

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APPENDIX C

OVERVIEW OF ECONOMIC MODEL EQUATIONS

We illustrate our approach for addressing conceptual questions of market-level impacts using a numerical simulation model. Our method involves specifying a set of nonlinear supply and demand relationships for the affected markets, simplifying the equations by transforming them into a set of linear equations, and then solving the equilibrium system of equations (see Fullerton and Metcalfe [2002] for an example).

C.1 Discussion and Specification of Model Equations

First, we consider the formal definition of the elasticity of supply with respect to changes in own price:

$$\epsilon_s = \frac{dQ_s / Q_s}{dp / p} \quad (\text{C.1})$$

Next, we can use “hat” notation to transform Eq. (D.1) to proportional changes and rearrange terms:

$$\hat{Q}_s = \epsilon_s \hat{p} \quad (\text{C.1a})$$

where

$$\begin{aligned} \hat{Q}_s &= \text{percentage change in the quantity of market supply,} \\ \epsilon_s &= \text{market elasticity of supply, and} \\ \hat{p} &= \text{percentage change in market price.} \end{aligned}$$

As Fullerton and Metcalfe (2002) note, we have taken the elasticity definition and turned it into a linear behavioral equation for our market.

To introduce the direct impact of the regulatory program, we assume the per-unit cost associated with the regulatory program (c)¹ leads to a proportional shift in the marginal cost of production. Under the assumption of perfect competition (price equals marginal cost), we can approximate this shift at the initial equilibrium point as follows:

¹The per-unit costs (c) are computed by dividing the total annualized costs reported in by the baseline consumption.

$$\hat{MC} = \frac{c}{MC_o} = \frac{c}{p_o}. \quad (C.1b)$$

The with-regulation supply equation can now be written as

$$\hat{Q}_s = \varepsilon_s (\hat{p} - \hat{MC}) . \quad (C.1c)$$

Next, we can specify a demand equation as follows:

$$\hat{Q}_d = \eta_d \hat{p} \quad (C.2)$$

where

\hat{Q}_d = percentage change in the quantity of market demand,

η_d = market elasticity of demand, and

\hat{p} = percentage change in market price.

Finally, we specify the market equilibrium conditions in the affected markets. In response to the exogenous increase in production costs, producer and consumer behaviors are represented in Eq. (C.1a) and Eq. (C.2), and the new equilibrium satisfies the condition that the change in supply equals the change in demand:

$$\hat{Q}_s = \hat{Q}_d . \quad (C.3)$$

We now have three linear equations in three unknowns (\hat{p} , \hat{Q}_d , and \hat{Q}_s), and we can solve for the proportional price change in terms of the elasticity parameters (ε_s and η_d) and the proportional change in marginal cost:

$$\begin{aligned} \overbrace{\varepsilon_s (\hat{p} - \hat{MC})}^{\hat{Q}_s \text{ (A.1.c)}} &= \overbrace{\eta_d (\hat{p})}^{\hat{Q}_d \text{ (A.2)}} \\ \varepsilon_s \hat{p} - \varepsilon_s \hat{MC} &= \eta_d (\hat{p}) \\ \varepsilon_s \hat{p} - \eta_d (\hat{p}) &= \varepsilon_s \hat{MC} \\ \hat{p} (\varepsilon_s - \eta_d) &= \varepsilon_s \hat{MC} \\ \hat{p} &= \frac{\varepsilon_s}{(\varepsilon_s - \eta_d)} \times \hat{MC} \end{aligned} \quad (C.4)$$

$$\hat{p} = \frac{\varepsilon_s}{\varepsilon_s - \eta_d} \times \hat{MC}. \quad (C.5)$$

Given this solution, we can solve for the proportional change in market quantity using Eq. (C.2).

C.2 Consumer and Producer Welfare Calculations

The change in consumer surplus in the affected markets can be estimated using the following linear approximation method:

$$\Delta CS = -[Q_I \times \Delta p] + [0.5 \times \Delta Q \times \Delta p]. \quad (C.6)$$

As shown, higher market prices and reduced consumption lead to welfare losses for consumers. A geometric representation of this calculation is illustrated in Figure C-1.

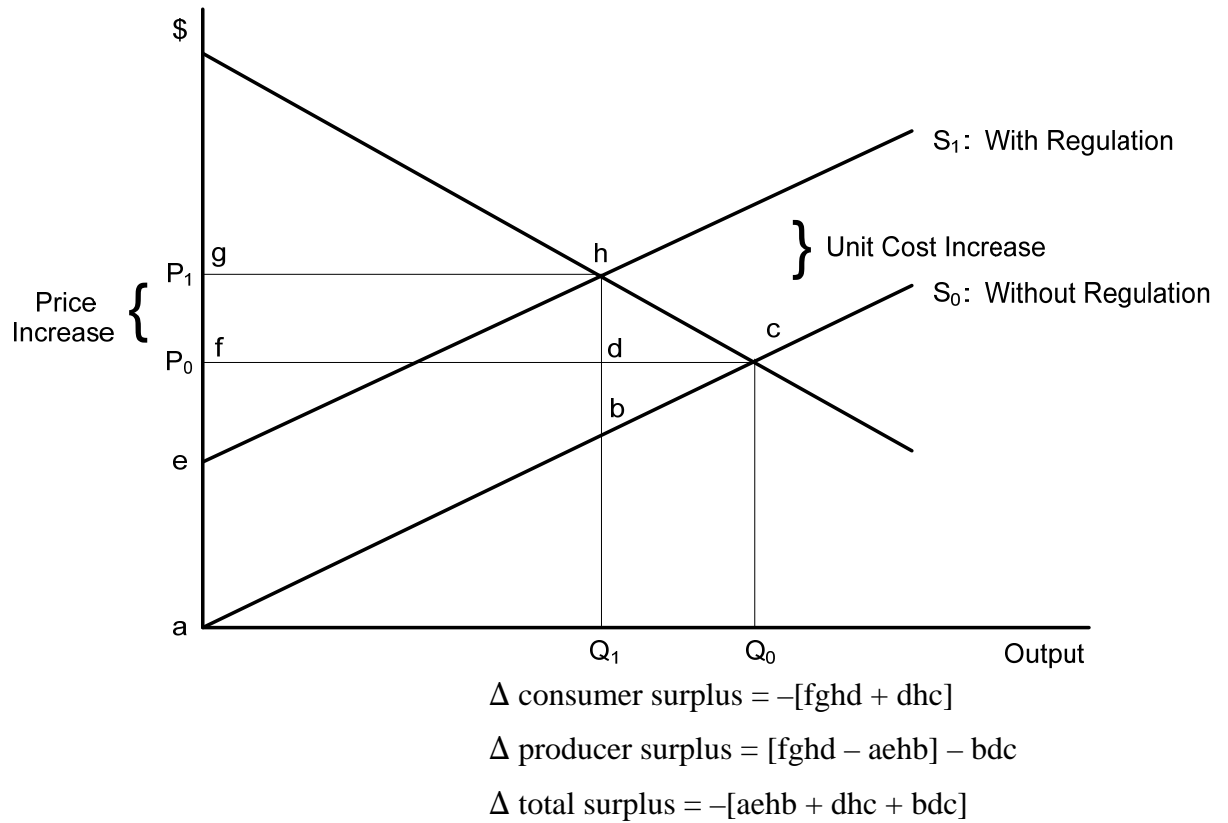


Figure C-1. Welfare Calculations

For affected supply, the change in producer surplus can be estimated with the following equation:

$$\Delta PS = [Q_I \times \Delta p] - [Q_I \times c] - [0.5 \times \Delta Q \times (\Delta p - c)]. \quad (C.7)$$

Increased regulatory costs and output declines have a negative effect on producer surplus, because the net price change ($\Delta p - c$) is negative. However, these losses are mitigated, to some degree, as a result of higher market prices. A geometric representation of this calculation is illustrated in Figure C-1.

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